State of the Market Report for PJM

Volume 2:
Detailed
Analysis

2010

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

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PREFACE

The PJM Market Monitoring Plan provides:

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

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM),[2] and is also known as the Independent Market Monitor for PJM (IMM), submits this *2010 State of the Market Report for PJM*.

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).

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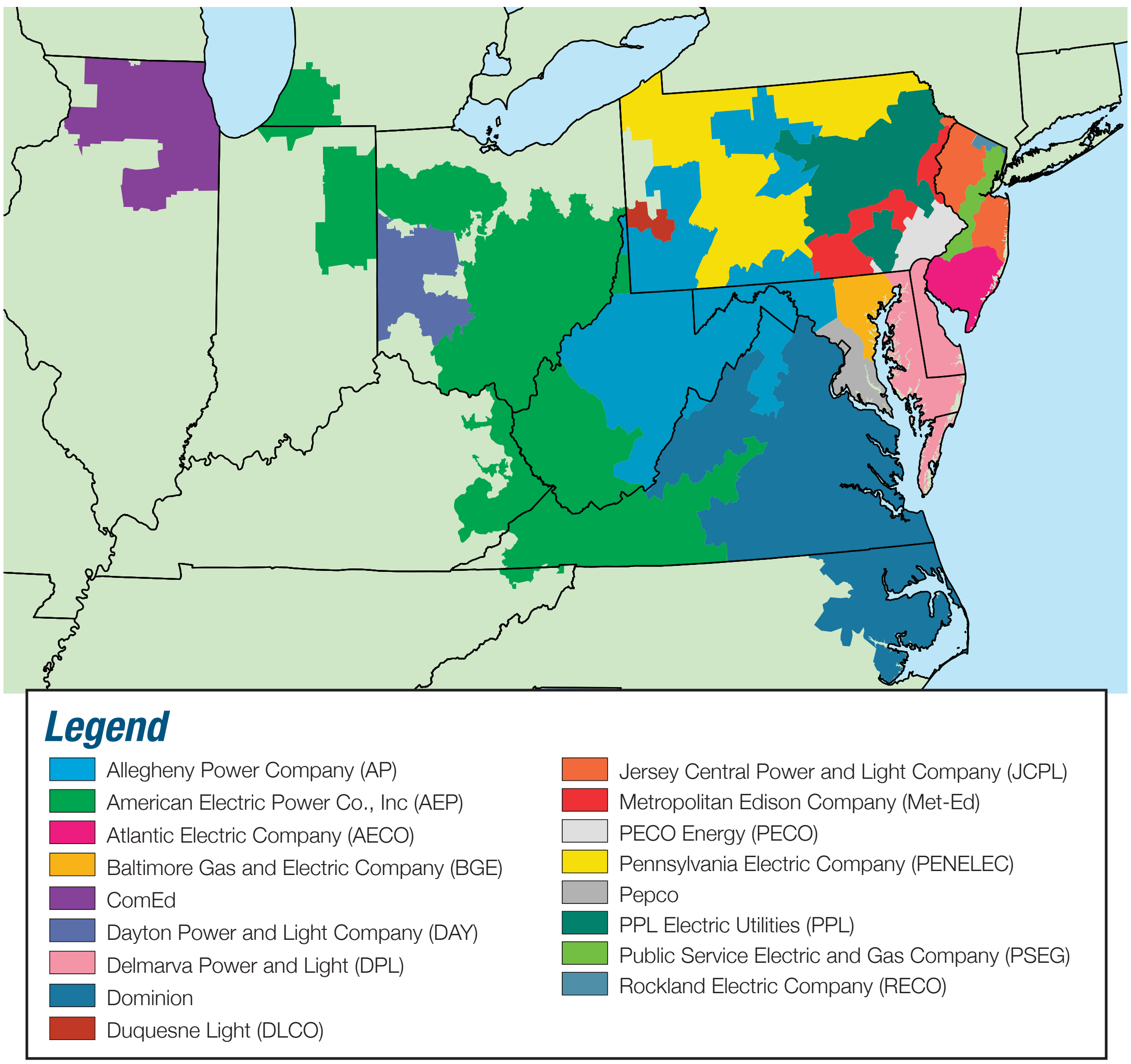
SECTION 1 - INTRODUCTION

The PJM Interconnection, L.L.C. operates a centrally dispatched, competitive wholesale electric power market that, as of December 31, 2010, had installed generating capacity of 166,512 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 2010, PJM had total billings of $34.77 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 in mid-1999. 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 2010 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."

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Conclusions

This report assesses the competitiveness of the markets managed by PJM in 2010, 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, do 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 2010:

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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 2010 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1185 with a minimum of 942 and a maximum of 1599 in 2010.

- 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 both Day-Ahead and Real-Time Energy Markets. In 2010, the markup component of the PJM real-time, load-weighted, average LMP was $0.31 per MWh, or 0.6 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**

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- 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 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 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 73 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

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.

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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 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.

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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 2010 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 in Market Design Recommendations

The PJM Market Monitoring Plan provides under the heading "Monitoring of PJM Market Rules, PJM Tariff and Market Design," in the section setting forth the MMU's function and responsibilities:

> PJM is responsible for proposing for approval by the Commission, consistent with tariff procedures and applicable law, changes to the PJM Market Rules, PJM Tariff and design of the PJM Markets. The Market Monitoring Unit shall evaluate and monitor existing and proposed PJM Market Rules, PJM Tariff provisions, and the design of the PJM Markets. However, if the Market Monitoring Unit detects a design flaw or other problem with the PJM Markets, the Market Monitoring Unit shall not effectuate its proposed market design since that is the responsibility of the Office of the Interconnection. The Market Monitoring Unit may initiate and propose, through the appropriate stakeholder processes, changes to the design of such markets, as well as changes to the PJM Market Rules and PJM Tariff. In support of this function, the Market Monitoring Unit may engage in discussions with stakeholders, State Commissions, PJM Management, or the PJM Board; participate in PJM stakeholder meetings or working groups regarding market design matters; publish proposals, reports or studies on such market design issues; and make filings with the Commission on market design issues. The Market Monitoring Unit may also recommend changes to the PJM Market Rules and PJM Tariff provisions to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[5]

In addition, the PJM Market Monitoring Plan provides, in describing MMU Reports: "In its annual, quarterly and other reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview."[6]

5 OATT Attachment M § IV.D.
6 OATT Attachment M § VI.A.

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,"[7] 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 *2010 State of the Market Report for PJM*, the MMU makes the following summary recommendations. The MMU's detailed recommendations are in the relevant sections of the report.

Energy Market

- The MMU recommends that changes be made to simplify and improve the Emergency Demand Response (DR) program. The MMU recommends that the option to specify a minimum dispatch price under the Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. The MMU also recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the Economic Program. (Page 133)

- The MMU recommends that there be substantial improvement in measurement and verification methods be implemented in order to ensure the credibility of PJM demand-side programs. These could take the form of improvements in the CBL calculation and/or improvements in the verification and customer documentation of load reducing activities. The MMU makes a number of detailed recommendations regarding ways to improve the measurement and verification process for demand response activity. PJM is currently engaged in a pilot study to evaluate measurement and verification methods. (Page 140 and Page 141)

- The MMU recommends resolution of the double counting issue in the Emergency Load Response Program. The double counting issue can be directly resolved by not permitting the overcompliance which results from the interaction between PLC management and the PJM DR Program. A simple way to achieve this result would be to revise Attachment A to PJM Manual 18 (Load Forecasting and Analysis) to cap the baseline for measuring compliance under GLD at the customers' PLC. The MMU recommends action on this issue prior to the 2011/2012 delivery year. (Page 143)

- The MMU recommends that the limits on operational parameters apply to both price and cost-based schedules in order to prevent the exercise of market power. (Page 275)

- The MMU recommends incorporating startup and notification times as additional parameters subject to limits in order to ensure the reliability of the grid, as well as to deter market manipulation by offering artificially lengthy startup and notification time parameters to withhold generation from the market. (Page 275)

- The MMU recommends that renewable energy credit markets be brought into PJM markets as RECs are an increasingly critical component of regulated wholesale energy prices. (Page 224)

7 18 CFR § 35.28(g)(3)(ii)(A); *see also* OATT Attachment M § IV.D.

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Interchange Transactions

- The MMU recommends that PJM modify a number of its transaction related rules to improve market efficiency, reduce operating reserves charges, reduce gaming opportunities and to make the markets more transparent. The MMU recommends changing the not willing to pay congestion product to eliminate uncollected congestions charges, eliminating internal source and sink bus designations for external energy transactions, eliminating or modifying the dispatchable transactions and up to congestion transactions products to reduce or eliminate gaming opportunities associated with the products. (Pages 334, 343 and 347)

- The MMU requests that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Page 327)

- 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. (Pages 301, 313, 320 and 327)

Capacity Markets

- The MMU recommends that the RPM market structure, definitions and rules be modified to improve the efficiency of market prices and to ensure that market prices reflect the forward locational marginal value of capacity. (Pages 357-359 and Page 362)

- The MMU recommends that the obligations of capacity resources be more clearly defined in the market rules. (Pages 357-358 and Page 408)

- The MMU recommends that the performance incentives in the RPM Capacity Market design be strengthened. (Page 360 and Page 361)

- The MMU recommends that the terms of Reliability Must Run (RMR) service be reviewed, refined and standardized. (Page 398)

Ancillary Services

- The Regulation Market design and implementation continue to be flawed and require a detailed review to ensure that the market will produce competitive outcomes. Some of the flaws identified by the MMU were addressed by PJM in 2010, but some remain. The MMU recommends a number of market design changes designed to improve the performance of the Regulation Market, including use of a single clearing price based on actual LMP, modifications to the LOC calculation methodology, a software change to save some data elements necessary for verifying market outcomes, and further documentation of the implementation of the market design through SPREGO. (Page 420 and Page 430)

- The MMU recommends that the single clearing price for synchronized reserves be determined based on the actual LMP. This is consistent with PJM's recommendation on this topic in the scarcity pricing matter. The MMU also recommends that documentation of the Tier 1 synchronized reserve deselection process be published. (Page 420 and Page 462)

- The MMU recommends that the DASR Market rules be modified to incorporate the application of the TPS test in order to address potential market power issues. (Page 420 and Page 465)

- The MMU recommends that PJM, FERC, reliability authorities and state regulators reevaluate the way in which black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market. (Page 420 and Page 469)

Congestion

- The MMU recommends that PJM continue its efforts to find ways to modify the generation and transmission interconnection process to minimize the uncertainty for potential market entrants. (Page 474)

- The MMU recommends that PJM propose modifications to the transmission planning process that would limit significant changes in the status of major transmission projects after they have been approved, and thus limit the uncertainty imposed on markets by the use of evaluation criteria that are very sensitive to changes in forecasts of economic variables. These issues are currently being considered in the PJM stakeholder process. (Page 536)

- The MMU recommends continued efforts to incorporate transmission investments into competitive markets. Transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities, and the lack of existing transmission, can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in an area. (Page 472)

Financial Transmission Rights and Auction Revenue Rights

- The MMU continues to recommend the complete elimination of unsecured credit, over an appropriate transition period, based on the MMU's view of PJM's role in evaluating the credit worthiness of complex corporate entities and due to a concern about inappropriate shifts of risks and costs among PJM members. (Page 550)

- The MMU recommends that when load switches among LSEs during the planning period, a proportional share of the underlying self scheduled FTRs follow the load in the same manner that ARRs do. (Page 539)

- The MMU recommends that PJM provide more comprehensive explanations to members regarding the reasons for FTR underfunding. (Page 539)

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Highlights and New Analysis

The following presents highlights and new analysis from each of the sections of the *2010 State of the Market Report for PJM*:

Section 2, Energy Market, Part 1

- Average offered supply increased by 554 MW, less than one percent, from 153,520 MW in 2009 to 154,074 MW in 2010. (Page 27 and Page 31)

- The PJM system peak load for the summer 2010 was 136,465 MW, which was 9,667 MW, or 7.6 percent, higher than the summer 2009 peak load. (Page 27 and Page 35)

- On average, PJM real-time load increased in 2010 by 4.7 percent from 2009, rising from 76,035 MW to 79,611 MW. PJM day-ahead load increased in 2010 by 2.6 percent from 2009, rising from 88,707 MW to 90,985 MW. The increase in load is consistent with changes in the Temperature-Humidity Index (THI). (Page 28 and Page 31)

- PJM Real-Time Energy Market prices increased in 2010 compared to 2009. The load-weighted average LMP was 23.8 percent higher in 2010 than in 2009, $48.35 per MWh versus $39.05 per MWh. The 2010 real-time, fuel cost adjusted, load-weighted, average LMP was 19.6 percent higher than the 2009 load-weighted, average LMP, $46.70 per MWh versus $39.05 per MWh.[8] In other words, if fuel costs in 2010 were the same as they had been in 2009, the 2010 load-weighted LMP would have been 3.4 percent lower, $46.70 per MWh, than the actual $48.35 per MWh, and 19.6 percent higher than the 2009 load-weighted average LMP. Higher loads and fuel costs contributed to upward pressure on LMP in 2010. (Page 31 and Page 77)

- PJM Day-Ahead Energy Market prices increased in 2010 compared to 2009. The load-weighted LMP was 22.7 percent higher in 2010 than in 2009, $47.65 per MWh versus $38.82 per MWh. (Page 82)

- Analysis of real-time LMP showed that 39.4 percent of the annual, load-weighted LMP was the result of coal costs; 37.5 percent was the result of gas costs and 3.1 percent was the result of the cost of emission allowances. Markup was 0.6 percent of LMP, consistent with a competitive market outcome. (Page 78)

- Levels of offer capping for local market power remained low. In 2010, 1.2 percent of unit hours and 0.4 percent of MW were offer capped in the Real-Time Energy Market and 0.2 percent of unit hours and 0.1 percent of MW were offer capped in the Day-Ahead Energy Market. (Page 27 and Page 41)

- The TPS test is applied whenever incremental relief is needed to solve a transmission constraint, but not all tested providers of effective supply are eligible for capping. Only uncommitted resources, which would be started to solve the constraint, are eligible to be offer capped. Only a small portion of the TPS tests resulted in offer capping. For example, of all the tests applied

8 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.

to the regional 500 kV constraints, no more than seven percent of the tests for any constraint resulted in offer capping. (Page 43 and Page 45)

- The overcollected portion of transmission losses increased in 2010 to $836.6 million or 51.2 percent of the total losses compared to $639.7 million or 50.4 percent of total losses in 2009. (Page 92)

- The total MWh of load reduction under the Economic Program increased by 15,600 MWh, from 57,157 MWh in 2009 to 72,757 MWh in 2010, a 21 percent increase. Total payments under the Economic Program increased by $1.5 million, from $1.4 million in 2009 to $2.9 million in 2010, a 111 percent increase. (Page 122)

- The total MW registered in the Load Management Program increased by 1,758.1 MW, from 7,294.3 MW in 2009 to 9,052.4 MW in 2010, a 24 percent increase. Total payments under the Load Management Program increased by $209 Million or 69 percent, from $303 Million in 2009 to $512 million in 2010. (Page 128)

- Analysis of Load Management emergency event performance for the 2010 summer period shows a bimodal distribution of event days by performance level, with high frequencies of both high and low performing registrations. For any given event, approximately 31 percent of participants showed little or no reduction and 47 percent of participants did not meet half of their committed MW. The large disparity in performance and the proportion of underperforming assets are indicative of over compliance offsetting under performing resources, and consistent with the presence of the double counting issue. (Page 134)

- One way to evaluate the likelihood that a customer has managed their PLC is to compare the PLC to the observed load reduction in real time. For customers that did not manage PLC in prior years, the PLC should reflect unrestricted usage during system peak conditions. It is unlikely that these customers would be able to show a reduction in real time greater than their PLC unless their PLC represented a managed consumption level. GLD participants accounting for 41 percent of total GLD reductions show reductions in real time which are greater than or equal to 100 percent of their PLC. It is reasonable to conclude that such GLD customers did manage their PLCs in the prior year. The results show the extent to which customers with managed PLCs are participating under the GLD option of the Load Management Program, and are consistent with the presence of the double counting problem. (Page 135)

- For the 2010/2011 delivery year, approximately 79 percent of registered sites representing 73 percent of registered MW in the Emergency Full Capacity option submitted a minimum dispatch price of either $999 or $1,000 per MWh. The minimum dispatch price, which is submitted by the participant, acts as a floor for energy compensation during an emergency event. Given the current program rules, market participants have an incentive to submit a minimum dispatch price at the maximum threshold for energy bids of $1,000/MWh. The ability to submit a minimum dispatch price is a guarantee of an energy payment for resources that are already required to curtail, regardless of their minimum dispatch price. (Page 113)

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Section 3, Energy Market, Part 2

- Net revenues increased for all zones from 2009 to 2010 as a result of higher energy revenues, and, in most zones, higher capacity revenues. (Page 163)

- Net revenues in 2010 were greater than or equal to full annual fixed cost recovery in the Pepco and BGE zones for a new entrant CT and less than full annual fixed cost recovery in the other zones. Net revenues in 2010 were greater than or equal to full annual fixed cost recovery in the AECO, BGE, DPL, and Pepco zones for a new entrant CC and less than full annual fixed cost recovery in the other zones. There were no control zones with sufficient net revenue to cover the levelized fixed costs of a new entrant CP in 2010. (Pages 176, 180 and 184)

- Analysis of actual 2010 net revenues shows that capacity market revenues were required to provide supplemental revenue to incent continued operations in PJM for units that do not recover 100 percent of fixed costs through energy market revenue. Such units included CTs, CCs and coal units. (Page 190 and Page 197)

- Analysis of actual 2010 net revenues shows that revenues from energy, ancillary and capacity markets were sufficient to cover avoidable costs for all CC technologies and nearly all CT technologies. (Page 199)

- Analysis of actual 2010 net revenues shows that a number of sub-critical and supercritical coal units did not recover avoidable costs even after capacity revenues were considered. The total installed capacity associated with coal units that did not cover their avoidable costs in 2010 was 6,769 MW, of which, 6,021 MW were located in the MAAC region. These units are considered at risk of retirement. Units accounting for 2,763 MW are recovering less than 65 percent of avoidable costs and units accounting for 4,862 MW are recovering less than 75 percent of avoidable costs. (Page 198 and Page 199)

- Units lacking controls for either NO_x emissions, SO_2 emissions, or both were identified as units at risk of significant capital expenditure on environmental control technologies in response to regulatory mandates. For existing units, project investments associated with environmental controls are avoidable in nature and units facing these investments may be retired if it is not expected that the units will recover investments through a combination of energy or capacity revenue. (Page 200)

- Analysis of actual, unit specific net revenues and avoidable costs for coal plants lacking environmental controls in 2010 found that between 14,345 MW and 19,068 MW of installed capacity, depending on the nature of the requirements, would require an increase in energy or capacity revenue in order to recover avoidable costs including the project investment costs and remain in operation if faced with mandatory investment in environmental controls. (Page 151)

- There were no scarcity pricing events in 2010 under PJM's current Emergency Action based Scarcity Pricing Rules. (Page 230)

- Analysis of net resource levels found there were no reserve shortages in 2010. There were a number of relatively high load days in July, August and September of 2010. (Page 231)

- Operating reserve charges increased 74.6 percent in 2010 compared to 2009. Higher loads, locationally volatile natural gas prices, and increases in outages were the primary causes. Eastern reliability credits increased 9,584.1 percent in 2010 compared to 2009, mainly as a result of units required to operate for a specific transmission outage, and an increase in weather-related alerts. (Page 234)

- Balancing transaction operating reserve credits paid in December 2010 represent 82.9 percent of all balancing transaction operating reserve credits since 2000. (Page 273)

- The concentration of operating reserve credits remains high, but decreased in 2010 compared to 2009. The top 10 units receiving total operating reserve credits, which make up less than one percent of all units in PJM's footprint, received 33.2 percent of total operating reserve credits in 2010, compared to 37.1 percent in 2009. In 2010, the top generation owner received 24.9 percent of the total operating reserve credits paid, a decrease from 2009, when the top generation owner received 32.8 percent of the total operating reserve credits. (Page 262)

- In 2010, coal units provided 49.3 percent, nuclear units 34.6 percent, gas 11.7 percent, oil 0.4 percent, hydroelectric 2.0 percent, waste 0.7 percent and wind 1.2 percent of total generation. Compared to calendar year 2009, generation from coal units increased 3.5 percent, and generation from nuclear units increased 2.1 percent. Generation from natural gas units increased 28.4 percent, and from oil units 106.8 percent. (Page 204)

- At the end of 2010, 76,415 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of approximately 167,000 MW in 2010. Wind projects account for approximately 38,301 MW of capacity or 50.1 percent of the capacity in the queues and combined-cycle projects account for 16,541 MW of capacity or 21.6 percent of the capacity in the queues. (Page 204)

- Many PJM jurisdictions have enacted legislation to require that a defined percentage of utilities' load be served by renewable resources, for which there are many standards and definitions. These are typically known as Renewable Portfolio Standards, or RPS. As of 2010, Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards, ranging from 0.02 percent of all load served in North Carolina, to 7.41 percent of all load served in New Jersey. Virginia has enacted a voluntary renewable portfolio standard. Indiana, Kentucky, and Tennessee have enacted no renewable portfolio standards. (Page 223)

Section 4, Interchange Transactions

- Real-time net exports increased from -1,407 GWh in 2009 to -9,661 GWh in 2010, and Day-ahead net exports decreased from -9,032.5 GWh in 2009 to -6,470.0 GWh in 2010.(Page 287)

- In 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 for a majority of hours in 2010, 58 percent between PJM and the Midwest ISO and 51 percent between PJM and NYISO. (Page 301)

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- System loop flows increased from 2.2 percent for the calendar year 2009 to 5.2 percent for the calendar year 2010. (Page 318)

- PJM initiated fewer TLRs in 2010 (110 TLRs) than in 2009 (129 TLRs). (Page 328)

- The Midwest ISO and PJM filed a settlement agreement resolving all complaints regarding the management of the Joint Operating Agreement. (Page 312)

- The Commission supported an expedited timeline in the Broader Regional Market docket, and ordered interface pricing modifications and the development of a market-to-market congestion management protocol by the second quarter of 2011. (Page 311)

- The Commission conditionally accepted a Congestion Management Protocol between PJM and Progress Energy Carolinas. (Page 315)

- Changes to the marginal loss surplus allocation created opportunities for market participants to submit uneconomic transactions for the sole purpose of receiving an allocation of the marginal loss surplus. Customers entering uneconomic bids profited by $9.6 million after the cost of transmission as a result of the change in the allocation methodology. (Page 342)

- The daily volume of up-to congestion bids increased from approximately 600 bids per day, prior to the September 17, 2010 modification to the up-to congestion product that eliminated the requirement to procure transmission, to approximately 950 bids per day. (Page 277)

- Total uncollected congestion charges for 2010 were $3.3 million, a 379 percent increase from the 2009 total uncollected congestion charges of $688,547. (Page 343)

- Balancing operating reserve credits, allocated to real-time dispatchable import transactions, were approximately $24 million in 2010, an increase from the 2009 total of approximately $91,000. (Page 347)

Section 5, Capacity Markets

- The RTO resource clearing price in the 2010/2011 RPM Base Residual Auction increased $72.25 per MW-day (70.8 percent) from the 2009/2010 RPM Base Residual Auction, and the RTO resource clearing price for the 2010/2011 RPM Third Incremental Auction increased $10.00 per MW-day (25.0 percent) from the 2009/2010 RPM Third Incremental Auction. (Page 386 and Page 387)

- RPM has resulted in new resources. New generation capacity resources (5,986.1 MW), reactivated generation capacity resources (849.7 MW), uprates to existing generation capacity resources (4,905.3 MW), and the net increase in capacity imports (4,126.1 MW) totaled 15,867.2 MW since the implementation of RPM. (Page 366 and Page 368)

- The results of the 2011/2012 and 2012/2013 ATSI Integration Auctions are reported. The integration of the ATSI zone resources added 13,175.2 MW to total internal capacity. The net effect from June 1, 2010, to June 1, 2013, was an increase in total internal capacity of 25,647.3 MW (16.1 percent) from 159,030.9 MW to 184,678.2 MW. (Page 365 and Page 367)

- Capacity in the RPM load management programs increased by 1,783.3 MW from 6,899.7 MW on June 1, 2009 to 8,683.0 MW on June 1, 2010. (Pages 376-378)

- Annual weighted average capacity prices increased from a 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 386 and Page 388)

- Average PJM equivalent demand forced outage rate (EFORd) decreased from 7.6 percent in 2009 to 7.2 percent in 2010. (Page 401)

- The PJM aggregate equivalent availability factor (EAF) decreased from 85.7 percent in 2009 to 84.8 percent in 2010. The equivalent maintenance outage factor (EMOF) increased from 2.8 percent in 2009 to 2.9 percent in 2010, the equivalent planned outage factor (EPOF) increased from 6.7 percent in 2009 to 7.4 percent in 2010, and the equivalent forced outage factor (EFOF) increased from 4.8 percent in 2009 to 4.9 percent in 2010. (Page 400 and Page 401)

Section 6, Ancillary Services

- Regulation prices were 23.3 percent lower in 2010 than in 2009 and lower than in any year since the current Regulation Market structure was introduced in 2005. Regulation total costs per MW were 7.4 percent higher in 2010 than in 2009. The total cost of regulation per MW was 77.4 percent higher than the market clearing price in 2010. The result was a decrease in the ratio of price to cost. With the exception of 2009, the ratio of price to cost has declined in every year since 2005, and the ratio of price to cost is at its lowest level since 2005. (Page 423 and Page 442)

- Total self-scheduled regulation MW in 2010 was 15.5 percent of all regulation, an increase from 10.9 percent in 2009. The supply of eligible regulation increased by two percent in 2010 relative to 2009 levels. (Page 421 and Page 436)

- Synchronized reserve prices were 36.1 percent higher in 2010 than in 2009, but lower than in any other year since 2005. Synchronized reserves total costs per MW were 47.5 percent higher in 2010 than in 2009. The total cost of synchronized reserves per MW was 36.6 percent higher than the market clearing price in 2010. The result was a decrease in the ratio of price to cost. (Page 425 and Page 462)

- Since 2001, the cost of ancillary services per MW of load has been relatively low and stable. (Page 420 and Page 427)

- Of the LSEs' obligation to provide regulation, 82.2 percent was purchased in the spot market, 15.4 percent was self scheduled, and 2.3 percent was purchased bilaterally. (Page 420 and Page 436)

- DASR prices are closely related to energy prices, peaking in the summer months. In 2010, the load weighted price of DASR was $0.16 per MW. In 2009, the load weighted price of DASR was $0.05 per MW. The maximum clearing price was $39.99 per MW in July. (Page 420 and Page 465)

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- Black start zonal charges ranged from $0.03 per MW in DLCO zone to $0.55 per MW in PSEG zone. (Page 420 and Page 466)

Section 7, Congestion

- Congestion costs in 2010 increased by 99 percent over congestion costs in 2009. Despite the increase, total congestion in 2010 was lower than total congestion in every year from 2005, when PJM grew through a series of major integrations, through 2008. (Page 472)

- In 2010, Dominion was the most congested zone. Dominion accounted for nearly 20 percent of the total congestion cost. In 2009, ComEd was the most congested zone, accounting for nearly 30 percent of the total congestion cost. (Page 494)

- Summer high-demand months (May through August) accounted for 45 percent of the total congestion cost in 2010. By contrast, the same period accounted for 26 percent of the total congestion cost in 2009. (Page 480)

- Review of the generation and transmission interconnection process. The generation and transmission interconnection process is complex and time consuming as a result of the nature of the required analyses. (Page 528)

- Review of backbone facilities. 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 531)

Section 8, Financial Transmission Rights and Auction Revenue Rights

- FTRs were paid at 96.9 percent of the target allocation level for the 2009 to 2010 planning period and were paid at 85.2 percent of the target allocation level for the 2010 to 2011 planning period through December 31, 2010. (Page 575)

- The net revenue from the 2011 to 2014 Long Term FTR Auction increased 60 percent ($18.7 million) from the 2010 to 2013 Long Term FTR Auction. In contrast, the net revenue from the 2010 to 2011 Annual FTR Auction decreased 21 percent ($280 million) from the 2009 to 2010 Annual FTR Auction. (Page 542)

- The percent of ARRs self-scheduled as FTRs in the Annual FTR Auction decreased by 8 percent from the 2009 to 2010 planning period, to the 2010 to 2011 planning period. (Page 540)

- The total secondary bilateral FTR obligation market volume increased from 8,810 MW in the 2009 to 2010 planning period to 24,034 MW in the first seven months of the 2010 to 2011 planning period. (Page 559)

- The buy bid prices for 24 hour counter flow FTRs were negative and greater in magnitude than the buy bid prices for prevailing flow FTRs in the 2011 to 2014 Long Term Auction with the result that the total weighted-average cleared price for all 24 hour buy bid FTRs was negative (-$0.16). The weighted-average cleared price for all 24 hour buy bid FTRs in the 2010 to 2013 Long Term Auction was $0.53. (Page 561)

- No ARRs were prorated in Stage 1A and Stage 1B for the 2010 to 2011 planning period. (Page 589)

- FTRs were profitable overall and were profitable for both physical entities and financial entities in 2010. Total FTR profits in 2010 were $909.6 million for physical entities and $138.7 million for financial entities. Self scheduled FTRs account for a large portion of the FTR profits of physical entities. (Page 542)

- On July 23, 2010, PJM reported that it had settled litigation brought against the Tower Companies arising from the default of their affiliate Power Edge, LLC in 2007, in Federal Court and at the FERC.[9] The FERC's investigation of whether manipulation of the FTR markets occurred continues.[10] (Page 540)

9 See FERC Docket No. EL08-44-000 and the Federal Court proceedings in United States District Counts in Delaware and Pennsylvania, DE No. 08-216-JJF and Eastern Dist PA, C.A. No. 08-CV-3649-NS.

10 See 127 FERC ¶ 61,007 at PP 2&5 (2009).

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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, 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 calendar years 2009 and 2010.

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 96.5 percent of the total price per MWh in 2010. The cost of energy was 72.5 percent of the total price per MWh in 2010, the cost of capacity was 18.1 percent and the cost of transmission service was 6.0 percent.

The total per MWh price of wholesale power for 2010, $66.72, was 19.5 percent higher than total per MWh price of wholesale power for 2009, $55.85. This increase in the total price per MWh is largely attributable to the 23.8 percent increase in the price of energy.

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 (AC^2) 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 TrAILCo 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.

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Table 1-7 Total price per MWh by category and total revenues by category: Calendar years 2009 and 2010

Category	Totals ($ Millions) 2009	Totals ($ Millions) 2010	Percent Change Totals	2009 $/MWh	2010 $/MWh	Percent Change $/MWh	2009 Proportion of $/MWh	2010 Proportion of $/MWh	Percent Change in Proportions
Energy	$26,008.22	$33,717.30	29.6%	$39.05	$48.35	23.8%	69.9%	72.5%	3.6%
Capacity	$7,338.36	$8,409.34	14.6%	$11.02	$12.06	9.4%	19.7%	18.1%	(8.4%)
Transmission Service Charges	$2,663.31	$2,786.58	4.6%	$4.00	$4.00	(0.1%)	7.2%	6.0%	(16.4%)
Operating Reserves (Uplift)	$321.83	$547.68	70.2%	$0.48	$0.79	62.5%	0.9%	1.2%	36.0%
Reactive	$242.32	$310.08	28.0%	$0.36	$0.44	22.2%	0.7%	0.7%	2.3%
PJM Administrative Fees	$203.49	$248.02	21.9%	$0.31	$0.36	16.4%	0.5%	0.5%	(2.6%)
Regulation	$228.18	$241.39	5.8%	$0.34	$0.35	1.0%	0.6%	0.5%	(15.4%)
Transmission Enhancement Cost Recovery	$63.21	$139.36	120.5%	$0.09	$0.20	110.6%	0.2%	0.3%	76.2%
Transmssion Owner (Schedule 1A)	$56.47	$61.38	8.7%	$0.08	$0.09	3.8%	0.2%	0.1%	(13.1%)
Synchronized Reserves	$34.27	$43.85	27.9%	$0.05	$0.06	22.2%	0.1%	0.1%	2.3%
NERC/RFC	$8.86	$13.81	56.0%	$0.01	$0.02	49.0%	0.0%	0.0%	24.7%
Black Start	$14.27	$11.45	(19.7%)	$0.02	$0.02	(23.3%)	0.0%	0.0%	(35.8%)
RTO Startup and Expansion	$9.12	$8.99	(1.4%)	$0.01	$0.01	(5.9%)	0.0%	0.0%	(21.2%)
Day Ahead Scheduling Reserve (DASR)	$2.32	$7.37	217.7%	$0.00	$0.01	203.5%	0.0%	0.0%	154.0%
Load Response	$1.35	$3.11	129.9%	$0.00	$0.00	119.6%	0.0%	0.0%	83.8%
Transmission Facility Charges	$1.39	$1.39	(0.4%)	$0.00	$0.00	(4.9%)	0.0%	0.0%	(20.4%)
Total	$37,196.97	$46,530.41	25.1%	$55.85	$66.72	19.5%	100.0%	100.0%	0.0%

Table 1-8 provides the average price by component for 2000 through 2010.

Table 1-8 shows that from 2007 through 2010, Energy, Capacity and Transmission Service Charges were the three largest components of the total price per MWh of wholesale power, contributing more than 96 percent of the total price per MWh on an annual basis in this period. Over the 2000 to 2010 period these three components respresented a minimum of 94.7 percent of the total price per MWh on an annual basis. Of these components, the cost of energy was consistently the largest, making up 69.9 to 91.1 percent of the total price per MWh for the 2000 through 2010 period. The cost of capacity varied between 0.04 percent and 19.73 percent over the same period due to the introduction of the RPM capacity market design in 2007. Transmission Service Charges contributed from 3.9 to 9.1 percent of the total price per MWh on an annual basis for the 2000 through 2010 period.

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Table 1-8 Total price per MWh by category: Calendar Years 2000 through 2010[24]

Category	Totals ($/MWh) 2000	Totals ($/MWh) 2001	Totals ($/MWh) 2002	Totals ($/MWh) 2003	Totals ($/MWh) 2004	Totals ($/MWh) 2005	Totals ($/MWh) 2006	Totals ($/MWh) 2007	Totals ($/MWh) 2008	Totals ($/MWh) 2009	Totals ($/MWh) 2010
Energy	$30.72	$36.65	$31.60	$41.23	$44.34	$63.46	$53.35	$61.66	$71.13	$39.05	$48.35
Capacity	$0.20	$0.32	$0.12	$0.08	$0.09	$0.03	$0.03	$3.97	$8.33	$11.02	$12.06
Transmission Service Charges	$2.17	$3.46	$3.37	$3.56	$3.26	$2.68	$3.15	$3.41	$3.65	$4.00	$4.00
Operating Reserves (Uplift)	$0.57	$1.07	$0.69	$0.86	$0.93	$0.97	$0.45	$0.63	$0.61	$0.48	$0.79
Reactive	$0.15	$0.22	$0.20	$0.24	$0.25	$0.26	$0.29	$0.31	$0.32	$0.36	$0.44
PJM Administrative Fees	$0.15	$0.36	$0.43	$0.54	$0.50	$0.38	$0.40	$0.38	$0.24	$0.31	$0.36
Regulation	$0.30	$0.50	$0.42	$0.50	$0.50	$0.79	$0.53	$0.63	$0.70	$0.34	$0.35
Transmission Enhancement Cost Recovery										$0.09	$0.20
Transmssion Owner (Schedule 1A)	$0.05	$0.08	$0.07	$0.07	$0.11	$0.09	$0.09	$0.09	$0.09	$0.08	$0.09
Synchronized Reserves			$0.11	$0.19	$0.16	$0.15	$0.10	$0.11	$0.09	$0.05	$0.06
NERC/RFC								$0.01	$0.01	$0.01	$0.02
Black Start			$0.00	$0.02	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
RTO Startup and Expansion			$0.04	$0.05	$0.10	$0.37	$0.15	$0.01	$0.01	$0.01	$0.01
Day Ahead Scheduling Reserve (DASR)									$0.00	$0.00	$0.01
Load Response		$0.00	$0.00	$0.00	$0.00	$0.00	$0.03	$0.07	$0.03	$0.00	$0.00
Transmission Facility Charges	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$34.32	$42.66	$37.05	$47.36	$50.25	$69.20	$58.58	$71.30	$85.24	$55.85	$66.72

Table 1-9 Percentage of total price per MWh by category: Calendar years 2000 through 2010[25]

Category	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Energy	89.52%	85.91%	85.29%	87.07%	88.24%	91.70%	91.07%	86.48%	83.45%	69.92%	72.46%
Capacity	0.59%	0.75%	0.33%	0.18%	0.18%	0.04%	0.05%	5.57%	9.77%	19.73%	18.07%
Transmission Service Charges	6.33%	8.11%	9.11%	7.51%	6.48%	3.88%	5.38%	4.78%	4.28%	7.16%	5.99%
Operating Reserves (Uplift)	1.66%	2.51%	1.86%	1.81%	1.85%	1.40%	0.77%	0.88%	0.72%	0.87%	1.18%
Reactive	0.44%	0.52%	0.54%	0.51%	0.50%	0.38%	0.50%	0.43%	0.38%	0.65%	0.67%
PJM Administrative Fees	0.43%	0.84%	1.15%	1.14%	0.99%	0.55%	0.68%	0.54%	0.29%	0.55%	0.53%
Regulation	0.89%	1.16%	1.13%	1.06%	1.00%	1.14%	0.90%	0.88%	0.82%	0.61%	0.52%
Transmission Enhancement Cost Recovery										0.17%	0.30%
Transmssion Owner (Schedule 1A)	0.14%	0.19%	0.18%	0.14%	0.21%	0.13%	0.15%	0.12%	0.10%	0.15%	0.13%
Synchronized Reserves			0.29%	0.40%	0.31%	0.22%	0.17%	0.15%	0.10%	0.09%	0.09%
NERC/RFC								0.01%	0.01%	0.02%	0.03%
Black Start			0.00%	0.03%	0.03%	0.03%	0.04%	0.03%	0.03%	0.04%	0.02%
RTO Startup and Expansion			0.10%	0.10%	0.21%	0.53%	0.25%	0.02%	0.02%	0.02%	0.02%
Day Ahead Scheduling Reserve (DASR)									0.00%	0.01%	0.02%
Load Response		-0.00%	0.00%	0.01%	0.00%	0.00%	0.05%	0.09%	0.03%	0.00%	0.01%
Transmission Facility Charges	0.01%	0.01%	0.01%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

24 Results reflect the fact that data were not available for January through May of 2000 and January of 2002.

25 Results reflect the fact that data were not available for January through May of 2000 and January of 2002.

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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 2010, 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 2010.

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 2010 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1185 with a minimum of 942 and a maximum of 1599 in 2010.

- 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 both Day-Ahead and Real-Time

1 Analysis of 2010 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."

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Energy Markets. In 2010, the markup component of the PJM real-time, load-weighted, average LMP was $0.31 per MWh, or 0.6 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 markup design mitigates market power and causes the market to provide competitive market outcomes.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[2] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs only in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to 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 and New Analysis

- Average offered supply increased by 554 MW, less than one percent, from 153,520 MW in 2009 to 154,074 MW in 2010.

- The PJM system peak load for the summer 2010 was 136,465 MW, which was 9,667 MW, or 7.6 percent, higher than the summer 2009 peak load.

- On average, PJM real-time load increased in 2010 by 4.7 percent from 2009, rising from 76,035 MW to 79,611 MW. PJM day-ahead load increased in 2010 by 2.6 percent from 2009, rising from 88,707 MW to 90,985 MW. The increase in load is consistent with changes in the Temperature-Humidity Index (THI).

- PJM Real-Time Energy Market prices increased in 2010 compared to 2009. The load-weighted average LMP was 23.8 percent higher in 2010 than in 2009, $48.35 per MWh versus $39.05 per MWh. The 2010 real-time, fuel cost adjusted, load-weighted, average LMP was 19.6 percent higher than the 2009 load-weighted, average LMP, $46.70 per MWh versus $39.05 per MWh.[4] In other words, if fuel costs in 2010 were the same as they had been in 2009, the 2010 load-weighted LMP would have been 3.4 percent lower, $46.70 per MWh, than the actual $48.35 per MWh, and 19.6 percent higher than the 2009 load-weighted average LMP. Higher loads and fuel costs contributed to upward pressure on LMP in 2010.

2 OATT Attachment M
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 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.

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- PJM Day-Ahead Energy Market prices increased in 2010 compared to 2009. The load-weighted LMP was 22.7 percent higher in 2010 than in 2009, $47.65 per MWh versus $38.82 per MWh.

- Analysis of real-time LMP showed that 39.4 percent of the annual, load-weighted LMP was the result of coal costs; 37.5 percent was the result of gas costs and 3.1 percent was the result of the cost of emission allowances. Markup was 0.6 percent of LMP, consistent with a competitive market outcome.

- Levels of offer capping for local market power remained low. In 2010, 1.2 percent of unit hours and 0.4 percent of MW were offer capped in the Real-Time Energy Market and 0.2 percent of unit hours and 0.1 percent of MW were offer capped in the Day-Ahead Energy Market.

- The three pivotal supplier test is applied whenever incremental relief is needed to solve a transmission constraint, but not all tested providers of effective supply are eligible for capping. Only uncommitted resources, which would be started to solve the constraint, are eligible to be offer capped. Only a small portion of the TPS tests resulted in offer capping. For example, of all the tests applied to the regional 500 kV constraints, no more than seven percent of the tests for any constraint resulted in offer capping.

- The overcollected portion of transmission losses increased in 2010 to $836.6 million or 51.2 percent of the total losses compared to $639.7 million or 50.4 percent of total losses in 2009.

- The total MWh of load reduction under the Economic Program increased by 15,600 MWh, from 57,157 MWh in 2009 to 72,757 MWh in 2010, a 21 percent increase. Total payments under the Economic Program increased by $1.5 million, from $1.4 million in 2009 to $2.9 million in 2010, a 111 percent increase.

- The total MW registered in the Load Management Program increased by 1,758.1 MW, from 7,294.3 MW in 2009 to 9,052.4 MW in 2010, a 24 percent increase. Total payments under the Load Management Program increased by $209 Million or 69 percent, from $303 Million in 2009 to $512 million in 2010.

- Analysis of Load Management emergency event performance for the 2010 summer period shows a bimodal distribution of event days by performance level, with high frequencies of both high and low performing registrations. For any given event, approximately 31 percent of participants showed little or no reduction and 47 percent of participants did not meet half of their committed MW. The large disparity in performance and the proportion of underperforming assets are indicative of over compliance offsetting under performing resources, and consistent with the presence of the double counting issue.

- One way to evaluate the likelihood that a customer has managed their PLC is to compare the PLC to the observed load reduction in real time. For customers that did not manage PLC in prior years, the PLC should reflect unrestricted usage during system peak conditions. It is unlikely that these customers would be able to show a reduction in real time greater than their PLC unless their PLC represented a managed consumption level. GLD participants accounting for 41 percent of total GLD reductions show reductions in real time which are greater than or equal to 100 percent of their PLC. It is reasonable to conclude that such GLD customers did manage their PLCs in the prior year. The results show the extent to which customers with managed PLCs are participating under the GLD option of the Load Management Program, and are consistent with the presence of the double counting problem.

- For the 2010/2011 delivery year, approximately 79 percent of registered sites representing 73 percent of registered MW in the Emergency Full Capacity option submitted a minimum dispatch price of either $999 or $1,000 per MWh. The minimum dispatch price, which is submitted by the participant, acts as a floor for energy compensation during an emergency event. Given the current program rules, market participants have an incentive to submit a minimum dispatch price at the maximum threshold for energy bids of $1,000/MWh. The ability to submit a minimum dispatch price is a guarantee of an energy payment for resources that are already required to curtail, regardless of their minimum dispatch price.

Summary Recommendations

- The MMU recommends that changes be made to simplify and improve the Emergency Demand Response (DR) program. The MMU recommends that the option to specify a minimum dispatch price under the Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. The MMU also recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the Economic Program.

- The MMU recommends that substantial improvement in measurement and verification methods be implemented in order to ensure the credibility of PJM demand-side programs. These could take the form of improvements in the CBL calculation and/or improvements in the verification and customer documentation of load reducing activities. The MMU makes a number of detailed recommendations regarding ways to improve the measurement and verification process for demand response activity. PJM is currently engaged in a pilot study to evaluate measurement and verification methods.

- The MMU recommends resolution of the double counting issue in the Emergency Load Response Program. The double counting issue can be directly resolved by not permitting the overcompliance which results from the interaction between PLC management and the PJM DR Program. A simple way to achieve this result would be to revise Attachment A to PJM Manual 18 (Load Forecasting and Analysis) to cap the baseline for measuring compliance under GLD at the customers' PLC. The MMU recommends action on this issue prior to the 2011/2012 delivery year.

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Overview

Market Structure

- **Supply.** During the summer months of 2010, the PJM Energy Market received an hourly average of 154,074 MWh in supply offers including hydroelectric generation.[5] The summer months of 2010 average daily offered supply was 554 MWh higher than the summer months of 2009 average daily offered supply of 153,520 MWh.

- **Demand.** The PJM system peak load for the summer months 2010 was 136,465 MW in the hour ended 1700 EPT on July 6, 2010, while the PJM peak load for the summer months 2009 was 126,798 MW in the hour ended 1700 EPT on August 10, 2009.[6] The summer 2010 peak load was 9,667 MW, or 7.6 percent, higher than the summer 2009 peak load.

- **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 and intermediate segments, but high concentration in the peaking segment.

- **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 2010. 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 increased from 0.1 percent in 2009 to 0.2 percent in 2010. In the Real-Time Energy Market offer-capped unit hours increased from 0.4 percent in 2009 to 1.2 percent in 2010.

  On June 9, 2010, PJM replaced Look-Ahead Unit Dispatch Software (LA UDS) with new short run look ahead Security Constrained Economic Dispatch (SCED 2; or IT SCED) optimization software. The three pivotal supplier test (TPS) is now run in SCED 2. Each pass of the SCED 2 software produces multiple security constrained optimization and unit commitment results for anticipated system conditions 15 to 120 minutes into the future. Generally, there is a SCED 2 pass every 15 minutes. The TPS test is calculated for any constraints that require incremental relief in each of the forward market solutions generated by each pass of the SCED 2 software. For example, this means that a SCED 2 pass that produces results for 15, 30, 45 and 120 minutes in the future will have four complete sets of TPS results, one set for each forward market solution.

5 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.

6 For the purpose of the *2010 State of the Market Report for PJM*, 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).

- **Local Market Structure.** In 2010, the AECO, AEP, AP, BGE, ComEd, DLCO, Dominion, DPL, Met-Ed, PENELEC, PPL and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 100 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.[7]

Market Performance: Markup, 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 2010 was $0.31 per MWh, or 0.6 percent. Coal steam units contributed -$0.99 to the total markup component of LMP. Combustion turbine units that use natural gas as their primary fuel source contributed $0.34 to the total markup component of LMP. Combined cycle units that use gas as their primary fuel source contributed $0.77 to the total markup component of LMP. The markup was $1.63 per MWh during peak hours and -$1.11 per MWh during off-peak hours.

  The markup component of the overall PJM day-ahead, load-weighted, average LMP was -$0.60 per MWh, or -1.3 percent. Coal steam units contributed -$0.68 to the total markup component of LMP. Natural gas steam units contributed $0.05 to the total markup component of LMP. The markup was $0.03 per MWh during peak hours and -$1.27 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 increased in 2010 by 4.7 percent from 2009, rising from 76,035 MW to 79,611 MW. PJM day-ahead load increased in 2010 by 2.6 percent from 2009, rising from 88,707 MW to 90,985 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.

7 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.

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PJM Real-Time Energy Market prices increased in 2010 compared to 2009. The system simple average LMP was 20.9 percent higher in 2010 than in 2009, $44.83 per MWh versus $37.08 per MWh. The load-weighted LMP was 23.8 percent higher in 2010 than in 2009, $48.35 per MWh versus $39.05 per MWh. The 2010 real-time, fuel cost adjusted, load-weighted, average LMP[8] was 19.6 percent higher than the 2009 load-weighted, average LMP, $46.70 per MWh versus $39.05 per MWh. In other words, if fuel costs in 2010 were the same as they had been in 2009, the 2010 load-weighted LMP would have been 3.4 percent lower, $46.70 per MWh, than the actual $48.35 per MWh, and 19.6 percent higher than the 2009 load-weighted average LMP. Higher loads and fuel costs contributed to upward pressure on LMP in 2010.

PJM Day-Ahead Energy Market prices increased in 2010 compared to 2009. The system simple average LMP was 20.5 percent higher in 2010 than in the 2009, $44.57 per MWh versus $37.00 per MWh. The load-weighted LMP was 22.7 percent higher in 2010 than in 2009, $47.65 per MWh versus $38.82 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 2010, 4.9 percent of real-time load was supplied by bilateral contracts, 19.3 percent by spot market purchases and 75.8 percent by self-supply. Compared with 2009, reliance on bilateral contracts decreased by 1.1 percentage points; reliance on spot supply increased by 3.2 percentage points; and reliance on self-supply decreased by 2.1 percentage points in 2010.

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.

8 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.

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- **Demand-Side Response Activity.** In 2010, in the Economic Program, participation was more concentrated among a smaller number of participants compared to 2009. Settled MWh and credits were higher in 2010 compared to 2009, which is partially attributable to higher price levels. However, there were generally fewer settlements submitted, fewer registered customers, and fewer active customers compared to the same period in 2009. Participation levels through calendar year 2009 and through the first three months of 2010 were generally lower compared to prior years due to a number of factors, including lower price levels, lower load levels and improved measurement and verification, but have showed strong growth through the summer period as price levels and load levels have increased. On the peak load day for the period 2010 (July 6, 2010), there were 1,725.7 MW registered in the Economic Load Response Program.

  In 2010, in the Emergency Program, specifically the Load Management (LM) Program, participation increased compared to 2009.[9] Participants in the LM Program are committed resources that receive RPM capacity credits and participation continues to increase through RPM delivery years. For the 2010/2011 delivery year, there were 9,052.4 MW registered in the LM Program, compared to 7,294.3 MW registered in the 2009/2010 delivery year.

  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 proportion of customers meeting RPM commitments is substantially lower for these events, less than 50 percent, which implies significant over compliance from a subset of larger customers. Further, the MMU has raised concerns with PJM and stakeholders on the measurement and verification protocols in place to quantify load reductions for the 2010/2011 delivery year and these methods will be under review in calendar year 2011.

  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 2010, Economic Program revenues increased by $1.5 Million or 111 percent, from $1.4 million to $2.9 million. In 2010, Load Management (LM) Program revenues increased by $209 million or 69 percent, from $303 million to $512 million. Synchronized Reserve credits increased by $1.3 million, from approximately $4.0 million to $5.3 million from 2009 to 2010. In 2009, since there were no Load Management Events, no emergency energy revenues were eligible. However, in 2010, there were six Load Management Events resulting in $13.8 million in emergency energy revenues.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in 2010, 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. The next section continues the analysis of the PJM Energy Market including additional measures of market performance.

9 The Capacity Only and Full options of the Emergency Program are integrated into RPM through the Load Management Program. The Energy Only option is a voluntary program that does not interact with RPM, however, there are currently no participants registered in this option.

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Aggregate hourly supply offered increased by about 554 MWh when comparing the summer of 2010 to the summer of 2009, while aggregate peak load increased by 9,667 MW, modifying the general supply demand balance from the summer of 2009 with a corresponding impact on Energy Market prices. Average load in 2010 also increased from 2009, rising from 76,035 MW to 79,611 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.

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.[10]

Energy Market results for 2010 generally reflected supply-demand fundamentals. Higher prices in the Energy Market were the result of higher demand and higher fuel costs. PJM Real-Time, load-weighted, average LMP for 2010 was $48.35, or 23.8 percent higher than the load-weighted, average LMP for 2009, which was $39.05. The 2010 real-time, fuel cost adjusted, load-weighted, average LMP was 19.6 percent higher than the 2009 load-weighted, average LMP, $46.70 per MWh versus $39.05 per MWh. In other words, if fuel costs in 2010 were the same as they had been in 2009, the 2010 load-weighted LMP would have been 3.4 percent lower, $46.70 per MWh, than the actual $48.35 per MWh, and 19.6 percent higher than the 2009 load-weighted average LMP. Higher loads and fuel costs contributed to upward pressure on LMP in 2010.

10 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.

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 2010.

Detailed Recommendations

- The MMU recommends that changes be made to simplify and improve the Emergency Demand Response (DR) program. The MMU recommends that the option to specify a minimum dispatch price under the Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. The MMU also recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the Economic Program.

- The MMU recommends that substantial improvement in measurement and verification methods be implemented in order to ensure the credibility of PJM demand-side programs. These could take the form of improvements in the CBL calculation and/or improvements in the verification and customer documentation of load reducing activities. The MMU makes a number of detailed recommendations regarding ways to improve the measurement and verification process for demand response activity. PJM is currently engaged in a pilot study to evaluate measurement and verification methods.

    - The MMU recommends that the testing program be modified to require verification of test methods and results. Load Management test results are submitted by CSPs directly to PJM. The test results consist of metered load data provided by the CSP which are compared to some baseline consumption level or firm service level determined by LM participation type.[11] There is no physical or technical oversight or verification by PJM or by the relevant LSE of actual testing. PJM screens the data for unreasonable test results, but relies on the CSP to submit accurate metered load data for the testing period with no verification. This form of testing is not an adequate measurement and verification protocol to ensure that demand side capacity resources can reliably reduce during a system emergency.

    - The MMU recommends that the testing program be modified to require verification of test methods and results. In addition, the MMU recommends refinement of the baseline methods used to calculate compliance in Load Management for GLD customers.

    - The MMU recommends that there be substantial improvement in measurement and verification methods be implemented in order to ensure the credibility of PJM demand-side programs. These could take the form of improvements in the CBL calculation and/or improvements in the verification and customer documentation of load reducing activities.

11 PJM filed for changes to the PJM Tariff and Operating Agreement which state that CSPs are responsible for ensuring that all Emergency Load Response Program participants have metering equipment capable of providing hourly integrated metered load data (see Docket ER09-1508-000). These changes were accepted effective September 28, 2009. However, customers in the non-hourly metered pilot submit test results based on DLC measurement and verification procedures. For more information, see PJM Manual 19, "Load Forecasting and Analysis", Revision 15 (October 1, 2009), Attachment B.

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- The MMU recommends that any settlement submitted with a consecutive 24 hour period of CBL greater than metered load should trigger a CBL review by PJM and that a customer should be required to provide documentation of load reduction actions taken, prior to acceptance of such settlements. Further, in order for PJM or the MMU to assess the accuracy of the CBL for a particular customer or for the Program in general, more hourly load data is required than is currently captured by PJM.

- The MMU recommends that any baseline approach that attempts to estimate unrestricted load consumption based on a comparable day or a comparable set of days be adjusted for ambient conditions and other variables impacting load for all participants.

- The MMU recommends that PJM continue to refine baseline methods used to estimate load reductions based on empirical analysis with the intent of adopting the most accurate methods possible.

- The MMU recommends two ways to further improve the Economic Program by increasing the probability that payments are made only for economic and deliberate load reducing activities in response to price. Load reduction in response to price must be clearly defined in the business rules and verified in a transparent daily settlement screen. The four steps in the normal operations review should be routinely applied to all registrations from the beginning of participation. This includes: the ongoing evaluation of whether CBL accurately represents customer load for each customer; analysis of settlements to determine responsiveness to price; the required submission of detailed description of load reduction activities on specific days; and review of the contract.

- The MMU recommends resolution of the double counting issue in the Emergency Load Response Program. The double counting issue can be directly resolved by not permitting the overcompliance which results from the interaction between PLC management and the PJM DR Program. A simple way to achieve this result would be to revise Attachment A to PJM Manual 18 (Load Forecasting and Analysis) to cap the baseline for measuring compliance under GLD at the customers' PLC. The MMU recommends action on this issue prior to the 2011/2012 delivery year.

Market Structure

Supply

During the June to September 2010 summer period, the PJM Energy Market received a daily average of 154,074 MW in total supply offers including hydroelectric generation. The summer 2010 average daily offered supply was 554 MW higher than the summer 2009 average daily offered supply of 153,520 MW.

During the summer of 2010, the peak demand was 9,667 MW, or 7.6 percent, higher than the 2009 peak, which, when combined with the shift up and to the right of the 2010 supply curve, resulted in a higher price level at the intersection of supply and demand (Figure 2-1). The summer 2010 point of

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supply and demand intersection was approximately $116, a 70.6 percent increase over the summer 2009 point of supply and demand intersection of $68.

Supply offer prices for the summer of 2010 were higher than those in 2009 primarily due to an increase in fuel costs in the PJM region. All fuel types experienced price increases for the summer months in 2010 compared to the summer months in 2009, including a 33.7 percent increase in natural gas prices, a 14.9 percent increase in oil prices, and a 19.0 percent increase in coal prices.[12] The net result of these factors was that the summer 2010 average aggregate supply curve shifted up and to the right.

Figure 2-1 Average PJM aggregate supply curves: Summers 2009 and 2010

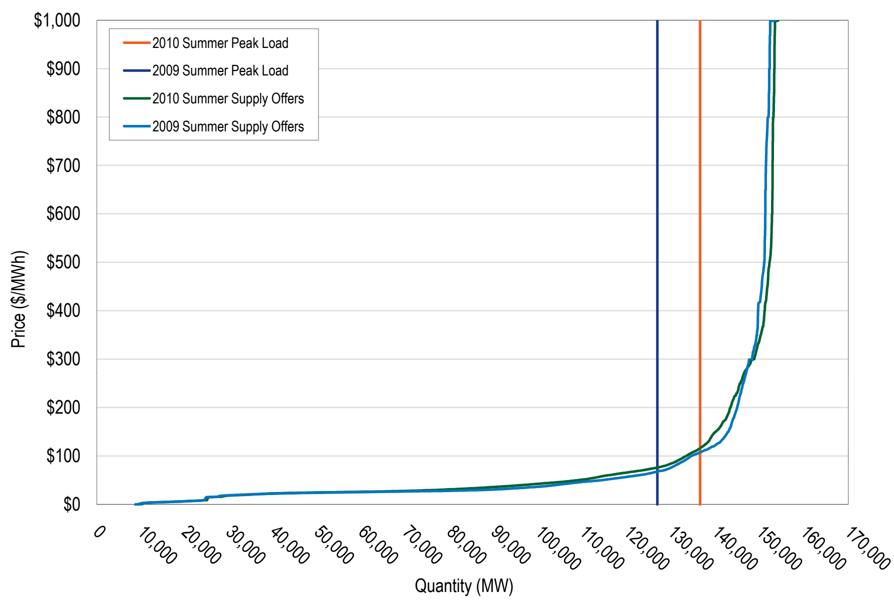

Table 2-2 shows unit deactivations for 2010.[13] A total of 741.0 MW was retired in 2010, including 299.0 MW from Edison Mission Group, 189.0 MW from American Municipal Power-Ohio, Inc., 137.0 MW from Dominion Resources, Inc., 89.0 MW from NRG Energy, Inc., 17.0 MW from City of Vineland, 6.6 MW from Castlebridge Energy Group, LLC, and 3.0 MW from INGENCO. This makes up 714.0 MW of coal, 17.0 MW of heavy oil, 6.6 MW of landfill gas, and 3.0 MW of diesel fuel. Of these retirements, 299.0 MW retired in the ComEd zone, 189.0 MW in the AEP zone, 140.0 MW in the Dominion zone, 89.0 MW in the DPL zone, 17.0 MW in the AECO zone, and 6.6 MW in the PSEG zone.

12 Natural gas, light oil, and heavy oil prices are the average of daily fuel price indices in the PJM footprint. Coal prices are the average of daily fuel prices for 1.2 percent sulfur content Central Appalachian coal and Powder River Basin coal. All fuel prices are from Platts.

13 See PJM Generator Deactivations at <http://pjm.com/planning/generation-retirements/gr-summaries.aspx>.

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Table 2-2 Unit deactivations: Calendar year 2010[15]

Company	Unit Name	ICAP	Primary Fuel	Zone Name	Age (Years)	Retirement Date
NRG Energy Inc	Indian River 2	89.0	Coal	DPL	48	May 01, 2010
Dominion Resources, Inc.	North Branch	74.0	Coal	Dominion	18	Aug 01, 2010
City of Vineland	Howard M. Down (Vineland) Unit 9	17.0	Heavy Oil	AECO	49	Aug 28, 2010
INGENCO	Richmond Plant	3.0	Diesel	Dominion	18	Aug 31, 2010
Dominion Resources, Inc.	Hall Branch (Altavista)	63.0	Coal	Dominion	19	Oct 13, 2010
American Municipal Power-Ohio, Inc.	Gorsuch	189.0	Coal	AEP	59	Nov 11, 2010
Castlebridge Energy Group LLC	Baleville Landfill	3.8	Landfill Gas	PSEG	9	Dec 22, 2010
Castlebridge Energy Group LLC	Kingsland Landfill	2.8	Landfill Gas	PSEG	11	Dec 22, 2010
Edison International	Will County 1	151.0	Coal	ComEd	55	Dec 30, 2010
Edison International	Will County 2	148.0	Coal	ComEd	55	Dec 30, 2010

Total internal capacity increased 1,712.7 MW from 157,318.2 MW on June 1, 2009, to 159,030.9 MW on June 1, 2010. This increase was the result of 406.9 MW of new generation, 165.0 MW that came out of retirement, 1,085.8 MW of net generation capacity modifications (cap mods), and 43.7 MW of demand resource (DR) modifications (mods). The net EFORd effect was 11.3 MW. The EFORd effect is the measure of the net internal capacity change attributable to EFORd changes and not capacity modifications.

Table 2-3 shows the frequency of generator offer prices for 2010, divided into ranges of $200. For example, daily generator offer prices between $0 and $200 in 2010 accounted for 60.8 percent of all daily generator offers in 2010. Of these daily generator offers, 88.6 percent were pool-scheduled for economic dispatch by PJM, 53.9 percent of all offers, while the other 11.4 percent were self-scheduled by the company, 6.9 percent of all offers. Daily generator offer prices above $800 in 2010 accounted for 3.6 percent of all daily generator offers, in which 92.1 percent were pool-scheduled, and the other 7.9 percent self-scheduled.

Table 2-3 Frequency distribution of unit offer prices: Calendar year 2010

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 2-4 shows the actual coincident summer peak loads for the years 1999 through 2010. The 2010 actual summer peak load of 136,465 MW was 9,667 MW more than the 2009 summer peak load of 126,798 MW and was the highest peak demand since 2007, when peak demand reached

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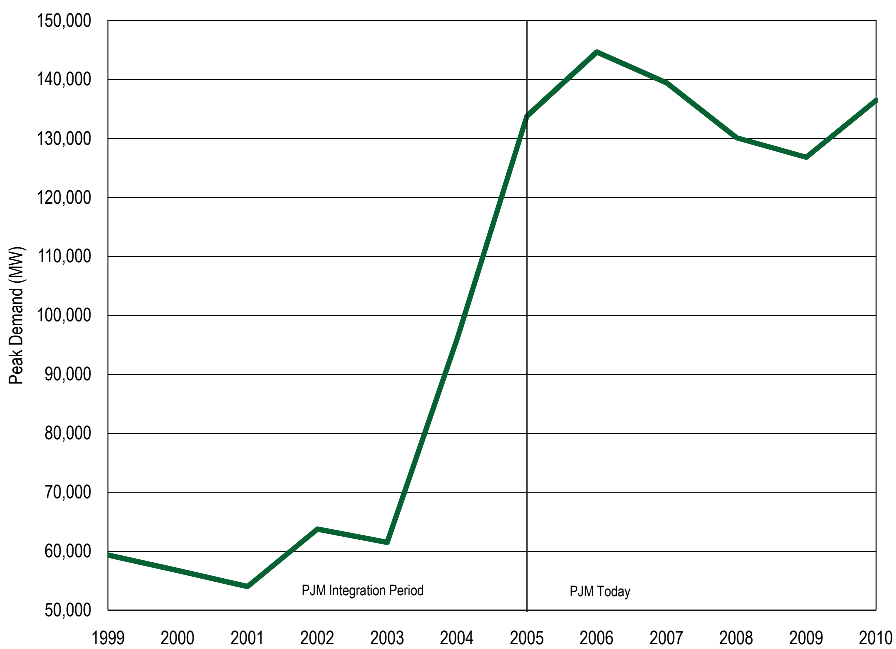
139,428 MW. This measure of peak load is the total amount of generation output and net energy imports required to meet the peak demand on the system, including losses, rather than the actual load served.[14]

Table 2-4 Actual PJM footprint peak loads: 1999 to 2010

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
1999	Tue, July 06	15	59,365	NA	NA
2000	Mon, June 26	17	56,727	(2,638)	(4.4%)
2001	Thu, August 09	16	54,015	(2,712)	(4.8%)
2002	Wed, August 14	17	63,762	9,747	18.0%
2003	Fri, August 22	16	61,499	(2,263)	(3.5%)
2004	Mon, December 20	19	96,016	34,517	56.1%
2005	Tue, July 26	16	133,761	37,746	39.3%
2006	Wed, August 02	17	144,644	10,883	8.1%
2007	Wed, August 08	16	139,428	(5,216)	(3.6%)
2008	Mon, June 09	17	130,100	(9,328)	(6.7%)
2009	Mon, August 10	17	126,798	(3,302)	(2.5%)
2010	Tue, July 06	17	136,465	9,667	7.6%

Figure 2-2 shows the yearly peak loads since 1999.

Figure 2-2 Actual PJM footprint peak loads: 1999 to 2010



14 Peak loads shown are eMTR load. See the *Technical Reference for the PJM Markets*, Section 5, "Load Definitions" for detailed definitions of load.

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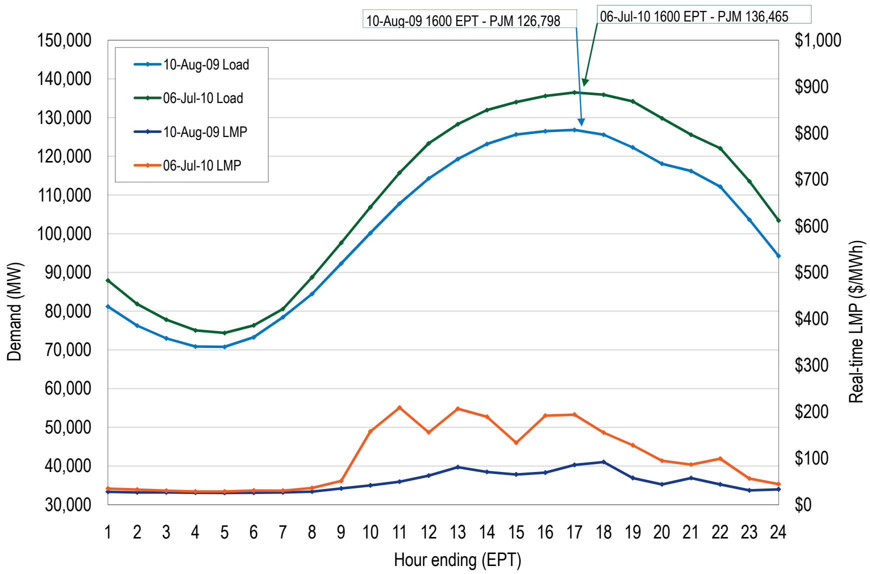
The hourly load and average PJM LMP for the 2010 and 2009 summer peak days are shown in Figure 2-3. The peak for 2010 occurred on July 6, at hour ending 1700. The hourly integrated LMP for this hour was $194.02 per MWh. The peak for 2009 occurred on August 10, at hour ending 1700. The hourly integrated LMP for this hour was $85.64 per MWh.

Figure 2-3 PJM summer peak-load comparison: Tuesday, July 6, 2010, and Monday, August 10, 2009



Market Concentration

During 2010, concentration in the PJM Energy Market was moderate overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.[15] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal during high demand periods. When transmission constraints exist, local markets are created with ownership that is typically significantly more concentrated than the overall Energy Market. PJM offer-capping rules that limit the exercise of local market power and generation owners' obligations to serve load were effective in most cases in preventing the exercise of market power in these areas during 2010. If those obligations were to change or the rules were to change, however, the market power related incentives and impacts would change as a result.

Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate that comparatively small numbers of sellers dominate a market; low concentration ratios mean larger numbers of sellers split market sales more equally. The best tests of market competitiveness are direct tests of the conduct of individual participants and their impact on price. The direct examination of offer behavior by individual market participants is one such test. Low aggregate market concentration ratios establish neither that a market is competitive

15 For the market concentration analysis, supply curve segments are based on a classification of units that generally participate in the PJM Energy Market at varying load levels. Unit class is a primary factor for each classification; however, each unit may have different characteristics that influence the exact segment for which it is classified.

nor that participants are unable to exercise market power. High concentration ratios do, however, indicate an increased potential for participants to exercise market power.

Despite their significant limitations, concentration ratios provide useful information on market structure.[16] The concentration ratio used here is the Herfindahl-Hirschman Index (HHI), calculated by summing the squares of the market shares of all firms in a market. Hourly PJM Energy Market HHIs were calculated based on the real-time energy output of generators, adjusted for hourly net imports by owner (Table 2-5).[17]

Actual net imports and import capability were incorporated in the hourly Energy Market HHI calculations because imports are a source of competition for generation located in PJM. Energy can be imported into PJM under most conditions. The hourly HHI was calculated by combining all export and import transactions from each market participant with its generation output from each hour. A market participant's market share increases with imports and decreases with exports.

Hourly HHIs were also calculated for baseload, intermediate and peaking segments of generation supply. Hourly Energy Market HHIs by supply curve segment were calculated based on hourly Energy Market shares, unadjusted for imports.

The "Merger Policy Statement" of the FERC states that a market can be broadly characterized as:

- **Unconcentrated.** Market HHI below 1000, equivalent to 10 firms with equal market shares;
- **Moderately Concentrated.** Market HHI between 1000 and 1800; and
- **Highly Concentrated.** Market HHI greater than 1800, equivalent to between five and six firms with equal market shares.[18]

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during 2010 was moderately concentrated (Table 2-5). Based on the hourly Energy Market measure, average HHI was 1185 with a minimum of 942 and a maximum of 1599 in 2010. The highest hourly market share was 31 percent and the highest average market share for 2010 was 21 percent.

16 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. 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.

17 See the *2010 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part 1," 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.

18 77 FERC ¶ 61,263, "Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement," Order No. 592, pp. 64-70.

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Table 2-5 PJM hourly Energy Market HHI: Calendar year 2010[19]

	Hourly Market HHI
Average	1185
Minimum	942
Maximum	1599
Highest market share (One hour)	31%
Highest market share (All hours)	21%
# Hours	8,760
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

Table 2-6 includes 2010 HHI values by supply curve segment, including base, intermediate and peaking plants. The hourly measure indicates that, on average, the baseload and intermediate segments of the supply curve are moderately concentrated, while the peaking segment of the supply curve is highly concentrated. Some units classified as peaking units in 2009 were classified as intermediate in 2010, based on their duty cycles in each year.

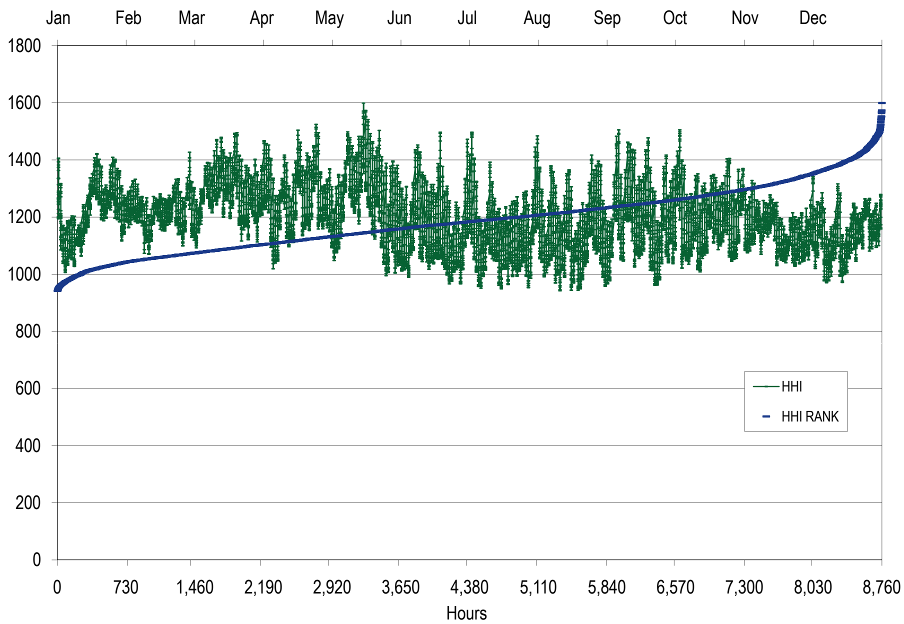
Table 2-6 PJM hourly Energy Market HHI (By segment): Calendar year 2010

	Minimum	Average	Maximum
Base	1064	1235	1553
Intermediate	631	1619	5331
Peak	579	6139	10000

Figure 2-4 presents the 2010 hourly HHI values in chronological order and an HHI duration curve that shows 2010 HHI values in ascending order of magnitude. The HHI values were in the unconcentrated range for 2.8 percent of the hours while HHI values were in the moderately concentrated range in the remaining 97.2 percent of hours, with a maximum value of 1599, as shown in Table 2-5.

19 This analysis includes all hours of 2010, regardless of congestion.

Figure 2-4 PJM hourly Energy Market HHI: Calendar year 2010



Local Market Structure and Offer Capping

In the PJM Energy Market, offer capping occurs only as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets. There are no explicit rules governing market structure or the exercise of market power in the aggregate Energy Market. PJM's market power mitigation goals have focused on market designs that promote competition and that limit market power mitigation to situations where market structure is not competitive and thus where market design alone cannot mitigate market power.

PJM has clear rules limiting the exercise of local market power.[20] The rules provide for offer capping when conditions on the transmission system create a structurally noncompetitive local market (as measured by the three pivotal supplier test), when units in that local market have made noncompetitive offers and when such offers would set the price above the competitive level in the absence of mitigation. Offer caps are set at the level of a competitive offer. Offer-capped units receive the higher of the market price or their offer cap. Thus, if broader market conditions lead to a price greater than the offer cap, the unit receives the higher market price. The rules governing the exercise of local market power recognize that units in certain areas of the system would be in a position to extract monopoly profits, but for these rules. The offer-capping rules exempted certain units from offer capping based on the date of their construction. Such exempt units could, and did, exercise market power, at times, that would not have been permitted if the units had not been exempt. The FERC eliminated the exemption effective May 17, 2008.[21]

20 OA Schedule 1, Section 6.4.2.
21 123 FERC ¶ 61,169 (2008).

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Under existing rules, PJM does not apply offer capping to suppliers when structural market conditions, as measured by the three pivotal supplier test, indicate that such suppliers are reasonably likely to behave in a competitive manner. The goal is to apply a clear rule to limit the exercise of market power by generation owners in load pockets, but to apply the rule in a flexible manner in real time and to lift offer capping when the exercise of market power is unlikely based on the real-time application of the market structure screen.

PJM's three pivotal supplier test represents the practical application of the FERC market power tests in real time.[22] The three pivotal supplier test is passed if no three generation suppliers in a load pocket are jointly pivotal. Stated another way, if the incremental output of the three largest suppliers in a load pocket is removed and enough incremental generation remains available to solve the incremental demand for constraint relief, where the relevant competitive supply includes all incremental MW at a cost less than, or equal, to 1.5 times the clearing price, then offer capping is suspended.

Levels of offer capping have historically been low in PJM, as shown in Table 2-7.

Table 2-7 Annual offer-capping statistics: Calendar years 2006 to 2010

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2006	1.0%	0.2%	0.4%	0.1%
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%

Table 2-8 presents data on the frequency with which units were offer capped in 2010. Table 2-8 shows the number of generating units that met the specified criteria for total offer-capped run hours and percentage of total run hours that were offer-capped for 2010. For example, in 2010, only 12 units were offer-capped for greater than, or equal to, 80 percent of their run hours and had 200 or more offer-capped run hours.

22 See the *Technical Reference for PJM Markets*, Section 8, "Three Pivotal Supplier Test."

Table 2-8 Real-time offer-capped unit statistics: Calendar year 2010

	2010 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%	2	0	0	0	1	13
80% and < 90%	0	2	1	7	8	13
75% and < 80%	0	0	0	0	3	7
70% and < 75%	3	0	0	0	4	13
60% and < 70%	0	1	1	1	0	34
50% and < 60%	1	0	0	5	0	22
25% and < 50%	4	2	4	9	17	41
10% and < 25%	2	0	0	4	2	37

Table 2-8 shows that a small number of units are offer capped for a significant number of hours or for a significant proportion of their run hours. For example, only 49 units (about 3.7 percent of all units) that had offer-capped run hours of at least 200 hours (about 2.3 percent of all hours) in 2010 were offer capped for 10 percent or more of their run hours. Only 17 units (or about 1.3 percent of all units) that had greater than, or equal to, 400 offer-capped run hours were offer capped for 10 percent or more of their run hours.

When compared to the 2009 offer-capped statistics, 52.1 percent of the categories show an increase in the number of units; 33.3 percent of the categories show no change and 14.6 percent of the categories show a decrease in the number of units.[23]

When compared to the 2008 offer-capped statistics, 41.7 percent of the categories show an increase in the number of units; 33.3 percent of the categories show no change and 25.0 percent of the categories show a decrease in the number of units.[24]

Units that are offer capped for greater than, or equal to, 60 percent of their run hours are designated as frequently mitigated units (FMUs). An FMU or units that are associated with the FMU (AUs) are entitled to include adders in their cost-based offers that are a form of local scarcity pricing.

Local Market Structure

In 2010, the AECO, AEP, AP, BGE, ComEd, DLCO, Dominion, DPL, Met-Ed, PENELEC, PPL and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 100 or more hours. Using the three pivotal supplier results for calendar year 2010, actual competitive conditions associated with each of these frequently binding constraints were analyzed in real time.[25]

23 See the *2010 State of the Market Report for PJM*, Volume II, Appendix C, “Energy Market” Table C-23 for 2009 data.
24 See the *2010 State of the Market Report for PJM*, Volume II, Appendix C, “Energy Market” Table C-22 for 2008 data.
25 See the *Technical Reference for PJM Markets,* Section 8,“Three Pivotal Supplier Test” for a more detailed explanation of the three pivotal supplier test.

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The DAY, JCPL, PECO, Pepco and RECO Control Zones were not affected by constraints binding for 100 or more hours.[26]

The three pivotal supplier test is applied by PJM on an ongoing basis in order to determine whether offer capping is required to prevent the exercise of local market power for any constraint.[27]

The MMU analyzed the results of the three pivotal supplier tests conducted by PJM for the Real-Time Energy Market for the period January 1, 2010, through December 31, 2010. The three pivotal supplier test is applied every time the system solution indicates that out of merit resources are needed to relieve a transmission constraint. Only uncommitted resources, which would be started to relieve the transmission constraint, are subject to offer capping. Already committed units that can provide incremental relief cannot be offer capped. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and does not result in offer capping when that is not the case. Local markets are noncompetitive when the number of suppliers is relatively small. The results show that the percentage of tests where one or more suppliers pass the three pivotal supplier test increases as the number of suppliers increases and as the residual supply in the local market increases. The results also show that the percentage of tests where one or more suppliers fail the three pivotal supplier test increases as the number of suppliers decreases and the residual supply in the local market decreases.

Information is provided for each constraint including the number of tests applied, the number of tests that could have resulted in offer capping, and the number of tests in which one or more owners passed and/or failed the three pivotal supplier test.[28] Additional information is provided for each constraint including the average MW required to relieve a constraint, the average supply available, the average number of owners included in each test and the average number of owners that passed or failed each test. In 2010, seven regional 500 kV transmission constraints occurred for more than 100 hours. The Bedington – Black Oak interface constraint and the Harrison – Pruntytown line, along with five interface constraints (5004/5005, Central, East, West and AP South) all experienced more than 100 hours of congestion.[29] The AP South, Central, East and West are the four interfaces for which generation owners were exempt from offer capping prior to May 17, 2008.

Table 2-9 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners.

Table 2-9 shows that most of the tests resulted in one or more owners failing for the AP South interface, the Bedington – Black Oak interface, and the Harrison – Pruntytown line.

26 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.

27 The FERC eliminated the exemption of interfaces effective May 17, 2008. 123 FERC ¶ 61,169 (2008)

28 The three pivotal supplier test in the Real-Time Energy Market is applied by PJM as necessary and may be applied multiple times within a single hour for a specific constraint. Each application of the test is done in a five-minute interval.

29 The 5004/5005 Interface is comprised of two, 500 kV lines, which include the Keystone – Juniata 5004 and the Conemaugh – Juniata 5005. These two lines are located between central and western Pennsylvania.

Table 2-9 Three pivotal supplier results summary for regional constraints: Calendar year 2010

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	6,489	1,745	27%	5,191	80%
	Off Peak	3,242	1,542	48%	1,981	61%
AP South	Peak	13,037	827	6%	12,617	97%
	Off Peak	6,849	684	10%	6,464	94%
Bedington - Black Oak	Peak	4,228	746	18%	4,080	96%
	Off Peak	2,303	555	24%	2,165	94%
Central	Peak	67	35	52%	37	55%
	Off Peak	45	13	29%	35	78%
East	Peak	22	9	41%	16	73%
	Off Peak	37	11	30%	30	81%
Harrison - Pruntytown	Peak	3,343	386	12%	3,129	94%
	Off Peak	3,315	402	12%	3,042	92%
West	Peak	687	489	71%	320	47%
	Off Peak	271	262	97%	22	8%

Table 2-10 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the regional 500 kV constraints.

Table 2-10 Three pivotal supplier test details for regional constraints: Calendar year 2010

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	319	1,760	18	5	13
	Off Peak	220	1,150	16	8	8
AP South	Peak	298	812	8	1	7
	Off Peak	327	800	8	1	7
Bedington - Black Oak	Peak	214	673	10	1	9
	Off Peak	179	732	8	1	7
Central	Peak	401	2,680	19	9	10
	Off Peak	574	3,228	15	5	10
East	Peak	301	2,671	15	7	9
	Off Peak	354	1,836	11	4	8
Harrison - Pruntytown	Peak	417	1,870	16	2	15
	Off Peak	441	1,840	16	2	14
West	Peak	467	2,577	19	12	6
	Off Peak	143	1,055	20	19	1

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The three pivotal supplier test is applied every time the system solution indicates that incremental relief is needed to relieve a transmission constraint. While every system solution that requires incremental relief to transmission constraints will result in a test, not all tested providers of effective supply are eligible for capping. Only uncommitted resources, which would be started as a result of incremental relief needs, are eligible to be offer capped. Already committed units that can provide incremental relief cannot, regardless of test score, be switched from price to cost offers. Table 2-11 provides, for the three regional constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping uncommitted units. Table 2-11 shows that only a small fraction of the tests applied to the regional 500 kV constraints resulted in offer capping. Of all the tests applied to the regional 500 kV constraints, no more than seven percent of the tests for any constraint resulted in offer capping.

Table 2-11 Summary of three pivotal supplier tests applied to uncommitted units for regional constraints: Calendar year 2010

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	6,489	709	11%	349	5%	49%
	Off Peak	3,242	176	5%	38	1%	22%
AP South	Peak	13,037	342	3%	154	1%	45%
	Off Peak	6,849	147	2%	45	1%	31%
Bedington - Black Oak	Peak	4,228	57	1%	26	1%	46%
	Off Peak	2,303	38	2%	6	0%	16%
Central	Peak	67	7	10%	0	0%	0%
	Off Peak	45	12	27%	3	7%	25%
East	Peak	22	4	18%	1	5%	25%
	Off Peak	37	2	5%	0	0%	0%
Harrison - Pruntytown	Peak	3,343	337	10%	151	5%	45%
	Off Peak	3,315	154	5%	70	2%	45%
West	Peak	687	84	12%	15	2%	18%
	Off Peak	271	18	7%	1	0%	6%

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Ownership of Marginal Resources

Table 2-12 shows the contribution to PJM real-time, annual, load-weighted LMP by individual marginal resource owner, utilizing generator sensitivity factors.[30] The contribution of each marginal resource to price at each load bus is calculated for the year and summed by the company that offers the marginal resource into the Real-Time Energy Market. The results show that, during calendar year 2010, the offers of one company contributed 18 percent of the real-time, annual, load-weighted PJM system LMP and that the offers of the top four companies contributed 48 percent of the real-time, annual, load-weighted, average PJM system LMP.

Table 2-12 Marginal unit contribution to PJM real-time, annual, load-weighted LMP (By parent company): Calendar year 2010

Company	Percent of Price
1	18%
2	11%
3	11%
4	9%
5	5%
6	5%
7	4%
8	4%
9	3%
Other (54 companies)	31%

Table 2-13 shows the contribution to PJM day-ahead, annual, load-weighted LMP by individual marginal resource owner, utilizing generator sensitivity factors.[31] The contribution of each marginal resource to price at each load bus is calculated for the year and summed by the company that offers the marginal resource into the Day-Ahead Energy Market. The results show that, during calendar year 2010, the offers of one company contributed 21 percent of the day-ahead, annual, load-weighted PJM system LMP and that the offers of the top four companies contributed 36 percent of the day-ahead, annual, load-weighted, average PJM system LMP.

30 See the *Technical Reference for PJM Markets,* Section 7, "Calculation and Use of Generator Sensitivity/Unit Participation Factors."
31 See the *Technical Reference for PJM Markets,* Section 7, "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

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Table 2-13 Marginal unit contribution to PJM day-ahead, annual, load-weighted LMP (By parent company): Calendar year 2010

Company	Percent of Price
1	21%
2	5%
3	5%
4	5%
5	5%
6	5%
7	5%
8	4%
9	4%
Other (152 companies)	41%

Fuel Type of Marginal Units

Table 2-14 shows the type of fuel used by marginal resources. In 2010, coal units were 68 percent of marginal resources and natural gas units were 26 percent of marginal resources.

Table 2-14 Type of fuel used (By real-time marginal units): Calendar year 2010

Fuel Type	2010
Coal	68%
Gas	26%
Oil	4%
Wind	2%
Municipal Waste	1%

Table 2-15 shows the type of fuel used by marginal resources. In 2010, the transactions that were on the margin accounted for 40 percent of marginal resources and the decrement bids that were on the margin accounted for 27 percent of all marginal resources.

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Table 2-15 Day-ahead marginal resources by type/fuel: Calendar year 2010

Type/Fuel	2010
Transaction	40%
DEC	27%
INC	20%
Coal	9%
Natural gas	3%
Price sensitive demand	1%
Wind	0%
Oil	0%
Municipal waste	0%
Diesel	0%

Market Conduct: Markup

The markup index is a summary measure of participant offer behavior or conduct for individual marginal units. The markup index for each marginal unit is calculated as (Price – Cost)/Price. The markup index is normalized and can vary from -1.00 when the offer price is less than marginal cost, to 1.00 when the offer price is higher than marginal cost. This index calculation method weights the impact of individual unit markups using sensitivity factors, to reflect their relative importance in the system dispatch solution. The markup index does not measure the impact of unit markup on total LMP.

Real-Time Markup Conduct

Table 2-16 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category. A unit is assigned to a price category for each interval in which it was marginal, based on its offer price at that time.

Table 2-16 Average, real-time marginal unit markup index (By price category): Calendar year 2010

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.09)	($2.88)
$25 to $50	(0.06)	($2.44)
$50 to $75	0.03	$1.59
$75 to $100	0.10	$7.86
$100 to $125	0.11	$12.10
$125 to $150	0.13	$17.65
> $150	0.08	$16.69

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Day-Ahead Markup Conduct

Table 2-17 shows the average markup index of marginal units in Day-Ahead Energy Market, by offer price category. A unit is assigned to a price category for each interval in which it was marginal, based on its offer price at that time.

Table 2-17 Average marginal unit markup index (By price category): Calendar year 2010

Price Category	Average Markup Index	Average Dollar Markup
Below $25	(0.11)	($3.13)
$25 to $50	(0.04)	($1.85)
$50 to $75	0.02	$1.29
$75 to $100	0.10	$8.61
$100 to $125	0.00	$0.40
$125 to $150	0.17	$21.98
Above $150	0.21	$42.28

Market Performance

Markup

The markup index, which is a measure of participant conduct for individual marginal units, does not measure the impact of participant behavior on market prices. As an example, if unit A has a $90 cost and a $100 price, while unit B has a $9 cost and a $10 price, both would show a markup of 10 percent, but the price impact of unit A's markup at the generator bus would be $10 while the price impact of unit B's markup at the generator bus would be $1. Depending on each unit's location on the transmission system, those bus-level impacts could also translate to different impacts on total system price.

The MMU calculates the impact on system prices of marginal unit price-cost markup, based on analysis using sensitivity factors. The calculation shows the markup component of price based on a comparison between the price-based offer and the cost-based offer of each actual marginal unit on the system.[32]

The price impact of markup must be interpreted carefully. The markup calculation is not based on a full redispatch of the system to determine the marginal units and their marginal costs that would have occurred if all units had made all offers at marginal cost. Thus the results do not reflect a counterfactual market outcome based on the assumption that all units made all offers at marginal cost. It is important to note that a full redispatch analysis is practically impossible and a limited redispatch analysis would not be dispositive. Nonetheless, such a hypothetical counterfactual analysis would reveal the extent to which the actual system dispatch is less than competitive if it showed a difference between dispatch based on marginal cost and actual dispatch. It is possible

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

that the unit-specific markup, based on a redispatch analysis, would be lower than the markup component of price if the reference point were an inframarginal unit with a lower price and a higher cost than the actual marginal unit. If the actual marginal unit has marginal costs that would cause it to be inframarginal, a new unit would be marginal. If the offer of that new unit were greater than the cost of the original marginal unit, the markup impact would be lower than the MMU measure. If the newly marginal unit is on a price-based schedule, the analysis would have to capture the markup impact of that unit as well.

The MMU calculates an explicit measure of the impact of marginal unit markups on LMP. 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.

Real-Time Markup

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

The markup component of price is the difference between the system price, when the system price is determined by marginal units with price-based offers, and the system price, based on the cost-based offers of those marginal units.

Table 2-18 shows the annual average unit markup index for marginal units, by unit type and primary fuel.

Table 2-18 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: Calendar year 2010

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($0.99)	(319.4%)
Gas	CC	$0.77	248.5%
Gas	CT	$0.34	109.8%
Gas	Diesel	($0.00)	(0.1%)
Gas	Steam	$0.03	9.9%
Interface	Interface	$0.00	0.0%
Municipal Waste	Diesel	$0.00	0.0%
Municipal Waste	Steam	$0.01	2.2%
Oil	CT	$0.02	6.1%
Oil	Diesel	($0.00)	(1.4%)
Oil	Steam	$0.11	36.7%
Uranium	Steam	$0.00	0.0%
Water	Hydro	$0.00	0.0%
Wind	Wind	$0.02	7.7%
Total		$0.31	100.0%

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Markup Component of Real-Time System Price

Table 2-19 shows the markup component of average prices and of average monthly on-peak and off-peak prices. In 2010, $0.31 per MWh of the PJM real-time, load-weighted average LMP was attributable to markup. In 2010, the markup component of LMP was -$1.11 per MWh off peak and $1.63 per MWh on peak.

Table 2-19 Monthly markup components of real-time load-weighted LMP: Calendar year 2010

	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$0.43	($0.22)	$0.97
Feb	($1.74)	($1.54)	($1.94)
Mar	($2.25)	($1.90)	($2.66)
Apr	($2.34)	($2.46)	($2.21)
May	($2.52)	$0.43	($5.28)
Jun	($1.65)	($2.21)	($0.97)
Jul	$6.78	$11.72	$1.59
Aug	$3.08	$6.00	($0.36)
Sep	$0.55	$2.04	($1.18)
Oct	($0.24)	$0.71	($1.21)
Nov	($0.64)	$0.50	($1.80)
Dec	$1.44	$2.78	($0.05)
2010	$0.31	$1.63	($1.11)

Markup Component of Real-Time Zonal Prices

The annual average real-time price component of unit markup is shown for each zone in Table 2-20. The smallest zonal all hours' annual average markup component was in the AEP Control Zone, -$2.26 per MWh, while the highest all hours' annual average zonal markup component was in the BGE Control Zone, $2.39 per MWh. On peak, the smallest annual average zonal markup was in the AEP Control Zone, -$1.94 per MWh, while the highest annual average zonal markup was in the BGE Control Zone, $5.22 per MWh. Off peak, the smallest annual average zonal markup was in the DLCO Control Zone, -$3.16 per MWh, while the highest annual average zonal markup was in the ComEd Control Zone, $0.87 per MWh.

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Table 2-20 Average real-time zonal markup component: Calendar year 2010

	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	$2.33	$5.05	($0.62)
AEP	($2.26)	($1.94)	($2.53)
AP	$0.41	$2.35	($1.61)
BGE	$2.39	$5.22	($0.72)
ComEd	$0.10	($0.51)	$0.87
DAY	($1.96)	($1.49)	($2.43)
DLCO	($1.80)	($0.52)	($3.16)
Dominion	$0.68	$2.32	($1.10)
DPL	$2.18	$4.52	($0.41)
JCPL	$1.98	$4.99	($1.50)
Met-Ed	$1.53	$3.82	($1.04)
PECO	$1.74	$4.15	($0.89)
PENELEC	($0.06)	$1.24	($1.51)
Pepco	$1.45	$3.36	($0.67)
PPL	$1.40	$3.64	($1.14)
PSEG	$1.92	$4.05	($0.46)
RECO	$2.00	$3.91	($0.35)

Markup by Real-Time System Price Levels

The price component measure uses load-weighted, price-based LMP and load-weighted LMP computed using cost-based offers for all marginal units. The markup component of price is computed by calculating the system price, based on the cost-based offers of the marginal units and comparing that to the actual system price to determine how much of the LMP can be attributed to markup.

Table 2-21 shows the average markup component of observed price when the PJM system LMP was in the identified price range.

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Table 2-21 Average real-time markup component (By price category): Calendar year 2010

	Average Markup Component	Frequency
Below $20	($1.66)	2.2%
$20 to $40	($2.92)	56.7%
$40 to $60	($0.48)	25.5%
$60 to $80	$5.72	8.0%
$80 to $100	$2.70	3.4%
$100 to $120	$15.49	1.7%
$120 to $140	$16.14	1.2%
$140 to $160	$26.03	0.6%
Above $160	$41.66	0.8%

Day-Ahead Markup

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

The markup component of the overall PJM day-ahead, load-weighted average LMP by primary fuel and unit type is shown in Table 2-22. The coal steam units accounted for 112.9 percent of the markup component of overall PJM day-ahead, load-weighted average LMP. The natural gas steam units accounted for -8.7 percent.

Table 2-22 Markup component of the overall PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: Calendar year 2010

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($0.68)	112.9%
Diesel	Diesel	($0.00)	0.6%
Municipal waste	Steam	$0.00	(0.0%)
Natural gas	CT	$0.02	(3.5%)
Natural gas	Diesel	($0.00)	0.3%
Natural gas	Steam	$0.05	(8.7%)
Oil	Diesel	($0.00)	0.3%
Oil	Steam	$0.01	(1.7%)
Total		($0.60)	100.0%

Markup Component of Day-Ahead System Price

The markup component of day-ahead price is the difference between the day-ahead system price, when the day-ahead system price is determined by marginal units with price-based offers, and the day-ahead system price, based on the cost-based offers of those marginal units.

Table 2-23 shows the markup component of average prices and of average monthly on-peak and off-peak prices. In 2010, -$0.60 per MWh of the PJM day-ahead, load-weighted average LMP was attributable to markup. In 2010, the markup component of LMP was -$1.27 per MWh off peak and $0.03 per MWh on peak.

Table 2-23 Monthly markup components of day-ahead, load-weighted LMP: Calendar year 2010

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($0.42)	($0.12)	($0.67)
Feb	($0.52)	($0.27)	($0.79)
Mar	($1.46)	($0.92)	($2.10)
Apr	($1.25)	($0.77)	($1.83)
May	($0.73)	($0.11)	($1.31)
Jun	($0.47)	$0.13	($1.20)
Jul	$0.36	$1.49	($0.83)
Aug	($0.16)	$0.87	($1.37)
Sep	($1.16)	($0.54)	($1.89)
Oct	($0.58)	$0.29	($1.47)
Nov	($0.93)	($0.29)	($1.58)
Dec	($0.40)	($0.04)	($0.81)
Annual	($0.60)	$0.03	($1.27)

Markup Component of Day-Ahead Zonal Prices

The annual average price component of unit markup is shown for each zone in Table 2-24. The smallest zonal all hours' markup component was in the DLCO Control Zone, -$1.14 per MWh, while the highest all hours' zonal markup component was in the RECO Control Zone, -$0.17 per MWh. On peak, the smallest zonal markup was in the DLCO Control Zone, -$0.35 per MWh, while the highest markup was in the PECO Control Zone, $0.53 per MWh. Off peak, the smallest zonal markup was in the DAY Control Zone, -$2.05 per MWh, while the highest markup was in the Dominion Control Zone, -$0.80 per MWh.

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Table 2-24 Day-ahead, average, zonal markup component: Calendar year 2010

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($0.36)	$0.38	($1.19)
AEP	($1.08)	($0.25)	($1.96)
AP	($0.73)	($0.07)	($1.42)
BGE	($0.34)	$0.25	($0.98)
ComEd	($0.42)	($0.06)	($0.80)
DAY	($1.13)	($0.30)	($2.05)
DLCO	($1.14)	($0.35)	($2.01)
Dominion	($0.48)	($0.18)	($0.80)
DPL	($0.43)	$0.19	($1.11)
JCPL	($0.31)	$0.48	($1.23)
Met-Ed	($0.43)	$0.26	($1.20)
PECO	($0.27)	$0.53	($1.14)
PENELEC	($0.77)	($0.09)	($1.50)
Pepco	($0.47)	$0.13	($1.12)
PPL	($0.44)	$0.30	($1.27)
PSEG	($0.29)	$0.43	($1.12)
RECO	($0.17)	$0.51	($1.05)

Markup by Day-Ahead System Price Levels

The annual average markup component of the identified price range and its frequency are shown in Table 2-25.

Table 2-25 shows the average markup component of observed price when the PJM day-ahead, system LMP was in the identified price range.

Table 2-25 Average, day-ahead markup (By price category): Calendar year 2010

	Average Markup Component	Frequency
Below $20	($2.85)	0%
$20 to $40	($1.97)	55%
$40 to $60	($0.09)	33%
$60 to $80	$0.45	7%
$80 to $100	$2.09	2%
$100 to $120	$2.00	1%
$120 to $140	$1.22	0%
$140 to $160	$14.28	0%
Above $160	($6.40)	0%

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Frequently Mitigated Unit and Associated Unit Adders

An FMU is a frequently mitigated unit. FMUs were first provided additional compensation as a form of scarcity pricing in 2005.[33] The definition of FMUs provides for a set of graduated adders associated with increasing levels of offer capping. Units capped for 60 percent or more of their run hours and less than 70 percent are entitled to an adder of either 10 percent of their cost-based offer or $20 per MWh. Units capped 70 percent or more of their run hours and less than 80 percent are entitled to an adder of either 15 percent of their cost-based offer (not to exceed $40) or $30 per MWh. Units capped 80 percent or more of their run hours are entitled to an adder of $40 per MWh or the unit-specific, going-forward costs of the affected unit as a cost-based offer.[34] These categories are designated Tier 1, Tier 2 and Tier 3, respectively.[35,36]

An AU, or associated unit, is a unit that is electrically and economically identical to an FMU, but does not qualify for the same adder. For example, if a generating station had two identical units, one of which was offer capped for more than 80 percent of its run hours, that unit would be designated a Tier 3 FMU. If the second unit were capped for 30 percent of its run hours, that unit would be an AU and receive the same Tier 3 adder as the FMU at the site, to ensure that the associated unit is not dispatched in place of the FMU, resulting in no effective adder for the FMU. In the absence of the AU designation, the associated unit would be an FMU after its dispatch and the FMU would be dispatched in its place after losing its FMU designation.

As another example, if a generating station had two identical units, one of which was offer capped for more than 80 percent of its run hours, that unit would be designated a Tier 3 FMU. If the second unit were capped for 72 percent of its run hours, that unit would be eligible for a Tier 2 FMU adder. However, the second unit is an AU to the first unit and would, therefore, be eligible for the higher Tier 3 adder.

FMUs and AUs are designated monthly, where a unit's capping percentage is based on a rolling 12-month average, effective with a one-month lag.[37]

Table 2-26 shows the number of FMUs and AUs in each month of 2010. For example, in December 2010, there were 49 FMUs and AUs in Tier 1, 21 FMUs and AUs in Tier 2, and 65 FMUs and AUs in Tier 3.

33 110 FERC ¶ 61,053 (2005).
34 OA, Schedule 1 § 6.4.2.
35 114 FERC ¶ 61, 076 (2006).
36 See "Settlement Agreement," Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).
37 OA, Schedule 1 § 6.4.2. In 2007, the FERC approved OA revisions to clarify the AU criteria.

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Table 2-26 Frequently mitigated units and associated units (By month): Calendar year 2010

	FMUs and AUs			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
Jan	35	31	27	93
Feb	35	28	31	94
Mar	42	16	44	102
Apr	38	13	47	98
May	35	19	35	89
Jun	29	16	41	86
Jul	21	21	46	88
Aug	25	31	59	115
Sep	34	31	56	121
Oct	55	24	57	136
Nov	44	25	61	130
Dec	49	21	65	135

Table 2-27 shows the number of months FMUs and AUs were eligible for any adder (Tier 1, Tier 2 or Tier 3) during 2010. Of the 176 units eligible in at least one month during 2010, 103 units (59 percent) were FMUs or AUs for more than eight months. Approximately one third of the units (52 units or 30 percent) were eligible every month during the year. In 2009, 61 units out of 186 units or 33 percent of the units were eligible every month during the year. This demonstrates that the group of FMUs and AUs is fairly stable, although units may move between the tier levels, month-to-month.

Table 2-27 Frequently mitigated units and associated units total months eligible: Calendar year 2010

Months Adder-Eligible	FMU & AU Count
1	18
2	1
3	12
4	24
5	19
6	6
7	7
8	16
9	10
10	8
11	3
12	52
Total	176

FMU and AU adders contributed $0.11 per MWh to system average real-time LMP in 2010, out of a real-time, load weighted LMP of $48.35 per MWh.

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Energy Market Opportunity Cost

In examination of the TPS test, FERC found on February 19, 2009 that PJM's mitigation procedures were unjust and unreasonable for failing to include all "legitimate and verifiable" opportunity costs in the determination of mitigated offer prices. The Cost Development Task Force (CDTF), now known as the Cost Development Subcommittee (CDS), has been working on the proposal and method for the calculation of opportunity costs since May 23, 2008. The CDTF and PJM committee process approved a proposal that PJM submitted to FERC on April 22, 2010 in a compliance filing. On October 25, 2010, the Commission issued approval of the PJM proposal. The proposal established a mechanism for determining mitigated offers that include opportunity costs for energy and environmentally-limited resources that are subject to operational limitations imposed by laws or regulations. PJM incorporated a new term to define opportunity costs as Energy Market Opportunity Cost to distinguish it from opportunity costs in the Regulation Market.

Energy market opportunity costs are the value of a foregone opportunity for a generating unit. Opportunity costs may result when a unit has limited run hours due to an externally imposed environmental limit; is requested to operate for a constraint by PJM; and is offer capped. Opportunity costs are the net revenue from a higher price hour that is foregone as a result of running at PJM's request during a lower price hour. The calculated opportunity cost adder applies only to cost based offers and is only relevant when a unit is offer capped for local market power mitigation.

The CDTF developed a calculation method for energy market opportunity costs. The calculation method is designed to calculate the margin (LMP minus cost) for every hour in the projected year. Those margins are the hourly opportunity cost.

For example, a unit is limited to 100 run hours for a year based on an environmental regulation. If the unit is required to run by PJM during a low price hour, it can add an opportunity cost to its cost based offer. The value of that opportunity cost adder is the margin from the 100th highest margin hour for the coming year.

In order to calculate the opportunity cost for each hour of the coming year, LMPs and costs must be estimated for each hour of that year. The calculation method uses published forward curves for the price of electricity at the PJM Western Hub and input fuel prices. The forward energy prices are available by month for PJM's West Hub. The forward fuel prices are available by month or by season or quarter and multiple locations.

It is not possible to have margins for individual units at their specific buses using only forward data. In order to develop margins and therefore opportunity costs for individual units at their specific buses, historical data must be used. The historical relationships between hourly prices at the West Hub and the monthly prices at the West Hub are used as the basis for hourly margins. The historical relationships between individual bus prices and the West Hub price are used as the basis for bus specific margins. The historical relationships between daily real time fuel prices and the forward prices are also used to develop the basis for daily, bus specific margins, together with transportation basis differentials.

The result is an hourly LMP estimate for each generator bus, a daily fuel cost estimate for each generator bus and therefore an hourly margin for each bus. (The net margin also accounts for

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emissions costs, the ten percent adder, VOM and FMU adders.) The hourly LMP and the fuel costs are the result of using the historical ratios multiplied by the forward curve data. The margins which result from comparing these hourly LMP and fuel cost data reflects the forward data, adjusted using historical data, to the specific generator bus. The only purpose of using the historical data is to translate the forward curve data to specific hours and buses.

As of the October 25, 2010, ruling by the Commission, units under energy or regulatory limits imposed by a regulatory agency are able to apply Energy Market Opportunity Costs to cost-based offers. On July 1, 2010, PJM submitted its filing to add non-regulatory opportunity costs, defined to include run hour limitations based on physical equipment limitations derived from original equipment manufacturer recommendations and insurance carrier requirements, and Out of Management Control (OMC) fuel supply limitations. Additionally, on December 30, 2010, PJM submitted a filing to include short term opportunity costs, and to impose mandatory review trigger levels for repeated opportunity cost requests.   The Commission has not yet issued an order.

The filing also includes a provision for a market participant to submit a request to PJM for consideration and approval of an alternate method of calculating Energy Market Opportunity Cost, if the standard methodology does not accurately represent the market participant's Energy Market Opportunity Cost. One market participant included opportunity costs as a component of cost based offers in 2010. As the standard opportunity cost methodology did not reflect the market conditions, unit characteristics, and regulatory limitations of this market participant, the MMU approved an alternate method of calculating Energy Market Opportunity Costs for this participant.

Market Performance: Load and LMP

The PJM system load and LMP reflect the configuration of the entire RTO. The PJM Energy Market includes the Real-Time Energy Market and the Day-Ahead Energy Market.

Load

Real-Time Load

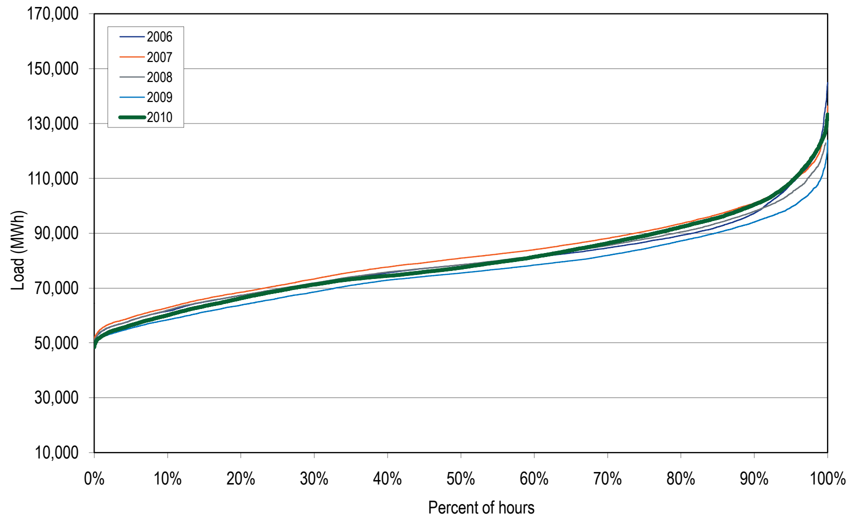
PJM real-time load is the total hourly accounting load in real time.[38]

PJM Real-Time Load Duration

Figure 2-5 shows PJM real-time load duration curves from 2006 to 2010. A load duration curve shows the percent of hours that load was at, or below, a given level for the year.

38 All real-time load data in Section 2, "Energy Market, Part 1," "Market Performance: Load and LMP" are based on PJM accounting load. See the *Technical Reference for PJM Markets,* Section 5, "Load Definitions," for detailed definitions of accounting load.

Figure 2-5 PJM real-time load duration curves: Calendar years 2006 to 2010



PJM Real-Time, Annual Average Load

Table 2-28 presents summary real-time load statistics for the 13-year period 1998 to 2010. The average hourly load of 79,611 MWh in 2010 was 4.7 percent higher than the 2009 annual average hourly load. This average hourly load was based on the PJM hourly accounting load. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load because of the implementation of marginal loss pricing.[39]

Table 2-28 PJM real-time average hourly load: Calendar years 1998 to 2010

	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%

39 Accounting load is used here because PJM uses accounting load in the settlement process, which determines how much load customers pay for. In addition, the use of accounting load with losses before June 1, and without losses after June 1, 2007, is consistent with PJM's calculation of LMP, which excludes losses prior to June 1 and includes losses after June 1.

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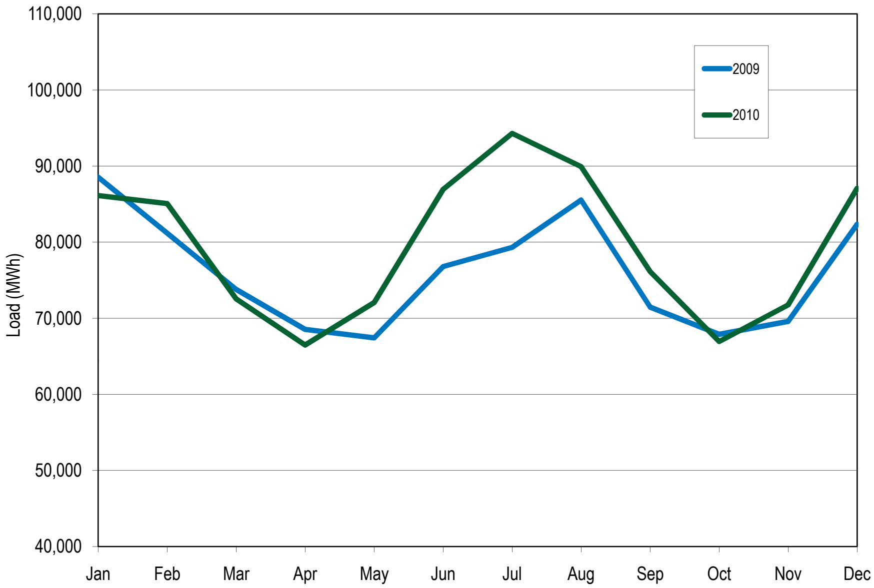
PJM Real-Time, Monthly Average Load

Figure 2-6 compares the real-time, monthly average hourly loads of 2010 with those of 2009.

Figure 2-6 PJM real-time average hourly load: Calendar years 2009 to 2010



PJM real-time load is significantly affected by temperature. PJM uses the Temperature-Humidity Index (THI), the Winter Weather Parameter (WWP) and the average temperature as the weather variables in the PJM load forecast model for different seasons.[40] THI is a measure of effective temperature using temperature and relative humidity for the cooling season (June, July and August).[41] Table 2-29 shows the monthly minimum, average and maximum of the PJM hourly THI for the cooling months in 2009 and 2010. When comparing 2010 to 2009, changes in THI were consistent with the changes in load. For the cooling months of 2010, the average THI was 73.02, 4.6 percent higher than the average 69.64 THI for 2009. The maximum THI (83.83) and minimum THI (56.02) in 2010 were 3.6 percent higher and 6.1 percent higher, respectively, than the maximum THI (80.82) and minimum THI (52.61) in 2009 during the cooling months.

Table 2-29 Monthly minimum, average and maximum of PJM hourly THI: Cooling periods of 2009 and 2010

	2009			2010			Difference		
	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max
Jun	52.61	67.83	77.92	56.02	71.64	81.12	6.5%	5.6%	4.1%
Jul	58.57	69.48	78.10	57.22	74.45	83.83	(2.3%)	7.2%	7.3%
Aug	57.21	71.57	80.82	59.15	72.93	81.41	3.4%	1.9%	0.7%

40 The weather stations that provided basis for the analysis are ABE, ACY, AVP, BWI, CMH, CRW, DAY, DCA, ERI, EWR, IAD, IPT, ORD, ORF, PHL, PIT and RIC.

41 Temperature and relative humidity data that were used to calculate THI were obtained from Telvent DTN. PJM hourly THI is the weighted-average zonal hourly THI weighted by average, annual peak zonal share (Coincident Factor) from 1998 to the year for which the calculation is made. For additional information on THI calculations, see PJM. "Manual 19: Load Forecasting and Analysis," Revision 15 (October 1, 2009), Section 3, pp. 9-10.

WWP is the wind-adjusted temperature for the heating season (January, February and December). The average temperatures are used for the months not covered by the THI or WWP. Table 2-30 shows the average THI, WWP and temperature for heating, cooling and shoulder seasons.[42]

Table 2-30 PJM average Summer THI, Winter WWP and temperature: cooling, heating and shoulder months of 2006 through 2010

	Summer THI	Winter WWP	Shoulder Average Temperature
2006	75.59	31.67	54.62
2007	75.45	27.10	56.55
2008	75.35	27.52	54.10
2009	74.23	25.56	55.09
2010	77.36	24.47	60.07

Day-Ahead Load

In the PJM Day-Ahead Energy Market, three types of financially binding demand bids are made and cleared:

- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero. A decrement bid is a financial bid that can be submitted by any market participant.

PJM day-ahead load is the hourly total of the above three types of cleared demand bids.

42 The Summer THI is calculated by taking average of daily maximum THI in June, July and August. The Winter WWP is calculated by taking average of daily minimum WWP in January, February and December. Average temperature is used for the rest of months. For additional information on the calculation of these weather variables, see PJM "Manual 19: Load Forecasting and Analysis," Revision 15 (October 1, 2009), Section 3, pp. 16. Load weighting using real-time zonal accounting load.

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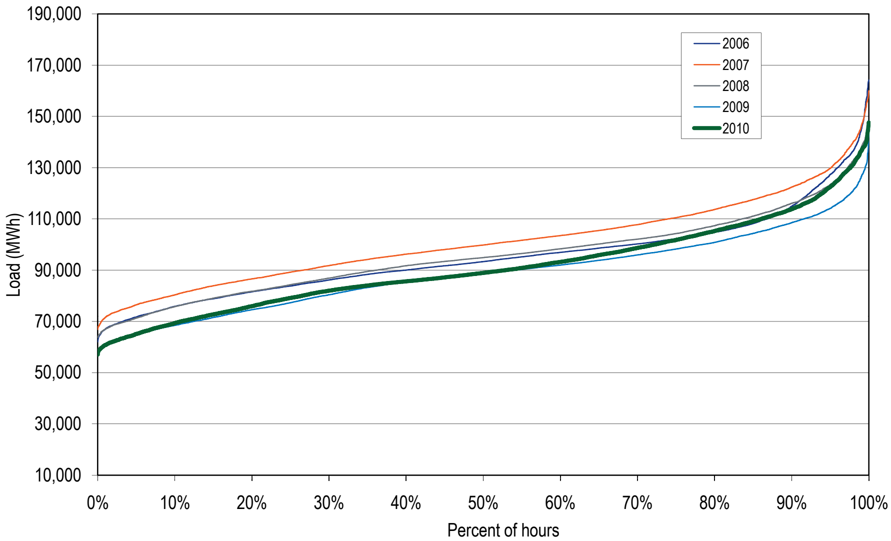
PJM Day-Ahead Load Duration

Figure 2-7 shows PJM day-ahead load duration curves from 2006 to 2010.

Figure 2-7 PJM day-ahead load duration curves: Calendar years 2006 to 2010



PJM Day-Ahead, Annual Average Load

Table 2-31 presents summary day-ahead load statistics for the 11 year period 2000 to 2010. The average load of 90,985 MWh in 2010 was 2.6 percent higher than the 2009 annual average load. The cleared fixed demand accounted for 81.2 percent, the cleared decrement bids accounted for 17.6 percent and the cleared price sensitive demand accounted for 1.3 percent of average load in 2010. The cleared decrement bids were 5.7 percent higher than in 2009, fixed demand in 2010 was 2.5 percent higher than in 2009 and price-sensitive demand in 2010 was 24.0 percent lower than in 2009. The cleared decrement bids in 2010 increased to 15,933 MWh from 15,136 MWh in 2009, the cleared fixed demand in 2010 increased to 73,853 MWh from 72,073 MWh, and the price-sensitive demand in 2010 dropped to 1,139 MWh from 1,498 MWh in 2009.

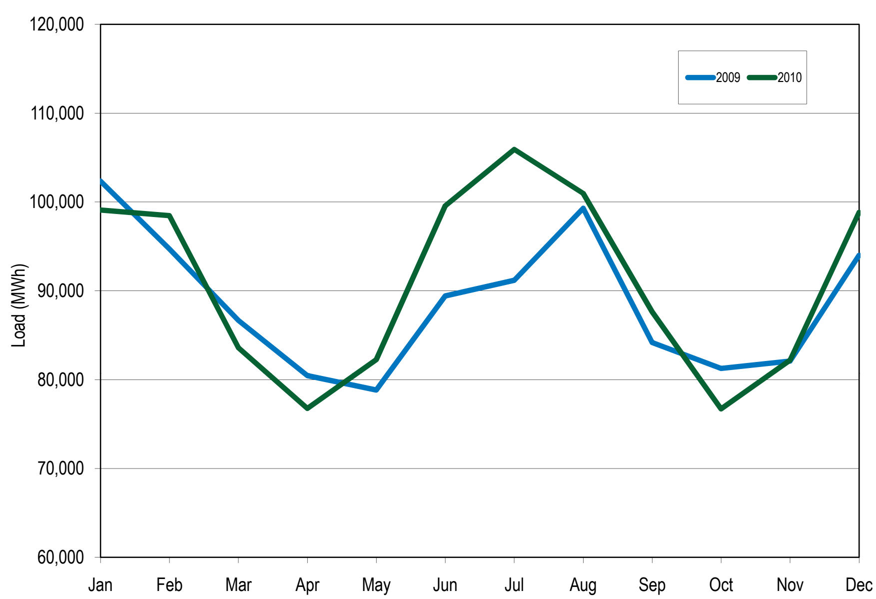
Table 2-31 PJM day-ahead average load: Calendar years 2000 to 2010

	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%

PJM Day-Ahead, Monthly Average Load

Figure 2-8 compares the day-ahead, monthly average loads of 2010 with those of 2009.

Figure 2-8 PJM day-ahead average load: Calendar years 2009 to 2010



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Real-Time and Day-Ahead Load

Table 2-32 presents summary statistics for the 2010 day-ahead and real-time loads and the average difference between them. The sum of day-ahead cleared fixed demand and price-sensitive demand averaged 4,619 MWh less than real-time average load. Total day-ahead load (including decrement bids) averaged 11,374 MWh more than real-time load. Table 2-32 shows that, at 81.2 percent, fixed demand was the largest component of day-ahead load. At 1.3 percent, price-sensitive load was the smallest component, with cleared decrement bids accounting for the remaining 17.6 percent of day-ahead load.

Table 2-32 Cleared day-ahead and real-time load (MWh): Calendar year 2010

	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	73,853	1,139	15,993	90,985	79,611	11,374	(4,619)
Median	71,824	1,030	15,850	88,925	77,430	11,496	(4,354)
Standard deviation	14,558	474	2,572	17,014	15,504	1,510	(1,062)
Peak average	82,017	1,320	17,360	100,697	88,066	12,631	(4,729)
Peak median	79,743	1,199	17,249	98,160	85,435	12,725	(4,524)
Peak standard deviation	12,820	487	2,123	14,666	13,753	913	(1,210)
Off peak average	66,682	981	14,792	82,455	72,186	10,269	(4,523)
Off peak median	64,834	893	14,601	80,629	70,318	10,311	(4,291)
Off peak standard deviation	11,991	402	2,320	14,116	12,942	1,174	(1,146)

Figure 2-9 shows the average 2010 hourly cleared volumes of fixed-demand bids, the sum of cleared fixed-demand and price-sensitive bids, total day-ahead load and real-time load. In 2010, real-time, hourly average load was higher than cleared fixed-demand load plus cleared price-sensitive load in the Day-Ahead Energy Market, although the reverse was true for 0.7 percent of the hours. When cleared decrement bids are included, day-ahead load always exceeded real-time load.

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Figure 2-9 Day-ahead and real-time loads (Average hourly volumes): Calendar year 2010

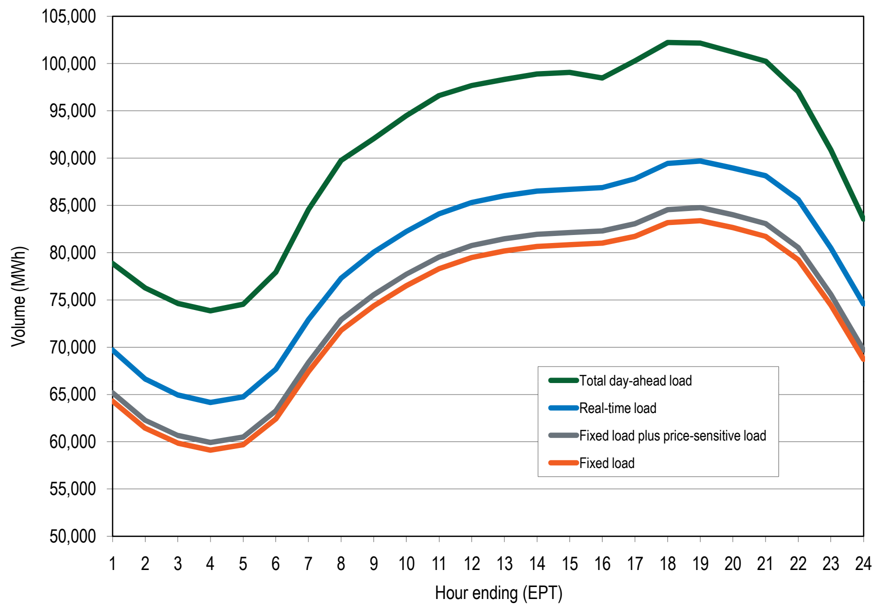
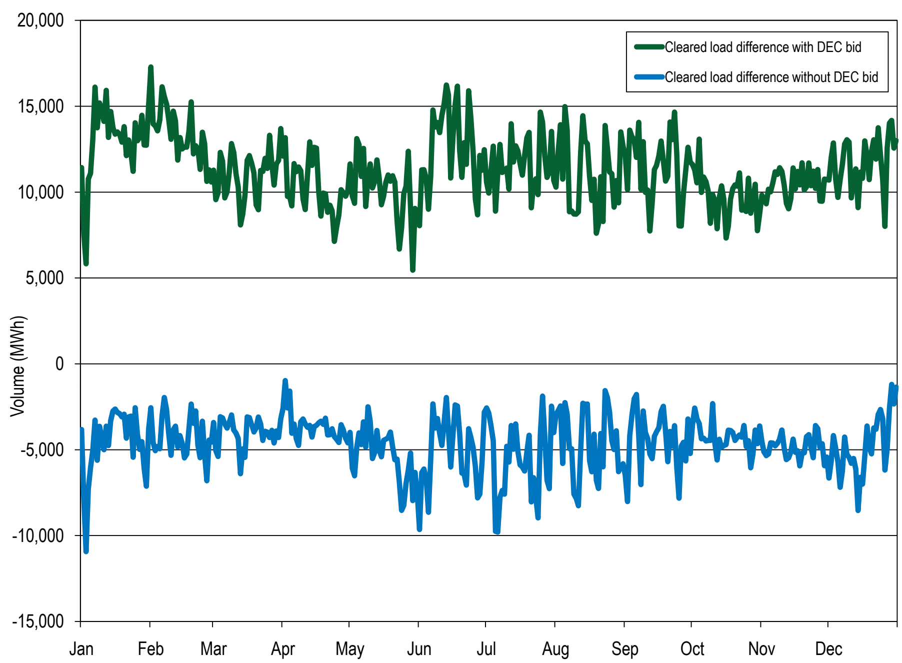


Figure 2-10 Difference between day-ahead and real-time loads (Average daily volumes): Calendar year 2010



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Real-Time and Day-Ahead Generation

Real-time generation is the actual production of electricity during the operating day.

In the Day-Ahead Energy Market, three types of financially binding generation offers are made and cleared:[43]

- **Self-Scheduled.** Offer to supply a fixed block of MWh that must run from a specific unit, or as a minimum amount of MWh that must run on a specific unit that also has a dispatchable component above the minimum.[44]

- **Generator Offer.** Offer to supply a schedule of MWh from a specific unit and the corresponding offer prices.

- **Increment Offer (INC).** Financial offer to supply specified MWh at, or above, a given price. An increment offer is a financial offer that can be submitted by any market participant.

Table 2-33 presents summary statistics for 2010 day-ahead and real-time generation and the average differences between them. Day-ahead cleared generation from physical units averaged 527 MWh higher than real-time generation. Day-ahead cleared generation plus cleared INC offers averaged 11,770 MWh more than real-time generation. Table 2-33 also shows that cleared generation and INC offers accounted for 88.1 percent and 11.9 percent of day-ahead supply, respectively.

Table 2-33 Day-ahead and real-time generation (MWh): Calendar year 2010

	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	83,112	11,243	94,355	82,585	527	11,770
Median	81,197	11,128	92,289	80,623	573	11,666
Standard deviation	16,715	1,555	17,349	15,556	1,158	1,793
Peak average	92,259	11,994	104,253	90,869	1,390	13,384
Peak median	89,688	11,886	101,694	88,351	1,337	13,343
Peak standard deviation	14,367	1,460	14,915	13,808	559	1,107
Off peak average	75,079	10,584	85,662	75,310	(231)	10,352
Off peak median	73,483	10,564	83,736	73,431	52	10,306
Off peak standard deviation	14,335	1,320	14,436	13,188	1,146	1,248

Figure 2-11 shows average hourly cleared volumes of day-ahead generation, day-ahead generation plus increment offers and real-time generation for 2010.[45] Day-ahead generation is all the self-scheduled and generator offers cleared in the Day-Ahead Energy Market. Real-time hourly average generation was lower than day-ahead generation from physical units 58.7 percent of the hours in

43 All references to day-ahead generation and increment offers are presented in cleared MWh in the "Real-Time and Day-Ahead Generation" portion of the *2010 State of the Market Report for PJM,* Volume II, Section 2, "Energy Market, Part 1."

44 The definition of self-scheduled is based on documentation from PJM. "eMKT User Guide" (December 1, 2008), pp. 50-52.

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

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2010. Overall, day-ahead generation from physical units was higher than real-time generation on an hourly average basis. However, on an hourly average basis, real-time generation did exceed day-ahead generation from physical units between hours ending 1 and 6, and during hours ending 23 and 24. When cleared increment offers are included, average hourly total day-ahead cleared MW offers exceeded real-time generation.

Figure 2-11 Day-ahead and real-time generation (Average hourly volumes): Calendar year 2010

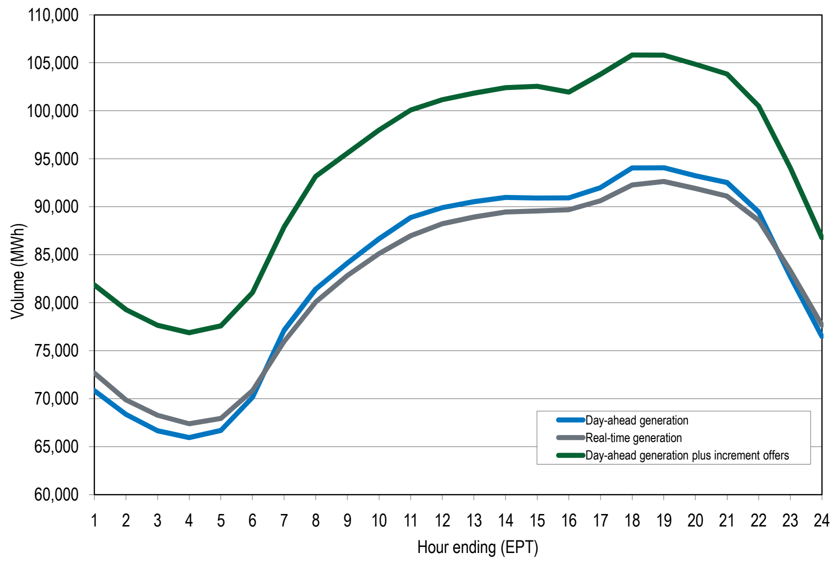
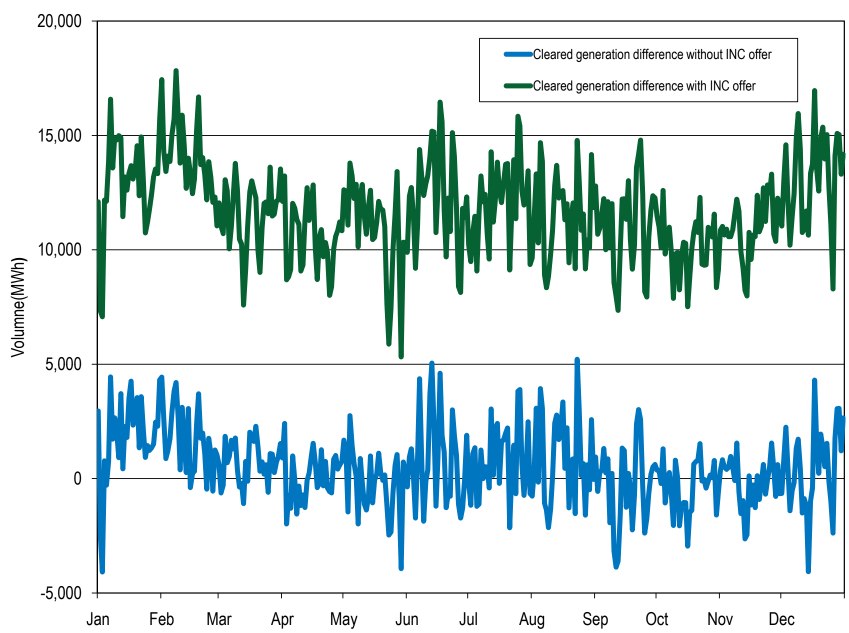


Figure 2-12 Difference between day-ahead and real-time generation (Average daily volumes): Calendar year 2010



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Locational Marginal Price (LMP)

The conduct of individual market entities within a market structure is reflected in market prices. The overall level of prices is a good general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them.[46]

Real-Time LMP

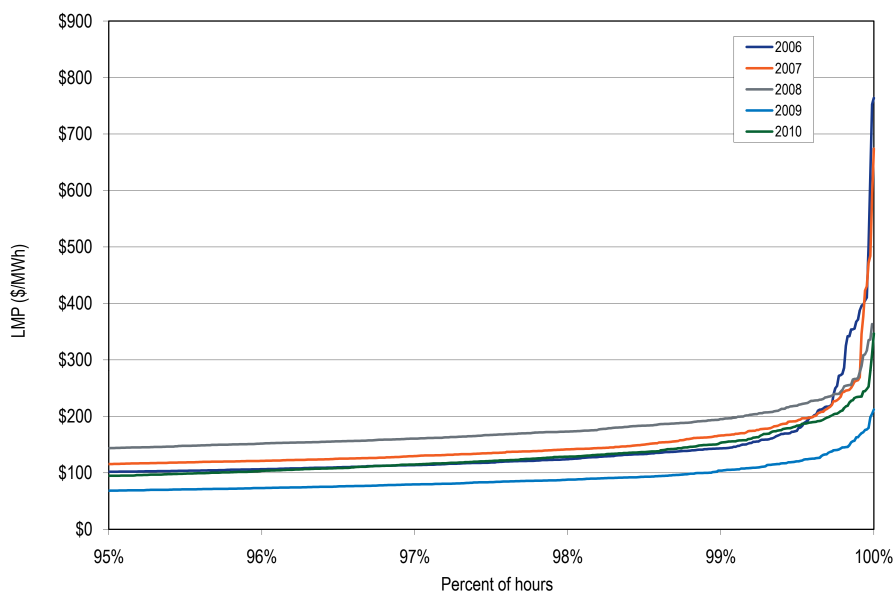
Real-time LMP is the hourly LMP for the PJM Real-Time Energy Market.

Real-Time Average LMP

PJM Real-Time LMP Duration

A price duration curve shows the percent of hours when LMP is at, or below, a given price for the year. Figure 2-13 presents price duration curves for hours above the 95th percentile from 2006 to 2010. As Figure 2-13 shows, LMPs were less than \$100 per MWh during 95 percent or more of the hours for the years 2009 and 2010 and less than \$150 during 95 percent or more of the hours for the years 2006 to 2008.[47]

Figure 2-13 Price duration curves for the PJM Real-Time Energy Market during hours above the 95th percentile: Calendar years 2006 to 2010



46 See the *2010 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market," for methodological background, detailed price data and the *Technical Reference for PJM Markets*, Section 4, "Calculating Locational Marginal Price" for more information on how bus LMPs are aggregated to system LMPs.

47 See the *2010 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

PJM Real-Time, Annual Average LMP

Table 2-34 shows the PJM real-time, annual, simple average LMP for the 13-year period 1998 to 2010.[48] The system simple average LMP for 2010 was 20.9 percent higher than the 2009 annual average, $44.83 per MWh versus $37.08 per MWh. Despite the increase, the PJM real-time, annual, simple average LMP in 2010 was lower than the average LMP in every year from 2005 through 2008.

Table 2-34 PJM real-time, simple average LMP (Dollars per MWh): Calendar years 1998 to 2010

	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%

48 The system annual, simple average LMP is the average of the hourly LMP without any weighting. The only exception is that market-clearing prices (MCPs) are included for January to April 1998. MCP was the single market-clearing price calculated by PJM prior to implementation of LMP.

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Zonal Real-Time, Annual Average LMP

Table 2-35 shows PJM zonal real-time, simple average LMP for 2009 and 2010. The largest zonal increase was in the BGE Control Zone which experienced an $11.92, or 28.6 percent increase from 2009 and the smallest increase was in the ComEd Control Zone which experienced a $4.30 increase, or 14.8 percent, from 2009.

Table 2-35 Zonal real-time, simple average LMP (Dollars per MWh): Calendar years 2009 to 2010

	2009	2010	Difference	Difference as Percent of 2009
AECO	$40.68	$50.67	$9.99	24.6%
AEP	$33.63	$38.36	$4.74	14.1%
AP	$38.29	$44.62	$6.33	16.5%
BGE	$41.71	$53.63	$11.92	28.6%
ComEd	$29.05	$33.35	$4.30	14.8%
DAY	$33.49	$38.11	$4.62	13.8%
DLCO	$32.73	$37.14	$4.41	13.5%
Dominion	$40.00	$50.94	$10.94	27.3%
DPL	$41.23	$51.04	$9.81	23.8%
JCPL	$40.93	$49.88	$8.95	21.9%
Met-Ed	$39.94	$49.14	$9.20	23.0%
PECO	$40.00	$49.11	$9.11	22.8%
PENELEC	$36.85	$43.07	$6.22	16.9%
Pepco	$41.88	$52.85	$10.98	26.2%
PPL	$39.44	$47.75	$8.31	21.1%
PSEG	$41.27	$50.97	$9.70	23.5%
RECO	$40.36	$49.18	$8.82	21.9%
PJM	$37.08	$44.83	$7.75	20.9%

Real-Time, Annual Average LMP by Jurisdiction

Table 2-36 shows the real-time, simple average LMP for all or part of the jurisdictions within the PJM footprint during 2009 and 2010. The largest increase was in Maryland which experienced an $11.52, or 27.6 percent increase from 2009, and the smallest increase was in Michigan which experienced a $3.79, or 11.1 percent, increase from 2009.

Table 2-36 Jurisdiction real-time, simple average LMP (Dollars per MWh): Calendar years 2009 to 2010

	2009	2010	Difference	Difference as Percent of 2009
Delaware	$40.80	$50.10	$9.30	22.8%
Illinois	$29.05	$33.35	$4.30	14.8%
Indiana	$33.08	$37.45	$4.37	13.2%
Kentucky	$33.48	$38.49	$5.01	15.0%
Maryland	$41.66	$53.18	$11.52	27.6%
Michigan	$34.09	$37.88	$3.79	11.1%
New Jersey	$41.08	$50.60	$9.52	23.2%
North Carolina	$38.92	$48.99	$10.07	25.9%
Ohio	$33.25	$37.48	$4.23	12.7%
Pennsylvania	$38.47	$46.09	$7.61	19.8%
Tennessee	$33.54	$39.27	$5.74	17.1%
Virginia	$39.29	$49.46	$10.17	25.9%
West Virginia	$34.60	$39.49	$4.89	14.1%
District of Columbia	$42.98	$53.03	$10.05	23.4%

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Hub Real-Time, Annual Average LMP

Table 2-37 shows the real-time, simple average LMPs at the PJM hubs for 2009 and 2010. Hub prices are average LMPs across a defined set of buses, created to provide market participants with trading points that exhibit greater price stability than individual buses. The largest price increase was for the Dominion Hub which experienced a $10.16, or 25.9 percent increase from 2009, and the smallest increase was for the AEP Gen Hub which experienced a $3.72, or 11.7 percent, increase from 2009.

Table 2-37 Hub real-time, simple average LMP (Dollars per MWh): Calendar years 2009 to 2010

	2009	2010	Difference	Difference as Percent of 2009
AEP Gen Hub	$31.83	$35.56	$3.72	11.7%
AEP-DAY Hub	$33.23	$37.57	$4.34	13.1%
Chicago Gen Hub	$28.28	$32.23	$3.95	14.0%
Chicago Hub	$29.25	$33.54	$4.30	14.7%
Dominion Hub	$39.27	$49.43	$10.16	25.9%
Eastern Hub	$41.23	$50.98	$9.75	23.7%
N Illinois Hub	$28.85	$33.08	$4.23	14.7%
New Jersey Hub	$41.04	$50.46	$9.41	22.9%
Ohio Hub	$33.24	$37.64	$4.40	13.2%
West Interface Hub	$34.66	$40.50	$5.84	16.9%
Western Hub	$38.30	$45.93	$7.63	19.9%

Real-Time, Load-Weighted, Average LMP

Higher demand (load) generally results in higher prices, all else constant. As a result, load-weighted, average prices are generally higher than simple average prices. Load-weighted LMP reflects the average LMP paid for actual MWh consumed during a year. Load-weighted, average LMP is the average of PJM hourly LMPs, each weighted by the PJM total hourly load.

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

Table 2-38 shows the PJM real-time, annual, load-weighted, average LMP for the 13-year period 1998 to 2010. The load-weighted, average system LMP for 2010 was 23.8 percent higher than the 2009 annual, load-weighted, average, $48.35 per MWh versus $39.05 per MWh. Despite the increase, the PJM real-time, annual, load-weighted, average LMP in 2010 was lower than the average LMP in every year from 2005 through 2008.

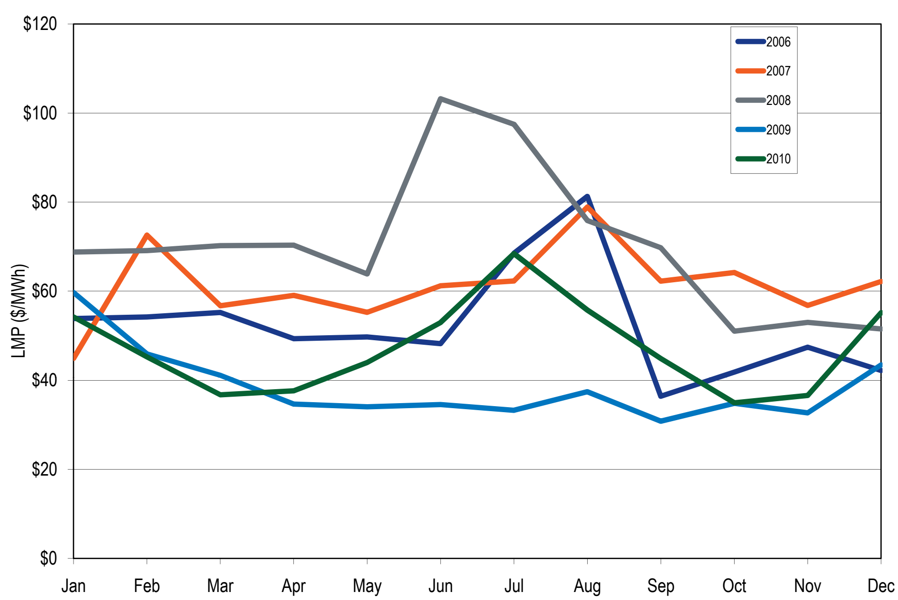
Table 2-38 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 1998 to 2010

	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%

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

Figure 2-14 shows the PJM real-time, monthly, load-weighted LMP from 2006 through 2010.

Figure 2-14 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2006 to 2010



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

Table 2-39 shows PJM zonal real-time, load-weighted, average LMP for 2009 and 2010. The largest zonal increase was in the BGE Control Zone which experienced a $14.91, or 33.7 percent, increase from 2009, and the smallest increase was in the AEP Control Zone which experienced a $5.23, or 14.9 percent, increase from 2009.

Table 2-39 Zonal real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 2009 to 2010

	2009	2010	Difference	Difference as Percent of 2009
AECO	$42.55	$57.02	$14.48	34.0%
AEP	$35.20	$40.43	$5.23	14.9%
AP	$40.59	$47.63	$7.04	17.3%
BGE	$44.28	$59.19	$14.91	33.7%
ComEd	$30.69	$36.21	$5.52	18.0%
DAY	$35.11	$40.51	$5.40	15.4%
DLCO	$33.86	$39.41	$5.55	16.4%
Dominion	$42.67	$56.08	$13.41	31.4%
DPL	$44.05	$56.51	$12.46	28.3%
JCPL	$43.26	$56.00	$12.75	29.5%
Met-Ed	$42.32	$53.47	$11.15	26.3%
PECO	$42.03	$53.60	$11.57	27.5%
PENELEC	$38.57	$45.17	$6.61	17.1%
Pepco	$44.50	$58.16	$13.66	30.7%
PPL	$42.10	$51.50	$9.40	22.3%
PSEG	$43.08	$55.78	$12.70	29.5%
RECO	$42.41	$54.85	$12.44	29.3%
PJM	$39.05	$48.35	$9.30	23.8%

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

Table 2-40 shows the real-time, load-weighted, average LMPs for all or part of the jurisdictions within the PJM footprint in 2009 and 2010[49]. The largest increase was in Maryland which experienced a $14.38, or 32.3 percent, increase from 2009, and the smallest increase was in Ohio which experienced a $4.76, or 13.7 percent, increase from 2009.

Table 2-40 Jurisdiction real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 2009 to 2010

	2009	2010	Difference	Difference as Percent of 2009
Delaware	$43.20	$55.09	$11.89	27.5%
Illinois	$30.69	$36.21	$5.52	18.0%
Indiana	$34.15	$39.06	$4.91	14.4%
Kentucky	$35.72	$40.96	$5.24	14.7%
Maryland	$44.48	$58.86	$14.38	32.3%
Michigan	$35.35	$40.23	$4.87	13.8%
New Jersey	$43.05	$56.00	$12.95	30.1%
North Carolina	$41.24	$53.80	$12.56	30.5%
Ohio	$34.71	$39.47	$4.76	13.7%
Pennsylvania	$40.54	$49.49	$8.95	22.1%
Tennessee	$35.47	$41.99	$6.53	18.4%
Virginia	$41.97	$54.24	$12.27	29.2%
West Virginia	$36.52	$41.72	$5.19	14.2%
District of Columbia	$45.35	$57.36	$12.01	26.5%

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

Fuel Cost

Changes in LMP can result from changes in the marginal costs of marginal units, the units setting LMP. In general, fuel costs make up between 80 percent and 90 percent of marginal cost depending on generating technology, unit efficiency, unit age and other factors. The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs.[50] Changes in emission allowance costs are another contributor to changes in the marginal cost of marginal units. To account for the changes in fuel and allowance costs between 2009 and 2010, the 2010 load-weighted LMP was adjusted to reflect the change in the daily price of fuels and emission allowances used by marginal units and the change in the amount of load affected by marginal units, using sensitivity factors.[51]

49 The PJM footprint includes 17 control zones. Each control zone is in one or more states or the District of Columbia, but such jurisdictions generally are not entirely covered by PJM control zones. The term jurisdiction is used here to refer to the states in which one or more of these control zones are located. For maps showing the PJM footprint and its control zones, see the 2010 State of the Market Report for PJM, Volume II, Appendix A, "PJM Geography."

50 See the *2010 State of the Market Report for PJM*, Volume II, Section 2,"Energy Market, Part 1," at Table 2-33, "Type of fuel used (By marginal units): Calendar year 2009."

51 For more information, see the *Technical Reference for PJM Markets*, Section 7, "Calculation and Use of Generator Sensitivity Factors."

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The prices of the primary fuel types used in the PJM footprint, including coal, natural gas and oil, all increased in price in 2010. In 2010, for example, the price of Northern Appalachian coal was 14.8 percent higher than in 2009. The price of Central Appalachian coal was 12.3 percent higher than in 2009. The price of Powder River Basin coal was 33.3 percent higher than in 2009. Eastern natural gas prices were 12.3 percent higher in 2010 than in 2009. Western natural gas prices were 11.0 percent higher in 2010 than 2009. No. 2 (light) oil prices were 29.3 percent higher and No. 6 (heavy) oil prices were 32.3 percent higher in 2010 than in 2009. Figure 2-15 shows spot average fuel prices for 2009 and 2010.[52]

Figure 2-15 Spot average fuel price comparison: Calendar years 2009 to 2010

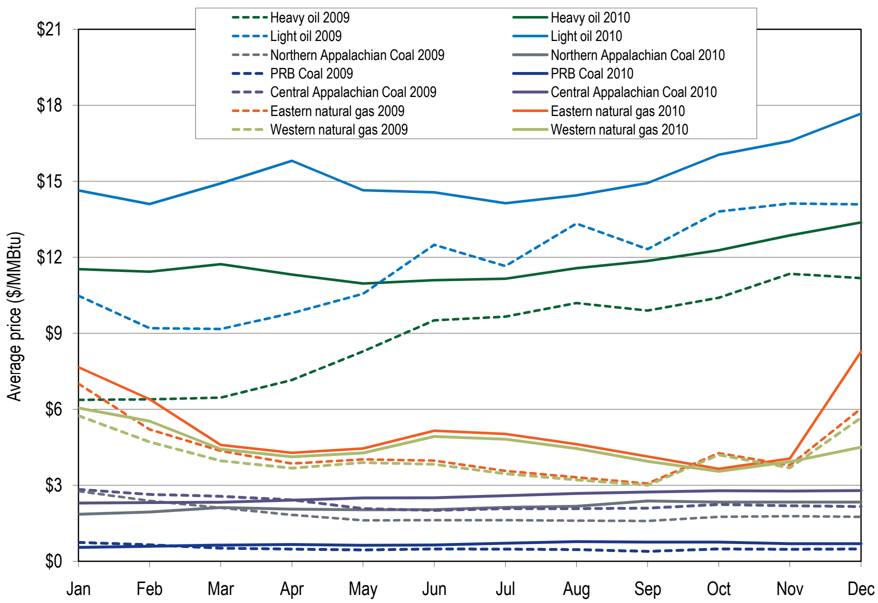

Table 2-41 compares the 2010 PJM real-time fuel-cost-adjusted, load-weighted, average LMP to the 2009 load-weighted, average LMP. The load-weighted, average LMP for 2010 was 23.4 percent higher than the load-weighted, average LMP for 2009. The real-time fuel-cost-adjusted, load-weighted, average LMP in 2010 was 19.6 percent higher than the load-weighted LMP in 2009. If fuel costs for the year 2010 had been the same as for 2009, the 2010 load-weighted LMP would have been lower, $46.70 per MWh instead of the observed $48.35 per MWh. Higher coal, gas and oil prices in 2010 resulted in higher prices in 2010 than would have occurred if fuel prices had remained at their 2009 levels. Net fuel cost increases and higher load levels were the primary reasons for the higher LMPs in 2010.

52 Eastern natural gas, Western natural gas, light oil, and heavy oil prices are the average of daily fuel price indices in the PJM footprint. Coal prices are the average of daily fuel prices for Central Appalachian coal, Northern Appalachian coal, and Powder River Basin coal. All fuel prices are from Platts.

Table 2-41 PJM real-time annual, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Year-over-year method

	2010 Load-Weighted LMP	2010 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$48.35	$46.70	(3.4%)
	2009 Load-Weighted LMP	2010 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$39.05	$46.70	19.6%
	2009 Load-Weighted LMP	2010 Load-Weighted LMP	Change
Average	$39.05	$48.35	23.8%

Components of Real-Time, Load-Weighted LMP

Observed LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal units generally determine system LMPs, based on their offers. Those offers can be decomposed into fuel costs, emission costs, variable operation and maintenance costs and markup. As a result, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal. Spot fuel prices were used, and emission costs were calculated using spot prices for NO_x, SO_2, and CO_2 and emission allowance costs and unit-specific emission rates, when applicable.

Table 2-42 shows that 39.4 percent of the annual, load-weighted LMP was the result of coal costs; 37.5 percent was the result of gas costs and 3.1 percent was the result of the cost of emission allowances. Markup was 0.6 percent of LMP. The fuel-related components of LMP reflect the impact of the cost of the identified fuel on LMP rather than all of the components of the offers of units burning that fuel on LMP.

As a result of the way in which LMP is calculated, there are differences between the components of LMP associated with individual unit characteristics, e.g. fuel costs and VOM, and observed LMP. This total net difference in 2010 was $0.64 per MWh. (Numbers in parentheses in the table are negative.) The components of this difference are listed in Table 2-42.[53]

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

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Table 2-42 Components of PJM real-time, annual, load-weighted, average LMP: Calendar year 2010

Element	Contribution to LMP	Percent
Coal	$19.07	39.4%
Gas	$18.12	37.5%
10% Cost Adder	$4.19	8.7%
VOM	$2.64	5.5%
Oil	$1.78	3.7%
NOX	$0.86	1.8%
NA	$0.57	1.2%
CO2	$0.40	0.8%
Markup	$0.31	0.6%
SO2	$0.25	0.5%
FMU Adder	$0.11	0.2%
Dispatch Differential	$0.06	0.1%
Shadow Price Limit Adder	$0.03	0.1%
Municipal Waste	$0.01	0.0%
Offline CT Adder	$0.00	0.0%
M2M Adder	($0.00)	(0.0%)
Wind	($0.02)	(0.0%)
Unit LMP Differential	($0.03)	(0.1%)
Total	$48.35	100.0%

Day-Ahead LMP

Day-ahead LMP is the hourly LMP for the PJM Day-Ahead Energy Market.

Day-Ahead Average LMP

PJM Day-Ahead LMP Duration

A price duration curve shows the percent of hours when LMP is at, or below, a given price for the year. Figure 2-16 presents day-ahead price duration curves for hours above the 95th percentile from 2006 to 2010. As Figure 2-16 shows, day-ahead LMP was less than $100 per MWh during 95 percent or more of the hours for the years 2006, 2007, 2009 and 2010 and less than $150 during 95 percent or more of the hours for 2008.

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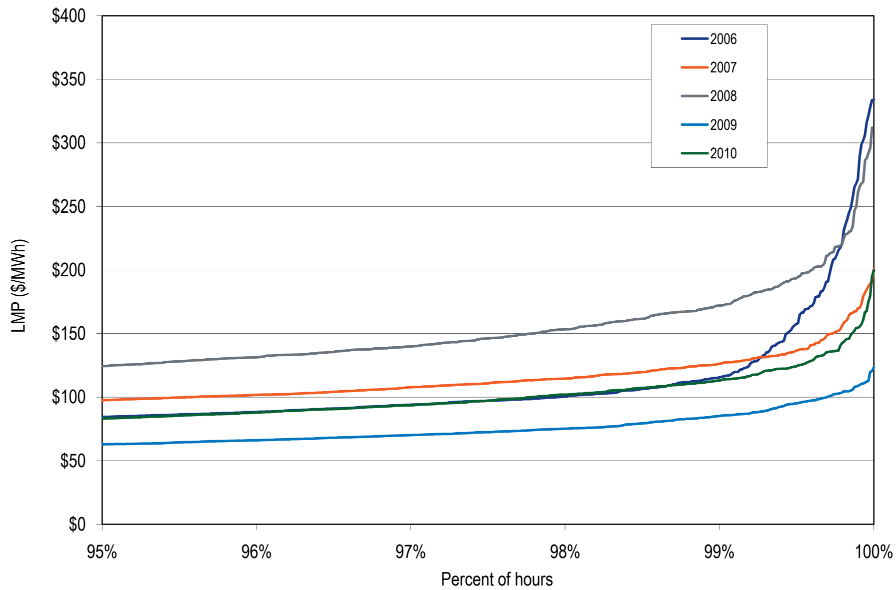
Figure 2-16 Price duration curves for the PJM Day-Ahead Energy Market during hours above the 95th percentile: Calendar years 2006 to 2010



PJM Day-Ahead, Annual Average LMP

Table 2-43 shows the PJM day-ahead annual, simple average LMP for the 11 year period 2000 to 2010. The system simple average LMP for 2010 was 20.5 percent higher than the 2009 annual average, $44.57 per MWh versus $37.00 per MWh. Despite the increase, the PJM day-ahead annual, simple average LMP in 2010 was lower than the average LMP in every year from 2005 through 2008.

Table 2-43 PJM day-ahead, simple average LMP (Dollars per MWh): Calendar years 2000 to 2010

	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%

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Zonal Day-Ahead, Annual Average LMP

Table 2-44 shows PJM zonal day-ahead, simple average LMP for 2009 and 2010. The largest zonal increase was in the BGE Control Zone which experienced a $10.67, or 25.1 percent, increase from 2009 and the smallest increase was in the ComEd Control Zone which experienced a $4.42, or 15.3 percent, increase from 2009.

Table 2-44 Zonal day-ahead, simple average LMP (Dollars per MWh): Calendar years 2009 to 2010

	2009	2010	Difference	Difference as Percent of 2009
AECO	$41.44	$50.44	$9.00	21.7%
AEP	$33.44	$38.30	$4.86	14.5%
AP	$37.80	$44.42	$6.62	17.5%
BGE	$42.57	$53.24	$10.67	25.1%
ComEd	$28.94	$33.37	$4.42	15.3%
DAY	$32.94	$37.97	$5.04	15.3%
DLCO	$32.33	$37.84	$5.51	17.0%
Dominion	$40.58	$51.16	$10.58	26.1%
DPL	$41.73	$50.80	$9.06	21.7%
JCPL	$41.36	$50.21	$8.85	21.4%
Met-Ed	$40.35	$48.98	$8.64	21.4%
PECO	$40.79	$49.58	$8.79	21.5%
PENELEC	$37.09	$43.94	$6.85	18.5%
Pepco	$42.54	$52.94	$10.41	24.5%
PPL	$39.90	$47.67	$7.78	19.5%
PSEG	$41.84	$50.89	$9.05	21.6%
RECO	$40.92	$49.68	$8.77	21.4%
PJM	$37.00	$44.57	$7.57	20.5%

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Day-Ahead, Annual Average LMP by Jurisdiction

Table 2-45 shows PJM's day-ahead, simple average LMPs for 2009 and 2010, by jurisdiction. The largest increase was in Maryland which experienced a $10.72, or 25.3 percent increase from 2009, and the smallest increase was in Michigan which experienced a $4.03, or 11.9 percent increase from 2009.

Table 2-45 Jurisdiction day-ahead, simple average LMP (Dollars per MWh): Calendar years 2009 to 2010

	2009	2010	Difference	Difference as Percent of 2009
Delaware	$41.15	$49.74	$8.59	20.9%
Illinois	$28.94	$33.37	$4.42	15.3%
Indiana	$32.87	$37.46	$4.59	14.0%
Kentucky	$33.22	$38.37	$5.14	15.5%
Maryland	$42.38	$53.10	$10.72	25.3%
Michigan	$33.94	$37.97	$4.03	11.9%
New Jersey	$41.64	$50.63	$8.99	21.6%
North Carolina	$39.50	$49.34	$9.84	24.9%
Ohio	$32.83	$37.39	$4.56	13.9%
Pennsylvania	$38.80	$46.31	$7.50	19.3%
Tennessee	$33.66	$39.26	$5.60	16.6%
Virginia	$39.88	$49.83	$9.96	25.0%
West Virginia	$34.34	$39.26	$4.92	14.3%
District of Columbia	$43.38	$53.02	$9.64	22.2%

Day-Ahead, Load-Weighted, Average LMP

Day-ahead, load-weighted LMP reflects the average LMP paid for day-ahead demand MWh cleared during a year. Day-ahead, load-weighted LMP is the average of PJM day-ahead hourly LMPs, each weighted by the PJM total cleared day-ahead hourly load, including day-ahead fixed load, price-sensitive load and decrement bids.

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

Table 2-46 shows the PJM day-ahead, annual, load-weighted, average LMP for the 11-year period 2000 to 2010. The day-ahead, load-weighted, average LMP for 2010 was 22.7 percent higher than the 2009 annual, load-weighted, average, at $47.65 per MWh versus $38.82 per MWh. Despite the increase, the PJM day-ahead, load-weighted, average LMP in 2010 was lower than the average LMP in every year from 2005 through 2008.

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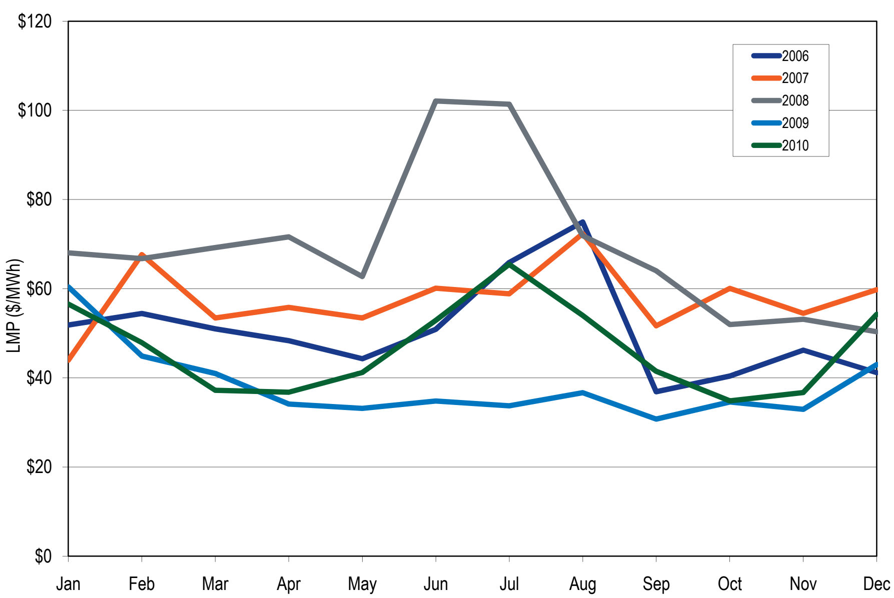
Table 2-46 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2000 to 2010

	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%

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

Figure 2-17 shows the PJM day-ahead, monthly, load-weighted LMP from 2006 through 2010.

Figure 2-17 Day-ahead, monthly, load-weighted, average LMP: Calendar years 2006 to 2010



Zonal Day-Ahead, Annual, Load-Weighted LMP

Table 2-47 shows PJM's zonal day-ahead, load-weighted, average LMPs for 2009 and 2010. The largest zonal increase was in the AECO Control Zone which experienced a $13.49, or 31.0 percent increase from 2009, and the smallest increase was in the ComEd Control Zone which experienced a $5.39, or 17.9 percent increase from 2009.

Table 2-47 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2009 to 2010

	2009	2010	Difference	Difference as Percent of 2009
AECO	$43.54	$57.03	$13.49	31.0%
AEP	$34.92	$40.35	$5.43	15.5%
AP	$39.97	$47.08	$7.11	17.8%
BGE	$44.94	$58.37	$13.43	29.9%
ComEd	$30.09	$35.48	$5.39	17.9%
DAY	$34.38	$40.18	$5.80	16.9%
DLCO	$33.37	$40.03	$6.66	20.0%
Dominion	$43.16	$56.08	$12.91	29.9%
DPL	$44.15	$55.76	$11.61	26.3%
JCPL	$43.51	$55.07	$11.56	26.6%
Met-Ed	$42.72	$52.78	$10.06	23.5%
PECO	$42.80	$53.63	$10.83	25.3%
PENELEC	$38.50	$45.52	$7.03	18.3%
Pepco	$44.83	$56.41	$11.58	25.8%
PPL	$42.32	$50.92	$8.60	20.3%
PSEG	$43.70	$54.99	$11.29	25.8%
RECO	$43.24	$55.56	$12.32	28.5%
PJM	$38.82	$47.65	$8.83	22.7%

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

Table 2-48 shows PJM's day-ahead, load-weighted, average LMP for 2009 and 2010 by jurisdiction. The largest increase was in Maryland which experienced a $12.73, or 28.4 percent increase from 2009, and the smallest increase was in Michigan which experienced a $4.32, or 12.3 percent, increase from 2009.

Table 2-48 Jurisdiction day-ahead, load weighted LMP (Dollars per MWh): Calendar years 2009 to 2010

	2009	2010	Difference	Difference as Percent of 2009
Delaware	$43.36	$54.23	$10.86	25.1%
Illinois	$30.09	$35.48	$5.39	17.9%
Indiana	$33.89	$39.24	$5.35	15.8%
Kentucky	$35.25	$40.62	$5.36	15.2%
Maryland	$44.90	$57.63	$12.73	28.4%
Michigan	$35.08	$39.40	$4.32	12.3%
New Jersey	$43.60	$55.27	$11.67	26.8%
North Carolina	$41.93	$54.05	$12.12	28.9%
Ohio	$34.22	$39.31	$5.09	14.9%
Pennsylvania	$40.69	$49.13	$8.44	20.7%
Tennessee	$35.51	$41.76	$6.25	17.6%
Virginia	$42.40	$54.40	$12.00	28.3%
West Virginia	$36.04	$41.58	$5.54	15.4%
District of Columbia	$45.86	$56.15	$10.28	22.4%

Components of Day-Ahead, Load-Weighted LMP

Observed LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal units generally determine system LMPs, based on their offers. Those offers can be decomposed into fuel costs, emission costs, variable operation and maintenance costs, markup, FMU adder and the 10 percent cost offer adder. As a result, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal. Spot fuel prices were used and emission costs were calculated using spot prices for NO_x, SO_2 and CO_2 emission credits, fuel-specific emission rates for NO_x and unit-specific emission rates for SO_2. The emission costs for NO_x and SO_2 are applicable throughout the year. The CO_2 emission costs are applicable to PJM units in PJM's RGGI participating states: Delaware, Maryland and New Jersey.

Table 2-49 Components of PJM day-ahead, annual, load-weighted, average LMP (Dollars per MWh): Calendar year 2010

Element	Contribution to LMP	Percent
INC	$16.25	34.1%
DEC	$12.99	27.3%
Coal	$7.76	16.3%
Gas	$5.76	12.1%
Transaction	$1.62	3.4%
10% Cost Adder	$1.52	3.2%
VOM	$0.92	1.9%
Price Sensitive Demand	$0.77	1.6%
NO_x	$0.32	0.7%
CO_2	$0.16	0.3%
Oil	$0.15	0.3%
SO_2	$0.10	0.2%
Constrained Off	$0.09	0.2%
Diesel	$0.01	0.0%
FMU Adder	$0.00	0.0%
Wind	($0.00)	(0.0%)
Markup	($0.60)	(1.3%)
NA	($0.15)	(0.3%)
Total	$47.65	100.0%

Marginal Losses

Marginal losses are the incremental change in system real power losses caused by changes in the system load and generation patterns.[54] Before June 1, 2007, the PJM economic dispatch and LMP models did not include marginal losses. The losses were treated as a static component of load, and the physical nature and location of power system losses were ignored. The PJM Tariff required implementation of marginal loss modeling when required technical systems became available. On June 1, 2007, PJM began including marginal losses in economic dispatch and LMP models.[55] The primary benefit of a marginal loss mechanism is that it more accurately models the physical reality of power system losses. More accurate models permit increased efficiency and optimize asset utilization. One characteristic of marginal loss modeling is that it creates a separate marginal loss price for every location on the power grid.

Table 2-50 shows the PJM real-time, simple average LMP components, including the loss component, for calendar years 2006 to 2010. As of June 1, 2007, PJM changed from a single node reference bus to a distributed load reference bus. While there is no effect on the total LMP, the components of LMP change with a shift in the reference bus. With a distributed load reference bus, the energy

54 For additional information, see the *Technical Reference for PJM Markets,* Section 6, "Marginal Losses."
55 For additional information, see OATT Section 3.4.

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component is now a load-weighted system price. In turn, this means that there is no congestion or losses included at the PJM price, unlike the case with a single node reference bus. The energy price equals the PJM price in a given hour and on a yearly average basis. Table 2-50 shows a $0.04 loss component included at the PJM price. The PJM price is weighted with accounting load, which differs from the state-estimated load used in determination of the energy component. The $0.04 loss component of the average PJM system price results from these different weights. The $2.08 and $1.00 congestion component of the average PJM system price for 2006 and 2007 respectively, resulted from the fact that the distributed load reference bus did not go into effect until June 1, 2007.

Table 2-50 PJM real-time, simple average LMP components (Dollars per MWh): Calendar years 2006 to 2010

	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

Table 2-51 shows the zonal real-time, simple average LMP components, including the loss component, for calendar years 2009 and 2010.

Table 2-51 Zonal real-time, simple average LMP components (Dollars per MWh): Calendar years 2009 to 2010

	2009				2010			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$40.68	$37.01	$1.83	$1.84	$50.67	$44.72	$3.64	$2.31
AEP	$33.63	$37.01	($2.16)	($1.22)	$38.36	$44.72	($4.83)	($1.53)
AP	$38.29	$37.01	$1.32	($0.03)	$44.62	$44.72	$0.12	($0.22)
BGE	$41.71	$37.01	$3.04	$1.67	$53.63	$44.72	$6.68	$2.23
ComEd	$29.05	$37.01	($5.61)	($2.35)	$33.35	$44.72	($8.58)	($2.80)
DAY	$33.49	$37.01	($2.72)	($0.79)	$38.11	$44.72	($5.69)	($0.91)
DLCO	$32.73	$37.01	($3.02)	($1.26)	$37.14	$44.72	($5.94)	($1.64)
Dominion	$40.00	$37.01	$2.37	$0.62	$50.94	$44.72	$5.35	$0.87
DPL	$41.23	$37.01	$2.32	$1.91	$51.04	$44.72	$3.82	$2.51
JCPL	$40.93	$37.01	$2.01	$1.91	$49.88	$44.72	$2.92	$2.23
Met-Ed	$39.94	$37.01	$2.03	$0.90	$49.14	$44.72	$3.47	$0.95
PECO	$40.00	$37.01	$1.71	$1.28	$49.11	$44.72	$2.84	$1.55
PENELEC	$36.85	$37.01	($0.06)	($0.09)	$43.07	$44.72	($1.42)	($0.24)
Pepco	$41.88	$37.01	$3.74	$1.13	$52.85	$44.72	$6.72	$1.41
PPL	$39.44	$37.01	$1.75	$0.68	$47.75	$44.72	$2.34	$0.69
PSEG	$41.27	$37.01	$2.27	$2.00	$50.97	$44.72	$3.99	$2.26
RECO	$40.36	$37.01	$1.55	$1.80	$49.18	$44.72	$2.50	$1.95

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Table 2-52 shows the real-time, annual, simple average LMP loss component at the PJM hubs for 2010, for each hub in PJM.

Table 2-52 Hub real-time, simple average LMP components (Dollars per MWh): Calendar year 2010

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$35.56	$44.72	($6.15)	($3.01)
AEP-DAY Hub	$37.57	$44.72	($5.42)	($1.73)
Chicago Gen Hub	$32.23	$44.72	($9.09)	($3.40)
Chicago Hub	$33.54	$44.72	($8.40)	($2.78)
Dominion Hub	$49.43	$44.72	$4.30	$0.40
Eastern Hub	$50.98	$44.72	$3.59	$2.66
N Illinois Hub	$33.08	$44.72	($8.61)	($3.02)
New Jersey Hub	$50.46	$44.72	$3.52	$2.21
Ohio Hub	$37.64	$44.72	($5.41)	($1.67)
West Interface Hub	$40.50	$44.72	($2.76)	($1.46)
Western Hub	$45.93	$44.72	$1.52	($0.31)

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

Table 2-53 shows the real-time, annual, load-weighted, average LMP components for PJM and its 17 control zones for 2010.

Table 2-53 Zonal and PJM real-time, annual, load-weighted, average LMP components (Dollars per MWh): Calendar year 2010

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$57.02	$49.26	$5.11	$2.66
AEP	$40.43	$47.58	($5.50)	($1.64)
AP	$47.63	$47.87	$0.02	($0.26)
BGE	$59.19	$48.69	$8.04	$2.46
ComEd	$36.21	$47.95	($8.85)	($2.90)
DAY	$40.51	$48.10	($6.66)	($0.93)
DLCO	$39.41	$47.89	($6.68)	($1.79)
Dominion	$56.08	$48.86	$6.30	$0.92
DPL	$56.51	$49.07	$4.59	$2.85
JCPL	$56.00	$49.58	$3.92	$2.51
Met-Ed	$53.47	$48.20	$4.22	$1.05
PECO	$53.60	$48.36	$3.54	$1.70
PENELEC	$45.17	$47.19	($1.73)	($0.28)
Pepco	$58.16	$48.70	$7.94	$1.51
PPL	$51.50	$47.90	$2.84	$0.76
PSEG	$55.78	$48.58	$4.73	$2.47
RECO	$54.85	$49.48	$3.20	$2.17
PJM	$48.35	$48.23	$0.08	$0.04

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Table 2-54 shows the PJM day-ahead, simple average LMP components, including the loss component, for calendar years 2006 through 2010. As of June 1, 2007, PJM changed from a single node reference bus to a distributed load reference bus. While there is no effect on the total LMP, the components of LMP change with a shift in the reference bus. With a distributed load reference bus, the energy component is now a load-weighted system price. In turn, this means that there is no congestion or losses included at the PJM price, unlike the case with a single node reference bus. The energy price equals the PJM price in a given hour and on a yearly average basis. In the Day-Ahead Energy Market, the distributed load reference bus is weighted with fixed-demand bids only and the day-ahead energy component is, therefore, a system fixed-demand-weighted price. The day-ahead system price calculation uses all types of demand, including fixed, price-sensitive and decrement bids. In the Real-Time Energy Market, the energy component equals the system load-weighted price; however, in the Day-Ahead Energy Market the energy component and the PJM system price are not equal, but the loss component and the congestion component have only a small effect. This is due to the use of all types of demand to weight the PJM price and not fixed demand only.

Table 2-54 PJM day-ahead, simple average LMP components (Dollars per MWh): Calendar years 2006 to 2010

	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)

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Table 2-55 shows the zonal day-ahead, simple average LMP components, including the loss component, for calendar years 2009 and 2010.[56]

Table 2-55 Zonal day-ahead, simple average LMP components (Dollars per MWh): Calendar years 2009 to 2010

	2009				2010			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$41.44	$37.15	$2.03	$2.26	$50.44	$44.61	$2.96	$2.87
AEP	$33.44	$37.15	($2.12)	($1.59)	$38.30	$44.61	($4.05)	($2.26)
AP	$37.80	$37.15	$0.62	$0.03	$44.42	$44.61	$0.06	($0.25)
BGE	$42.57	$37.15	$3.33	$2.08	$53.24	$44.61	$5.75	$2.88
ComEd	$28.94	$37.15	($5.09)	($3.12)	$33.37	$44.61	($7.38)	($3.86)
DAY	$32.94	$37.15	($2.77)	($1.45)	$37.97	$44.61	($4.74)	($1.89)
DLCO	$32.33	$37.15	($3.37)	($1.46)	$37.84	$44.61	($4.75)	($2.02)
Dominion	$40.58	$37.15	$2.47	$0.96	$51.16	$44.61	$5.10	$1.45
DPL	$41.73	$37.15	$2.25	$2.33	$50.80	$44.61	$3.17	$3.02
JCPL	$41.36	$37.15	$1.82	$2.39	$50.21	$44.61	$2.59	$3.01
Met-Ed	$40.35	$37.15	$2.10	$1.10	$48.98	$44.61	$3.13	$1.24
PECO	$40.79	$37.15	$1.87	$1.78	$49.58	$44.61	$2.69	$2.28
PENELEC	$37.09	$37.15	($0.10)	$0.03	$43.94	$44.61	($0.68)	$0.01
Pepco	$42.54	$37.15	$3.75	$1.64	$52.94	$44.61	$6.16	$2.18
PPL	$39.90	$37.15	$1.88	$0.86	$47.67	$44.61	$2.20	$0.86
PSEG	$41.84	$37.15	$2.12	$2.57	$50.89	$44.61	$3.04	$3.24
RECO	$40.92	$37.15	$1.47	$2.30	$49.68	$44.61	$2.19	$2.88

56 For some zones, energy component plus congestion component plus loss component may not equal the total day-ahead LMP because the total is based on the underlying data, which is not rounded.

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

Table 2-56 shows zonal and PJM day-ahead, annual, load-weighted, average LMP components for calendar year 2010.

Table 2-56 Zonal and PJM day-ahead, load-weighted, average LMP components (Dollars per MWh): Calendar year 2010

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$57.03	$49.69	$3.87	$3.47
AEP	$40.35	$47.45	($4.67)	($2.43)
AP	$47.08	$47.42	($0.05)	($0.28)
BGE	$58.37	$48.37	$6.80	$3.20
ComEd	$35.48	$47.12	($7.62)	($4.02)
DAY	$40.18	$47.71	($5.52)	($2.01)
DLCO	$40.03	$47.49	($5.26)	($2.20)
Dominion	$56.08	$48.48	$6.05	$1.54
DPL	$55.76	$48.66	$3.73	$3.37
JCPL	$55.07	$48.61	$3.13	$3.32
Met-Ed	$52.78	$47.72	$3.70	$1.35
PECO	$53.63	$47.94	$3.18	$2.51
PENELEC	$45.52	$46.41	($0.88)	($0.00)
Pepco	$56.41	$47.24	$6.85	$2.32
PPL	$50.92	$47.45	$2.51	$0.95
PSEG	$54.99	$48.02	$3.47	$3.50
RECO	$55.56	$49.69	$2.67	$3.20
PJM	$47.65	$47.67	$0.05	($0.07)

Marginal Loss Accounting

With the implementation of marginal loss pricing, PJM calculates transmission loss charges for each PJM member. The loss charge is based on the applicable day-ahead and real-time loss component of LMP (loss LMP). Each PJM member is charged for the cost of losses on the transmission system, based on the difference between the loss LMP at the location where the PJM member injects energy and the loss LMP where the PJM member withdraws energy.

More specifically, total loss charges are equal to the load loss payments minus generation loss credits, plus explicit loss charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

- **Day-Ahead, Load Loss Payments.** Day-ahead, load loss payments are calculated for all cleared demand, decrement bids and Day-Ahead Energy Market sale transactions. (Decrement bids and energy sales can be thought of as scheduled load.) Day-ahead, load loss payments are calculated using MW and the load bus loss component of LMP (loss LMP), the decrement bid loss LMP or the loss LMP at the source of the sale transaction, as applicable.

- **Day-Ahead, Generation Loss Credits.** Day-ahead, generation loss credits are calculated for all cleared generation and increment offers and Day-Ahead Energy Market purchase transactions. (Increment offers and energy purchases can be thought of as scheduled generation.) Day-ahead, generation loss credits are calculated using MW and the generator bus loss LMP, the increment offer loss LMP or the loss LMP at the sink of the purchase transaction, as applicable.

- **Balancing, Load Loss Payments.** Balancing, load loss payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing, load loss payments are calculated using MW deviations and the real-time loss LMP for each bus where a deviation exists.

- **Balancing, Generation, Loss Credits.** Balancing, generation loss credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing, generation loss credits are calculated using MW deviations and the real-time loss LMP for each bus where a deviation exists.

- **Explicit Loss Charges.** Explicit loss charges are the net loss charges associated with point-to-point energy transactions. These charges equal the product of the transacted MW and loss LMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit loss charges equal the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time loss LMP at the transactions' sources and sinks.

Marginal Loss Costs and Loss Credits

Table 2-57 shows the total marginal loss costs collected and total loss credits redistributed in calendar years 2007 to 2010. Marginal loss costs totaled $1.635 billion in 2010. Revenues resulting from marginal losses are approximately twice those collected from average losses, thus resulting in an over collection.[57] The overcollected portion of transmission losses that was credited back to load plus exports in 2010 was $836.6 million or 51.2 percent of the total losses. In determining the overcollected loss amount, PJM accumulates the day-ahead and balancing transmission loss charges paid by all customer accounts each hour, subtracts the spot market energy value of the actual transmission loss MWh during that hour, and allocates this amount as transmission loss credits each hour.[58]

57 For additional information on over collection, see the *Technical Reference for PJM Markets,* Section 6, "Marginal Losses – Loss Revenue Surplus."

58 See PJM. "Manual 28: Operating Agreement Accounting," Revision 39 (January 1, 2008). Note that the overcollection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.

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Table 2-57 Marginal loss costs and loss credits: Calendar years 2007 to 2010[59]

	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	$836,596,012	51.2%

Monthly Marginal Loss Costs

Table 2-58 shows a monthly summary of marginal loss costs by type for 2010. The highest monthly loss cost was in July and totaled $227.9 million or 13.9 percent of the total. The majority of the marginal loss costs was in the Day-Ahead Energy Market and totaled $1.666 billion. The day-ahead costs were offset, in part, by a total of -$30.9 million in the balancing market.

Table 2-58 Marginal loss costs by type (Dollars (Millions)): Calendar year 2010

	Marginal Loss Costs (Millions)								
	Day Ahead				Balancing				
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
Jan	$45.5	($136.3)	$7.0	$188.9	$1.2	($2.8)	($4.0)	$0.0	$188.9
Feb	$31.6	($100.1)	$3.0	$134.7	$0.4	($0.6)	($1.3)	($0.4)	$134.3
Mar	$21.0	($70.5)	$2.7	$94.2	$0.2	($0.2)	($1.2)	($0.8)	$93.4
Apr	$16.8	($59.9)	$3.8	$80.4	($0.2)	$0.1	($1.7)	($2.0)	$78.4
May	$17.6	($77.6)	$6.0	$101.2	$0.4	($1.3)	($3.3)	($1.6)	$99.6
Jun	$20.3	($127.4)	$10.8	$158.5	$3.2	($0.3)	($5.8)	($2.3)	$156.3
Jul	$39.0	($180.9)	$12.0	$231.9	$1.5	($0.7)	($6.2)	($4.0)	$227.9
Aug	$16.0	($144.7)	$8.5	$169.2	$1.9	$0.5	($3.3)	($1.9)	$167.3
Sep	$11.7	($95.8)	$7.6	$115.2	$0.5	($0.6)	($3.2)	($2.0)	$113.1
Oct	$9.6	($75.7)	$10.3	$95.6	($0.8)	($0.9)	($5.4)	($5.3)	$90.3
Nov	$10.8	($82.9)	$8.9	$102.6	($0.7)	($0.3)	($4.1)	($4.6)	$98.0
Dec	$24.2	($154.0)	$15.1	$193.3	$2.1	$2.0	($6.1)	($6.0)	$187.2
Total	$264.0	($1,305.8)	$95.8	$1,665.6	$9.7	($5.1)	($45.6)	($30.9)	$1,634.7

Zonal Marginal Loss Costs

Table 2-59 shows the marginal loss costs by type in each control zone in 2010. The AEP, ComEd and Dominion control zones had the highest marginal loss costs in 2010, with $324.4 million, $295.3 million and $189.2 million, respectively. Energy flows in PJM are generally from west to

59 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.

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east, reflecting the fact that less expensive generation in the western portion of PJM is dispatched to assist in meeting the demand of load centers located in the eastern portion of PJM. Generation supplied from western resources to satisfy eastern load generally results in increased west-to-east transmission flow and increased losses. As may be seen in Table 2-59, the marginal loss generation credits in the western zones are generally greater in magnitude than those of the eastern zones. The characteristics of the marginal loss component of LMP are analogous to those of the congestion component of LMP, or CLMP. Generation congestion credits are generally negative for units located on the unconstrained side of a transmission element, indicating that an increase in output tends to increase the flow of energy across the constrained element. Analogously, the generation marginal loss credits are generally negative for units for which an increase in output tends to increase system losses.

Table 2-59 Marginal loss costs by control zone and type (Dollars (Millions)): Calendar year 2010

	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	$36.1	$9.0	$0.2	$27.4	$2.0	($0.6)	($0.1)	$2.5	$29.8
AEP	($84.9)	($386.6)	$27.0	$328.7	$4.7	$5.4	($3.5)	($4.3)	$324.4
AP	($10.5)	($127.6)	$10.9	$127.9	$3.6	$6.3	($5.2)	($7.9)	$120.1
BGE	$90.0	$27.3	$5.4	$68.1	$5.4	($3.0)	($4.1)	$4.4	$72.4
ComEd	($245.9)	($540.4)	$7.0	$301.5	($8.0)	($4.8)	($3.1)	($6.2)	$295.3
DAY	($6.1)	($69.1)	$14.1	$77.1	($0.4)	$2.1	($11.1)	($13.6)	$63.5
DLCO	($37.5)	($58.8)	$0.2	$21.6	($3.1)	($0.3)	($0.1)	($2.9)	$18.7
Dominion	$125.7	($53.2)	$11.0	$190.0	$3.4	($1.0)	($5.2)	($0.8)	$189.2
DPL	$68.1	$12.7	$1.4	$56.9	($2.6)	($1.5)	($0.9)	($2.0)	$54.9
JCPL	$80.5	$29.9	$0.5	$51.1	$0.0	($1.1)	($0.4)	$0.7	$51.8
Met-Ed	$21.9	$1.5	$0.3	$20.7	$0.0	($0.2)	($0.2)	$0.0	$20.7
PECO	$82.2	$26.0	$0.3	$56.4	($1.4)	($0.6)	($0.1)	($0.9)	$55.5
PENELEC	($32.7)	($115.6)	$0.2	$83.1	$4.1	($2.4)	$0.1	$6.7	$89.8
Pepco	$116.9	$52.0	$3.3	$68.2	($2.7)	($1.8)	($2.3)	($3.2)	$65.0
PJM	($109.0)	($133.3)	$0.7	$25.0	$0.4	($11.1)	($0.0)	$11.5	$36.4
PPL	$37.3	($23.9)	$1.7	$62.9	$2.7	$1.5	$0.0	$1.2	$64.1
PSEG	$127.6	$44.0	$11.6	$95.3	$0.8	$8.3	($9.3)	($16.9)	$78.4
RECO	$4.2	$0.3	$0.1	$3.9	$0.5	($0.2)	($0.1)	$0.7	$4.7
Total	$264.0	($1,305.8)	$95.8	$1,665.6	$9.7	($5.1)	($45.6)	($30.9)	$1,634.7

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Table 2-60 shows the monthly marginal loss cost, by control zone in 2010.

Table 2-60 Monthly marginal loss costs by control zone (Dollars (Millions)): Calendar year 2010

	Marginal Loss Costs by Control Zone (Millions)												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
AECO	$2.6	$1.5	$1.4	$1.4	$1.6	$3.3	$6.7	$4.1	$2.1	$1.2	$1.3	$2.5	$29.8
AEP	$40.0	$25.9	$16.4	$13.8	$14.8	$31.5	$53.5	$37.8	$19.2	$15.8	$16.0	$39.8	$324.4
AP	$13.7	$11.2	$6.8	$6.5	$8.4	$11.3	$16.7	$12.0	$6.9	$5.1	$6.5	$14.8	$120.1
BGE	$8.8	$6.7	$3.7	$3.3	$4.8	$7.3	$11.3	$7.8	$5.0	$3.8	$3.8	$6.2	$72.4
ComEd	$36.1	$23.9	$19.8	$16.2	$16.9	$23.7	$32.0	$26.4	$23.0	$19.3	$22.2	$35.8	$295.3
DAY	$6.6	$5.3	$4.2	$2.6	$4.6	$5.6	$9.7	$6.7	$4.6	$3.3	$4.1	$6.0	$63.5
DLCO	$3.0	$2.3	$1.6	$1.3	$1.4	$1.5	$1.7	$1.3	$1.3	$0.2	$1.1	$1.9	$18.7
Dominion	$20.1	$15.9	$9.0	$8.9	$10.8	$21.0	$28.6	$20.2	$13.1	$10.3	$10.6	$20.7	$189.2
DPL	$5.7	$3.6	$2.6	$2.8	$3.2	$4.7	$8.5	$6.0	$4.4	$2.9	$3.1	$7.3	$54.9
JCPL	$6.3	$4.0	$3.3	$2.3	$3.3	$5.1	$8.2	$4.9	$3.0	$1.7	$2.8	$6.7	$51.8
Met-Ed	$2.8	$1.6	$1.4	$1.0	$1.4	$2.1	$2.3	$2.1	$1.3	$1.3	$1.3	$2.1	$20.7
PECO	$4.2	$3.7	$2.3	$1.9	$3.6	$7.1	$9.3	$6.9	$4.4	$3.5	$2.6	$6.1	$55.5
PENELEC	$10.4	$7.2	$3.6	$3.6	$5.8	$8.6	$11.1	$8.9	$8.0	$5.9	$6.6	$10.1	$89.8
Pepco	$6.7	$5.7	$4.5	$3.8	$5.0	$6.4	$9.1	$6.0	$4.2	$4.2	$3.9	$5.5	$65.0
PJM	$5.5	$3.7	$2.9	$2.4	$5.2	$3.2	$1.6	$1.8	$1.2	$1.9	$2.8	$4.1	$36.4
PPL	$8.8	$6.3	$3.7	$2.2	$3.2	$5.4	$6.2	$6.3	$5.2	$4.6	$4.1	$8.2	$64.1
PSEG	$7.0	$5.4	$5.8	$4.3	$5.3	$7.9	$10.4	$7.7	$5.8	$5.0	$4.9	$8.8	$78.4
RECO	$0.5	$0.2	$0.2	$0.2	$0.3	$0.5	$0.8	$0.5	$0.4	$0.2	$0.2	$0.5	$4.7
Total	$188.9	$134.3	$93.4	$78.4	$99.6	$156.3	$227.9	$167.3	$113.1	$90.3	$98.0	$187.2	$1,634.7

Virtual Offers and Bids

The PJM Day-Ahead Energy Market includes the ability to make increment offers (INC) and decrement bids (DEC) at any hub, transmission zone, aggregate, or single bus for which LMP is calculated. Since increment offers and decrement bids do not require physical generation or load, they are also referred to as virtual offers and bids. Virtual offers and bids also provide participants the flexibility, for example, to cover one side of a bilateral transaction, hedge day-ahead generator offers or demand bids, and arbitrage day-ahead and real-time prices.

There is a substantial volume of virtual offers and bids in the PJM Day-Ahead Market and such offers and bids may each be marginal, based on the way in which the optimization algorithm works.

Any market participant in the PJM Day-Ahead Energy Market can use increment offers and decrement bids as financial instruments that do not require physical generation or load. Increment offers and decrement bids may be submitted at any hub, transmission zone, aggregate, or single bus for which LMP is calculated. Table 2-61 shows the average volume of trading in virtual bids per hour, as well as the average total MW values of all virtual bids per hour.

Table 2-61 Monthly volume of cleared and submitted INCs, DECs: Calendar year 2010

	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	11,144	21,634	282	936	17,513	29,406	266	893
Feb	12,387	23,827	387	1,122	17,602	28,542	270	883
Mar	10,811	21,062	308	915	15,019	24,968	253	763
Apr	10,512	19,940	289	784	13,875	24,458	246	705
May	11,165	19,744	218	806	15,556	25,194	223	787
Jun	11,534	22,956	254	1,496	17,689	27,422	258	1,246
Jul	11,276	23,414	250	1,585	17,223	25,690	304	1,284
Aug	10,567	20,751	226	1,332	15,656	21,745	327	1,140
Sep	10,944	21,365	263	1,232	15,522	22,646	311	1,072
Oct	10,454	20,253	234	1,129	14,011	22,154	253	1,030
Nov	11,134	17,495	220	1,035	15,315	22,618	271	1,055
Dec	12,656	20,957	277	1,340	16,560	26,995	274	1,266
Annual	11,208	21,101	267	1,143	15,952	25,135	271	1,011

Table 2-62 shows the frequency with which generation offers, import or export transactions, decrement bids, increment offers and price-sensitive demand are marginal for each month in 2010.[60] Together, increment offers and decrement bids represented 47.0 percent of the marginal bids or offers in 2010.

Table 2-62 Type of day-ahead marginal units: Calendar year 2010

	Generation	Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	16.5%	30.9%	32.5%	19.4%	0.7%
Feb	14.9%	34.1%	24.3%	26.1%	0.6%
Mar	10.6%	29.9%	34.1%	24.7%	0.7%
Apr	11.5%	32.9%	32.8%	22.5%	0.3%
May	12.3%	36.0%	28.6%	22.5%	0.6%
Jun	14.1%	35.2%	27.8%	22.5%	0.5%
Jul	12.5%	40.7%	24.3%	21.7%	0.9%
Aug	11.1%	52.5%	17.7%	17.8%	0.9%
Sep	12.6%	43.8%	23.2%	18.4%	0.4%
Oct	14.4%	43.7%	23.0%	18.7%	0.3%
Nov	12.1%	48.0%	26.6%	13.3%	0.2%
Dec	9.7%	48.0%	27.7%	14.4%	0.3%
Annual	12.7%	39.7%	26.9%	20.1%	0.5%

60 These percentages compare the number of times that bids and offers of the specified type were marginal to the total number of marginal bids and offers. There is no weighting by time or by load.

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In order to evaluate the ownership of virtual bids, the MMU categorized all participants owning virtual bids in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 2-63 shows virtual bids by the type of bid parent organization: financial or physical player.[61]

Table 2-63 PJM virtual bids by type of bid parent organization (MW): Calendar year 2010

	Category	Total Virtual Bids MW	Percentage
2010	Financial	169,223,448	41.8%
2010	Physical	235,801,427	58.2%
2010	Total	405,024,876	100.0%

Table 2-64 shows virtual bids bid by top ten aggregates.[62] In 2010, more virtual offers and bids were submitted at the WESTERN HUB than any other location. Total virtual MW at WESTERN HUB were 31.3 percent of the total PJM offered virtual bids. The top ten locations for virtual offers and bids accounted for 52.7 percent of all virtual offers and bids in PJM in 2010.

Table 2-64 PJM virtual offers and bids by top ten aggregates (MW): Calendar year 2010

Aggregate Name	Aggregate Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	59,498,730	67,461,162	126,959,892
N ILLINOIS HUB	HUB	12,227,336	13,489,896	25,717,232
AEP-DAYTON HUB	HUB	5,903,338	7,754,930	13,658,269
PPL	ZONE	524,776	8,491,950	9,016,726
PSEG	ZONE	2,412,903	5,229,766	7,642,670
BGE	ZONE	3,675,033	3,624,029	7,299,062
Pepco	ZONE	5,922,591	1,215,146	7,137,737
JCPL	ZONE	3,939,569	2,210,312	6,149,881
MISO	INTERFACE	1,223,081	3,768,471	4,991,553
ComEd	ZONE	2,251,251	2,422,361	4,673,613
Top ten total		97,578,609	115,668,025	213,246,633
PJM total		184,846,624	220,178,252	405,024,876
Top ten total as percent of PJM total		52.8%	52.5%	52.7%

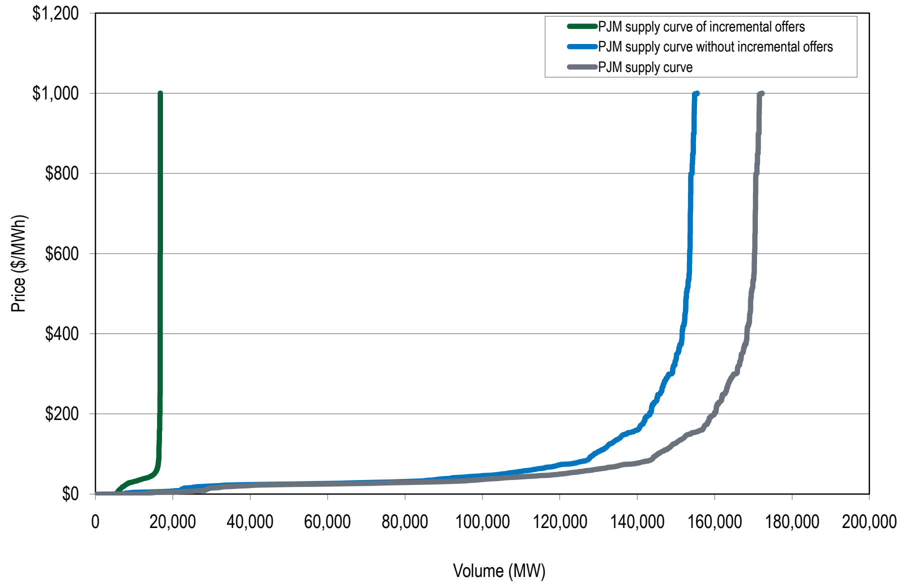
Figure 2-18 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve without increment offers and the system aggregate supply curve

61 There was an error in the classification of Financial and Physical participants in the initially published *2009 State of the Market Report for PJM*, which was corrected in the errata to the 2009 report published at <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2009/2009-errata.pdf>.

62 There was an error in the information about virtual offers by the top ten aggregates in the initially published *2009 State of the Market Report for PJM*, which was corrected in the errata to the 2009 report published at <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2009/2009-errata.pdf>.

with increment offers for an example day in March 2010. There were average hourly increment offers of 16,768 MW and average hourly total offers of 172,255 MW for the example day.

Figure 2-18 PJM day-ahead aggregate supply curves: 2010 example day



Price Convergence

When the PJM Day-Ahead Energy Market was introduced, it was expected that competition, exercised substantially through the use of virtual offers and bids, would tend to cause prices in the Day-Ahead and Real-Time Energy Markets to converge. But price convergence does not necessarily mean a zero or even a very small difference in prices between Day-Ahead and Real-Time Energy Markets. There may be factors, from operating reserve charges to risk that result in a competitive, market-based differential. In addition, convergence in the sense that Day-Ahead and Real-Time prices are equal at individual buses or aggregates is not a realistic expectation. PJM markets do not provide a mechanism that could result in convergence within any individual day as there is at least a one-day lag after any change in system conditions. As a general matter, virtual offers and bids are based on expectations about both Day-Ahead and Real-Time Market conditions and reflect the uncertainty about conditions in both markets and the fact that these conditions change hourly and daily. Substantial, virtual trading activity does not guarantee that market power cannot be exercised in the Day-Ahead Energy Market. Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative (Figure 2-19). There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis (Figure 2-20).

As Table 2-65 shows, day-ahead and real-time prices were relatively close, on average, in 2010. The simple annual average LMP in the Real-Time Energy Market was $0.26 per MWh or 0.6 percent higher than the simple annual average LMP in the Day-Ahead Energy Market in 2010.

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Table 2-65 Day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar year 2010

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Average	$44.57	$44.83	$0.26	0.6%
Median	$39.97	$36.88	($3.09)	(8.4%)
Standard deviation	$18.83	$26.20	$7.38	28.2%
Peak average	$52.67	$53.25	$0.58	1.1%
Peak median	$45.48	$43.20	($2.29)	(5.3%)
Peak standard deviation	$20.07	$28.93	$8.85	30.6%
Off Peak average	$37.46	$37.44	($0.02)	(0.1%)
Off Peak median	$33.73	$31.83	($1.90)	(6.0%)
Off Peak standard deviation	$14.27	$20.93	$6.66	31.8%

The price difference between the Real-Time and the Day-Ahead Energy Markets results, in part, from volatility in the Real-Time Energy Market that is difficult, or impossible, to anticipate in the Day-Ahead Energy Market. In 2010, the real-time, load-weighted, hourly LMPs were higher than day-ahead, load-weighted, hourly LMPs by more than $50 per MWh for 200 hours, more than $100 per MWh for 36 hours, more than $150 per MWh for 11 hours and more than $300 per MWh for 0 hours. Although real-time prices were higher than day-ahead prices on average in 2010, real-time prices were lower than day-ahead prices for 63.4 percent of the hours. During hours when real-time prices were higher than day-ahead prices, the average positive difference between them was $13.27 per MWh, which is much greater than the difference, $0.26, when all hours are included. During hours when real-time prices were less than day-ahead prices, the average negative difference was -$7.24 per MWh.

Table 2-66 shows the difference between the Real-Time and the Day-Ahead Energy Market Prices from 2000 to 2010. From 2000 to 2003, the real-time simple annual average LMP was lower than the day-ahead simple annual average LMP. Since 2004, the real-time simple annual average LMP has been higher than the day-ahead simple annual average LMP.[63]

63 Since the Day-Ahead Energy Market starts from June 1, 2000, the data in 2000 starts from June 1, 2000. However, the starting date for years 2001 to 2008 is January 1.

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Table 2-66 Day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar years 2000 to 2010

	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%

Table 2-67 provides frequency distributions of the differences between PJM real-time load-weighted hourly LMP and PJM day-ahead load-weighted hourly LMP for calendar years 2006 through 2010. The table shows the number of hours (frequency) and the percent of hours (cumulative percent) when the hourly LMP difference was within a given $50 per MWh price interval. From calendar year 2006 to calendar year 2010, LMP differences occurred predominantly in the range between -$50 per MWh and $50 per MWh. The largest PJM real-time and day-ahead load-weighted hourly LMP difference occurred in the calendar year of 2006 where an hourly price difference was greater than $500 per MWh. In 2007, the PJM real-time and day-ahead load-weighted hourly LMP differences are less than $150 per MWh in all but 14 hours. In 2008, the PJM real-time and day-ahead load-weighted hourly LMP differences are less than $150 per MWh in all but 7 hours. In 2009, the PJM real-time and day-ahead load-weighted hourly LMP differences were less than $100 per MWh in all but 5 hours. In 2010, the PJM real-time and day-ahead load-weighted hourly LMP differences are less than $150 per MWh in all but 11 hours.

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Table 2-67 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): Calendar years 2006 to 2010

	2006		2007		2008		2009		2010	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Fre-quency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($150)	1	0.01%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($150) to ($100)	1	0.02%	0	0.00%	1	0.01%	0	0.00%	0	0.00%
($100) to ($50)	9	0.13%	33	0.38%	88	1.01%	3	0.03%	13	0.15%
($50) to $0	5,205	59.54%	4,600	52.89%	5,120	59.30%	5,108	58.34%	5,543	63.42%
$0 to $50	3,372	98.04%	3,827	96.58%	3,247	96.27%	3,603	99.47%	3,004	97.72%
$50 to $100	152	99.77%	255	99.49%	284	99.50%	41	99.94%	164	99.59%
$100 to $150	9	99.87%	31	99.84%	37	99.92%	5	100.00%	25	99.87%
$150 to $200	4	99.92%	5	99.90%	4	99.97%	0	100.00%	9	99.98%
$200 to $250	1	99.93%	1	99.91%	2	99.99%	0	100.00%	2	100.00%
$250 to $300	3	99.97%	3	99.94%	0	99.99%	0	100.00%	0	100.00%
$300 to $350	0	99.97%	2	99.97%	1	100.00%	0	100.00%	0	100.00%
$350 to $400	1	99.98%	1	99.98%	0	100.00%	0	100.00%	0	100.00%
$400 to $450	0	99.98%	1	99.99%	0	100.00%	0	100.00%	0	100.00%
$450 to $500	1	99.99%	1	100.00%	0	100.00%	0	100.00%	0	100.00%
>= $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

Figure 2-19 shows the hourly differences between day-ahead and real-time load-weighted hourly LMP in 2010. Although the average difference between the Day-Ahead and Real-Time Energy Market was $0.26 per MWh for the entire year, Figure 2-19 demonstrates the considerable variation, both positive and negative, between day-ahead and real-time prices. The highest difference between real-time and day-ahead load-weighted hourly LMP was $225.84 per MWh for the hour ended 1600 on August 11, 2010, when the real-time load-weighted hourly LMP was $346.59 and the day-ahead load-weighted hourly LMP was $120.75.

Figure 2-19 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: Calendar year 2010

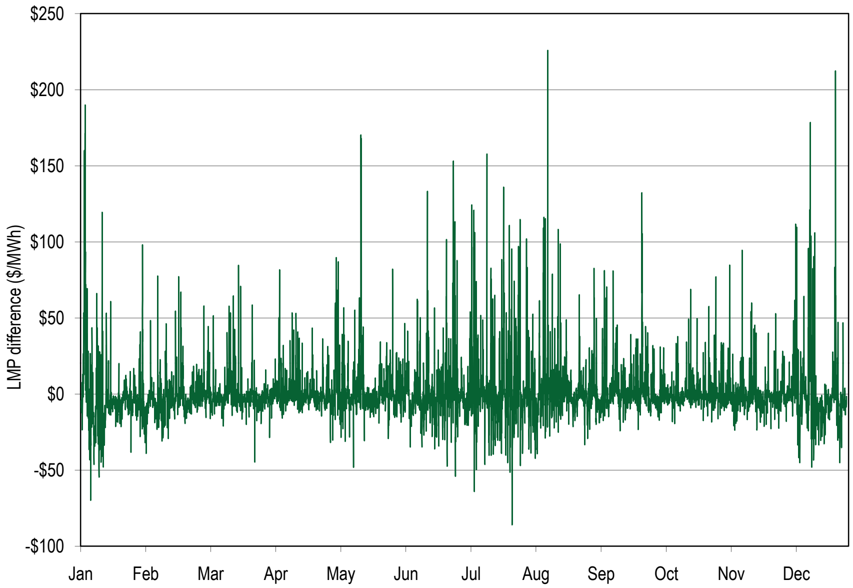

Figure 2-20 shows the monthly simple average differences between the day-ahead and real-time LMP in 2010. The highest monthly difference was in September.

Figure 2-20 Monthly simple average of real-time minus day-ahead LMP: Calendar year 2010

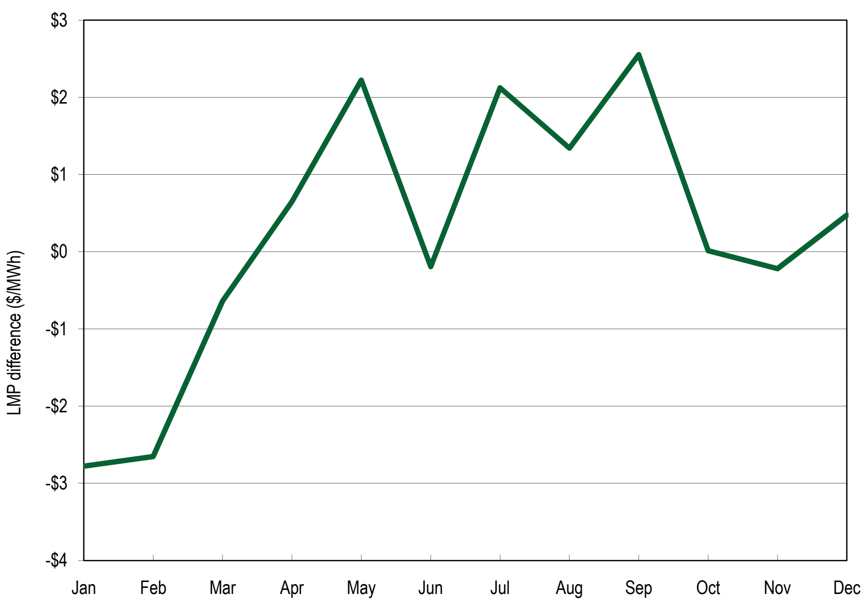

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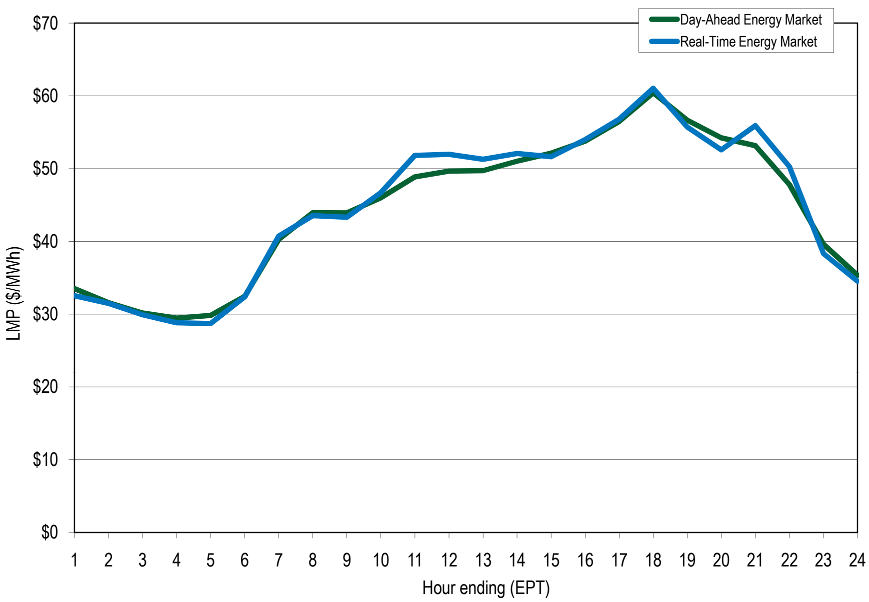
Figure 2-21 shows simple day-ahead and real-time LMP on an average hourly basis. Real-time simple average LMP was greater than day-ahead simple average LMP for 11 out of 24 hours.[64]

Figure 2-21 PJM system simple hourly average LMP: Calendar year 2010



Zonal Price Convergence

Table 2-68 shows 2010 zonal day-ahead and real-time simple annual average LMP. The difference between zonal day-ahead and real-time simple annual average LMP ranged from $0.87 in the PENELEC Control Zone, where the day-ahead simple annual average LMP was higher than the real-time simple annual average LMP, to $0.39 in the BGE Control Zone, where the day-ahead simple annual average LMP was lower than the real-time simple annual average LMP.

64 See the *2010 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market," for more details on the frequency distribution of prices.

Table 2-68 Zonal day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar year 2010

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
AECO	$50.44	$50.67	$0.22	0.4%
AEP	$38.30	$38.36	$0.06	0.2%
AP	$44.42	$44.62	$0.20	0.5%
BGE	$53.24	$53.63	$0.39	0.7%
ComEd	$33.37	$33.35	($0.02)	(0.1%)
DAY	$37.97	$38.11	$0.14	0.4%
DLCO	$37.84	$37.14	($0.70)	(1.9%)
Dominion	$51.16	$50.94	($0.22)	(0.4%)
DPL	$50.80	$51.04	$0.25	0.5%
JCPL	$50.21	$49.88	($0.33)	(0.7%)
Met-Ed	$48.98	$49.14	$0.16	0.3%
PECO	$49.58	$49.11	($0.47)	(1.0%)
PENELEC	$43.94	$43.07	($0.87)	(2.0%)
Pepco	$52.94	$52.85	($0.09)	(0.2%)
PPL	$47.67	$47.75	$0.08	0.2%
PSEG	$50.89	$50.97	$0.09	0.2%
RECO	$49.68	$49.18	($0.51)	(1.0%)

Price Convergence by Jurisdiction

Table 2-69 shows the 2010 day-ahead and real-time simple annual average LMPs by jurisdiction. The difference between day-ahead and real-time simple annual average LMP ranged from $0.37 in Virginia, where the day-ahead simple annual average LMP was higher than the real-time simple annual average LMP, to $0.36 in Indiana and Delaware, where the day-ahead simple annual average LMP was lower than the real-time simple annual average LMP.

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Table 2-69 Jurisdiction day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar year 2010

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Delaware	$49.74	$50.10	$0.36	0.7%
Illinois	$33.37	$33.35	($0.02)	(0.1%)
Indiana	$37.46	$37.45	($0.01)	(0.0%)
Kentucky	$38.37	$38.49	$0.13	0.3%
Maryland	$53.10	$53.18	$0.08	0.1%
Michigan	$37.97	$37.88	($0.09)	(0.2%)
New Jersey	$50.63	$50.60	($0.03)	(0.1%)
North Carolina	$49.34	$48.99	($0.34)	(0.7%)
Ohio	$37.39	$37.48	$0.09	0.2%
Pennsylvania	$46.31	$46.09	($0.22)	(0.5%)
Tennessee	$39.26	$39.27	$0.01	0.0%
Virginia	$49.83	$49.46	($0.37)	(0.7%)
West Virginia	$39.26	$39.49	$0.23	0.6%
District of Columbia	$53.02	$53.03	$0.01	0.0%

Load and Spot Market

Real-Time Load and Spot Market

Participants in the PJM Real-Time Energy Market can use their own generation to meet load, to sell in the bilateral market or to sell in the spot market in any hour. Participants can both buy and sell via bilateral contracts and buy and sell in the spot market in any hour. If a participant has positive net bilateral transactions in an hour, it is buying energy through bilateral contracts (bilateral purchase). If a participant has negative net bilateral transactions in an hour, it is selling energy through bilateral contracts (bilateral sale). If a participant has positive net spot transactions in an hour, it is buying energy from the spot market (spot purchase). If a participant has negative net spot transactions in an hour, it is selling energy to the spot market (spot sale).

Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In addition to directly serving load, load serving entities can also transfer their responsibility to serve load to other parties through eSchedules transactions referred to as wholesale load responsibility (WLR) or retail load responsibility (RLR) transactions. When the responsibility to serve load is transferred via a bilateral contract, the entity to which the responsibility is transferred becomes the load serving entity. Supply from its own generation (self-supply) means that the parent company is generating power from plants that it owns in order to meet demand. Supply from bilateral purchases means that the parent company is purchasing power under bilateral contracts at the same time that it is meeting load. Supply from spot market purchases means that the parent company is not generating enough power from owned plants and/or not purchasing enough power under bilateral contracts to meet load at a defined time and, therefore, is purchasing the required balance from the spot market.

The PJM system's reliance on self-supply, bilateral contracts and spot purchases to meet real-time load is calculated by summing across all the parent companies of PJM billing organizations that serve load in the Real-Time Energy Market for each hour. Table 2-70 shows the monthly average share of real-time load served by self-supply, bilateral contract and spot purchase in 2009 and 2010 based on parent company. For 2010, 11.8 percent of real-time load was supplied by bilateral contracts, 20.2 percent by spot market purchase and 68.0 percent by self-supply. Compared with 2009, reliance on bilateral contracts decreased 1.1 percentage points, reliance on spot supply increased by 3.2 percentage points and reliance on self-supply decreased by 2.1 percentage points.

Table 2-70 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: Calendar years 2009 to 2010

	2009			2010			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	12.6%	15.4%	72.0%	12.0%	17.4%	70.5%	(0.6%)	2.1%	(1.5%)
Feb	13.4%	14.5%	72.1%	13.5%	18.1%	68.4%	0.0%	3.7%	(3.7%)
Mar	13.8%	16.7%	69.5%	12.8%	18.2%	68.9%	(0.9%)	1.5%	(0.6%)
Apr	13.5%	17.2%	69.3%	12.6%	19.3%	68.1%	(0.9%)	2.0%	(1.2%)
May	14.6%	18.8%	66.7%	11.6%	19.9%	68.5%	(3.0%)	1.1%	1.9%
Jun	12.5%	16.5%	71.0%	10.4%	19.0%	70.5%	(2.1%)	2.5%	(0.5%)
Jul	12.6%	16.9%	70.5%	9.8%	19.5%	70.7%	(2.8%)	2.5%	0.2%
Aug	11.7%	16.0%	72.3%	10.6%	20.5%	68.9%	(1.2%)	4.5%	(3.4%)
Sep	12.5%	18.1%	69.4%	12.0%	22.3%	65.7%	(0.5%)	4.2%	(3.7%)
Oct	13.0%	19.8%	67.2%	13.0%	25.1%	61.9%	(0.0%)	5.3%	(5.3%)
Nov	13.2%	19.0%	67.8%	12.8%	22.7%	64.5%	(0.4%)	3.7%	(3.4%)
Dec	11.7%	16.8%	71.5%	11.5%	21.8%	66.7%	(0.2%)	5.0%	(4.8%)
Annual	12.9%	17.0%	70.1%	11.8%	20.2%	68.0%	(1.1%)	3.2%	(2.1%)

Day-Ahead Load and Spot Market

In the PJM Day-Ahead Energy Market, participants can not only use their own generation, bilateral contracts and spot market purchases to supply their load serving obligation, but can also use virtual resources to meet their load serving obligations in any hour. Virtual supply is treated as generation in the day-ahead analysis and virtual demand is treated as demand in the day-ahead analysis.

The PJM system's reliance on self-supply, bilateral contracts, and spot purchases to meet day-ahead load (cleared fixed-demand, price-sensitive load and decrement bids) is calculated by summing across all the parent companies of PJM billing organizations that serve load in the Day-Ahead Energy Market for each hour. Table 2-71 shows the monthly average share of day-ahead load served by self-supply, bilateral contracts and spot purchases in 2009 and 2010, based on parent companies. For 2010, 4.9 percent of day-ahead load was supplied by bilateral contracts, 19.3

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percent by spot market purchases, and 75.8 percent by self-supply. Compared with 2009, reliance on bilateral contracts decreased by 0.0 percentage points, reliance on spot supply increased by 4.4 percentage points, and reliance on self-supply decreased by 4.4 percentage points.

Table 2-71 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: Calendar years 2009 to 2010

	2009			2010			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	4.4%	13.7%	81.9%	4.6%	17.8%	77.6%	0.2%	4.1%	(4.3%)
Feb	4.5%	12.3%	83.2%	4.6%	18.4%	77.0%	0.1%	6.1%	(6.2%)
Mar	4.3%	12.8%	82.9%	4.8%	18.4%	76.8%	0.4%	5.7%	(6.1%)
Apr	4.4%	13.8%	81.7%	4.9%	19.1%	76.0%	0.4%	5.3%	(5.7%)
May	4.6%	15.6%	79.8%	6.6%	19.0%	74.4%	2.0%	3.4%	(5.4%)
Jun	4.7%	13.9%	81.4%	4.6%	18.6%	76.7%	(0.0%)	4.7%	(4.7%)
Jul	5.6%	16.0%	78.4%	4.7%	18.6%	76.6%	(0.9%)	2.6%	(1.7%)
Aug	5.2%	15.3%	79.5%	4.8%	19.3%	75.9%	(0.4%)	4.0%	(3.6%)
Sep	4.8%	16.1%	79.2%	4.6%	20.7%	74.8%	(0.2%)	4.6%	(4.4%)
Oct	5.0%	17.8%	77.2%	4.9%	22.7%	72.4%	(0.2%)	4.9%	(4.8%)
Nov	5.8%	15.9%	78.3%	4.9%	20.7%	74.4%	(0.9%)	4.8%	(3.9%)
Dec	5.2%	15.6%	79.2%	4.6%	19.2%	76.2%	(0.6%)	3.6%	(2.9%)
Annual	4.9%	14.9%	80.2%	4.9%	19.3%	75.8%	(0.0%)	4.4%	(4.4%)

Demand-Side Response (DSR)

Markets require both a supply side and a demand side to function effectively. The demand side of wholesale electricity markets is underdeveloped. Wholesale power markets will be more efficient when the demand side of the electricity market becomes fully functional.

A fully functional demand side of the electricity market means that end use customers or their designated intermediaries will have the ability to see real-time energy price signals in real time, will have the ability to react to real-time prices in real time, and will have the ability to receive the direct benefits or costs of changes in real-time energy use. In addition, customers or their designated intermediaries will have the ability to see current capacity prices, will have the ability to react to capacity prices and will have the ability to receive the direct benefits or costs of changes in the demand for capacity. A functional demand side of these markets means that customers will have the ability to make decisions about levels of power consumption based both on the value of the uses of the power and on the actual cost of that power.

Most end use customers pay a fixed retail rate with no direct relationship to the hourly wholesale market LMP. End use customers pay load serving entities (LSEs) an annual amount designed to

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recover, among other things, the total cost of wholesale power for the year.[65] End use customers paying fixed retail rates do not face even the hourly zonal average LMP. Thus, it would be a substantial step forward for customers to face the hourly zonal average price. But the actual market price of energy and the appropriate price signal for end use customers is the nodal locational marginal price. Within a zone, the actual costs of serving load, as reflected in the nodal hourly LMP, can vary substantially as a result of transmission constraints. A customer on the high price side of a constraint would have a strong incentive to add demand side resources if they faced the nodal price while that customer currently has an incentive to use more energy than is efficient, under either a flat retail rate or a rate linked to average zonal LMP. The nodal price provides a price signal with the actual locational marginal value of energy. In order to achieve the full benefits of nodal pricing on the supply and the demand side, load should ultimately pay nodal prices. However, a transition to nodal pricing could have substantial impacts and therefore must be managed carefully.

Today, most end use customers do not face the market price of energy, that is the locational marginal price of energy (LMP), or the market price of capacity, the locational capacity market clearing price. Most end use customers pay a fixed retail rate with no direct relationship to the hourly wholesale market LMP, either on an average zonal or on a nodal basis. This results in a market failure because when customers do not know the market price and do not pay the market price, the behavior of those customers is inconsistent with the market value of electricity. This market failure does not imply that PJM markets have failed. This market failure means that customers do not pay the actual hourly locational cost of energy as a result of the disconnect between wholesale markets and retail pricing. When customers pay a price less than the market price, customers will tend to consume more than if they faced the market price and when customers pay a price greater than the market price, customers will tend to consume less than they would if they faced the market price. This market failure is relevant to the wholesale power market because the actual hourly locational price of power used by customers is determined by the wholesale power market, regardless of the average price actually paid by customers. The transition to a more functional demand side requires that the default energy price for all customers be the day-ahead or real-time hourly locational marginal price (LMP) and the locational clearing price of capacity. While the initial default energy price could be the average LMP, the transition to nodal LMP pricing should begin.

PJM's Economic Load Response Program (ELRP) is designed to address this market failure by attempting to replicate the price signal to customers that would exist if customers were exposed to the real-time wholesale zonal price of energy and by providing settlement services to facilitate the participation of third party Curtailment Service Providers (CSPs) in the market.[66] In PJM's Economic Load Response Program (ELRP), participants have the option to receive credits for load reductions based on a more locationally defined pricing point than the zonal LMP. However, less than one percent of participants have taken this option while almost all participants received credits based on the zonal average LMP. PJM's proposed PRD program did incorporate some aspects of nodal pricing, although the link between the nodal wholesale price and the retail price was extremely attenuated.

65 In PJM, load pays the average zonal LMP, which is the weighted average of the actual nodal locational marginal price. Load serving entities (LSEs) make direct payments through the PJM settlement process on behalf of individual customers. LSEs settle using average LMP for zones or aggregates. At the LSE level, there would be no difference in payments between average and nodal LMP because LSEs make payments for all their customers. The LSE level is not where the relevant price signal occurs because LSEs simply pass through the payment obligations of individual customers. Individual customers, almost with exception, pay average LMP for a zone or an aggregate. While individual customers have the option to pay nodal LMP, very few customers do so.

66 While the primary purpose of the ELRP is to replicate the hourly zonal price signal to customers on fixed retail rate contracts, customers with zonal or nodal hourly LMP contracts are currently eligible to participate in the DA scheduling and the PJM dispatch options of the Program.

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PJM's Load Management (LM) Program in the RPM market also attempts to replicate the price signal to customers that would exist if customers were exposed to the locational market price of capacity. The PJM market design also creates the opportunity for demand resources to participate in ancillary services markets.[67]

PJM's demand side programs, by design, provide a work around for end use customers that are not otherwise exposed to the incremental costs of energy and capacity. They should be understood as one relatively small part of a transition to a fully functional demand side for its markets. The complete transition to a fully functional demand side will require explicit agreement and coordination among the Commission, state public utility commissions and RTOs/ISOs.

A different approach to compensating demand response currently is under consideration at the FERC. In a proposed rule issued March 18, 2010, the Commission proposes requiring the organized markets to pay LMP to participants in demand response programs over and above the savings that result from the decision not to consume.[68] This rule would operate as a subsidy to participants in demand response programs from all other participants in the markets and could significantly alter consumption choices, particularly if it is extended to customers who already pay LMP for energy. Such a rule could also aggravate the consequences of PJM's inadequate rules for measurement and verification of the levels of demand response provided. On May 13, 2010, the MMU filed comments explaining its concerns:

> [T]he result of the proposed implementation of this policy would be that demand side participants would receive the LMP plus the avoided cost of purchasing power. For customers already paying retail rates equal to the LMP, such compensation would be twice LMP. This proposal is inconsistent with fundamental economics and, if adopted by the Commission would over compensate participants in economic load response programs, negatively affect the efficient operation of the energy markets and provide no offsetting social benefit.[69]

The MMU also explained how its analysis of levels of demand response participation should be evaluated, noting that "the evidence does not support the claim that the removal of the incentive program resulted in a reduction of activity in the Economic Program."[70] Currently, a decision on the proposed rule is pending.

67 See the *2010 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Service Markets."
68 See *Demand Response Compensation in Organized Wholesale Energy Markets*, Notice of Proposed Rulemaking, 130 FERC ¶61,213 ("DSR NOPR").
69 "Comments of the Independent Market Monitor for PJM," Docket No. RM10-17-000, at 2.
70 "Comments of the Independent Market Monitor for PJM," Docket No. RM10-17-000, at 9.

PJM Load Response Programs Overview

All load response programs in PJM can be grouped into the Economic and the Emergency Programs. Table 2-72 provides an overview of the key features of PJM load response programs.[71]

Table 2-72 Overview of Demand Side Programs

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.

Economic Load Response

In the Economic Load Response Program (ELRP, or the Economic Program), all hours are eligible and all participation is voluntary. The ELRP Program is designed to facilitate the participation of demand response in PJM Energy Markets. Participation in the ELRP takes three forms: submitting a sell offer into the Day-Ahead Market that clears; submitting a sell offer into the Real-Time Market that is dispatched; and self scheduling load reductions while providing notification to PJM. In the first two methods, a load reduction offer is submitted to PJM through the eMkt system specifying the minimum reduction price, including any associated shutdown costs, and the minimum duration of the load reduction.

The fundamental purpose of PJM's Economic Load Response Program is, or should be, to address a specific market failure, which is that many retail customers do not pay the market price or LMP. Based on this purpose, the design goal of the Economic Program incentives should be to replicate the price signal to customers that would exist if customers were exposed to the real-time wholesale

71 For more detail on the historical development of PJM Load Response Programs see the *2010 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part 1". <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2010.shtml>.

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price. The real-time hourly nodal LMP is the appropriate price signal as it reflects the incremental value of each MWh consumed.[72]

Retail customers pay retail rates including components that reflect the cost of generation (or power purchased from the wholesale market), the cost of transmission and the cost of distribution. Under a rate design consistent with the purpose of the demand-side program, the hourly LMP would replace only the generation component of retail rates in order to provide the appropriate wholesale market price signal to customers. Accordingly, the appropriate compensation for load reductions in the Economic Program is LMP less the generation component of the applicable retail rate per MWh. Nonetheless, it would be a reasonable approach to the policy objective of increasing demand side participation to pay the full LMP to retail customers who pay flat retail rates, for accurately measured load reductions. But it would not be reasonable to pay full LMP to customers who already pay LMP directly rather than a flat retail rate. In that case, the market failure that the program is designed to address does not exist. Payment of full LMP to customers already paying LMP would be paying the customer twice for the same action.

The Economic Load Response Program's primary function is to provide a mechanism for fixed rate customers to receive the full market value of savings associated with changes in energy consumption, determined by the hourly Locational Marginal Price (LMP).

The PJM Economic Load-Response Program is a PJM-managed accounting mechanism that provides for payment of the savings that result from load reductions to the load-reducing customer. Such a mechanism is required because of the complex interaction between the wholesale market and the retail incentive and regulatory structures faced by both LSEs and customers. The broader goal of the Economic Program is a transition to a structure where customers do not require mandated payments, but where customers see and react to market prices or enter into contracts with intermediaries to provide that service. Even as currently structured, however, and even with the reintroduction of the defined subsidies, if they exclude previously identified inappropriate components, the Economic Program represents a minimal and relatively efficient intervention into the market.[73]

Emergency Load Response

In the Emergency Load Response Program, only hours in which PJM has declared an Emergency Event are eligible. Participation may be voluntary or mandatory, and payments may include energy payments, capacity payments or both.

As a result of Reliability Pricing Model (RPM) implementation on June 1, 2007, the Load Management (LM) Program was introduced as the mechanism for Emergency Program customers and other DR providers to participate in RPM. Customers in the Emergency-Full and Emergency-Capacity Only options of the Emergency Program are committed capacity resources, which receive RPM capacity payments and which are subject to RPM penalties for noncompliance during emergency events.

72 This does not mean that every retail customer should be required to pay the real-time nodal LMP, regardless of their risk preferences. However, it would provide the appropriate price signal if every retail customer were required to pay the real-time nodal LMP as a default. That risk could be hedged via a contract with an intermediary. The transition to full nodal pricing from average zonal LMP will appropriately be implemented gradually because it can be expected to have significant impacts on some customers.

73 One such inappropriate component was the payment of subsidies to customers who were already exposed to hourly LMP pricing.

Emergency-Full customers are also eligible for energy payments for reductions during emergency events.[74]

There are three options for Emergency Load Response registration and participation: energy only; capacity only; and capacity plus energy (full emergency option).

Energy Only

In the Energy Only option, participants submit a minimum dispatch price for load reductions during emergency events, which include shutdown costs and a minimum duration. All participation is voluntary. This option of the Emergency Program is similar to the Economic Program in that it provides only energy payments and all participation is voluntary. However, compensation differs significantly between the two programs as Energy Only participants in the Emergency Program receive the greater of LMP or the value of the submitted minimum dispatch price, including shutdown, for the duration of the emergency reduction.

Capacity Only

In the Capacity Only Program option, participants are considered a capacity resource, and are obligated to reduce load during emergency events. This option includes registered Interruptible Load for Reliability (ILR) as well as Demand Response (DR) offered into RPM Auctions. Participation during an emergency event or capacity testing is mandatory and failure to reduce will result in a compliance test failure charge. The participant receives capacity payments, however, no energy offers are submitted and no energy payments during emergency events are applicable. This option exists to accommodate registrations in which the Curtailment Service Provider may only provide capacity related services or situations in which the customer is participating in the Economic Program or in Ancillary Service markets through another program registration.

Capacity plus Energy (Full Emergency Option)

Similar to the Energy Only option, participants in the Full Emergency option submit minimum dispatch prices associated with reductions during emergency events. In addition, they are considered committed capacity resources and receive capacity payments. Participation during an emergency event or capacity testing is mandatory and failure to reduce will result in a compliance test failure charge. This option only applies to Demand Response (DR) offered into RPM Auctions.

Minimum Dispatch Price

During an emergency event, participants registered in the Full Emergency option and the Emergency Energy Only option will be paid the higher of the submitted minimum dispatch price or the zonal real-time LMP for emergency reductions. The minimum dispatch price, which is submitted by the participant, acts as a floor for energy compensation during an emergency event. Given the current program rules, market participants have an incentive to submit a minimum dispatch price at the

74 For additional information on RPM provisions for customers in the Emergency Load Response Program, see PJM, "Manual 18: PJM Capacity Market", Revision 10 (June 1, 2010).

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maximum threshold for energy bids of $1,000/MWh. For the 2010/2011 delivery year, approximately 79 percent of registered sites representing 73 percent of registered MW in the Emergency Full Capacity option submitted a minimum dispatch price of either $999 or $1,000 per MWh.

There is no relationship between the minimum dispatch price and the locational price of energy or the participant's costs associated with not consuming energy. The minimum dispatch price is also not a meaningful signal from the participant about its willingness to curtail. In the Emergency Full option, end use participants are already contractually obligated to curtail during an emergency event because they are capacity resources and receive capacity payments. Thus, the ability to submit a minimum dispatch price is a guarantee of an energy payment for resources that are already required to curtail, regardless of their minimum dispatch price. The appropriate energy payment for a load reduction during an emergency event is the hourly LMP less any generation component of their retail rate. For customers on a real-time LMP contract, no energy payment is necessary because the customer saves the hourly LMP by not consuming during an emergency event. Any energy payment to customers on a flat retail rate in excess of the real-time LMP net of generation costs results in a subsidy, subject to the caveat that such a subsidy may be an appropriate policy for a limited transition period.[75]

In the Economic Program, customers also have the opportunity to submit a minimum price at which they will curtail. However, customers in the Economic Program will be dispatched economically and paid the real-time LMP less the generation and transmission component of their fixed retail rate only if they are dispatched.[76] Under the Emergency Energy Only option and the Emergency Full option, participants are made whole to a minimum strike price offer regardless of the hourly LMP. There is no economic reason to compensate load reductions up to $1,000/MWh during an emergency event regardless of the hourly LMP.

The MMU recommends that the option to specify a minimum dispatch price under the Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. The MMU also recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the Economic Program.

Load Management

Load Management generally refers to the integration of load response resources into RPM and thus encompasses both Emergency Load Response Options pertaining to capacity: Full and Capacity Only.

The Load Management (LM) program was, from its inception in June 2007, comprised of two types of resources: Interruptible Load for Reliability (ILR) resources and Demand Resources (DR).[77] Customers offering DR resources submit a capacity sell bid into an RPM Auction and are paid the clearing price. Interruptible load for reliability (ILR) resources must be certified at least three months prior to the delivery year and are paid the final zonal ILR price. The ILR option was eliminated on

75 Energy Only participants are also paid the higher of the real-time LMP and the submitted minimum dispatch price. However, there are currently no participants registered under this option.
76 OA Schedule 1 § 3.3A.4(a).
77 As part of the transition to RPM, effective June 1, 2007, the PJM active load management (ALM) program was changed to the load management (LM) program.

March 26, 2009 for the delivery year beginning June 1, 2012.[78] A DR resource must be registered in the Emergency Full option or the Capacity Only option.

The purpose of the Load Management Program is to provide a mechanism for end-use customers to avoid paying the capacity market clearing price in return for agreeing to not use capacity when it is needed by customers who have paid for capacity. The fact that customers in the Load Management Program only have to agree to interrupt ten times per year for a maximum duration of six hours per interruption represents a flaw in the design of the program. There is no reason to believe that the customers who pay for capacity will need the capacity used by participating LM customers only ten times per year. In fact, it can be expected that the probability of needing that capacity will increase with the amount of MW that participating LM customers clear in the RPM auctions.

Measurement Options

Participation in the Load Management (LM) Program can be distinguished by measurement and verification protocol: (1) Direct Load Control (DLC), (2) Firm Service Level (FSL), and (3) Guaranteed Load Drop (GLD).

The DLC method is used for customers in the Pilot Program for non-hourly metered customers. For DLC customers, a CSP will interface directly with customer equipment, sending a communication to cycle when PJM has declared an event. Load reductions are estimated through PJM reported or site surveyed impact studies. GLD customers establish a baseline of unrestricted consumption absent the emergency event. The load reduction for GLD customers is defined as the difference between baseline consumption and actual consumption. FSL customers establish a firm consumption level which they must reach during an emergency event and the difference between that firm service level and the Peak Load Contribution (PLC) is the amount nominated in the LM Program.

Recent Developments

Economic Incentive Payments

In a notice of proposed rulemaking issued March 18, 2010, the Commission proposed to require the organized markets to pay full LMP to participants in demand response programs.[79] This proceeding, applicable to all of the organized markets, terminated and replaced a filing by PJM to reintroduce incentive payments in the Economic Program since the expiration of such provision effective December 31, 2007.[80] On August 24, 2009, PJM filed a proposal that would have provided for compensating fixed price demand response customers at LMP less the generation portion of their retail rates (LMP – G), rather than LMP less the generation and transmission portions.[81] In addition, it would have provided for incentive payments to reduce consumption in the nine percent of hours when LMP is at its highest levels, and would sunset when there were 1,000 MW of additional price responsive demand capability for small and medium-sized end-use customers.[82]

78 126 FERC ¶ 61,275 (2009).

79 DSR NOPR. See discussion *supra* at pp.1–4 and footnote 3.

80 PJM Interconnection, LLC, Letter Order, Docket No. ER04-1193-000 (October 29,2004).

81 *Id.* at P 23; Supplemental Report and Submittal of PJM Interconnection, L.L.C. in Support of Further Commission Action on Rehearing, initially filed in EL08-12-000 (“Supplemental Report”). The FERC determined to initiate a new proceeding with this filing, docketed as EL09-68-000.

82 Supplemental Report at 5-6.

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Under the proposal, fixed rate customers would have been eligible for full LMP for reductions during these 9 percent of hours, and customers already on an hourly Day-Ahead or Real-Time LMP contract would be eligible for an incentive payment of $75/MWh for each reduction during these nine percent of hours.

Role of Relevant Electric Retail Regulatory Authorities (RERRAs)

In two interrelated proceedings, PJM and the Commission addressed the role of relevant electric retail regulatory authorities (or RERRAs) in approving participation in its Economic and Emergency Load Response Programs.[83] Demand response programs raise a jurisdictional conundrum because, on the one hand, they concern retail consumption, a state issue, and, on the other hand, they involve treating demand response as if it were a wholesale supply resource, a Federal issue. PJM submitted a filing to address the issue, and the Commission concurrently took up the issue in its rulemaking proceeding concerning reform of the organized markets.[84] Under the resulting rule, RERRAs must take affirmative action to permit participation by customers served by EDCs that distributed four million MWh or less during the previous fiscal year and take affirmative action to prohibit participation by customers served by EDCs that distributed more than four million MWh for the year.[85]

Load Management Task Force Proposed Rule Changes

The Load Management Task Force (LMTF) was established by the Markets Implementation Committee (MIC) on February 17, 2010, to review recommendations and observations published in the review of Load Management Test Performance from the 2009/2010 Delivery Year. Three proposals were developed for Load Management business rule changes and presented to the MIC for voting on October 12, 2010, and ultimately to the MC on November 11, 2010. Each proposal addressed six areas: (1) clarify resolution process and CSP role in case of meter malfunction; (2) provide for PJM to calculate load drop estimates and require 24 hours of load data in compliance submittal; (3) allow CSP to forgo retesting specific resources rather than requiring all failed resources to retest simultaneously; (4) eliminate application of daily deficiency and test/event penalty to same MW; (5) establish more stringent replacement capacity criteria; and (6) clarify protocols for Guaranteed Load Drop (GLD) measurement and verification. The three proposals were identical except for the sixth provision, specifically addressing the double counting issue.

Double Counting Issue

PJM procures capacity for load-serving entities (LSEs) through the Reliability Pricing Model (RPM). LSEs use customers' Peak Load Contribution or PLC to allocate capacity obligations and the cost of capacity among their customers.[86] Use of PLC as a basis for allocating capacity obligations and capacity costs predates the establishment of PJM's current capacity market, the Reliability Pricing Model (RPM); emergency demand response programs; and even the organized wholesale electricity markets. Large, sophisticated customers have also managed their PLCs for many years

83 Dockets Nos. ER09-701-000 and RM07-19-000.

84 *Id.*

85 PJM filing in ER09-701-005; Letter Order in Docket No. ER09-701-005 (July 29, 2010); OA Schedule 1 § 1.5A.

86 The peak load contribution (PLC) is measured by a customer's consumption during the five coincident peak hours in the prior year.

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to achieve a lower PLC and, as a result, reduce their obligation to purchase capacity and reduce their payments for capacity. (Such customers are termed self managing.)

Prior to the introduction of demand response programs it was reasonable to assume that customers managing their PLC would continue to manage their PLC going forward in order to continue to reduce their obligation to purchase capacity. It was not deemed necessary to formalize a managed PLC as an obligation to reduce customer load during times of system peak load because continued management of the PLC resulted in reduced loads on high load days. Prior to the introduction of RPM and DR programs, the incentives to manage PLC and the resultant actions were consistent with economic signals and generally resulted in a match between reduced peak loads and reduced capacity payments. PLC management was and continues to be, in effect, a market based demand side management program.

The PJM Emergency Demand Response program provides customers an alternative to managing PLC as a way to reduce the obligation to purchase capacity. A customer can register as a capacity resource in the Program and receive credit for the amount of capacity it is willing to curtail in a given delivery year. The amount that can be nominated in the Program is limited to the customer's current PLC.[87] In return for not paying for the capacity associated with that curtailed load, the customer agrees to reduce load by that amount when customers who are paying for the capacity need it. A party that manages PLC avoids paying for capacity, but also assumes responsibility for determining when to curtail. Participants in PJM's Emergency Load Response Program curtail when called by PJM.

Self managed customers who elect the Guaranteed Load Drop (GLD) measurement and verification option will show substantial apparent measured over compliance during an Emergency LM event. The over compliance results from the fact that the GLD option measures compliance as the reduction in real time consumption from a baseline established by actual recent consumption. This baseline consumption reflects full load rather than managed load and thus will reflect consumption above a customer's PLC. The reduction observed for compliance will show the full reduction capability of the customer, including the load that the customer already reduced to manage its PLC. The measured reduction may be significantly higher than the amount nominated in the LM Program, which may not exceed the PLC.

Double counting takes two forms. Double counting may exist at an individual customer level or at a CSP portfolio level.

At the level of an individual customer, when a customer that previously managed its PLC shows measured over compliance based on GLD, the result is a disconnect between the amount of capacity that a customer did not pay for based on its availability to be curtailed, and the amount offered by the customer in the delivery year as a reduction. In the same delivery year, due to the lag between PLC management and associated savings, the customer pays for capacity equal to the lower PLC and, if consumption is greater than PLC, may request and receive credit for not using capacity that was not paid for. That credit constitutes double counting. This double counting at an individual customer level occurs when the PJM rules limiting nominations to the PLC are interpreted as permitting a reduction from peak load by the amount of the PLC rather than permitting only a

87 OATT Attachment DD-1 § J.

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reduction below the PLC level. Only the second is a logical interpretation and consistent with the fundamental economics and appropriate incentives.

At the portfolio level, the double counting issue is exacerbated when customers with managed PLCs are included in a portfolio managed by a Curtailment Service Provider (CSP). Although a GLD customer that has managed its PLC cannot claim a capacity benefit greater than its nomination, the netting rules permit a CSP to use measured over compliance from such customers in its portfolio to offset underperforming resources in its portfolio. Netting is not the issue. The use of apparent overcompliance as the basis for netting creates the double counting issue at the portfolio level.

It is double counting because the self managing customer is incurring a capacity obligation only equal to its PLC and therefore paying for capacity only equal to its PLC, but the CSP is being paid for reducing load from peak to PLC. The customer, through the CSP, is selling back to PJM capacity that it did not purchase. The CSP itself is not paid twice for this load reduction, but the customer is paid for the load reduction through its lower PLC and the CSP is paid again for the same load reduction.

Netting is appropriate when it recognizes additional reductions below PLC in excess of nominated levels. However, the rules should explicitly prohibit CSPs from crediting apparent over compliance against underperforming parts of its portfolio when such over compliance is attributable to reductions which occur at MW levels greater than PLC.

The data on customer compliance show that some LM participants that selected the GLD method for measurement and verification managed their PLCs in prior years, and that the load reductions associated with these participants account for a significant portion of overall compliance. Table 2-51 shows that, in 2010, of the total load reductions submitted for Load Management events by customers using the GLD measurement and verification approach, 41 percent of the MW of submitted load reductions were in excess of customers' PLCs and that 28 percent of such MW were in excess of 150 percent of customers' PLCs. This is strong evidence that double counting is a significant issue.

PJM has been working to address this issue with stakeholders.[88] The double counting issue can be directly resolved by not permitting the overcompliance which results from the interaction between PLC management and the PJM DR Program. A simple way to achieve this result would be to revise Attachment A to PJM Manual 18 (Load Forecasting and Analysis) to cap the baseline for measuring compliance under GLD at the customers' PLC. The MMU has stated that the issue requires urgent action prior to the 2011/2012 delivery year.[89]

The issue is further complicated by the disconnect between the load reduction value used to measure compliance and the addback process, which is part of determining the customer's capacity obligation for the following year. When an LM customer, which does not directly manage PLC, reduces load during an Emergency event, that reduction will generally reduce the customer's PLC and therefore its obligation to purchase and pay for capacity in the following year.[90] If the

88 For more information including a detailed example, see the IMM/PJM joint statement regarding double counting: <http://www.MonitoringAnalytics.com/reports/Market_Messages/Messages/PJM_IMM_Joint_Statement_DR_Double_Counting_20110204.pdf>.

89 The MMU's presentation to the MIC on the Double Counting Issue: <http://www.pjm.com/~/media/committees-groups/committees/mic/20101012/20101012-item-04g-plc-add-back-proposal-ma.ashx>.

90 If the event coincides with one of the five coincident peak hours.

customer appropriately participates in the LM program, it is paid for its reductions from its PLC. The addback means that the reduction is added back to the customer's load in order to ensure that its peak load and therefore PLC are correctly calculated for the next year. The addback prevents the PLC for such a customer from being inappropriately reduced as a result of participation in the LM program. The addback ensures that in the following year, the customer's load obligation reflects unmanaged levels and thus the customer will be able to nominate up to its full reduction in that year. The problem arises because the addback is limited to the amount nominated in the current delivery year. Thus, when a customer shows measured overcompliance in excess of its nomination, the addback is limited to the nomination. As a result, the customer's PLC is understated for the next year, which means that the customer's capacity obligation is understated and creating the potential for an additional double counting issue for the customer.

Price Responsive Demand

In 2010, PJM proposed business rules for the integration of Price Responsive Demand (PRD) into PJM Markets. PRD customers would be end use customers on time varying retail rate contracts that utilize advanced metering infrastructure (AMI) and automated response capabilities such that changes in consumption occur automatically as result of changes in price signal.

PJM sought to incorporate information on PRD into the Energy Markets and the Capacity Market to improve real time dispatch efficiencies and to reflect PRD response in capacity auctions through load forecasts reflecting PRD.

While the goal of directly addressing the disconnect between wholesale and retail prices is a good one, the PRD construct would not have effectively accomplished that objective.[91] The PRD construct did not actually require that customers pay the nodal LMP and thus the central issue was not effectively addressed. In the PRD construct, participating customers would have the ability to set price in emergency conditions while avoiding capacity charges rather than being treated as an economic resource and interrupted prior to the declaration of an emergency.

Demand Response Saturation Analysis

On December 2, 2010, PJM proposed, and by order issued January 31, 2011, the Commission approved, an unlimited demand-side capacity product, which it terms "Annual DR," that could have significantly improved the market design for PJM's capacity market.[92] Unfortunately, the potential benefit of an unlimited demand-side product will not be realized without the elimination of the current flawed DR product, which PJM now refers to as "Limited DR." PJM provided testimony explaining how Limited DR is seriously flawed and poses an increasing reliability risk, but did not propose to eliminate it.[93]

PJM also proposed and the Commission accepted another new product, which PJM terms "Extended Summer DR." This product creates potentially significant new problems because it does not fit into a market that defines capacity as an annual product.

91 See "MMU Proposal on Price Responsive Demand (PRD)," presented to the MRC (November 17, 2010), which can be accessed at: <http://www.MonitoringAnalytics.com /reports/Presentations/2010/IMM_MRC_MMU_Proposal_on_PRD_20101117.pdf>.

92 PJM filing in Docket No. ER11-2288-000; 134 FERC ¶ 61,066.

93 PJM filing in Docket No. ER11-2288-000, Attachments A (Affidavit of Thomas A. Falin on Behalf of PJM Interconnection, L.L.C.) & B (Affidavit of Michael E. Bryson on Behalf of PJM Interconnection, L.L.C.).

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A single unlimited demand-side capacity product is all that the PJM capacity market needs, and such a product could provide maximum flexibility for participants whatever their particular operational characteristics or preexisting investment. Given that Curtailment Service Providers (CSPs) can and do aggregate participants into portfolios eligible to serve as DR, the market design can accommodate participation by any customer. CSPs are better situated than PJM to play the role of aggregator, and providing CSPs with an incentive to do so will sustain the growth of demand-side participation in PJM markets.

The MMU filed a protest explaining the above concerns. In rejecting them, the Commission explained, among other things, "arguments to eliminate or change PJM's current Limited DR product [are] outside of the scope of the proceeding" and "PJM's proposal will ensure that enough capacity is committed to meet the area's needs, and also send a price signal to encourage the development of less-limited resources."[94,95]

Participation

In 2010, in the Economic Program, participation became more concentrated compared to 2009. There were lower participation levels in terms of settlements submitted and active registrations in 2010 compared to 2009, however, activity in terms of settled MWh and credits increased. The number of sites registered decreased more significantly than the level of registered MW. While the number of settlements submitted is down compared to 2009, credits increased as result of higher price levels compared to 2009 and reductions increased which suggests larger customers on average.

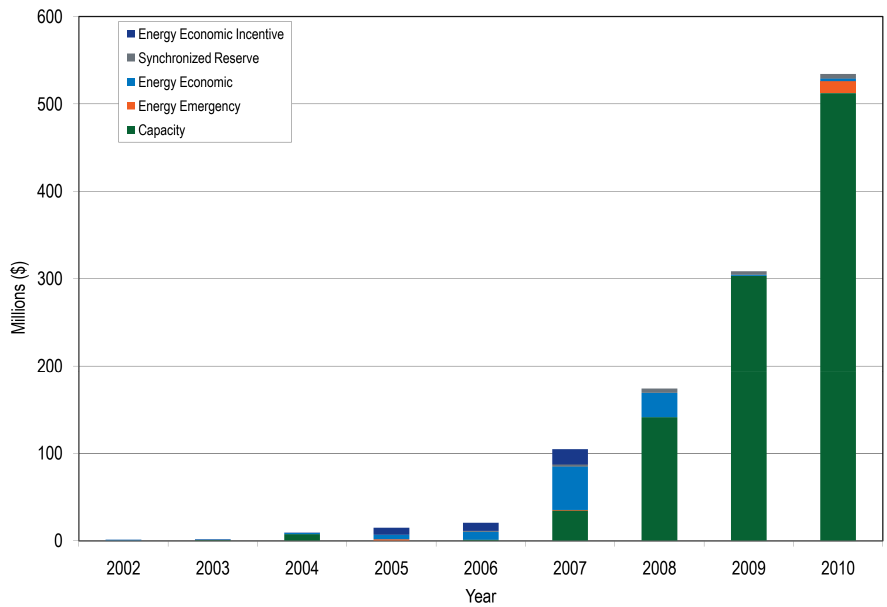
In 2010, the Emergency Program, specifically, the LM Program, participation increased compared to 2009. For the 2010/2011 delivery year, there were 9,052.4 MW registered in the LM Program, compared to 7,294.3 MW registered in the 2009/2010 delivery year.

Figure 2-22 shows all revenue from PJM Demand Side Response Programs by market for the period 2002 through 2010. Since the implementation of the RPM design on June 1, 2007, the capacity market has become the primary source of revenue to DSR participants. Economic Program revenue declined in 2008 while capacity revenue increased significantly. In 2010, Economic Program revenue increased by $1.5 Million or 111 percent, from $1.4 Million to $2.9 Million. Capacity revenue increased by $209 million or 69 percent, from $303 million to $512 million. Synchronized Reserve credits increased by $1.3 million, from approximately $4.0 million to $5.3 million from 2009 to 2010. Emergency energy payments are made to resources through the Emergency Program for reductions during PJM-declared Load Management Events. In 2009, since there were no Load Management Events, no emergency energy revenues were paid. In 2010, there were six Load Management Events resulting in $13.8 million in emergency energy revenues.

94 134 FERC ¶ 61,066 at PP 32 & 41.

95 "Protest of the Independent Market Monitor for PJM," in Docket No. ER11-2288-000 at 1–2 (December 20, 2010).

Figure 2-22 Demand Response revenue by market: Calendar years 2002 through 2010



Economic Program

Table 2-73 shows the number of registered sites and MW per peak load day for calendar years 2002 through 2010.[96] On July 6, 2010, there were 1,725.7 MW registered in the Economic Program compared to the 2,486.6 MW on August 10, 2009, and a 30.6 percent decrease in peak load day capability. Program totals are subject to monthly and seasonal variation, as registrations begin, expire and renew. Table 2-74 shows registered sites and MW for the last day of each month for the period calendar years 2007 through 2010. Registered sites and MW have been consistently lower than historical levels since April of 2009.[97] Registrations dipped sharply in June but rebounded in July, which is likely the result of expirations and renewals. Registration in the Economic Program means that customers have been signed up and can participate if they choose. Thus, registrations represent the maximum level of potential participation.

96 Table 2-73 and Table 2-74 reflect distinct registration counts. They do not reflect the number of distinct sites registered for the Economic Program, as multiple sites may be aggregated within a single registration.

97 The site count and registered MW associated with May 2007 are for May 9, 2007. Several new sites registered in May of 2007 overstated their MW capability, and it remains overstated in PJM data.

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Table 2-73 Economic Program registration on peak load days: Calendar years 2002 to 2010

	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

Table 2-74 Economic Program registrations on the last day of the month: January 2007 through December 2010

	2007		2008		2009		2010	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	508	1,530	4,906	2,959	4,862	3,303	1,841	2,623
Feb	953	1,567	4,902	2,961	4,869	3,219	1,842	2,624
Mar	959	1,578	4,972	3,012	4,867	3,227	1,845	2,623
Apr	980	1,648	5,016	3,197	2,582	3,242	1,849	2,587
May	996	3,674	5,069	3,588	1,250	2,860	1,875	2,819
Jun	2,490	2,168	3,112	3,014	1,265	2,461	813	1,608
Jul	2,872	2,459	4,542	3,165	1,265	2,445	1,192	2,159
Aug	2,911	2,582	4,815	3,232	1,653	2,650	1,616	2,398
Sep	4,868	2,915	4,836	3,263	1,879	2,727	1,609	2,447
Oct	4,873	2,880	4,846	3,266	1,875	2,730	1,606	2,444
Nov	4,897	2,948	4,851	3,271	1,874	2,730	1,605	2,444
Dec	4,898	2,944	4,851	3,290	1,853	2,627	1,598	2,439
Avg.	2,684	2,408	4,727	3,185	2,508	2,852	1,608	2,435

Table 2-75 shows the zonal distribution of capability in the Economic Program on July 6, 2010. The PECO Control Zone includes 136 sites or 15 percent of sites and 7 percent of registered MW in the Economic Program. The BGE Control Zone includes 62 sites or 7 percent of sites and 28 percent of registered MW in the Economic Program.

Table 2-75 Distinct registrations and sites in the Economic Program: July 6, 2010[98]

	Registrations	Sites	MW
AECO	32	33	14.6
AEP	45	45	52.3
AP	53	55	185.0
BGE	62	63	476.0
ComEd	75	76	111.7
DAY	8	8	10.5
DLCO	89	89	199.3
Dominion	37	40	97.7
DPL	31	31	72.8
JCPL	40	43	100.9
Met-Ed	49	51	55.3
PECO	136	137	116.9
PENELEC	48	49	35.4
Pepco	26	26	26.9
PPL	114	119	144.3
PSEG	53	94	25.7
RECO	1	1	0.3
Total	899	960	1,725.7

The total MWh of load reduction and the associated payments under the Economic Program are shown in Table 2-76.[99] Load reduction levels increased by 15,600 MWh, from 57,157 MWh in 2009 to 72,757 MWh in calendar year 2010, a 21 percent increase.[100] Total payments in the Economic Program increased $1.5 Million, from $1.4 Million in 2009 to $2.9 Million in 2010, a 111 percent increase. Payments per MWh were $42.2 in 2010 compared to $23 in 2009. The Economic Program's actual load reduction per peak-day, registered MW increased to 42.2 MWh for calendar year 2010, an increase of 83 percent from 2009.[101] In calendar year 2010, the maximum hourly load reduction attributable to the Economic Program was 548.3 MW on August 10.

98 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 reflects the number of registered end-user sites, including sites that are aggregated to a single registration.

99 The "Total MWh" and "Total Payments" for the Economic Program shown here are also subject to subsequent settlement adjustments in 2010.

100 The Economic Program payments and MWh presented in this report do not include all settlement adjustments for 2010. The data are provided by PJM's DSR department; Economic Program payments and MWh reductions are based on the January, 2011, PJM billing information and are subject to adjustments.

101 The "Total MWh" and "Total Payments" for calendar year 2009 are different from those reported in the *2009 State of the Market Report for PJM*, as a result of adjusted settlements. The "Total MWh" increased by 5,474 MWh and the "Total Payments" increased by $152,720.

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Table 2-76 Performance of PJM Economic Program participants: Calendar years 2002 through 2010

	Total MWh	Total Payments	$/MWh	Total MWh per Peak-Day, Registered MW
2002	6,727	$801,119	$119	20.1
2003	19,518	$833,530	$43	30.0
2004	58,352	$1,917,202	$33	66.6
2005	157,421	$13,036,482	$83	71.2
2006	258,468	$18,584,013	$72	234.8
2007	714,148	$49,033,576	$69	285.9
2008	452,222	$27,087,495	$60	197.1
2009	57,157	$1,389,136	$24	23.0
2010	72,757	$2,933,761	$40	42.2

Total Payments in Table 2-76 include incentive payments in the Economic Program for the years 2006 and 2007. The economic incentive program expired in November of 2007.[102] Table 2-77 shows total MWh reductions and payments less incentive payments for the years 2002 through 2010.[103]

Table 2-77 Performance of PJM Economic Program participants without incentive payments: Calendar years 2002 through 2010

	Total MWh	Total Payments	$/MWh	Total MWh per Peak-Day, Registered MW
2002	6,727	$801,119	$119	20.1
2003	19,518	$833,530	$43	30.0
2004	58,352	$1,917,202	$33	66.6
2005	157,421	$13,036,482	$83	71.2
2006	258,468	$10,213,828	$40	234.8
2007	714,148	$31,600,046	$44	285.9
2008	452,222	$27,087,495	$60	197.1
2009	57,157	$1,389,136	$24	23.0
2010	72,757	$2,933,761	$40	42.2

Figure 2-23 shows monthly economic program payments, excluding incentive payments, for 2007 through 2010. Economic Program credits consistently declined from June 2008 through 2009. In 2009, payments were down significantly in every month compared to the same time period in 2007 and 2008.[104] While there are a number of factors that could explain this reduction, declining price levels for energy are the single biggest factor. Energy prices declined significantly in 2008

102 In 2006 and 2007, when LMP was greater than, or equal to, $75 per MWh, customers were paid the full LMP and the amount not paid by the LSE, equal to the generation and transmission components of the applicable retail rate (recoverable charges), was charged to all LSEs in the zone of the load reduction. As of December 31, 2007, the incentive payments totaled $17,391,099, an increase of 108 percent from calendar year 2006. No incentive credits were paid in November and December 2007 because the total exceeded the specified cap.

103 Settlement data for 2010 including reductions, credits and incentive payments data received from PJM DSR group February 10, 2011.

104 December credits are likely understated due to the lag associated with the submittal and processing of settlements. Settlements may be submitted up to 60 days following an event day. EDC/LSEs have up to 10 business days to approve which could account for a maximum lag of approximately 74 calendar days.

and again in 2009.[105] Similarly, in 2010, credits were down compared to 2009 through April, but increased significantly for the summer months of 2010, when price levels were generally higher compared to the same period in 2009. Lower prices mean reduced incentives to reduce load and fewer hours eligible for load reductions, given a fixed rate contract. Higher prices mean increased incentives to reduce load and a higher frequency of hours in which reduction is economic.

Figure 2-23 Economic Program payments: Calendar years 2007 to 2010[106]

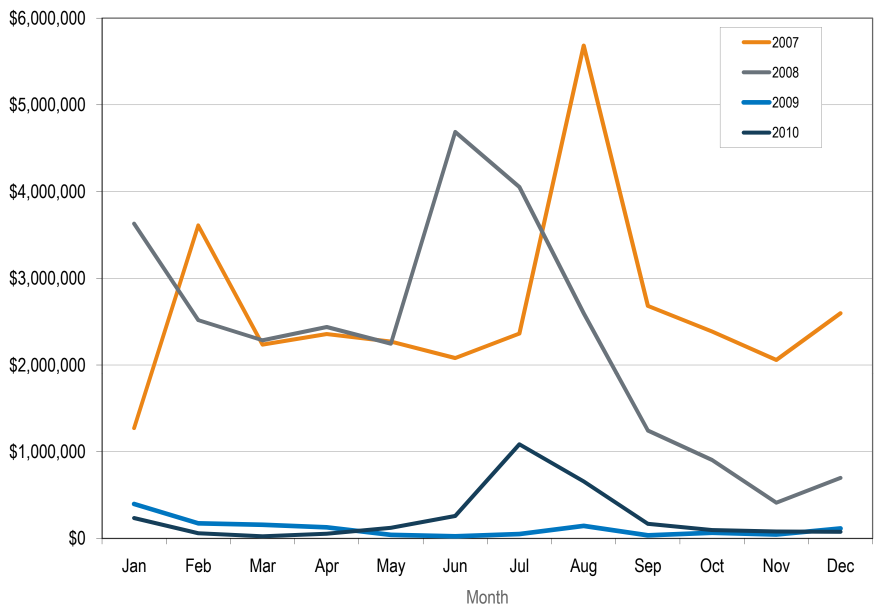

Table 2-78 shows 2010 performance in the Economic Program by control zone and participation type. The total number of curtailed hours for the Economic Program was 33,477 and the total payment amount was $2,933,761.[107] Overall, approximately 73 percent of the MWh reductions, 75 percent of payments and 79 percent of curtailed hours resulted from the real-time, self scheduled option of the Economic Program. Approximately 19 percent of the MWh reductions, 14 percent of payments and 6 percent of curtailed hours resulted from the day-ahead option.[108] Approximately 8 percent of the MWh reductions, 10 percent of the payments and 14 percent of the curtailed hours resulted from the dispatched in real-time option of the program (Table 2-78). The Dominion Control Zone accounted for $1,443,851 or 49 percent of all Economic Program credits, associated with 4,155 or 12 percent of total program MWh reductions.

105 The reduction was also the result in part of the revisions to the Customer Baseline Load (CBL) calculation effective June 12, 2008 and the newly implemented activity review process effective November 3, 2008.

106 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.

107 If two different retail customers curtail the same hour in the same zone, it is counted as two curtailed hours.

108 On February 2, 2007, PJM proposed to the FERC that customers with day-ahead, LMP-based contracts be eliminated from participation in the day-ahead Economic Program. On June 15, 2007, the Commission issued an order, 119 FERC ¶ 61,280, rejecting PJM's proposed revision to its OATT.

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Table 2-78 PJM Economic Program by zonal reduction: Calendar year 2010

	Real Time			Day Ahead			Dispatched in Real Time			Totals		
	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours
AECO	9	$406	8				78	$4,620	79	87	$5,026	87
AEP	7	$56	3							7	$56	3
AP	4,350	$119,040	1,242				110	$11,535	39	4,460	$130,576	1,281
BGE	1,806	$300,724	251				1,873	$145,183	232	3,679	$445,908	483
ComEd	132	$3,726	131				2,166	$36,168	986	2,298	$39,894	1,117
DAY	0	$8	2				11	$1,165	1	11	$1,173	3
DLCO										0	$0	0
Dominion	13,250	$971,759	952	13,486	$421,454	2,094	1,054	$50,637	1,109	27,790	$1,443,851	4,155
DPL	1	$248	10							1	$248	10
JCPL	200	$18,384	31				35	$2,155	130	235	$20,539	161
Met-Ed	33	$1,359	36							33	$1,359	36
PECO	33,030	$779,969	23,258				463	$44,408	1,833	33,493	$824,377	25,091
PENELEC	40	$645	36				3	$273	14	43	$918	50
Pepco	28	$1,564	75				30	$1,542	132	58	$3,106	207
PPL	445	$11,283	442	3	$407	11	51	$3,558	225	500	$15,249	678
PSEG	61	$1,458	114							61	$1,458	114
RECO	0	$24	1							0	$24	1
Total	53,393	$2,210,653	26,592	13,489	$421,862	2,105	5,875	$301,246	4,780	72,757	$2,933,761	33,477
Max	33,030	$971,759	23,258	13,486	$421,454	2,094	2,166	$145,183	1,833	33,493	$1,443,851	25,091
Avg	3,337	$138,166	1,662	6,744	$210,931	1,053	534	$27,386	435	4,280	$172,574	1,969

Table 2-79 shows total settlements submitted by month for calendar years 2007 through 2010. For January through July of 2008, total monthly settlements were higher than the monthly totals for 2007, despite the recent expiration of the incentive program. In October of 2008, settlement submissions dropped significantly from the prior month and from the same month in 2007, a trend that continued through early 2009. This drop in participation corresponds with the implementation of the PJM daily review process, as well as the lower overall price levels in PJM. April of 2009 showed the lowest level of settlements submitted in the three year period, after which, settlements began to show steady growth. Settlements dropped off significantly after the summer period in 2009, and January through May of 2010 were generally lower than historical levels while summer of 2010 showed a moderate increase, consistent with 2009.

Table 2-79 Settlement days submitted by month in the Economic Program: 2007 through 2010

Month	2007	2008	2009	2010
Jan	937	2,916	1,264	1,415
Feb	1,170	2,811	654	546
Mar	1,255	2,818	574	411
Apr	1,540	3,406	337	338
May	1,649	3,336	918	673
Jun	1,856	3,184	2,727	1,221
Jul	2,534	3,339	2,879	3,007
Aug	3,962	3,848	3,760	2,158
Sep	3,388	3,264	2,570	660
Oct	3,508	1,977	2,361	699
Nov	2,842	1,105	2,321	672
Dec	2,675	986	1,240	894
Total	26,423	32,990	21,605	12,694

Table 2-80 shows the number of distinct Curtailment Service Providers (CSPs) and distinct customers actively submitting settlements by month for the period 2007 through 2010. The number of active customers per month decreased in early 2009, reaching a three year low in April. Since then, monthly customer counts vary significantly. In 2010, monthly customers appear to follow seasonal trends, high in the summer period and lower in shoulder months, however, the number of active customers in calendar year 2010 decreased 309, or 41 percent, over calendar year 2009.

Table 2-80 Distinct customers and CSPs submitting settlements in the Economic Program by month: Calendar years 2007 through 2010

	2007		2008		2009		2010	
Month	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers
Jan	11	72	13	261	17	257	11	162
Feb	10	89	13	243	12	129	9	92
Mar	9	87	11	216	11	149	7	124
Apr	11	98	12	208	9	76	5	77
May	12	109	12	233	9	201	6	140
Jun	12	195	17	317	20	231	11	152
Jul	15	259	16	295	21	183	18	243
Aug	19	321	17	306	15	400	14	302
Sep	15	279	17	312	11	181	11	97
Oct	11	245	13	226	11	93	8	37
Nov	10	204	14	208	9	143	7	40
Dec	11	243	13	193	10	160	7	46
Total Distinct Active	21	405	24	522	25	747	24	438

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Table 2-81 shows a frequency distribution of MWh reductions and credits at each hour for calendar year 2010. The period from hour ending 0800 EPT to 2300 EPT accounts for 91 percent of MWh reductions and 96 percent of credits.

Table 2-81 Hourly frequency distribution of Economic Program MWh reductions and credits: Calendar year 2010

	MWh Reductions				Program Credits			
Hour Ending (EPT)	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
1	350	0.48%	350	0.48%	$5,266	0.18%	$5,266	0.18%
2	388	0.53%	738	1.01%	$5,205	0.18%	$10,472	0.36%
3	623	0.86%	1,361	1.87%	$6,054	0.21%	$16,526	0.56%
4	636	0.87%	1,997	2.74%	$7,365	0.25%	$23,890	0.81%
5	679	0.93%	2,676	3.68%	$5,957	0.20%	$29,847	1.02%
6	737	1.01%	3,412	4.69%	$8,269	0.28%	$38,116	1.30%
7	1,693	2.33%	5,105	7.02%	$61,823	2.11%	$99,939	3.41%
8	2,577	3.54%	7,682	10.56%	$104,459	3.56%	$204,398	6.97%
9	2,750	3.78%	10,432	14.34%	$62,738	2.14%	$267,136	9.11%
10	2,529	3.48%	12,961	17.81%	$56,830	1.94%	$323,966	11.04%
11	2,465	3.39%	15,426	21.20%	$61,498	2.10%	$385,464	13.14%
12	2,671	3.67%	18,097	24.87%	$78,027	2.66%	$463,491	15.80%
13	3,015	4.14%	21,112	29.02%	$105,347	3.59%	$568,838	19.39%
14	4,581	6.30%	25,692	35.31%	$208,282	7.10%	$777,120	26.49%
15	7,481	10.28%	33,173	45.60%	$328,263	11.19%	$1,105,383	37.68%
16	8,266	11.36%	41,439	56.96%	$501,740	17.10%	$1,607,123	54.78%
17	8,890	12.22%	50,330	69.18%	$522,020	17.79%	$2,129,143	72.57%
18	8,268	11.36%	58,598	80.54%	$387,450	13.21%	$2,516,592	85.78%
19	3,730	5.13%	62,328	85.67%	$132,037	4.50%	$2,648,629	90.28%
20	2,909	4.00%	65,238	89.67%	$90,234	3.08%	$2,738,863	93.36%
21	2,403	3.30%	67,641	92.97%	$91,082	3.10%	$2,829,945	96.46%
22	2,103	2.89%	69,744	95.86%	$60,969	2.08%	$2,890,914	98.54%
23	1,704	2.34%	71,448	98.20%	$25,243	0.86%	$2,916,157	99.40%
24	1,309	1.80%	72,757	100.00%	$17,604	0.60%	$2,933,761	100.00%

Table 2-82 shows the frequency distribution of Economic Program MWh reductions and credits by real-time zonal, load-weighted, average LMP in various price ranges. Reductions occurred primarily when zonal, load-weighted, average LMP was between $25 and $75 per MWh and between $100 and $150 per MWh. Approximately 63 percent of MWh reductions and 29 percent of program credits are associated with hours when the applicable zonal LMP was less than or equal to $100.

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Table 2-82 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): Calendar year 2010

	MWh Reductions				Program Credits			
LMP	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
$0 to $25	474	0.65%	474	0.65%	$535	0.02%	$535	0.02%
$25 to $50	28,381	39.01%	28,854	39.66%	$315,284	10.75%	$315,819	10.77%
$50 to $75	10,504	14.44%	39,359	54.10%	$280,607	9.56%	$596,426	20.33%
$75 to $100	6,137	8.44%	45,496	62.53%	$257,765	8.79%	$854,191	29.12%
$100 to $125	9,628	13.23%	55,124	75.77%	$308,797	10.53%	$1,162,988	39.64%
$125 to $150	8,035	11.04%	63,159	86.81%	$447,272	15.25%	$1,610,260	54.89%
$150 to $200	5,527	7.60%	68,686	94.40%	$542,000	18.47%	$2,152,260	73.36%
$200 to $250	1,856	2.55%	70,542	96.96%	$299,433	10.21%	$2,451,693	83.57%
$250 to $300	991	1.36%	71,533	98.32%	$172,615	5.88%	$2,624,308	89.45%
> $300	1,224	1.68%	72,757	100.00%	$309,452	10.55%	$2,933,761	100.00%

Emergency Program

The zonal distribution of DSR capability in the Emergency Program option is shown in Table 2-83 by program option. On July 6, 2010, the peak-load day for the year, there were no available resources in the Emergency-Energy Only option of the Emergency Program.[109] There were 6,382 sites accounting for 6,875.3 MW registered in the Emergency Full option and 1,499 sites accounting for 2,177.1 MW registered in Emergency Capacity Only option. The ComEd Control Zone showed the highest number of registered sites in Emergency-Full option at 899 or 14 percent, while the AEP Control Zone showed the highest MW capability with 1,039.1 MW registered, or 15 percent of MW registered in the option. The ComEd Control Zone showed the highest participation in the Capacity Only option of the Emergency Program with 585 sites, or 39 percent of total sites, and 514.6 MW, or 24 percent of total MW registered in the option. Total peak-load day registrations in the Emergency Program increased by 6 percent, from 7,417 in 2009 to 7,881 in 2010, and total peak day registered MW increased by 24 percent, from 24 percent, from 7,294.3 MW in 2009 to 9,052.4 MW in 2010.

109 The number of registered sites and MW levels are measured as a one-day snapshot. For the Emergency Full and Capacity Only options, which are essentially portals for the Load Management Program, registrations and MW levels are constant through the delivery year.

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Table 2-83 Registered sites and MW in the Emergency Program[110]

	Energy Only		Full		Capacity Only	
	Sites	MW	Sites	MW	Sites	MW
AECO	0	0.0	102	58.5	8	18.0
AEP	0	0.0	688	1,039.1	169	805.4
AP	0	0.0	672	612.0	105	180.5
BGE	0	0.0	441	758.1	28	79.3
ComEd	0	0.0	899	949.9	585	514.6
DAY	0	0.0	163	135.0	17	72.2
DLCO	0	0.0	263	158.3	13	46.4
Dominion	0	0.0	502	919.3	35	86.9
DPL	0	0.0	174	140.8	19	37.7
JCPL	0	0.0	206	161.0	19	17.5
Met-Ed	0	0.0	196	149.4	36	38.3
PECO	0	0.0	455	312.1	191	113.9
PENELEC	0	0.0	304	297.0	31	15.1
Pepco	0	0.0	265	177.8	30	38.8
PPL	0	0.0	643	671.2	87	60.1
PSEG	0	0.0	406	334.3	126	52.4
RECO	0	0.0	3	1.7	0	0.0
Total	0	0.0	6,382	6,875.3	1,499	2,177.1

Load Management Program

The increase in registrations in the Emergency Program for peak periods in 2010 compared to 2009 is due to increased participation in the Load Management (LM) Program, that is, increased load response participation in RPM. Table 2-84 shows registered MW in the Load Management Program by program type for delivery years 2007/2008 through 2010/2011.

110 Table 2-83 shows registered sites and MW in the Emergency Program as of July 6, 2010, the peak load day of 2010. As all resources are registered in either the Capacity Only or Full options, all resources in the Emergency Program are considered RPM Resources participating in the Load Management (LM) Program and Table 2-84 reflects the same participation. Registered sites and MW remain constant in the LM Program through delivery years.

Table 2-84 Registered MW in the Load Management Program by program type: Delivery years 2007 through 2010

Delivery Year	Total DR MW	Total ILR MW	Total LM MW
2007/2008	560.7	1,584.6	2,145.3
2008/2009	1,017.7	3,480.5	4,498.2
2009/2010	1,020.5	6,273.8	7,294.3
2010/2011	1,070.0	7,982.4	9,052.4

Table 2-85 shows zonal monthly capacity credits that were paid during the calendar year 2010 to ILR and DR resources. Capacity revenue increased by $209 million or 69 percent, from $303 million in 2009 to $512 million in 2010. Credits from January to May are associated with participation in the 2009/2010 RPM delivery year, while credits from June to December are associated with participation in the 2010/2011 RPM delivery year. The increase in capacity credits after May is the result of a significant increase in both DR and ILR participation in RPM delivery year 2010/2011, as well as increases in RPM clearing prices.

Table 2-85 Zonal monthly capacity credits: Calendar year 2010

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Total
AECO	$538,827	$486,683	$538,827	$521,446	$538,827	$498,630	$515,251	$515,251	$498,630	$515,251	$498,630	$515,251	$6,181,503
AEP	$3,871,619	$3,496,946	$3,871,619	$3,746,728	$3,871,619	$7,469,753	$7,718,744	$7,718,744	$7,469,753	$7,718,744	$7,469,753	$7,718,744	$72,142,765
APS	$3,380,342	$3,053,212	$3,380,342	$3,271,298	$3,380,342	$4,134,986	$4,272,819	$4,272,819	$4,134,986	$4,272,819	$4,134,986	$4,272,819	$45,961,772
BGE	$4,971,814	$4,490,671	$4,971,814	$4,811,433	$4,971,814	$4,877,253	$5,039,828	$5,039,828	$4,877,253	$5,039,828	$4,877,253	$5,039,828	$59,008,617
ComEd	$4,423,355	$3,995,288	$4,423,355	$4,280,666	$4,423,355	$7,893,843	$8,156,971	$8,156,971	$7,893,843	$8,156,971	$7,893,843	$8,156,971	$77,855,431
DAY	$667,966	$603,324	$667,966	$646,419	$667,966	$1,114,399	$1,151,545	$1,151,545	$1,114,399	$1,151,545	$1,114,399	$1,151,545	$11,203,019
DLCO	$387,642	$350,129	$387,642	$375,138	$387,642	$1,082,462	$1,118,544	$1,118,544	$1,082,462	$1,118,544	$1,082,462	$1,118,544	$9,609,756
Dominion	$1,655,820	$1,495,580	$1,655,820	$1,602,407	$1,655,820	$5,271,768	$5,447,494	$5,447,494	$5,271,768	$5,447,494	$5,271,768	$5,447,494	$45,670,728
DPL	$1,117,919	$1,009,733	$1,117,919	$1,081,857	$1,117,919	$1,053,129	$1,088,233	$1,088,233	$1,053,129	$1,088,233	$1,053,129	$1,088,233	$12,957,663
JCPL	$1,374,149	$1,241,167	$1,374,149	$1,329,822	$1,374,149	$1,259,066	$1,301,034	$1,301,034	$1,259,066	$1,301,034	$1,259,066	$1,301,034	$15,674,770
Met-Ed	$1,357,392	$1,226,031	$1,357,392	$1,313,605	$1,357,392	$1,166,215	$1,205,089	$1,205,089	$1,166,215	$1,205,089	$1,166,215	$1,205,089	$14,930,813
PECO	$2,717,550	$2,454,561	$2,717,550	$2,629,887	$2,717,550	$2,735,060	$2,826,229	$2,826,229	$2,735,060	$2,826,229	$2,735,060	$2,826,229	$32,747,192
PENELEC	$1,325,705	$1,197,411	$1,325,705	$1,282,941	$1,325,705	$1,768,655	$1,827,610	$1,827,610	$1,768,655	$1,827,610	$1,768,655	$1,827,610	$19,073,870
Pepco	$1,161,239	$1,048,861	$1,161,239	$1,123,780	$1,161,239	$1,265,186	$1,307,359	$1,307,359	$1,265,186	$1,307,359	$1,265,186	$1,307,359	$14,681,351
PPL	$3,583,739	$3,236,926	$3,583,739	$3,468,134	$3,583,739	$3,982,417	$4,115,164	$4,115,164	$3,982,417	$4,115,164	$3,982,417	$4,115,164	$45,864,184
PSEG	$2,266,920	$2,047,540	$2,266,920	$2,193,793	$2,266,920	$2,454,980	$2,536,813	$2,536,813	$2,454,980	$2,536,813	$2,454,980	$2,536,813	$28,554,286
RECO	$24,425	$22,061	$24,425	$23,637	$24,425	$8,967	$9,266	$9,266	$8,967	$9,266	$8,967	$9,266	$182,938
Total	$34,826,423	$31,456,124	$34,826,423	$33,702,990	$34,826,423	$48,036,768	$49,637,993	$49,637,993	$48,036,768	$49,637,993	$48,036,768	$49,637,993	$512,300,658

For more information on DR participation in RPM Auctions, see Section 5: Capacity Markets.

Load Management Event Compliance

In calendar year 2010, PJM declared six Load Management events. The first event, declared on May 26, 2010 affected resources committed in the 2009/2010 Delivery Year, as it occurred prior to June 1, 2010. However, since it fell outside of the summer compliance period of June through September, curtailment was not required and no compliance or associated penalties were assessed for this event.[111] Participants that did curtail were eligible to receive emergency energy credits. The

111 See RAA, Schedule 6 § L.

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five following events affected resources committed in the 2010/2011 Delivery Year. Since each of these events occurred within the summer compliance period, each was considered in compliance assessment. Table 2-86 lists Load Management Events declared by PJM in calendar year 2010.[112]

Table 2-86 PJM declared Load Management Events: Calendar year 2010

Event Date	Event Times	Delivery Year	Geographical area for long lead time
26-May-10	HE 1900 - 2000	2009/2010	DC portion of Pepco
11-Jun-10	HE 1700 - 2000	2010/2011	DC portion of Pepco
7-Jul-10	HE 1500 - 1900	2010/2011	AECO, BGE, Dominion, DPL, JCPL, PECO, Pepco, PSEG
11-Aug-20	HE 1500 - 1900	2010/2011	DC portion of Pepco
23-Sep-10	HE 1200 - 2000	2010/2011	BGE, states of VA, WV, and MD portions of AP
24-Sep-10	HE 1400 - 1800	2010/2011	BGE, Pepco, states of VA, WV and MD portions of AP

The event on May 26 marks the first time in the history of PJM Load Response Programs that PJM deployed emergency demand side resources subzonally. The June 11 event marks the first time performance was assessed at a subzonal level. Prior to this, load management events and thus compliance were aggregated to a zonal basis. While all PJM Emergency Actions, including Load Management Events, may be issued for part of a zone, the only locational requirement for the aggregation of multiple end use customers to a single registration is that they reside in the same control zone. Similarly, compliance for testing and for zonal Emergency Events, is aggregated for each CSP to a zonal portfolio. Some market participants were not prepared to deploy resources on a sub-zonal level, and they submitted event compliance data for all resources within the Pepco Zone. PJM indicated for this single event, that if the CSP had notified PJM prior to the start of the event, PJM would accept compliance data from Pepco resources even outside the subzonal area called (the Washington, D.C. area) and consider these resources in the assessment of compliance for the event.

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. A requirement to identify the subzonal location of demand resources would be a positive step towards nodal pricing and the ability of PJM to deploy demand resources in a manner more consistent with the nodal deployment of generation and more consistent with nodal pricing.

Table 2-87 shows performance for the June 11 event. The first column shows the nominal value which represents the reduction capability indicated by the participant at registration. The second column shows Load Management MW commitments, which are used to assess RPM compliance. Differences between these two columns may reflect differences between MW offered and cleared for any partially cleared DR resource. In addition, RPM commitments consider any RPM transactions, such as capacity replacement sales or purchases for Demand Resources, while the nominal ICAP

112 For all events listed in Table 2-86 except the September 23 Event, PJM deployed only long lead time resources, which are those that require between one to two hours notification. As a result, the nominal ICAP stated in event compliance tables in this section may not equal total nominal ICAP for the zone. For the September 23 Event, PJM deployed short lead time resources for MD portions of AP in addition to long lead time resources. Short lead time resources are those which require no more than an hour notification. Approximately 95 percent of registrations, accounting for 83 percent of registered MW, are designated as long lead time resources.

does not. Overall, the aggregated performance was 94.8 percent, or 130.2 MW out of 137.2 MW committed.

Table 2-87 Load Management event performance: June 11, 2010

Zone	Nominal ICAP	Committed MW	Load Reduction Observed	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
Pepco	143.9	137.2	131.5	(5.7)	95.8%	91.4%

The July 7 event was the largest in terms of deployed MW and the widest ranging geographically. Performance for this event is shown in Table 2-88. Overall, the aggregated performance across zones was 99.5 percent, or 2,712.5 MW of 2,725.3 committed MW.[113] PECO showed the highest aggregated performance percentage of 104.6, or 438.4 of 419.1 committed MW. Dominion showed the highest performance in terms of MW reduction, with 935.2 MW in observed load reduction or 36 percent of total observed load reductions. Aggregated performance was 88.5 percent for the August 11 event or 53.1 MW of 60.0 committed MW (Table 2-89), 101.4 percent for the September 23 event (Table 2-90), or 799.7 MW of 788.9 committed MW, and 99 percent for the September 24 event (Table 2-91), or 956.9 MW of 966.7 committed MW.

Table 2-88 Load Management event performance: July 7, 2010

Zone	Nominal ICAP	Committed MW	Load Reduction Observed	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
AECO	76.5	70.4	71.5	1.1	101.5%	93.4%
BGE	428.4	409.7	421.7	12.0	102.9%	98.4%
Dominion	1,006.0	974.6	935.2	(39.3)	96.0%	93.0%
DPL	149.0	137.7	143.7	6.0	104.3%	96.5%
JCPL	168.5	154.7	155.2	0.5	100.3%	92.1%
PECO	432.1	419.1	438.4	19.3	104.6%	101.5%
Pepco	191.8	179.3	170.5	(8.8)	95.1%	88.9%
PSEG	385.5	379.8	383.7	3.9	101.0%	99.5%
Total	2,837.8	2,725.3	2,719.9	(5.4)	99.8%	95.8%

113 The tables in this section show aggregated event day performance by zone. Actual performance and performance based penalties are assessed zonally or subzonally by CSP. For events spanning multiple hours, event performance is defined as the average hourly response over the event period. Hourly performance varies, generally starting at a minimal performance level and increasing as the event continues.

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Table 2-89 Load Management event performance: August 11, 2010

Zone	Nominal ICAP	Committed MW	Load Reduction Observed	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
Pepco	63.8	60.0	53.1	(6.9)	88.5%	83.2%

Table 2-90 Load Management event performance: September 23, 2010

Zone	Nominal ICAP	Committed MW	Load Reduction Observed	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
AP	407.8	379.2	367.4	(11.7)	96.9%	90.1%
BGE	428.4	409.7	432.9	23.1	105.6%	101.1%
Total	836.2	788.9	800.3	11.4	101.4%	95.7%

Table 2-91 Load Management event performance: September 24, 2010

Zone	Nominal ICAP	Committed MW	Load Reduction Observed	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
AP	406.3	377.7	355.1	(22.6)	94.0%	87.4%
BGE	428.4	409.7	429.6	19.8	104.8%	100.3%
Pepco	191.8	179.3	172.6	(6.7)	96.3%	90.0%
Total	1,026.5	966.7	957.2	(9.5)	99.0%	93.3%

Table 2-92 shows aggregated performance by zone across all five Load Management Events in the 2010/2011 Delivery Year compliance period.[114] On average, participants demonstrated load reductions of 4,662.0 MW, or about 99.7 percent, of the 4,678.2 committed MW deployed by PJM.

Table 2-92 Aggregated Load Management performance across all events in the 2010/2011 Delivery Year compliance period

Zone	Nominal ICAP	Committed MW	Load Reduction Observed	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
AECO	76.5	70.4	71.5	1.1	101.5%	93.4%
AP	814.2	756.9	722.5	(34.3)	95.5%	88.7%
BGE	1,285.1	1,229.2	1,284.1	54.9	104.5%	99.9%
Dominion	1,006.0	974.6	935.2	(39.3)	96.0%	93.0%
DPL	149.0	137.7	143.7	6.0	104.3%	96.5%
JCPL	168.5	154.7	155.2	0.5	100.3%	92.1%
PECO	432.1	419.1	438.4	19.3	104.6%	101.5%
Pepco	591.2	555.8	527.7	(28.1)	94.9%	89.3%
PSEG	385.5	379.8	383.7	3.9	101.0%	99.5%
Total	4,908.1	4,678.2	4,662.0	(16.1)	99.7%	95.0%

114 Nominal ICAP, commited MW and load reductions observed in Table 2-92 and Table 2-94 represent the zonal totals for all events days. If a zone had multiple events, these columns reflect the sum of all events.

While aggregated performance across all events was 99.7 percent, performance for specific customers varied significantly. Table 2-93 shows the distribution of participant event days across various levels of performance throughout all five events in the 2010/2011 compliance period. For any given event, approximately 31 percent of participants showed little or no reduction. Approximately 47 percent of participants did not meet half of their committed MW. The majority of participants, between 62 and 68 percent, showed less than 100 percent reduction to their commitment. Figure 2-24 shows the data in Table 2-93.[115] The distribution appears bimodal, with high frequencies of both low performing and over performing registrations. The large disparity in performance and the proportion of underperforming assets are indicative of over compliance offsetting under performing resources, and consistent with the presence of the double counting issue.

Table 2-93 Distribution of participant event days across ranges of performance levels across all events in the 2010/2011 Delivery Year compliance period

Ranges of performance as a percentage of committed MW	Number of participant event days	Proportion of participant event days	Cumulative Proportion
0% or no load reduction	646	13%	13%
0% -10%	561	11%	23%
10% - 20%	254	5%	28%
20% - 30%	203	4%	32%
30% - 40%	235	5%	37%
40% - 50%	205	4%	41%
50% - 60%	181	4%	44%
60% - 70%	196	4%	48%
70% - 80%	230	4%	53%
80% - 90%	226	4%	57%
90% - 100%	395	8%	65%
100% - 120%	731	14%	79%
120% - 150%	358	7%	86%
150% - 200%	301	6%	92%
200% - 300%	220	4%	96%
> 300%	209	4%	100%
Total	5,151	100%	

115 Participant event days, shown in Table 2-92, Figure 2-24, and Table 2-94, are defined as distinct event performances by registration. If a registration was deployed for multiple events, each event constitutes a single participant even day. In addition, the load reduction values associated do not reflect actual MWh curtailments, but average curtailments in each event, summed for all events in the period.

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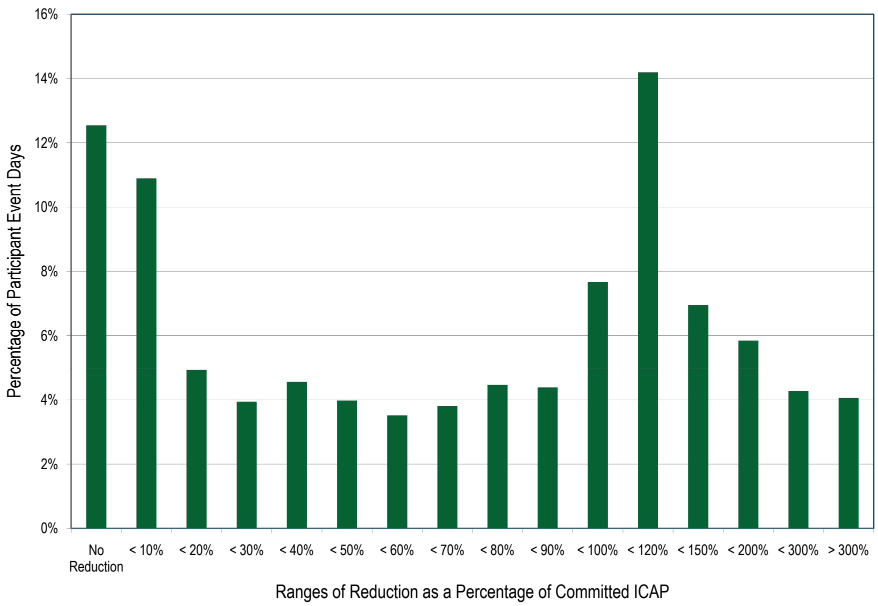
Figure 2-24 Distribution of participant event days across ranges of performance levels across all events in the 2010/2011 Delivery Year compliance period



It is difficult to determine whether Guaranteed Load Drop (GLD) customers have managed their PLCs without more load data than is provided for compliance settlements. However, one way to evaluate the likelihood that a customer has managed their PLC is to compare the PLC to the observed load reduction in real time. For customers that did not manage PLC in prior years, the PLC should reflect unrestricted usage during system peak conditions. It is unlikely that these customers would be able to show a reduction in real time greater than their PLC unless their PLC represented a managed consumption level. Table 2-94 shows the distribution of GLD participant event days and observed load reductions across ranges of load reduction as a percentage of PLC for all events in the 2010/2011 Delivery Year.

About 77 percent of GLD participants submitting event compliance data show reductions in real time which are less than or equal to 75 percent of their PLC. These GLD participants account for 1,548 MW of event day reductions, which is 48 percent of GLD event day reductions and 33 percent of total event day reductions. Observed reductions for these customers account for 75 percent or less of their purchased capacity, which is based on historical peak usage levels. It is reasonable to conclude that these customers did not manage their PLCs in the prior year.

About 14 percent of GLD participants submitting event compliance data show reductions in real time which are greater than or equal to 100 percent of their PLC. These GLD participants account for 1,344 MW of event day reductions, which is 41 percent of GLD reductions and 29 percent of total reductions. It is reasonable to conclude that such GLD customers, showing a reduction greater than or equal to PLC, did manage their PLCs in the prior year. Reductions from customers with reductions equal to from 150 percent to 300 percent or more of their PLC accounted for 28 percent of total GLD reductions. The results in Table 2-94 show the extent to which customers with managed PLCs are participating under the GLD option of the Load Management Program, and are consistent with the presence of the double counting problem.

Table 2-94 Distribution of GLD participant event days and observed load reductions across ranges of load reduction as a percentage of Peak Load Contribution (PLC) for all events in the 2010/2011 Delivery Year

Ranges of load reduction as a percentage of PLC	Number of GLD participant event days	Proportion of total GLD participant event days	Cumulative Proportion	Observed reductions (MW)	Proportion of total GLD observed reductions	Cumulative Proportion
0% - 25%	1,929	50%	50%	483	15%	15%
25% - 50%	643	17%	67%	618	19%	34%
50% - 75%	406	11%	77%	447	14%	48%
75% - 100%	323	8%	86%	360	11%	59%
100% - 150%	306	8%	94%	429	13%	72%
150% - 200%	80	2%	96%	294	9%	81%
200% - 300%	71	2%	98%	378	12%	93%
300% or greater	87	2%	100%	244	7%	100%
Total	3,845	100%		3,252	100%	

Emergency Energy Payments

For any PJM declared Load Management event in calendar year 2010, participants registered under the "Full" option of the Emergency Load Response Program that were deployed and that demonstrated a load reduction were eligible to receive emergency energy payments, which is equal to the higher of hourly zonal LMP or an energy offer made by the participant, including a dollar per MWh minimum dispatch price and an associated shutdown cost.[116] In other words, participants are "made whole" to their emergency offer, regardless of the zonal LMP. Table 2-95 shows the distribution of registrations and associated MW in the Emergency Full Option across ranges of minimum dispatch prices. The majority of participants, about 79 percent, have a minimum dispatch price of $999/MWh or higher. Energy offers are further increased by shutdown costs submitted, which, in the 2010/2011 Delivery Year, range from $0 to $5,000. Depending on the size of the registration, the shutdown costs can significantly increase the $/MWh energy offer.

116 For the June 11 Event, this includes Pepco resources outside of the District of Columbia for which PJM granted an exception.

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Table 2-95 Distribution of registrations and associated MW in the Emergency Full Option across ranges of Minimum Dispatch Prices effective for the 2010/2011 Delivery Year

Ranges of Strike Prices ($/MWh)	Registrations	Percent of Total	Nominated MW (ICAP)	Percent of Total
$0 - $1	187	2.9%	663.1	9.6%
$2 - $200	72	1.1%	138.5	2.0%
$201 - $500	1,072	16.8%	924.8	13.5%
$500 - $998	29	0.5%	159.4	2.3%
$999+	5,022	78.7%	4,989.6	72.6%
Total	6,382	100%	6,875.3	100%

Table 2-96 shows emergency credits and make whole payments for each event in calendar year 2010. The emergency credit is market value of the load reductions observed during the event, based on applicable zonal LMPs. Make whole payments represent the difference between the market valuation of the load reduction, based on zonal LMP, and the submitted energy offer.

Table 2-96 Emergency credits and make whole payments by event: Calendar Year 2010

Event	Emergency Credits	Emergency Make Whole Payments	Total
26-May-10	$14,472	$109,792	$124,264
11-Jun-10	$41,623	$499,603	$541,226
07-Jul-10	$1,854,655	$5,586,294	$7,440,949
11-Aug-10	$48,741	$216,879	$265,620
23-Sep-10	$323,878	$2,090,838	$2,414,716
24-Sep-10	$461,699	$2,509,486	$2,971,185
Total	$2,745,068	$11,012,892	$13,757,960

Energy payments in the Emergency Program differ significantly from energy payments in the Economic Program and even capacity payments through the Load Management Program in that they are not based on or tied to any market price signal; they are simply guaranteed offers which are subject to no documentation or justification. In fact, their value should be aligned with the Economic Program, since it is designed to compensate for energy reductions and higher incentives would naturally occur as emergency events approach through higher energy market prices. However, because the two programs are not aligned and because the emergency credits are significantly more attractive to participants than Economic Program payments, there exists an incentive for participants to delay any economic load reductions on days when an emergency event may be called.

In addition, the measurement protocol used to determine emergency energy payments is misaligned with other Load Response Programs. All emergency energy payments are based on the "same day" method, which is the difference between usage for one hour prior to the event and usage throughout the event. If a customer opts for a different method in performance calculations, the same event and same load reducing activities will be associated with two different load reduction values, one for emergency energy settlements, another for performance calculations.

Load Management Testing

In the 2007/2008 and the 2008/2009 delivery years, Load Management (LM) compliance was assessed only for actual PJM declared events. If no event was declared, no capacity testing was required. On December 12, 2008, PJM filed amendments to the tariff providing for LM testing if no emergency event is called by August 15 of the delivery year. These amendments were approved by the Commission on March 26, 2009 and were effective in the 2009/2010 delivery year.[117]

All of a provider's committed DR and certified ILR resources in the same zone are required to test at the same time for a one hour period between 12:00 PM EPT to 8:00 PM EPT on a non-holiday weekday between June 1 and September 30.[118] The resource provider must notify PJM of the intent to test 48 hours in advance.

Depending on initial test results, multiple tests may be conducted. If a Curtailment Service Provider (CSP) shows greater than or equal to 75 percent test compliance across a portfolio of resources, all noncompliant resources are eligible for retesting. However, if the initial test shows less than 75 percent compliance, no associated resources are eligible for a retest.

There were 5,734 MW of Committed ICAP not deployed in an event during the compliance period for the 2010/2011 Delivery year and thus required to perform testing. Load Management testing results are shown in Table 2-97. Overall, test results showed 615.0 MW available over RPM commitments, or 111 percent test compliance. The RECO control zone showed the highest percentage of compliance, with load reductions at 199 percent of RPM Commitments, while the AEP control zone showed the highest level of MW reduction in testing, with load reductions at 1,946.3 MW, or 120.1 MW over RPM commitments.

Table 2-97 Load Management test results and compliance by zone for the 2010/2011 delivery year

Zone	Nominal ICAP	Committed MW	Load Reduction Test Results	Over/Under Compliance	Percent Test Compliance	Percent of Nominal ICAP
AEP	1,897.5	1,826.2	1,946.3	120.1	107%	103%
AP	390.6	380.6	445.6	65.0	117%	114%
BGE	415.8	414.1	415.8	1.7	100%	100%
ComEd	1,478.3	1,438.0	1,604.8	166.8	112%	109%
DAY	207.2	206.0	226.9	20.9	110%	110%
DLCO	204.9	200.9	269.9	69.0	134%	132%
DPL	32.1	32.1	32.1	0.0	100%	100%
JCPL	10.0	10.0	10.0	-0.0	100%	100%
Met-Ed	188.1	185.5	201.3	15.8	108%	107%
PENELEC	315.1	295.6	348.1	52.5	118%	110%
Pepco	24.8	24.7	25.4	0.7	103%	102%
PPL	738.4	717.1	817.9	100.8	114%	111%
PSEG	1.2	1.2	1.3	0.1	109%	109%
RECO	1.7	1.7	3.3	1.6	199%	199%
Grand Total	5,905.6	5,733.7	6,348.7	615.0	111%	108%

117 For more information, see PJM, "Manual 18, PJM Capacity Market", Revision 10 (June 1, 2010), Section 8.6.
118 For more information, see PJM, "Manual 18, PJM Capacity Market", Revision 10 (June 1, 2010), Section 8.6.

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Load Management test results are submitted by CSPs directly to PJM. The test results consist of metered load data provided by the CSP which are compared to some baseline consumption level or firm service level determined by LM participation type.[119] There is no physical or technical oversight or verification by PJM or by the relevant LSE of actual testing. PJM screens the data for unreasonable test results, but relies on the CSP to submit accurate metered load data for the testing period with no verification.

This form of testing is not an adequate measurement and verification protocol to ensure that demand side capacity resources can reliably reduce during a system emergency. The MMU recommends that the testing program be modified to require verification of test methods and results.

Measurement and Verification

Traditionally, there have been two approaches to measurement and verification of demand side resources. The less common is specifying a firm MW level to which usage will be reduced. This method is limited to capacity based demand side products. In PJM's Load Management Program, this measurement and verification option is called Firm Service Level (FSL).

The more common approach for both economic and capacity demand side products is to establish a base line usage level by analyzing prior usage levels for a set of days that are intended to be representative of or similar to the day of the reduction. Similar can be defined by day of the week, peak or off peak, and, in more complicated scenarios, weather conditions. In the Economic Program, the baseline method is the default approach, and the standard baseline is refered to as Customer Baseline Load (CBL). In the Load Management Program, this measurement and verification option is called Guaranteed Load Drop (GLD) and there are several baseline methods to choose from. The extent to which the DSR Program can accurately quantify and compensate actual load reductions is dependent on the Program's ability to establish what a customer's metered load would have been absent any load reduction. This is a very difficult task and the methods used to date have been flawed, resulting in payments for reductions in usage that did not occur.

Baseline Pilot Study

The MMU made several presentations to the Load Management Task Force (LMTF), noting that baseline methods are inconsistent between the Economic and Emergency Load Response Programs, that neither Program's baselines are sufficient and that the baseline calculations in the Emergency Program are particularly prone to bias and to gaming. The MMU proposed that an empirical study of all current and proposed baseline methods be conducted with the goal to improve baseline methods for both the Emergency and Economic Programs. Since the study would address baseline issues in both the Economic and Emergency Programs, PJM considered the proposal out of the scope of the then current LMTF Charter.

The MMU appealed to the MIC to amend the LMTF charter to include a pilot study which would: (1) evaluate the accuracy and bias of all current and proposed baseline methods in the Economic and

119 PJM filed for changes to the PJM Tariff and Operating Agreement which state that CSPs are responsible for ensuring that all Emergency Load Response Program participants have metering equipment capable of providing hourly integrated metered load data (see Docket ER09-1508-000). These changes were accepted effective September 28, 2009. However, customers in the non-hourly metered pilot submit test results based on DLC measurement and verification procedures. For more information, see PJM Manual 19, "Load Forecasting and Analysis", Revision 15 (October 1, 2009), Attachment B.

Emergency Programs, (2) identify any obstacles to implementation associated with each baseline method and (3) attempt to establish objective baseline selection criteria where possible for multiple accurate baseline methods. Charter changes were approved effective September 8, 2010. In November of 2010, PJM hired a consultant to complete the study and in December, PJM began requesting hourly load data from participants. The MMU will provide input throughout the process, including a parallel and/or supplemental analysis to be reported in the stakeholder process in 2011.

Economic Program

Participants in the Economic Program are paid based on the reductions in MWh usage that can be attributed to demand side actions. Most participants in the Economic Program measure their reductions by comparing metered load against a Customer Baseline Load (CBL), or an estimate of what metered load would have been absent the reduction.[120] The default CBL employed for approximately 85 percent of Economic Program Participants is the simple average usage over the highest four of the last five similar days.

Customer Base Line (CBL) - History

Since the beginning of the program, there have been significant issues with the approach to measuring demand-side response MW. An inaccurate or unrepresentative CBL can lead to payments when the customer has taken no action to respond to market prices. Substantial improvement in measurement and verification methods must be implemented in order to ensure the credibility of PJM demand-side programs. These could take the form of improvements in the CBL calculation and/or improvements in the verification and customer documentation of load reducing activities. The goal should be to treat the measurement of demand-side resources like the measurement of any other resource in the wholesale power market, including generation and load, that is paid by other participants or makes payments to other participants. PJM made changes to improve the settlement review process over two years ago, but they did not go far enough.[121]

Current weekday CBL methodology includes the highest four of most recent five weekdays, with a maximum lag on eligible days set at 45. Low usage days (load less than 75 percent of the average) and event days (days with curtailment events or demand reductions) are eliminated and replaced with prior days, unless there are not enough eligible days in the last 45 weekdays. Saturdays are considered separately, as are Sundays and holidays. The elimination of event days means that CBL measurements are not limited to the most recent five weekdays and can include weekdays from as far back as 45 days.

CBL Issues

The CBL is a generic formula applied to nearly every customer's usage and is not adequate to serve as the sole or primary basis for determining if an intentional load reduction took place. There are no mandatory CBL enhancements for customers with highly volatile load patterns. If a customer normally has lower load on one particular weekday, that day will appear as a reduction eligible for payment under the current CBL methodology although no deliberate load reducing actions were

120 On-site generation meter data is the other method used to determine the load reduction, if used only for economic load reduction.
121 123 FERC ¶ 61,257 (2008).

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taken in response to real time price signals. There are no mandatory adjustments to the standard CBL for load levels that are a function of weather. In a mild week following a week of extreme temperatures and high load levels, a customer can submit settlements without taking any load reducing action and it will appear as a reduction eligible for payment because metered load is below CBL. A customer's CBL calculation is only reviewed in the Economic Program registration process and the review criteria are unclear. In the registration process, an alternative CBL may be proposed by the CSP or the relevant LSE/EDC.[122] PJM has developed thirteen alternative CBL calculations, three of which include a weather sensitivity adjustment. While the weather adjusted alternative CBL calculations likely provide a more accurate baseline for all customer consumption, an alternative CBL is an optional program feature rather than a required one, and, as a result, the majority of settlements submitted use an unadjusted standard CBL. In 2010, there were 12,421 settlements submitted and processed for CBL calculations. Of those 12,421 CBL calculations, 10,109 or 83 percent utilized the standard, unadjusted CBL and 2,400 or 17 percent utilized an alternative CBL. Of those alternative CBL calculations, 1,988 or 16 percent of all CBL calculations includes an adjustment for weather sensitivity.

Determining the accuracy of a CBL is a difficult task. More data is required than the metered load associated with settlement and the CBL used to determine the reduction amount. However, that is the only data currently available to PJM at the time of settlement review. Complete historical data is required in order to determine whether the CBL is representative of normal load patterns.

In the future, retail markets will reflect hourly wholesale prices and customers will receive direct savings associated with reducing consumption in response to real-time prices. There will not be a need for a PJM Economic Load Response Program, or for an extensive measurement and verification protocol. In the transition to that point, there is a need for robust measurement and verification techniques to ensure that transitional programs are incenting the desired behavior. These techniques are designed to estimate what consumption would have been, absent any load reducing activities, which is a very difficult task.

Analysis of Settlements

PJM and the MMU only have access to meter data submitted as part of a settlement day. Neither PJM nor the MMU have sufficient data to determine if hours submitted for settlement represent deliberate actions taken or normal load fluctuations due to other variables.

In the *2009 State of the Market Report for PJM*, the MMU reported that a large number of consecutive hours showing a metered load less than CBL may be an indication that the CBL is not an adequate method to determine load reductions.[123] If a CBL is accurately modeling load patterns, then a CBL greater than real time load indicates load reducing actions are taking place. If, for any settlement, the number of consecutive hours showing load reduction is beyond a reasonable window for load reducing actions in response to price, it should trigger a CBL review and warrant further substantiation from the customer and CSP.

122 If, however, agreement cannot be reached, then PJM will determine the alternative CBL.

123 A similar and more extensive analysis of settlements also appears in the *2008 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part 1", p. 108.

The occurrence of 24 hour settlement submissions and therefore the frequency of 24 consecutive hours where the CBL is greater than metered load have decreased significantly every year since 2008. However, this does not indicate that the CBL is more accurate and there are still instances of requests for settlements passing the daily activity review screen that include 24 consecutive hours of reduction. These settlements are paid without any documentation of load reducing activities in response to real time price signals.

It is extremely implausible that any customer would take load reduction actions for 24 consecutive hours in response to real time price signals. It is also extremely implausible that an accurate CBL would result in metered load less than base line load for every hour of the day. It is more likely that the CBL is biased upward because it is based on usage from prior days with higher load. Under these circumstances, it is impossible to determine whether the customer took any load reducing actions, from the settlement data. The MMU recommends that any settlement submitted with a consecutive 24 hour period of CBL greater than metered load should trigger a CBL review by PJM and that a customer should be required to provide documentation of load reduction actions taken, prior to acceptance of such settlements. Further, in order for PJM or the MMU to assess the accuracy of the CBL for a particular customer or for the Program in general, more hourly load data is required than is currently captured by PJM.

Load Management Program

There are three measurement and verification protocols in the Load Management (LM) Program: (1) Direct Load Control (DLC), (2) Firm Service Level (FSL), and (3) Guaranteed Load Drop (GLD). The DLC method is used for 8 percent of registered MW in the LM Program, while the FSL method is used for 36 percent and the GLD method is used for 56 percent.[124]

The DLC method is used for customers in the Pilot Program for non-hourly metered customers. For DLC customers, a CSP will interface directly with customer equipment, sending a communication to cycle when PJM has declared an event. Load reductions are estimated through PJM reported or site surveyed impact studies. While customers are required to provide documentation of technical capabilities to enroll in this option, no telemetry or load data are required for verification of actual event performance. Rather, the CSP submits to PJM the time at which the equipment is deployed. There is no way for PJM or the MMU to determine if any load reduction took place in an emergency event.

FSL customers are contractually obligated to reduce load to a nominal value. The measurement and verification of load reductions under FSL option for purposes of event compliance is relatively straightforward.

The Guaranteed Load Drop (GLD) program option involves establishing a baseline of consumption absent the emergency event, similar to the measurement and verification procedure in the Economic Program. There are several techniques for estimation available to participants ranging in complexity. The comparable day option determines reductions based on consumption on similar day experience. Another option determines reduction as differences from hourly load immediately prior to or following an event. A third option is the standard CBL calculation used in the Economic Program. Other options include regression analysis and load profile modeling.

124 Of the 56 percent of registered MW nominated as Guaranteed Load Drop, 7 percent elect the behind the meter generation option for measurement and verification.

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The prior section addresses shortfalls of the standard CBL calculation used in the Economic Program, including the potential for an upward bias based on prior days with warmer temperatures. The potential for an upward bias during an actual Emergency Event is minimal, since Emergency Events coincide with peak load conditions in PJM which are highly correlated with peak temperatures. However, this design flaw is an issue when applied to Load Management testing as participants have discretion as to when testing will take place. Currently, GLD customers can test on any day in the summer period, and choose any other day in that period to serve as the baseline consumption to estimating load reductions. There are no objective criteria to establish comparability between the baseline day and test day.

In the proposed business rule changes developed by the LMTF, PJM attempts to establish objective criteria. For weather sensitive customers, a day that is closest in temperature humidity index (THI) would serve as the comparable day. For non-weather sensitive customers, the day immediately preceding the test day or event day would serve as the comparable day. These changes were bundled with changes associated with the double counting issue and deferred by PJM until May 2011. PJM's proposal represents an improvement to the Program by establishing some criteria for comparability, rather than allowing participants that have financial incentives to show large reductions to determine subjectively which day in the summer period is the most comparable. However, PJM's proposed rule changes do not ensure that the day chosen for will be comparable to the test day for two reasons. The weather sensitive criterion is strong, however, the designation of weather sensitivity is made by the participant. Historically, only a very small proportion of participants opt into weather sensitive baseline calculations. For non-weather sensitive participants, load can fluctuate significantly in any two consecutive days, so choosing a test day following an abnormally high load day will overstate reduction capability.

The MMU recommends that any baseline approach designed to estimate unrestricted load consumption based on a comparable day or a comparable set of days be adjusted for ambient conditions and other variables impacting load for all participants.

Conclusions: Demand Side

If retail markets reflected hourly wholesale prices and customers received direct savings associated with reducing consumption in response to real-time prices, there would not be a need for a PJM Economic Load Response Program, or for extensive measurement and verification protocols. In the transition to that point, however, there is a need for robust measurement and verification techniques to ensure that transitional programs incent the desired behavior. The baseline methods used in PJM programs today, particularly in the Emergency Program which consists entirely of capacity resources, are not adequate to determine and quantify deliberate actions taken to reduce consumption. The baseline pilot study being conducted by PJM will provide empirical analysis and objective criteria for improving current measurement and verification protocols in PJM Load Response Programs. The MMU recommends that PJM continue to refine baseline methods used to estimate load reductions based on empirical analysis with the intent of adopting the most accurate methods possible.

Emergency Program

In the 2010/2011 delivery year, all participants in the Emergency Program were capacity resources, integrated into RPM through the Load Management Program. The purpose of the Load Management Program is to provide a mechanism for end-use customers to avoid paying the Capacity Market clearing price in return for agreeing to not use capacity when it is needed by customers who have paid for capacity. The fact that customers in the Load Management Program only have to agree to interrupt ten times per year represents a flaw in the design of the program. There is no reason to believe that the customers who pay for capacity will need the capacity used by participating LM customers only ten times per year. In fact, it can be expected that the probability of needing that capacity will increase with the amount of MW that participating LM customers clear in the RPM auctions. Under the Emergency Energy Only option and the Emergency Full option, participants are made whole to a minimum strike price offer regardless of the hourly LMP. There is no economic reason to compensate load reductions up to $1,000/MWh during an emergency event regardless of the hourly LMP. Compensation in the Emergency Program should be directly aligned with the RPM market clearing price. The appropriate energy market price signal for load reduction in any hour is the hourly LMP. This means that the appropriate compensation in any PJM Program is the LMP less the generation component of a fixed retail rate, which is already made available through participation in the Economic Program. There is no need for energy payments through the Emergency Program. The current design of the Emergency Program incents resources to seek overcompensation through Emergency Energy payments equal to the greater of LMP or a submitted minimum dispatch price, which, in most cases is set at $1,000/MWh.

The MMU recommends that the option to specify a minimum dispatch price under the Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. The MMU also recommends that the Emergency Program Energy Only option should be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the Economic Program.

While the introduction of Load Management testing for any delivery year without an emergency event is an improvement to the Program, the current state of testing does not constitute an adequate measurement and verification protocol to ensure that demand side capacity resources can reliably reduce during a system emergency. The MMU recommends that the testing program be modified to require verification of test methods and results. In addition, the MMU recommends refinement of the baseline methods used to calculate compliance in Load Management for GLD customers. The baseline pilot study being conducted by PJM and the MMU will provide empirical analysis and objective criteria for improving baseline methods associated with the GLD option in the Load Management Program.

Economic Program

In PJM's Economic Load Response Program, the primary tool used to establish what unrestricted load would have been is the standard CBL. The modifications to the CBL calculations effective June, 2008, and the new review process, effective November, 2008, represent significant improvements to the Economic Program, but the review process is not yet adequate to ensure that other customers are receiving the benefit of actual demand reductions when payments are made under the program. The new review process is not yet developed to the point that it can establish

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that load reductions are the result of identifiable load reducing actions taken in response to price. There is no explicit or implicit screening mechanism in place to verify that CBL calculations are representative of customer load.

The MMU recommends that any settlement submitted with a consecutive 24 hour period of CBL greater than metered load should trigger a CBL review by PJM and that a customer should be required to provide documentation of load reduction actions taken, prior to acceptance of such settlements. Further, in order for PJM or the MMU to assess the accuracy of the CBL for a particular customer or for the Program in general, more hourly load data is required than is currently captured by PJM.

The “normal operations” screen defines an explicit threshold for the proportion of available days submitted for settlement, at or above which the CSP and end use customer must substantiate their submitted demand reductions. It is not clear why it is appropriate to require documentation of load reduction activities above a threshold and require no documentation of load reduction activities below that threshold.

The definition of the standard or default CBL should continue to be refined to ensure that it reflects the actual normal use of individual customers including normal daily and hourly fluctuations in usage and usage that is a function of measurable weather conditions. The baseline pilot study being conducted by PJM and the MMU will provide empirical analysis and objective criteria for improving baseline methods used to estimate load reductions in the Economic Program.

The MMU recommends two ways to further improve the Economic Program by increasing the probability that payments are made only for economic and deliberate load reducing activities in response to price. Load reduction in response to price must be clearly defined in the business rules and verified in a transparent daily settlement screen. The four steps in the normal operations review should be routinely applied to all registrations from the beginning of participation. This includes: the ongoing evaluation of whether CBL accurately represents customer load for each customer; analysis of settlements to determine responsiveness to price; the required submission of detailed description of load reduction activities on specific days; and review of the contract.

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SECTION 3 - ENERGY MARKET, PART 2

The Market Monitoring Unit (MMU) analyzed measures of PJM Energy Market structure, participant conduct and market performance for 2010. 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 and New Analysis

- Net revenues increased for all zones from 2009 to 2010 as a result of higher energy revenues, and, in most zones, higher capacity revenues.

- Net revenues in 2010 were greater than or equal to full annual fixed cost recovery in the Pepco and BGE zones for a new entrant CT and less than full annual fixed cost recovery in the other zones. Net revenues in 2010 were greater than or equal to full annual fixed cost recovery in the AECO, BGE, DPL, and Pepco zones for a new entrant CC and less than full annual fixed cost recovery in the other zones. There were no control zones with sufficient net revenue to cover the levelized fixed costs of a new entrant CP in 2010.

- Analysis of actual 2010 net revenues shows that capacity market revenues were required to provide supplemental revenue to incent continued operations in PJM for units that do not recover 100 percent of fixed costs through energy market revenue. Such units included CTs, CCs and coal units.

- Analysis of actual 2010 net revenues shows that revenues from energy, ancillary and capacity markets were sufficient to cover avoidable costs for all CC technologies and nearly all CT technologies.

- Analysis of actual 2010 net revenues shows that a number of sub-critical and supercritical coal units did not recover avoidable costs even after capacity revenues were considered. The total installed capacity associated with coal units that did not cover their avoidable costs in 2010 was 6,769 MW, of which, 6,021 MW were located in the MAAC region. These units are considered at risk of retirement. Units accounting for 2,763 MW are recovering less than 65 percent of avoidable costs and units accounting for 4,862 MW are recovering less than 75 percent of avoidable costs.

- Units lacking controls for either NO_x emissions, SO_2 emissions, or both were identified as units at risk of significant capital expenditure on environmental control technologies in response to regulatory mandates. For existing units, project investments associated with environmental controls are avoidable in nature and units facing these investments may be retired if it is not expected that the units will recover investments through a combination of energy or capacity revenue.

- Analysis of actual, unit specific net revenues and avoidable costs for coal plants lacking environmental controls in 2010 found that between 14,345 MW and 19,068 MW of installed capacity, depending on the nature of the requirements, would require an increase in energy or capacity revenue in order to recover avoidable costs including the project investment costs and remain in operation if faced with mandatory investment in environmental controls.

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- There were no scarcity pricing events in 2010 under PJM's current Emergency Action based Scarcity Pricing Rules.

- Analysis of net resource levels found there were no reserve shortages in 2010. There were a number of relatively high load days in July, August and September of 2010.

- Operating reserve charges increased 74.6 percent in 2010 compared to 2009. Higher loads, locationally volatile natural gas prices, and increases in outages were the primary causes. Eastern reliability credits increased 9,584.1 percent in 2010 compared to 2009, mainly as a result of units required to operate for a specific transmission outage, and an increase in weather-related alerts.

- Balancing transaction operating reserve credits paid in December 2010 represent 82.9 percent of all balancing transaction operating reserve credits since 2000.

- The concentration of operating reserve credits remains high, but decreased in 2010 compared to 2009. The top 10 units receiving total operating reserve credits, which make up less than one percent of all units in PJM's footprint, received 33.2 percent of total operating reserve credits in 2010, compared to 37.1 percent in 2009. In 2010, the top generation owner received 24.9 percent of the total operating reserve credits paid, a decrease from 2009, when the top generation owner received 32.8 percent of the total operating reserve credits.

- In 2010, coal units provided 49.3 percent, nuclear units 34.6 percent, gas 11.7 percent, oil 0.4 percent, hydroelectric 2.0 percent, waste 0.7 percent and wind 1.2 percent of total generation. Compared to calendar year 2009, generation from coal units increased 3.5 percent, and generation from nuclear units increased 2.1 percent. Generation from natural gas units increased 28.4 percent, and from oil units 106.8 percent.

- At the end of 2010, 76,415 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of approximately 167,000 MW in 2010. Wind projects account for approximately 38,301 MW of capacity or 50.1 percent of the capacity in the queues and combined-cycle projects account for 16,541 MW of capacity or 21.6 percent of the capacity in the queues.

- Many PJM jurisdictions have enacted legislation to require that a defined percentage of utilities' load be served by renewable resources, for which there are many standards and definitions. These are typically known as Renewable Portfolio Standards, or RPS. As of 2010, Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards, ranging from 0.02 percent of all load served in North Carolina, to 7.41 percent of all load served in New Jersey. Virginia has enacted a voluntary renewable portfolio standard. Indiana, Kentucky, and Tennessee have enacted no renewable portfolio standards.

Recommendations

- The MMU recommends that the limits on operational parameters apply to both price and cost-based schedules in order to prevent the exercise of market power.

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- The MMU recommends incorporating startup and notification times as additional parameters subject to limits in order to ensure the reliability of the grid, as well as to deter market manipulation by offering artificially lengthy startup and notification time parameters to withhold generation from the market.

- The MMU recommends that renewable energy credit markets be brought into PJM markets as RECs are an increasingly critical component of regulated wholesale energy prices.

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 2010, while total net revenues were not adequate to cover annual fixed costs for a new entrant coal plant (CP) in any zone, total net revenues were adequate to cover annual fixed costs for a new entrant CT in Pepco zone and in BGE zone, and total net revenues were adequate for a new entrant CC in the AECO, BGE, DPL and Pepco zones. While the results varied by zone, the net revenues for the CT and CC technologies generally covered a larger proportion of total fixed costs than for other technologies, reflecting a relatively favorable spread between LMP and the cost of natural gas compared to the spread between LMP and the cost of delivered coal.

In 2010, total net revenues were higher than in 2009. The increases in total net revenues by technology type were the result of increases in energy revenues, from an increase in energy prices which exceeded increases in fuel costs, and in most cases, increases in capacity revenues, from capacity prices determined in prior RPM auctions. 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 had higher total net revenue in 2010 compared to 2009 (Table 3-9). For the new entrant CT, all zones had higher energy net revenue, and all zones but two, BGE and Pepco, had higher available capacity revenues.[1] The 2010/2011 Base Residual Auction (BRA) cleared with much less 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 only slight increases or, in the case of SWMAAC, decreases, in capacity revenue available for calendar year 2010, while zones that previously cleared in the unconstrained RTO LDA saw significant increases in capacity 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 available capacity revenue in BGE and Pepco were more than offset by increases in energy net revenue. The six zones which had previously cleared in the EMAAC LDA (AECO, DPL, JCPL, PECO, PSEG and RECO) that were part of the MAAC+APS LDA for the 2009/2010 BRA had slightly higher capacity revenues available. Of these six zones, DPL showed the highest increase in capacity prices as DPL South separated and cleared at a slightly higher price than the RTO LDA in the 2010/2011 BRA. The five zones that had cleared in the unconstrained RTO LDA (AEP, ComEd, DAY, DLCO and Dominion) for the 2009/2010 BRA had significantly higher capacity revenues available as a result of higher capacity prices for the 2010/2011 BRA. The four zones that cleared in the MAAC+APS LDA and that had cleared with the unconstrained RTO LDA in the 2008/2009 BRA (AP, Met-Ed, PENELEC, and PPL) had significantly higher capacity revenues available associated with the constrained MAAC+APS LDA in the 2009/2010 BRA, but slightly lower capacity revenues associated with the 2010/2011BRA.

For the new entrant CC, all zones had higher total net revenue in 2010 compared to 2009 (Table 3-11). For the new entrant CC, all zones showed an increase in energy net revenue. For the two SWMAAC zones, higher energy net revenue more than offset decreases in capacity revenues.

For the new entrant coal plant (CP), all zones had higher total net revenue in 2010 compared to 2009 (Table 3-13). For the CP, all zones showed an increase in energy net revenues. For the two SWMAAC zones, higher energy net revenue more than offset decreases in capacity revenues.

- **Actual Net Revenue and Avoidable Costs.** Avoidable costs are the costs which must be paid each year in order to keep a unit operating. Avoidable costs are less than total fixed costs, which include the return on and of capital, and more than marginal costs, which are the short run incremental costs of producing energy. It is rational for an owner to continue to operate a unit if it is covering its avoidable costs and therefore contributing to covering fixed costs. It is not rational for an owner to continue to operate a unit if it is not covering and not expected to

1 This section discusses available 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.

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cover its avoidable costs. As a general matter, under those conditions, retirement of the unit is the logical option. The analysis, which compares net revenues to avoidable costs, is a measure of the extent to which units in PJM may be at risk of retirement.

It is not rational for an owner to invest in environmental controls if a unit is not covering and is not expected to cover its avoidable costs plus the annualized fixed costs of the investment. As a general matter, under those conditions, retirement of the unit is the logical option. The analysis, which compares net revenues to avoidable costs plus the annualized fixed costs of investments in environmental controls where relevant, is a measure of the extent to which such units in PJM may be at risk of retirement.

- For both the CT and CC technologies, as well as for the gas-fired and oil-fired steam technologies, RPM revenue has provided a required supplemental revenue stream to incent continued operations in PJM for units that do not recover 100 percent of fixed costs through energy market revenue. Nuclear and run of river hydro technologies generally recover avoidable costs entirely from the energy market.

- The coal plant technologies have higher avoidable costs and are more dependent on energy market net revenues than the CT and CC technologies. The total installed capacity of sub-critical coal and supercritical coal units that did not cover avoidable costs from energy revenues plus capacity revenues in 2010 was 6,769 MW. Generally, coal units that did not recover avoidable costs in 2010 tended to be smaller and less efficient, facing higher operating costs and higher avoidable costs. These units may be considered for deactivation.

- Other coal plants received significant energy market revenues but had made project investments associated with maintaining or improving reliability or environmental regulations, in which case, failure to cover avoidable costs, as defined in RPM, may be only a failure to recover the annual project recovery rate. If project costs are sunk, or if the project life is longer than the PJM defined recovery period for the calculation of the avoidable cost rate, it is rational to bid units below avoidable costs, as defined in RPM. In either case, these units may be at a lower risk of retirement than units under recovering avoidable costs excluding capital recovery as they may stay in service for the duration of the project life.

- Coal plants also face a higher risk of capital expenditures to comply with environmental regulations. There are pending regulations that would require significant capital expenditures in environmental controls for existing coal units in PJM and a significant portion of these units would require additional revenues if faced with project investment for environmental controls. The MMU analyzed two scenarios based on actual energy and capacity revenues and avoidable costs in 2010 for units that may require project investments in environmental controls. In the first scenario, units accounting for 14,345 MW of installed capacity would require additional revenue for recovery of project investments. In the second scenario, which assumes more stringent unit specific NO_x control requirements, units accounting for 19,068 MW of installed capacity would require additional revenue for recovery of project investments. For existing units, project investments associated with environmental controls are avoidable in nature and units facing these investments may be retired if it is not expected that the units will recover investments through a combination of energy or capacity revenue.

Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1, through December 31, 2010, PJM installed capacity resources fell slightly from 167,853.8 MW on January 1 to 166,512.1 MW on December 31, a decrease of 1,341.7 MW or 0.8 percent.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of 2010, 40.8 percent was coal; 29.1 percent was natural gas; 18.3 percent was nuclear; 6.1 percent was oil; 4.8 percent was hydroelectric; 0.4 percent was solid waste, and 0.4 percent was wind.

- **Generation Fuel Mix.** In 2010, coal provided 49.3 percent, nuclear 34.6 percent, gas 11.7 percent, oil 0.4 percent, hydroelectric 2.0 percent, solid waste 0.7 percent and wind 1.2 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 2010.** PJM did not declare a scarcity event in 2010.

  Scarcity exists when demand plus reserve requirements approach the available generating capacity of the system. Scarcity pricing means that market prices reflect the fact that the system is using close to its available capacity and that competitive prices may exceed accounting short-run marginal costs. Under the current PJM rules, high prices, or scarcity pricing, result from high offers by individual generation owners for specific units when the system is close to its available capacity. These offers give the aggregate energy supply curve its steep upward sloping tail. As demand increases and units with higher offers are required to meet demand, prices increase.

- **Scarcity and High Load Analyses.** The MMU analysis of net resource levels in the June through September period showed no evidence of reserve shortage events in the period. There were, however, a number of relatively high load days in July, August and September of 2010.

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

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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 2010.** The level of operating reserve credits and corresponding charges increased in 2010 by 74.6 percent compared to 2009, to $569 million in 2010 from $325 million in 2009. Reliability credits increased 268.0 percent, or $82 million, in 2010 compared to 2009.

  The overall increase in operating reserve charges in 2010 is comprised of a 4.5 percent decrease in day-ahead operating reserve charges, a 71.1 percent decrease in synchronous condensing charges and a 109.1 percent increase in balancing operating reserve charges. The increase in balancing charges can be attributed primarily to higher levels of demand in 2010 along with sustained periods of higher natural gas prices during winter months. December 2010, which includes 8.5 percent of the days in the year, accounted for 16.9 percent, or $96,032,958 of the annual operating reserve charges.

- **New Operating Reserve Rules.** New rules governing the payment of operating reserves credits and the allocation of operating reserves charges became effective on December 1, 2008. The new operating reserve rules represent positive steps towards the goals of removing the ability to exercise market power and refining the allocation of operating reserves charges to better reflect causal factors. The MMU calculated the impact of the new operating reserve rules in three areas.

  One purpose of the rule changes was to allocate a larger portion of the balancing operating reserve charges to those requiring additional resources to maintain system reliability, defined as real-time load and exports. This rule change had a significant impact in 2010. The new operating reserve rules resulted in an increase of $112,691,690 in charges assigned to real-time load and exports for 2010.

  The rule changes resulted in a reduced allocation of charges to deviations, which reduced operating reserve payments assigned to virtual market activity. The net result is that virtual offers and bids paid $26 million less in operating reserve charges in 2010 than they would have paid under the old rules.

  As a result of the introduction of segmented make whole payments in place of 24 hour make whole payments, balancing operating credits were $18 million, or 6.0 percent, higher for 2010 than they would have been under the old rules.

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.

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In 2010, energy market revenues were generally higher for new entrant combustion turbines and combined cycles, both using natural gas, as energy market prices increased more than the average delivered price of natural gas in most zones. Energy market net revenues for new entrant coal plants were substantially higher in all zones as energy market prices increased more than the average delivered price of low sulfur coal.

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. All zones had more high demand days in 2010 than in 2009 and all zones showed a higher frequency of hours of real-time LMP greater than $200. The average on peak LMP for PJM increased 21 percent for 2010 compared to 2009. The PJM average real-time LMP was greater than $200 for twenty-six hours in 2010, compared to two hours in 2009. As a result, the average increase in energy net revenue for a new entrant CT was 274 percent, and the increases in energy net revenue for BGE and Pepco zones were 355 and 368 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. When less efficient coal units are on the margin, net revenues are higher for more efficient coal units. Coal units also receive higher net revenue when load following and peaking gas-fired units set price. In 2010, particularly in the third quarter, CCs and CTs ran more often, which resulted in an increase in the net revenue received by coal plants.

Net Revenue

Net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue quantifies the contribution to capital and avoidable costs received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services. Although generators receive operating reserve payments as a revenue stream, these payments are not included when the analysis is based on perfect dispatch.[2] Operating reserve payments are included when the analysis is based on the peak-hour, economic dispatch model and actual net revenues.[3]

2 Under the PJM model, operating reserve payments compensate generation owners when units operate at PJM's request when LMP is less than marginal cost over defined hours of operation. Operating reserve does not apply in perfect dispatch because the theoretical unit only operates when LMP is greater than marginal cost.

3 The peak-hour, economic dispatch model is a realistic representation of market outcomes that, in contrast to the perfect dispatch model, considers unit operating limits. The model can result in the dispatch of a unit for a block that yields negative net energy revenue and is made whole by operating reserve payments.

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Gross Energy Market revenue is the product of the Energy Market price and generation output. Gross revenues are also received from the Capacity and Ancillary Service Markets. Net revenue equals total gross revenue less the variable costs of energy production. In other words, net revenue is the amount that remains, after short run variable costs of energy production have been subtracted from gross revenue, to cover fixed costs, which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses. Fixed costs, in this sense, include all but short run variable costs.

In a perfectly competitive, energy-only market in long-run equilibrium, net revenue from the energy market would be expected to equal the total of all annualized fixed costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets intended to contribute to the payment of fixed costs. In PJM, the Energy, Capacity and Ancillary Service Markets are all significant sources of revenue to cover fixed costs of generators, as are payments for the provision of black start and reactive services. Thus, in a perfectly competitive market in long-run equilibrium, with energy, capacity and ancillary service payments, net revenue from all sources would be expected to equal the annualized fixed costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate above and below the equilibrium level based on actual conditions in all relevant markets.

Theoretical Energy Market Net Revenue

The net revenues presented in this section are theoretical as they are based on explicitly stated assumptions about how a new unit with specific characteristics would operate, rather than on an analysis of actual net revenues for actual units operating in PJM. Energy Market net revenues were developed separately for both the Real-Time and the Day-Ahead Energy Markets.

The Real-Time Energy Market revenues in Table 3-1 and the Day-Ahead Energy Market revenues in Table 3-2 reflect net Energy Market revenues from all hours during 1999 to 2010 for the Real-Time Energy Market and from all hours during 2000 to 2010 for the Day-Ahead Energy Market, when the PJM hourly LMP exceeded the identified marginal cost of generation. The tables include the dollars per installed MW-year that would have been received by a unit in PJM if it had operated whenever system price exceeded the identified marginal cost in dollars per MWh, adjusted for unit forced outages.[4] For example, during 2010, if a unit had marginal costs (fuel plus variable operation and maintenance expense) equal to $30 per MWh, it had an incentive to operate whenever the Real-Time Energy Market LMP exceeded $30 per MWh. If such a unit had operated during all profitable hours in 2010, adjusted for forced outages, it would have received $129,146 per installed MW-year in net revenue from the Real-Time Energy Market alone. For the Day-Ahead Energy Market, the same unit would have received $123,943 per installed MW-year in net revenue from the Day-Ahead Energy Market.[5]

Table 3-1 illustrates the relationship between generator marginal cost and net revenue from the PJM Real-Time Energy Market alone for the years 1999 through 2010.

4 Real-Time and Day-Ahead Energy Market net revenue calculations reflect a forced outage rate equal to the actual PJM system forced outage rate for each year. Since these tables include a range of marginal cost from $10 to $200, an outage rate by class cannot be utilized because there is no simple mapping of marginal cost to class of generation, e.g. the $100 marginal cost could include steam-oil, gas–fired CC and efficient gas-fired CTs. Class-specific forced outage rates are used for the class-specific net revenue calculations.

5 This unit would not receive Real-Time Energy Market revenues in addition to Day-Ahead Energy Market revenues as any energy scheduled in the Day-Ahead Energy Market would be credited at the day-ahead energy market-clearing price and would not be eligible for Real-Time Energy Market revenues for the same hour of operation.

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Table 3-1 PJM Real-Time Energy Market net revenue (By unit marginal cost (Dollars per MWh)): Calendar years 1999 to 2010

Marginal Cost	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
$10	$152,087	$150,774	$186,887	$153,620	$231,927	$263,115	$394,619	$322,668	$388,984	$459,738	$220,494	$283,747
$20	$94,690	$89,418	$116,116	$85,661	$159,751	$185,956	$314,917	$242,179	$308,397	$379,750	$141,212	$203,458
$30	$72,489	$59,776	$78,368	$51,898	$110,126	$121,218	$241,977	$171,735	$235,215	$302,122	$73,039	$129,146
$40	$62,367	$39,519	$56,055	$31,650	$73,828	$74,920	$184,479	$120,014	$177,918	$233,568	$38,171	$82,421
$50	$57,080	$25,752	$42,006	$19,776	$47,277	$44,577	$141,078	$83,857	$132,033	$179,669	$21,792	$56,843
$60	$54,132	$16,888	$33,340	$13,101	$29,566	$25,328	$107,057	$58,812	$95,768	$138,282	$13,197	$40,790
$70	$52,259	$11,750	$27,926	$9,080	$18,001	$13,624	$80,473	$41,608	$67,644	$106,343	$8,353	$30,125
$80	$50,959	$8,586	$24,389	$6,623	$10,650	$6,929	$59,903	$29,643	$46,859	$81,666	$5,366	$22,648
$90	$49,840	$6,700	$22,080	$5,079	$6,273	$3,494	$44,043	$21,585	$32,467	$62,360	$3,479	$17,114
$100	$48,818	$5,640	$20,521	$4,109	$3,770	$1,784	$32,184	$16,188	$23,110	$47,397	$2,349	$13,049
$110	$47,863	$4,930	$19,375	$3,507	$2,250	$951	$23,338	$12,653	$16,898	$35,713	$1,588	$9,928
$120	$46,926	$4,385	$18,480	$3,063	$1,315	$518	$16,831	$10,283	$12,655	$26,971	$1,067	$7,497
$130	$46,007	$3,958	$17,716	$2,758	$723	$260	$12,070	$8,645	$9,795	$20,281	$731	$5,679
$140	$45,114	$3,609	$17,030	$2,501	$387	$124	$8,528	$7,466	$7,737	$15,222	$484	$4,358
$150	$44,228	$3,317	$16,421	$2,287	$218	$51	$5,903	$6,667	$6,302	$11,288	$323	$3,355
$160	$43,374	$3,102	$15,884	$2,115	$142	$24	$3,946	$6,030	$5,202	$8,351	$205	$2,591
$170	$42,523	$2,923	$15,395	$1,970	$94	$9	$2,554	$5,508	$4,357	$6,196	$119	$1,978
$180	$41,685	$2,768	$14,944	$1,828	$51	$0	$1,679	$5,083	$3,722	$4,630	$69	$1,468
$190	$40,856	$2,623	$14,542	$1,700	$23	$0	$1,113	$4,699	$3,219	$3,464	$41	$1,077
$200	$40,036	$2,488	$14,162	$1,607	$10	$0	$706	$4,347	$2,831	$2,643	$15	$806

Table 3-2 illustrates the relationship between generator marginal cost and net revenue from the PJM Day-Ahead Energy Market alone for the years 2000 through 2010.[6]

6 The Day-Ahead Energy Market began on June 1, 2000. For the analysis presented in Table 3-2, Real-Time Energy Market LMP was used in the Day-Ahead Energy Market analysis for the period from January 1, 2000 to May 31, 2000.

Table 3-2 PJM Day-Ahead Energy Market net revenue (By unit marginal cost (Dollars per MWh)): Calendar years 2000 to 2010

Marginal Cost	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
$10	$158,429	$189,366	$154,267	$234,622	$254,455	$392,425	$216,637	$364,734	$456,557	$218,865	$281,075
$20	$95,823	$115,372	$83,083	$159,572	$176,265	$311,563	$165,614	$283,295	$375,221	$138,961	$199,891
$30	$61,816	$68,718	$44,916	$102,907	$109,583	$235,006	$117,447	$207,702	$295,084	$70,736	$123,934
$40	$38,762	$42,283	$25,011	$61,674	$59,650	$173,084	$77,340	$146,320	$221,678	$29,918	$69,720
$50	$23,141	$27,936	$15,126	$34,891	$27,638	$125,929	$47,954	$97,297	$161,374	$13,695	$40,641
$60	$14,281	$20,375	$9,894	$19,169	$11,152	$90,176	$29,201	$59,674	$115,287	$6,695	$24,802
$70	$9,523	$16,304	$6,804	$10,504	$4,039	$63,340	$18,423	$34,135	$80,996	$3,134	$15,286
$80	$6,840	$13,933	$4,856	$5,858	$1,375	$43,467	$12,613	$19,326	$56,349	$1,433	$9,230
$90	$5,100	$12,540	$3,522	$3,389	$415	$29,224	$9,180	$11,257	$39,159	$599	$5,466
$100	$3,927	$11,478	$2,570	$1,954	$121	$19,208	$7,037	$6,530	$27,761	$189	$3,153
$110	$3,244	$10,705	$1,885	$1,150	$42	$12,186	$5,742	$3,730	$20,157	$38	$1,761
$120	$2,683	$10,098	$1,385	$620	$14	$7,409	$4,873	$2,081	$14,650	$4	$1,015
$130	$2,299	$9,579	$1,000	$315	$0	$4,361	$4,203	$1,167	$10,633	$0	$596
$140	$2,056	$9,139	$712	$148	$0	$2,397	$3,628	$703	$7,706	$0	$352
$150	$1,884	$8,708	$494	$34	$0	$1,229	$3,136	$421	$5,594	$0	$202
$160	$1,787	$8,312	$354	$0	$0	$574	$2,703	$241	$4,034	$0	$115
$170	$1,701	$7,926	$243	$0	$0	$234	$2,314	$118	$2,929	$0	$64
$180	$1,616	$7,564	$145	$0	$0	$83	$1,991	$51	$2,173	$0	$32
$190	$1,532	$7,232	$78	$0	$0	$31	$1,717	$11	$1,611	$0	$13
$200	$1,447	$6,908	$30	$0	$0	$11	$1,475	$0	$1,209	$0	$0

Figure 3-1 displays the information from Table 3-1, and Figure 3-2 displays the information from Table 3-2. As Figure 3-1 illustrates, the Real-Time Energy Market net revenue curve for 2010 is higher than for 2009 for all levels of marginal costs. As Figure 3-2 illustrates, the Day-Ahead Energy Market net revenue curve for 2010 is higher than for 2009 for all levels of marginal cost below $200.

The increase in 2010 Real-Time Energy Market net revenue compared to 2009 was the result of changes in the frequency distribution of energy prices. In 2010, prices were greater than or equal to $30 per MWh more frequently than in 2009. The 2010 simple average LMP was $44.83 per MWh, a substantial increase compared to $37.08 per MWh in 2009. The Real-Time Energy Market LMP was greater than, or equal to, $30 per MWh during 62 percent of all hours in 2009, and during 77 percent of all hours in 2010.

The increase in 2010 compared to 2009 Day-Ahead Energy Market net revenue is also the result of changes in the frequency distribution of energy prices. In 2010, prices were greater than, or equal to, $30 more frequently than in 2009 as the simple average LMP was $44.57 per MWh in 2010 compared to $37.00 per MWh in 2009. The Day-Ahead Energy Market LMP was greater than or equal to $30 per MWh during 69 percent of all hours in 2009, and during 82 percent of all hours in 2010.

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Average price levels in 2010 were significantly higher than in 2009 and, as a result, net revenue levels were higher for specific marginal cost levels, as shown in Figure 3-1 and Figure 3-2. The distribution of prices reflects a number of factors including load levels and fuel costs. Load levels in 2010 were higher compared to those in 2009, and price levels increased more than fuel costs. An efficient CT could have produced energy at an average cost of $60 in 2010. An efficient CC could have produced energy at an average cost of $40 in 2010. An efficient CP could have produced energy at an average cost of $30 in 2010. Energy Market net revenues for a new entrant CT, CC and CP were higher in nearly all zones in 2010 due to PJM price levels increasing more rapidly than the average prices of natural gas and delivered coal. The result is that, while natural gas-fired units and coal-fired units experienced slightly higher marginal costs compared to 2009, the increase in average PJM prices in 2010 was greater, meaning higher energy net revenue in all control zones for 2010.

Figure 3-1 PJM Real-Time Energy Market net revenue (By unit marginal cost): Calendar years 1999 to 2010

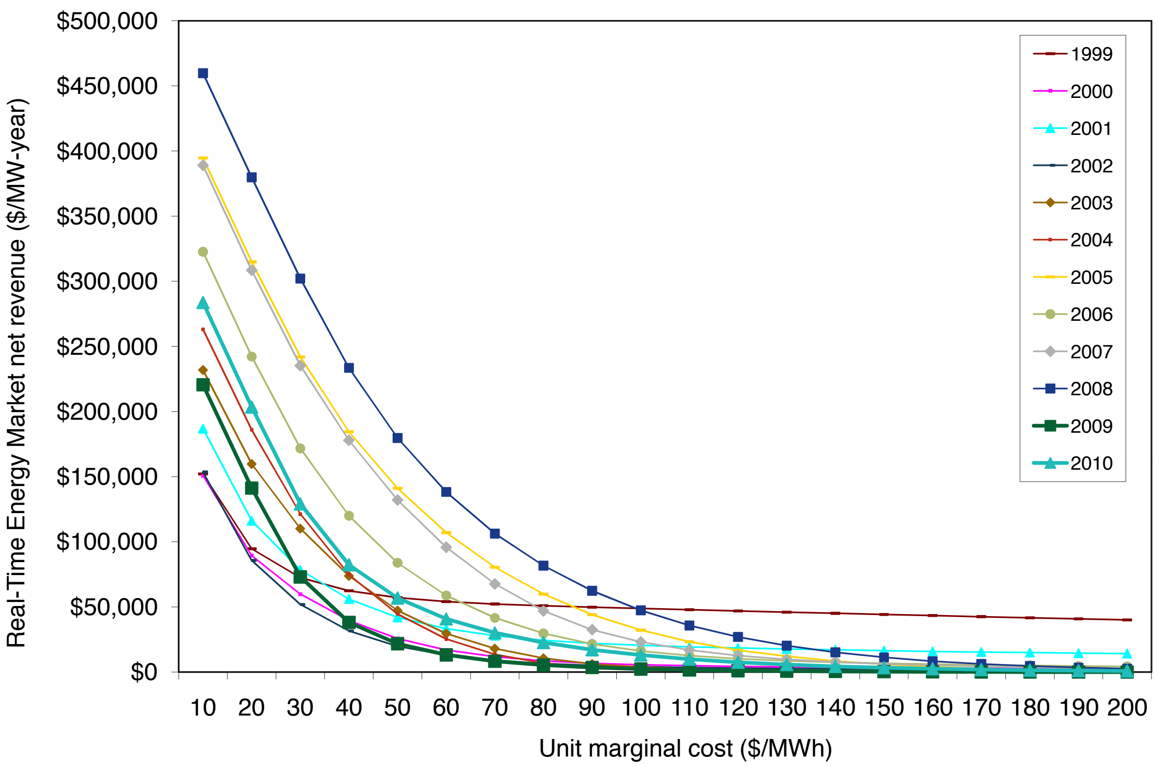
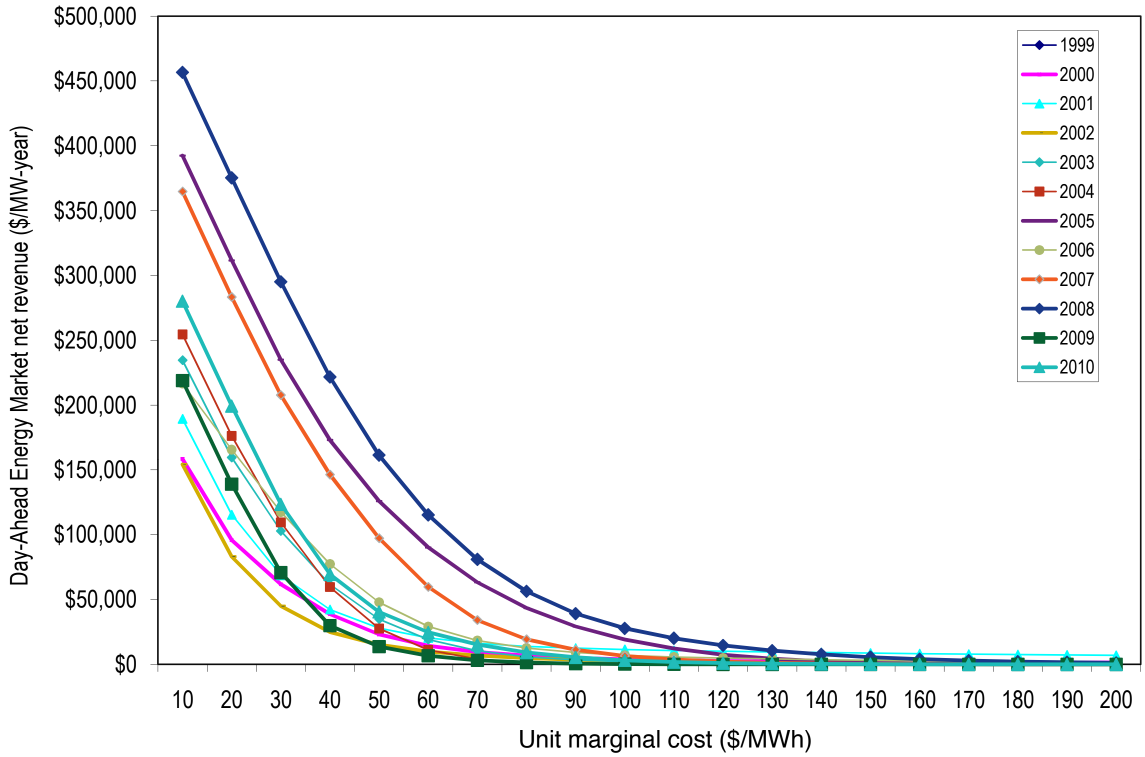


Figure 3-2 PJM Day-Ahead Energy Market net revenue (By unit marginal cost): Calendar years 2000 to 2010



Differences in the shape and position of Real-Time and Day-Ahead Energy Market net revenue curves result from different distributions of Energy Market prices in each year. These differences illustrate, among other things, the significance of a relatively small number of high-priced hours to the profitability of high marginal cost units.[7] The Real-Time and Day-Ahead Energy Market curves are very similar for lower marginal cost levels, particularly below $30 per MWh. The Real-Time Energy Market curve shows significantly higher net revenues as marginal costs increase beyond $80 per MWh because, while average Real-Time LMP is very close to Day-Ahead LMP, the Real-Time LMP is more volatile and shows a higher frequency of high priced hours compared to Day-Ahead LMP.

The theoretical net revenues displayed in Table 3-1 and Table 3-2 are calculated under perfect dispatch assumptions and therefore represent an upper bound of the direct contribution to generator fixed costs from the Energy Market. All other things constant, these Energy Market net revenues show how the frequency distribution of price levels in a given year affects the amount of revenue a generator would have received at the specified levels of marginal cost.

The Energy Market net revenues shown in Table 3-1 and Table 3-2 do not consider operating constraints that may affect actual net revenue of an individual plant. Such operating constraints are less likely to affect the net revenue calculations for CTs, given their operational flexibility and the operating reserve revenue guarantee. For a CC plant, a two-hour hot status notification plus

7 See the *2010 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part 1," at "Load and LMP" and Appendix C, "Energy Market" for detailed data on prices and their annual distribution.

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startup time for a summer weekday could prevent a unit from running during two positive net revenue hours in the afternoon peak and two more positive net revenue hours in the evening peak separated by two negative net revenue hours. The actual impact depends on the relationship between LMP and the operating cost of the unit. Similarly, a CP plant with an eight-hour cold status notification plus startup time could run overnight during negative net revenue hours although the lower relative operating costs of a steam unit would generally reduce the significance of the issue. Ramp limitations might prevent a CC or steam unit from starting and ramping up to full output in time to operate for all positive net revenue Conversely, the net revenue measure does not include the potentially significant contribution to fixed cost from the explicit or implicit sale of the option value of physical units or from bilateral agreements to sell output at a price other than the PJM Day-Ahead or Real-Time Energy Market prices, e.g., a forward price.

Capacity Market Net Revenue

Generators receive revenue from the sale of capacity in addition to revenue from the Energy and Ancillary Service Markets. In the PJM market design, the sale of capacity provides an important source of revenues to cover generator fixed costs. The Capacity Credit Market (CCM) design was in effect until June 1, 2007. For the period from January 1 through May 31, 2007, PJM capacity resources received a weighted-average payment from the CCM of $3.21 per MW-day of unforced capacity. This was the lowest level of CCM revenues since the opening of the CCM in mid-1999.

On June 1, 2007, with the implementation of the RPM, PJM capacity resources began to receive capacity payments determined in the first RPM Auction for their corresponding Locational Deliverability Area (LDA). The RPM Base Residual Auction clearing prices are shown by zone and LDA in Table 3-3.[8]

8 The value in Table 3-3 associated with DPL represents a load-weighted average clearing price for the DPL control zone, because the DPL South LDA is sub-zonal. Table 3-3 shows capacity revenues per unforced MW-year from RPM BRAs. Table 3-4 shows capacity revenues per installed MW-year from RPM BRAs, adjusted using the system forced outage rate.

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

	Base Residual Auction 2009/2010			Base Residual Auction 2010/2011			RPM Revenue
Zone	LDA	$/MW-Day	$/MW in 2010	LDA	$/MW-Day	$/MW in 2010	2010 $/MW
AECO	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
AEP	RTO	$102.04	$15,408	RTO	$174.29	$37,298	$52,706
AP	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
BGE	SWMAAC	$237.33	$35,837	RTO	$174.29	$37,298	$73,135
ComEd	RTO	$102.04	$15,408	RTO	$174.29	$37,298	$52,706
DAY	RTO	$102.04	$15,408	RTO	$174.29	$37,298	$52,706
DLCO	RTO	$102.04	$15,408	RTO	$174.29	$37,298	$52,706
Dominion	RTO	$102.04	$15,408	RTO	$174.29	$37,298	$52,706
DPL	MAAC+APS	$191.32	$28,889	DPL South/RTO	$178.57	$38,214	$67,103
JCPL	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
Met-Ed	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
PECO	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
PENELEC	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
Pepco	SWMAAC	$237.33	$35,837	RTO	$174.29	$37,298	$73,135
PPL	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
PSEG	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
RECO	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
PJM	NA	$154.47	$23,325	NA	$174.42	$37,327	$60,652

Table 3-4 shows zonal capacity revenue for the twelve-year period 1999 to 2010.[9] Results for 1999 through 2006 reflect the load-weighted averages from the CCM construct. Results for 2007 combine the CCM values for the January through May period and the RPM Auction values for the June through December period.[10] Capacity revenue for 2010 includes five months of the 2009/2010 auction clearing price and seven months of the 2010/2011 auction clearing price.[11] These capacity revenues are adjusted for the yearly, system wide forced outage rate.[12]

9 In tables with zonal net revenues, data for a transmission zone are displayed for all full calendar years following integration into PJM markets.

10 In Table 3-4, the 2007 column represents an average of all revenue associated with the sale of capacity by zone followed by a weighted-average of capacity revenue for the PJM footprint. The zonal results combine load-weighted averages from both daily and monthly CCM prices for January through May as well as the associated LDA clearing price for the remaining seven months

11 The 2007 capacity revenue value for PJM in Table 3-4 similarly combines load-weighted CCM and RPM BRA revenues. The 2008-2010 RPM revenue values for PJM are load-weighted averages based on the BRA LDA clearing prices in Table 3-3 and the cleared MW associated with each. The result is a load-weighted, average revenue associated with the sale of capacity per MW-year for the whole PJM footprint.

12 The PJM capacity revenues presented in Table 3-4 differ slightly from those presented in Table 3-9, Table 3-11 and Table 3-13 as capacity revenues by technology type are adjusted for technology-specific outage rates.

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Table 3-4 Capacity revenue by PJM zones (Dollars per MW-year): Calendar years 1999 to 2010

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
AECO	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$58,663	$61,423	$26,424
AEP	NA	NA	NA	NA	NA	NA	$2,089	$1,958	$8,551	$27,928	$35,836	$48,912	$20,879
AP	NA	NA	NA	NA	$7,633	$6,493	$2,089	$1,958	$8,551	$27,928	$53,511	$61,423	$21,198
BGE	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$37,868	$68,190	$76,336	$67,871	$29,188
ComEd	NA	NA	NA	NA	NA	NA	$3,607	$1,958	$8,551	$27,928	$35,836	$48,912	$21,132
DAY	NA	NA	NA	NA	NA	NA	$2,089	$1,958	$8,551	$27,928	$35,836	$48,912	$20,879
DLCO	NA	NA	NA	NA	NA	NA	$2,089	$1,958	$8,551	$27,928	$35,836	$48,912	$20,879
Dominion	NA	NA	NA	NA	NA	NA	NA	$1,958	$8,551	$27,928	$35,836	$48,912	$24,637
DPL	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$58,663	$62,273	$26,495
JCPL	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$58,663	$61,423	$26,424
Met-Ed	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$8,551	$27,928	$53,511	$61,423	$20,951
PECO	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$58,663	$61,423	$26,424
PENELEC	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$8,551	$27,928	$53,511	$61,423	$20,951
Pepco	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$37,868	$68,190	$76,336	$67,871	$29,188
PPL	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$8,551	$27,928	$53,511	$61,423	$20,951
PSEG	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$58,663	$61,423	$26,424
RECO	NA	NA	NA	NA	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$58,663	$61,423	$29,197
PJM	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$29,966	$37,095	$44,814	$56,287	$22,346

New Entrant Net Revenues

In order to provide a more realistic estimate of the net revenues that would result from investment in new generation resources, a peak-hour, economic dispatch scenario was analyzed. In contrast to the perfect dispatch scenario, economic dispatch uses technology-specific operating constraints in the calculation of a new entrant's operations and potential net revenue in PJM markets. All technology specific, zonal net revenue calculations included in the new entrant net revenue analysis in this section are based on the economic dispatch scenario.

Analysis of both the Real-Time and Day-Ahead Energy Market net revenues for a new entrant includes three power plant configurations: a natural gas-fired CT, a two-on-one, natural gas-fired CC and a conventional CP, single reheat steam generation plant. The CT plant consists of two GE Frame 7FA CTs, equipped with full inlet air mechanical refrigeration and selective catalytic reduction (SCR) for NO_x reduction. The CC plant consists of two GE Frame 7FA CTs equipped with evaporative cooling, duct burners, a heat recovery steam generator (HRSG) for each CT with steam reheat and SCR for NO_x reduction with a single steam turbine generator. The coal plant is a western Virginia sub-critical steam CP, equipped with selective catalytic reduction system (SCR) for NOx control, a Flue Gas Desulphurization (FGD) system with chemical injection for SOx and mercury control, and a bag-house for particulate control.

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All net revenue calculations include the effect of actual hourly local ambient air temperature[13] on plant heat rates[14] and generator output for each of the three plant configurations.[15] Plant heat rates were calculated for each hour to account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.[16] The effect of ambient air conditions on plant generation capability was calculated hourly.

NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost, where applicable. These costs are included in the PJM definition of marginal cost. NO_x and SO_2 emission allowance costs were obtained from actual historical daily spot cash prices.[17] NO_x emission allowance costs were included only during the annual NO_x attainment period from May 1 through September 30. SO_2 emission allowance costs were calculated for every hour of the year.

A forced outage rate for each class of plant was calculated from PJM data.[18] This class-specific outage rate was then incorporated into all revenue calculations. Additionally, each plant was given a continuous 15 day planned, annual outage in the fall season.

Variable operation and maintenance (VOM) expenses were estimated to be $7.46 per MWh for the CT plant, $3.23 per MWh for the CC plant and $3.07 per MWh for the CP plant.[19] The VOM expenses for the CT and CC plants include accrual of anticipated, routine major overhaul expenses.[20] The delivered fuel cost for natural gas is from published commodity daily cash prices, with a basis adjustment for transportation costs.[21] Coal delivered cost was developed from the published prompt-month price, adjusted for rail transportation cost.[22]

Real-time ancillary service revenues for the provision of synchronized reserve service for all three plant types are set to zero. GE Frame 7FA CTs are typically not configured to provide Tier 2 synchronized reserve in PJM. Steam units do provide Tier 1 synchronized reserve, but the 2010 Tier 1 revenues were minimal. Real-time ancillary service revenues for the provision of regulation service for both the CT and CC plant are also set to zero since these plant types typically do not provide regulation service in PJM. Additionally, no black start service capability is assumed for the reference CT plant configuration in either costs or revenues. Real-time ancillary service revenues for the provision of regulation were calculated for the CP plant. The regulation offer price was the sum of the calculated hourly cost to supply regulation service plus an adder of $12 per PJM market rules.[23] This offer price was compared to the hourly clearing price in the PJM Regulation Market. The clearing price includes both the offer price and the lost opportunity cost of the marginal unit in each hour. If the reference CP could provide regulation at a total cost, including the CP opportunity cost, that is less than the regulation-clearing price, the regulation service net revenue equals the market price of regulation minus the cost of CP regulation.

13 Hourly ambient conditions supplied by Telvent DTN for multiple points in PJM RTO. PJM net revenue calculations include the average of all points in PJM RTO. Zonal net revenue calculations include zone specific ambient air temperatures.

14 These heat rate changes were calculated by Pasteris Energy, Inc., a consultant to the MMU, utilizing GE Energy's GateCycle Power Plant and Simulation Software. Neither GE Energy nor GE has reviewed this report or the calculations and results of the work done by Pasteris Energy, Inc. for the MMU.

15 Pasteris Energy, Inc.

16 All heat rate calculations are expressed in Btu per net kWh. No-load costs are included in the heat rate and subsequently the dispatch price since each unit type is dispatched at full load for every economic hour, but is off for every uneconomic hour. Therefore, there is a single offer point and no offer curve.

17 NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.

18 Outage figures obtained from the PJM eGADS database.

19 These estimates were provided by a consultant to the MMU, Pasteris Energy, Inc.

20 Routine combustor inspection, hot gas path and major inspection costs collected through the VOM adder. This figure was established by Pasteris Energy, Inc. and compares favorably with actual operation and maintenance costs from similar PJM generating units.

21 Gas daily cash prices obtained from Platts.

22 Coal prompt prices obtained from Platts.

23 The adder reflects the modifications to the regulation market rules that were effective on December 1, 2008.

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Generators receive revenues for the provision of reactive services based on cost-of-service filings with the United States Federal Energy Regulatory Commission (FERC). The actual reactive service payments filed with and approved by the FERC for each generator class were used to determine the reactive revenues. Reactive service revenues are based on the weighted-average reactive service rate per MW-year calculated from the data in the FERC filings. In 2010, for CTs, the calculated rate is $2,384 per installed MW-year; for CCs, the calculated rate is $3,198 per installed MW-year and for CPs, the calculated rate is $1,783 per installed MW-year.[24]

Zonal Real-Time Energy Market net revenue under a peak-hour, economic dispatch scenario for 1999 to 2010 is shown in Table 3-5, Table 3-6 and Table 3-7 for new entrant CT, CC and CP facilities. The difference in net revenue among zones is a direct result of the locational variation in hourly LMP and delivered fuel costs.[25] The difference in net revenue among the generation technologies is a direct result of the variation in marginal cost associated with each.

Table 3-5 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year):[26] Net revenue for calendar years 1999 to 2010

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
AECO	$56,278	$12,077	$40,825	$19,449	$5,274	$6,765	$18,309	$23,165	$41,985	$65,046	$10,735	$49,154	$29,089
AEP	NA	NA	NA	NA	NA	NA	$641	$4,638	$5,959	$4,458	$3,206	$10,929	$4,972
AP	NA	NA	NA	NA	$1,069	$864	$5,190	$10,695	$17,726	$17,701	$12,546	$32,870	$12,333
BGE	$54,770	$7,193	$23,048	$20,049	$4,196	$2,899	$22,293	$31,725	$56,613	$47,525	$14,995	$61,400	$28,892
ComEd	NA	NA	NA	NA	NA	NA	$1,747	$7,131	$9,271	$4,886	$2,393	$8,642	$5,678
DAY	NA	NA	NA	NA	NA	NA	$793	$4,342	$5,776	$4,672	$2,981	$10,340	$4,817
DLCO	NA	NA	NA	NA	NA	NA	$665	$5,408	$9,805	$7,746	$4,704	$17,087	$7,569
Dominion	NA	NA	NA	NA	NA	NA	NA	$26,830	$43,653	$43,465	$14,319	$48,940	$35,441
DPL	$57,625	$12,712	$49,833	$22,430	$5,587	$2,881	$14,259	$17,265	$34,151	$35,422	$13,410	$47,388	$26,080
JCPL	$55,947	$9,803	$37,473	$13,933	$2,982	$14,472	$16,933	$15,932	$37,836	$35,166	$11,622	$44,372	$24,706
Met-Ed	$54,998	$8,068	$30,697	$17,372	$3,603	$2,271	$15,174	$17,503	$36,393	$25,498	$10,057	$44,747	$22,198
PECO	$56,510	$11,760	$37,989	$14,761	$4,836	$1,600	$16,114	$15,600	$28,560	$27,081	$9,513	$41,761	$22,174
PENELEC	$54,997	$7,360	$18,137	$12,117	$1,731	$1,264	$3,117	$6,585	$10,957	$5,953	$6,019	$22,092	$12,527
Pepco	$54,556	$7,022	$18,108	$22,024	$4,610	$3,915	$25,840	$37,801	$58,816	$54,838	$23,362	$70,361	$31,771
PPL	$55,305	$7,753	$26,748	$12,589	$2,265	$1,120	$12,403	$13,612	$25,472	$21,531	$8,970	$38,365	$18,844
PSEG	$56,271	$10,171	$36,818	$13,499	$4,555	$13,163	$16,881	$15,980	$32,405	$28,809	$9,155	$42,106	$23,318
RECO	NA	NA	NA	NA	$4,213	$3,749	$12,971	$13,606	$32,295	$23,966	$7,846	$37,166	$16,977
PJM	$55,612	$8,498	$30,254	$14,496	$2,763	$919	$6,141	$10,996	$17,933	$12,442	$5,113	$36,925	$16,841

24 The CT plant reactive revenues are based on 44 filings with the FERC for CT reactive costs. The CC plant revenues are based on 27 filings with the FERC for CC reactive costs, and the CP plant revenues are based on 18 filings with the FERC for CP reactive costs. These figures have not changed from those reported in the *2009 State of the Market Report for PJM* as there were no reactive filings with the FERC in calendar year 2010 for PJM resources.

25 Zonal net revenues for 2009 and 2010 reflect locational zonal fuel costs which consider a variety of locational fuel indices, actual unit consumption patterns, and zone specific delivery charges.

26 The energy net revenues presented for PJM for 2010 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 3-6 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 calendar years 1999 to 2010

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
AECO	$80,930	$29,354	$68,323	$46,203	$35,658	$52,625	$77,223	$78,489	$107,344	$154,085	$48,544	$108,930	$56,729
AEP	NA	NA	NA	NA	NA	NA	$12,533	$21,695	$29,990	$29,194	$25,145	$44,299	$27,562
AP	NA	NA	NA	NA	$19,036	$20,163	$35,748	$41,735	$65,495	$68,874	$52,645	$85,547	$35,134
BGE	$78,672	$21,290	$42,575	$45,040	$29,165	$33,539	$75,682	$83,645	$131,526	$133,647	$55,496	$125,692	$59,223
ComEd	NA	NA	NA	NA	NA	NA	$21,779	$30,731	$42,289	$30,764	$18,839	$33,705	$28,529
DAY	NA	NA	NA	NA	NA	NA	$11,872	$19,706	$30,024	$29,754	$25,301	$43,620	$27,408
DLCO	NA	NA	NA	NA	NA	NA	$10,781	$18,897	$32,552	$28,813	$26,316	$47,493	$39,371
Dominion	NA	NA	NA	NA	NA	NA	NA	$78,267	$110,994	$123,330	$53,240	$108,343	$50,636
DPL	$83,748	$34,057	$79,508	$49,163	$33,913	$39,091	$61,167	$61,072	$99,001	$117,134	$52,338	$107,753	$53,790
JCPL	$80,716	$25,825	$61,175	$36,979	$26,955	$63,200	$67,269	$56,368	$108,661	$126,738	$50,649	$103,923	$52,346
Met-Ed	$79,528	$22,995	$53,339	$41,469	$27,374	$31,279	$57,351	$59,317	$102,856	$99,239	$44,671	$100,209	$44,601
PECO	$81,255	$28,010	$61,526	$38,389	$31,489	$34,570	$61,212	$57,349	$89,797	$102,673	$44,636	$97,940	$49,814
PENELEC	$79,720	$23,011	$39,473	$42,071	$22,929	$21,460	$26,611	$30,472	$51,289	$44,971	$38,615	$67,791	$34,930
Pepco	$78,343	$20,865	$36,952	$46,354	$29,914	$36,202	$82,427	$91,120	$133,305	$144,783	$71,539	$141,024	$62,102
PPL	$79,926	$22,122	$48,045	$34,624	$25,278	$24,688	$51,686	$52,858	$85,950	$92,238	$42,046	$90,886	$41,247
PSEG	$82,577	$28,650	$62,468	$37,769	$34,549	$63,575	$78,181	$66,446	$105,692	$119,564	$47,113	$101,655	$50,958
RECO	NA	NA	NA	NA	$33,679	$44,473	$64,071	$61,510	$103,158	$108,670	$43,137	$91,866	$47,394
PJM	$80,546	$24,794	$54,206	$38,625	$27,155	$27,389	$35,608	$44,692	$66,616	$62,039	$31,581	$88,275	$40,943

Table 3-7 PJM Real-Time Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): Net revenue for calendar years 1999 to 2010

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
AECO	$92,532	$113,438	$108,787	$105,966	$168,971	$167,610	$301,137	$228,664	$303,350	$337,789	$92,287	$160,597	$181,761
AEP	NA	NA	NA	NA	NA	NA	$142,931	$122,131	$158,510	$152,316	$29,034	$65,893	$111,803
AP	NA	NA	NA	NA	$140,178	$114,188	$225,283	$173,387	$243,442	$257,660	$62,730	$109,575	$165,805
BGE	$90,218	$99,688	$81,733	$103,811	$163,240	$138,798	$297,298	$243,615	$339,865	$309,846	$47,837	$98,635	$167,882
ComEd	NA	NA	NA	NA	NA	NA	$136,055	$117,135	$152,722	$203,863	$53,680	$116,282	$129,956
DAY	NA	NA	NA	NA	NA	NA	$132,250	$114,159	$157,981	$130,757	$40,214	$86,984	$110,391
DLCO	NA	NA	NA	NA	NA	NA	$119,344	$102,923	$145,539	$138,614	$36,538	$84,666	$104,604
Dominion	NA	NA	NA	NA	NA	NA	NA	$235,662	$316,223	$282,137	$52,969	$152,362	$207,871
DPL	$96,172	$124,924	$129,746	$109,500	$168,958	$150,777	$280,855	$208,044	$296,729	$320,362	$44,299	$159,204	$174,131
JCPL	$92,252	$105,657	$99,367	$94,661	$155,564	$177,105	$284,427	$198,595	$310,102	$315,991	$81,687	$155,249	$172,555
Met-Ed	$91,053	$102,018	$92,371	$99,157	$157,131	$135,061	$269,900	$205,508	$299,833	$282,260	$64,568	$150,184	$162,420
PECO	$92,923	$112,043	$101,558	$96,113	$163,941	$144,385	$279,306	$203,152	$284,280	$290,745	$82,938	$148,818	$166,684
PENELEC	$91,889	$109,408	$84,093	$107,445	$154,295	$114,543	$210,236	$156,723	$222,720	$239,391	$84,807	$124,253	$141,650
Pepco	$89,875	$99,351	$75,464	$105,125	$164,995	$142,377	$307,867	$254,964	$344,407	$328,211	$76,426	$170,080	$179,929
PPL	$91,447	$100,853	$86,582	$89,955	$152,675	$127,012	$260,567	$196,349	$279,724	$286,355	$78,012	$125,429	$156,247
PSEG	$95,195	$121,405	$108,158	$96,439	$174,161	$180,518	$309,870	$219,768	$310,978	$248,728	$105,739	$135,636	$175,550
RECO	NA	NA	NA	NA	$176,678	$159,188	$292,449	$213,850	$304,891	$259,424	$78,553	$148,988	$204,253
PJM	$92,935	$108,624	$95,361	$96,828	$159,912	$124,497	$222,911	$177,852	$244,419	$179,457	$49,022	$128,990	$140,067

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New Entrant Combustion Turbine

In the peak-hour, economic dispatch analysis, Real-Time Energy Market net revenue was calculated for a CT plant dispatched by PJM operations. For this dispatch scenario, it was assumed that the CT plant could be dispatched by PJM operations in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any block when the real-time, average LMP was greater than, or equal to, the cost to generate, including the cost for a complete startup and shutdown cycle[27] for at least two hours during each four-hour block.[28] The blocks were dispatched independently, and, if there were not at least two economic hours in any given block, then the CT was not dispatched. The startup costs were used in determining the economic hours in each block, but once the CT was dispatched on a particular day, startup costs were not used to evaluate whether to continue to run the unit in the next consecutive four-hour block. The calculations account for operating reserve credits based on PJM rules, as applicable, since the assumed operation is under the direction of PJM operations.[29]

Net revenues for the new entrant CT under peak-hour, economic dispatch are shown in Table 3-8 for the years 1999 through 2010. This table shows the contribution of each market individually to the new entrant CT's total net revenue.

Table 3-8 Real-time PJM-wide net revenue for a CT under peak-hour, economic dispatch by market (Dollars per installed MW-year): Calendar years 1999 to 2010

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$55,612	$16,677	$0	$0	$2,248	$74,537
2000	$8,498	$20,200	$0	$0	$2,248	$30,946
2001	$30,254	$30,960	$0	$0	$2,248	$63,462
2002	$14,496	$11,516	$0	$0	$2,248	$28,260
2003	$2,763	$5,554	$0	$0	$2,248	$10,566
2004	$919	$5,376	$0	$0	$2,248	$8,543
2005	$6,141	$2,048	$0	$0	$2,248	$10,437
2006	$10,996	$1,758	$0	$0	$2,194	$14,948
2007	$17,933	$28,442	$0	$0	$2,154	$48,529
2008	$12,442	$35,691	$0	$0	$2,398	$50,532
2009	$5,113	$48,441	$0	$0	$2,384	$55,939
2010	$36,925	$55,309	$0	$0	$2,384	$94,619

Table 3-9 shows the total net revenue (the Total column in Table 3-8) for the new entrant CT in each zone.[30]

27 Startup and shutdown fuel burns and emission rates were obtained from design data for a new entry plant. Gas daily cash prices were obtained from Platts fuel prices. Emissions allowance costs were included in startup costs where applicable. Per PJM "Manual M-15: Cost Development Guidelines," Revision 15 (October 27, 2010), startup and shutdown station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. No-load costs are included in the heat rate.

28 The first block represents the four-hour period starting at hour ending 0800 EPT until hour ending 1100 EPT. The second block represents the four-hour period starting at hour ending 1200 EPT until hour ending 1500 EPT. The third block represents the four-hour period starting at hour ending 1600 EPT until hour ending 1900 EPT, and the fourth block represents the four-hour period starting at hour ending 2000 EPT until the hour ending 2300 EPT.

29 The calculation of operating reserve payments does not reflect changes to operating reserves rules effective December 1, 2008.

30 New entrant CT zonal net revenue for 2010 reflects the estimated zonal, daily delivered price of natural gas.

Table 3-9 Real-time zonal combined net revenue from all markets for a CT under peak-hour, economic dispatch (Dollars per installed MW-year): Calendar years 1999 to 2010

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
AECO	$75,203	$34,525	$74,033	$33,213	$13,077	$14,389	$22,605	$27,117	$81,801	$122,598	$70,287	$111,894	$56,729
AEP	NA	NA	NA	NA	NA	NA	$4,936	$8,590	$16,230	$33,727	$40,513	$61,376	$27,562
AP	NA	NA	NA	NA	$10,800	$8,487	$9,485	$14,647	$27,996	$46,970	$67,078	$95,611	$35,134
BGE	$73,695	$29,641	$56,256	$33,813	$11,998	$10,522	$26,589	$35,678	$94,710	$115,532	$91,770	$130,476	$59,223
ComEd	NA	NA	NA	NA	NA	NA	$7,602	$11,083	$19,542	$34,155	$39,700	$59,089	$28,529
DAY	NA	NA	NA	NA	NA	NA	$5,089	$8,294	$16,046	$33,941	$40,288	$60,787	$27,408
DLCO	NA	NA	NA	NA	NA	NA	$4,960	$30,782	$53,923	$37,015	$42,012	$67,534	$39,371
Dominion	NA	NA	NA	NA	NA	NA	NA	$9,360	$20,075	$72,734	$51,626	$99,387	$50,636
DPL	$76,550	$35,160	$83,041	$36,193	$13,389	$10,505	$18,554	$21,217	$73,967	$92,974	$72,963	$110,964	$53,790
JCPL	$74,871	$32,251	$70,681	$27,697	$10,784	$22,096	$21,229	$19,884	$77,652	$92,718	$71,175	$107,113	$52,346
Met-Ed	$73,923	$30,516	$63,905	$31,136	$11,406	$9,894	$19,469	$21,455	$46,663	$54,767	$64,589	$107,488	$44,601
PECO	$75,434	$34,208	$71,197	$28,525	$12,638	$9,224	$20,409	$19,552	$68,376	$84,633	$69,066	$104,501	$49,814
PENELEC	$73,921	$29,808	$51,345	$25,881	$9,533	$8,887	$7,413	$10,537	$21,227	$35,222	$60,552	$84,833	$34,930
Pepco	$73,480	$29,470	$51,316	$35,788	$12,413	$11,539	$30,135	$41,753	$96,912	$122,845	$100,138	$139,437	$62,102
PPL	$74,229	$30,201	$59,956	$26,353	$10,068	$8,744	$16,699	$17,564	$35,743	$50,800	$63,502	$101,106	$41,247
PSEG	$75,196	$32,618	$70,026	$27,263	$12,357	$20,786	$21,177	$19,933	$72,221	$86,361	$68,708	$104,847	$50,958
RECO	NA	NA	NA	NA	$12,016	$11,373	$17,266	$17,558	$72,112	$81,518	$67,399	$99,907	$47,394
PJM	$74,537	$30,946	$63,462	$28,260	$10,566	$8,543	$10,437	$14,948	$48,530	$50,532	$55,939	$94,619	$40,943

New Entrant Combined Cycle

Under peak-hour, economic dispatch, Energy Market net revenues were calculated for a CC plant dispatched by PJM operations for continuous output from the peak-hour period beginning with the hour ending 0800 EPT and continuing to the hour ending 2300 EPT for any day when the PJM real-time, average LMP was greater than, or equal to, the cost to generate, including the cost for a complete startup and shutdown cycle for at least eight hours during that time period.[31] If there were not eight economic hours in any given day, then the CC was not dispatched. For every hour the plant is dispatched, the applicable LMP is compared to the incremental costs of duct burner firing, including fuel and, if applicable, emissions allowance credits.[32] If LMP is greater than or equal to the incremental costs of duct-firing for any hour the plant is operating, the duct burner is dispatched. The calculations account for operating reserve payments based on PJM rules, when applicable, since the assumed operation is under the direction of PJM operations. This dispatch scenario uses the same variable operation and maintenance cost, outage, fuel cost, emission and plant performance assumptions reflected in the Table 3-6 results.

31 Startup and shutdown fuel burns and emission rates were obtained from design data for a new entry plant. Gas daily cash prices were obtained from Platts fuel prices. Emissions allowance costs were included in startup costs where applicable. Per PJM "Manual M-15: Cost Development Guidelines," Revision 15 (October 27, 2010), startup and shutdown station power consumption costs were obtained from the station service rates published quarterly by PJM settlements and netted against the MW produced during startup at the preceding applicable hourly LMP. No-load costs are included in the heat rate.

32 Duct burner firing dispatch rate is developed using same methodology described for unfired dispatch rate, with temperature adjustments to duct burner fired heat rate and output provided by Pasteris Energy, Inc.

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Net revenues for the new entrant CC under peak-hour, economic dispatch are shown in Table 3-10 for the years 1999 through 2010. This table shows the contribution of each market individually to the new entrant CC's total net revenue.

Table 3-10 Real-time PJM-wide net revenue for a CC under peak-hour, economic dispatch by market (Dollars per installed MW-year): Calendar years 1999 to 2010

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$80,546	$16,999	$0	$0	$3,155	$100,700
2000	$24,794	$19,643	$0	$0	$3,155	$47,592
2001	$54,206	$29,309	$0	$0	$3,155	$86,670
2002	$38,625	$10,492	$0	$0	$3,155	$52,272
2003	$27,155	$5,281	$0	$0	$3,155	$35,591
2004	$27,389	$5,241	$0	$0	$3,155	$35,785
2005	$35,608	$2,054	$0	$0	$3,155	$40,817
2006	$44,692	$1,743	$0	$0	$3,094	$49,529
2007	$66,616	$31,098	$0	$0	$3,094	$100,809
2008	$62,039	$38,691	$0	$0	$3,198	$103,928
2009	$31,581	$46,596	$0	$0	$3,198	$81,376
2010	$88,275	$38,588	$0	$0	$3,198	$130,061

Table 3-11 shows the total net revenue (the Total column in Table 3-10) for the new entrant CC in each zone.

Table 3-11 Real-time zonal combined net revenue from all markets for a CC under peak-hour, economic dispatch (Dollars per installed MW-year): Calendar years 1999 to 2010

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
AECO	$101,084	$52,152	$100,786	$59,850	$44,094	$61,021	$82,432	$83,326	$151,617	$217,072	$112,738	$171,758	$103,161
AEP	NA	NA	NA	NA	NA	NA	$17,742	$26,533	$41,958	$61,521	$65,604	$76,549	$48,318
AP	NA	NA	NA	NA	$29,766	$28,560	$40,957	$46,572	$77,463	$101,201	$111,482	$117,797	$69,225
BGE	$98,827	$44,088	$75,039	$58,688	$37,601	$41,935	$80,891	$88,482	$173,918	$207,969	$138,066	$199,824	$103,777
ComEd	NA	NA	NA	NA	NA	NA	$28,702	$35,568	$54,257	$63,092	$59,298	$65,955	$51,145
DAY	NA	NA	NA	NA	NA	NA	$17,081	$24,543	$41,992	$62,081	$65,760	$75,870	$47,888
DLCO	NA	NA	NA	NA	NA	NA	$15,990	$83,104	$155,267	$61,141	$66,775	$79,742	$77,003
Dominion	NA	NA	NA	NA	NA	NA	NA	$23,734	$44,520	$155,658	$93,699	$140,593	$91,641
DPL	$103,903	$56,855	$111,972	$62,811	$42,349	$47,487	$66,376	$65,909	$110,969	$180,121	$116,532	$170,582	$94,656
JCPL	$100,871	$48,623	$93,639	$50,626	$35,391	$71,596	$72,478	$61,205	$152,934	$189,725	$114,843	$166,751	$96,557
Met-Ed	$99,682	$45,793	$85,803	$55,117	$35,810	$39,675	$62,560	$64,155	$114,824	$131,566	$103,508	$132,459	$80,913
PECO	$101,410	$50,808	$93,990	$52,036	$39,925	$42,967	$66,421	$62,187	$134,069	$165,660	$108,830	$160,768	$89,923
PENELEC	$99,875	$45,809	$71,937	$55,718	$31,365	$29,856	$31,820	$35,309	$63,257	$77,299	$97,452	$100,041	$61,645
Pepco	$98,497	$43,663	$69,416	$60,001	$38,350	$44,598	$87,636	$95,957	$175,698	$219,105	$154,109	$215,157	$108,516
PPL	$100,081	$44,920	$80,509	$48,272	$33,714	$33,084	$56,895	$57,695	$97,918	$124,566	$100,883	$123,136	$75,139
PSEG	$102,731	$51,448	$94,932	$51,416	$42,985	$71,972	$83,390	$71,284	$149,965	$182,551	$111,307	$164,483	$98,205
RECO	NA	NA	NA	NA	$42,115	$52,870	$69,280	$66,348	$147,431	$171,658	$107,331	$154,695	$101,466
PJM	$100,700	$47,592	$86,670	$52,272	$35,591	$35,785	$40,817	$49,529	$100,809	$103,928	$81,376	$130,061	$72,094

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New Entrant Coal Plant

The new entrant CP Real-Time Energy Market net revenues were calculated assuming that the plant had a 24-hour minimum run time and was dispatched by PJM operations for all available plant hours, both reasonable assumptions for a large CP. The calculations account for operating reserve payments based on PJM rules, when applicable, since the assumed operation is under the direction of PJM operations.

Net revenues for the new entrant CP under peak-hour, economic dispatch are shown in Table 3-12 for the years 1999 through 2010. This table shows the contribution of each market individually to the new entrant CP's total net revenue. Regulation revenue is calculated for any hours in which the new entrant CP's regulation offer is below the regulation-clearing price.

Table 3-12 Real-time PJM-wide net revenue for a CP under peak-hour, economic dispatch by market (Dollars per installed MW-year): Calendar years 1999 to 2010

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$92,935	$17,798	$0	$5,596	$1,692	$118,022
2000	$108,624	$20,755	$0	$3,492	$1,692	$134,564
2001	$95,361	$30,862	$0	$1,356	$1,692	$129,271
2002	$96,828	$11,493	$0	$2,118	$1,692	$112,131
2003	$159,912	$5,688	$0	$2,218	$1,692	$169,509
2004	$124,497	$5,537	$0	$1,399	$1,692	$133,124
2005	$222,911	$2,100	$0	$1,727	$1,692	$228,430
2006	$177,852	$1,810	$0	$1,107	$1,692	$182,461
2007	$244,419	$29,343	$0	$1,172	$2,350	$277,284
2008	$179,457	$36,107	$0	$796	$1,783	$218,144
2009	$49,022	$43,931	$0	$231	$1,783	$94,968
2010	$128,990	$36,117	$0	$174	$1,783	$167,064

Table 3-13 shows the total net revenue (the Total column 7 in Table 3-12) for the new entrant CP in each zone.[33]

33 New Entrant CP zonal net revenue for 2010 incorporates the zone specific, delivered price of coal.

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Table 3-13 Real-time zonal combined net revenue from all markets for a CP under peak-hour, economic dispatch (Dollars per installed MW-year): Calendar years 1999 to 2010

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
AECO	$118,254	$137,752	$143,257	$121,785	$179,117	$176,827	$306,995	$233,787	$345,739	$396,564	$151,958	$218,375	$210,868
AEP	NA	NA	NA	NA	NA	NA	$150,176	$127,588	$170,532	$182,201	$66,176	$94,972	$131,941
AP	NA	NA	NA	NA	$152,458	$123,620	$231,963	$178,701	$255,474	$288,025	$117,241	$138,658	$185,768
BGE	$115,926	$124,106	$116,306	$119,714	$173,476	$148,097	$303,218	$248,764	$380,425	$379,157	$124,582	$166,838	$200,051
ComEd	NA	NA	NA	NA	NA	NA	$144,924	$122,647	$164,740	$234,487	$91,497	$145,678	$150,662
DAY	NA	NA	NA	NA	NA	NA	$139,572	$119,691	$169,421	$160,462	$77,760	$116,152	$130,510
DLCO	NA	NA	NA	NA	NA	NA	$125,720	$240,844	$157,544	$168,655	$73,721	$113,765	$146,708
Dominion	NA	NA	NA	NA	NA	NA	NA	$108,418	$328,069	$312,361	$90,049	$181,505	$204,080
DPL	$121,871	$149,240	$164,219	$125,338	$179,145	$160,037	$287,243	$213,209	$339,158	$379,198	$103,715	$217,051	$203,285
JCPL	$117,951	$129,972	$133,840	$110,499	$165,751	$186,365	$290,815	$203,813	$352,520	$374,748	$141,256	$213,033	$201,714
Met-Ed	$116,776	$126,376	$126,885	$115,061	$167,368	$144,386	$276,296	$210,720	$311,760	$312,370	$119,008	$179,319	$183,860
PECO	$118,636	$136,379	$136,046	$112,096	$174,147	$153,658	$285,681	$208,382	$326,717	$349,522	$142,528	$206,581	$195,864
PENELEC	$117,603	$133,724	$118,787	$123,416	$164,692	$123,984	$217,133	$162,124	$234,790	$269,748	$140,148	$153,536	$163,307
Pepco	$115,585	$123,766	$110,090	$121,020	$175,224	$151,666	$314,137	$260,110	$384,940	$397,620	$153,255	$238,386	$212,150
PPL	$117,166	$125,227	$121,146	$105,991	$162,900	$136,365	$267,023	$201,584	$291,701	$316,263	$132,526	$154,502	$177,700
PSEG	$120,910	$145,675	$142,694	$112,410	$184,332	$189,717	$316,131	$224,904	$353,386	$307,268	$165,919	$193,358	$204,725
RECO	NA	NA	NA	NA	$186,860	$168,414	$298,796	$219,016	$347,309	$318,225	$138,107	$206,773	$235,438
PJM	$118,022	$134,564	$129,271	$112,131	$169,509	$133,124	$228,430	$182,461	$277,284	$218,144	$94,968	$167,064	$163,748

New Entrant Day-Ahead Net Revenues

Day-Ahead Energy Market net revenues were calculated for the CT, CC and CP technologies for the peak-hour, economic dispatch scenario used for the Real-Time Energy Market analysis. The results for the Day-Ahead Energy Market for each class are presented in Table 3-14, Table 3-15 and Table 3-16 [34]

Table 3-14 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2010

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
AECO	$12,077	$29,022	$18,894	$2,634	$1,360	$11,975	$13,446	$20,649	$26,001	$6,373	$29,417	$15,622
AEP	NA	NA	NA	NA	NA	$563	$1,218	$2,267	$1,827	$1,180	$6,516	$2,262
AP	NA	NA	NA	$595	$0	$3,959	$7,326	$7,244	$6,719	$5,397	$21,371	$6,576
BGE	$7,193	$14,772	$14,087	$1,779	$42	$9,857	$13,886	$20,904	$27,271	$7,792	$38,774	$14,214
ComEd	NA	NA	NA	NA	NA	$374	$1,709	$4,392	$1,984	$480	$5,361	$2,383
DAY	NA	NA	NA	NA	NA	$477	$1,104	$2,003	$1,628	$733	$6,428	$2,062
Dominion	NA	NA	NA	NA	NA	NA	$10,991	$15,078	$22,582	$7,613	$31,080	$17,469
DLCO	NA	NA	NA	NA	NA	$308	$854	$1,818	$1,428	$1,098	$8,128	$2,272
DPL	$12,712	$35,962	$21,844	$2,419	$95	$7,869	$9,733	$12,438	$19,152	$6,840	$28,205	$14,297
JCPL	$9,803	$24,565	$16,658	$1,531	$489	$7,104	$8,263	$16,080	$14,163	$5,007	$26,623	$11,844
Met-Ed	$8,068	$19,353	$17,218	$1,273	$50	$8,737	$12,771	$14,559	$12,492	$4,619	$27,017	$11,469
PECO	$11,760	$26,271	$17,522	$2,089	$0	$10,129	$8,598	$11,330	$12,688	$4,920	$25,963	$11,934
PENELEC	$7,360	$16,870	$15,415	$537	$0	$1,477	$3,461	$3,736	$4,535	$3,303	$15,763	$6,587
Pepco	$7,022	$14,469	$13,780	$2,143	$0	$12,988	$18,258	$23,028	$32,677	$15,816	$50,566	$17,341
PPL	$7,753	$18,174	$15,151	$993	$0	$7,052	$8,259	$9,586	$10,351	$4,345	$22,048	$9,428
PSEG	$10,171	$25,298	$16,750	$258	$7,332	$7,332	$8,127	$12,718	$13,686	$4,051	$24,878	$11,873
RECO	NA	NA	NA	$1,346	$11	$5,925	$7,143	$11,711	$11,445	$3,156	$22,543	$7,910
PJM	$7,418	$20,390	$13,921	$1,282	$1	$2,996	$5,229	$6,751	$6,623	$1,966	$22,981	$8,142

Table 3-15 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2010

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
AECO	$29,354	$63,679	$45,357	$31,788	$43,308	$74,855	$62,589	$83,745	$115,974	$51,240	$96,081	$63,452
AEP	NA	NA	NA	NA	NA	$10,462	$12,393	$19,516	$20,140	$23,139	$39,674	$20,887
AP	NA	NA	NA	$14,992	$14,077	$29,993	$30,144	$44,880	$50,885	$47,963	$79,090	$39,003
BGE	$21,290	$37,791	$34,829	$23,003	$23,810	$60,143	$64,078	$94,045	$118,704	$58,133	$110,793	$58,784
ComEd	NA	NA	NA	NA	NA	$9,888	$12,746	$35,333	$24,163	$14,225	$27,543	$20,650
DAY	NA	NA	NA	NA	NA	$8,451	$9,671	$19,014	$19,147	$21,226	$38,678	$19,364
Dominion	NA	NA	NA	NA	NA	NA	$57,718	$80,321	$101,261	$21,270	$93,788	$70,871
DLCO	NA	NA	NA	NA	NA	$7,709	$8,390	$17,819	$15,605	$21,270	$42,658	$18,909
DPL	$34,057	$73,455	$48,709	$28,595	$28,534	$59,804	$49,939	$74,526	$101,261	$52,846	$93,757	$58,680
JCPL	$25,825	$51,367	$39,102	$23,929	$48,514	$56,951	$42,774	$85,349	$112,307	$50,315	$93,788	$57,293
Met-Ed	$22,995	$44,572	$38,810	$22,806	$22,786	$52,522	$50,581	$75,423	$84,379	$44,189	$87,136	$49,654
PECO	$28,010	$55,775	$40,411	$27,252	$26,450	$59,822	$47,607	$70,234	$85,673	$46,590	$88,938	$52,433
PENELEC	$23,011	$43,234	$47,776	$17,460	$13,209	$23,711	$22,590	$35,002	$39,701	$38,970	$68,844	$33,955
Pepco	$20,865	$37,135	$34,523	$24,379	$26,052	$67,659	$71,755	$99,380	$133,227	$73,603	$132,021	$65,509
PPL	$22,122	$42,383	$35,750	$19,862	$17,037	$48,895	$43,246	$64,603	$77,511	$41,987	$77,977	$44,670
PSEG	$28,650	$57,168	$41,945	$27,192	$47,450	$65,167	$51,543	$87,724	$106,457	$47,111	$89,472	$59,080
RECO	NA	NA	NA	$25,148	$31,204	$54,167	$50,064	$85,050	$96,618	$41,780	$82,357	$58,299
PJM	$26,132	$48,253	$35,993	$21,865	$18,193	$28,413	$31,670	$44,434	$47,342	$28,360	$78,976	$37,239

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Table 3-16 PJM Day-Ahead Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2010

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
AECO	$113,438	$111,272	$108,715	$174,964	$156,185	$302,113	$215,274	$252,783	$323,135	$95,836	$156,696	$182,765
AEP	NA	NA	NA	NA	NA	$140,898	$111,399	$150,551	$149,397	$23,732	$62,642	$106,436
AP	NA	NA	NA	$145,314	$108,867	$219,168	$158,105	$223,836	$250,837	$55,868	$105,988	$158,498
BGE	$99,688	$83,030	$94,034	$161,419	$127,630	$284,669	$223,199	$304,373	$312,579	$48,315	$85,346	$165,844
ComEd	NA	NA	NA	NA	NA	$133,407	$108,663	$149,353	$210,403	$48,765	$114,310	$127,483
DAY	NA	NA	NA	NA	NA	$126,886	$98,084	$148,879	$123,738	$33,606	$84,563	$102,626
Dominion	NA	NA	NA	NA	NA	NA	$215,727	$289,976	$277,629	$51,927	$151,933	$197,438
DLCO	NA	NA	NA	NA	NA	$121,687	$92,737	$137,774	$139,537	$28,243	$83,593	$100,595
DPL	$124,924	$128,020	$111,746	$172,871	$141,541	$286,686	$201,807	$278,619	$324,485	$42,395	$154,904	$178,909
JCPL	$105,657	$94,134	$99,105	$164,028	$161,584	$278,746	$188,852	$289,222	$320,484	$81,671	$155,257	$176,249
Met-Ed	$102,018	$88,922	$99,331	$161,077	$127,001	$269,696	$199,865	$275,949	$286,549	$63,430	$146,606	$165,495
PECO	$112,043	$102,119	$101,674	$169,018	$137,889	$284,530	$198,441	$272,984	$297,666	$86,272	$150,181	$173,893
PENELEC	$109,408	$89,643	$118,915	$157,282	$108,203	$207,894	$147,998	$208,246	$251,168	$86,110	$130,041	$146,810
Pepco	$99,351	$82,420	$93,756	$163,851	$130,908	$295,462	$233,288	$313,215	$333,200	$76,927	$168,309	$180,972
PPL	$100,853	$86,022	$93,528	$156,929	$120,447	$263,597	$190,672	$263,141	$291,459	$78,730	$121,740	$160,647
PSEG	$121,405	$108,221	$106,049	$173,952	$162,402	$295,693	$207,951	$294,953	$250,151	$108,656	$131,909	$178,304
RECO	NA	NA	NA	$172,622	$143,445	$279,769	$207,438	$291,031	$315,939	$78,117	$151,109	$204,934
PJM	$116,784	$95,119	$97,493	$162,285	$113,892	$220,824	$167,282	$221,757	$174,191	$45,844	$126,772	$140,204

The energy net revenues for both the Real-Time and Day-Ahead Energy Markets are shown in Table 3-17, Table 3-18 and Table 3-19 for the CT, CC and CP plants.

On average, the Real-Time Energy Market net revenue was 39 percent higher than the Day-Ahead Market net revenue for the CT plant, 18 percent higher for the CC plant and 3 percent higher for the CP.[35]

35 The Day-Ahead Energy Market was implemented on June 1, 2000. For the analysis presented in Table 3-17, Table 3-18 and Table 3-19, the Real-Time Energy Market LMP was used from January 1, 2000, to May 31, 2000.

Table 3-17 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

	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%
Avg.	$13,316	$8,142	$5,175	39%

Table 3-18 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

	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%
Avg.	$45,544	$37,239	$8,305	18%

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Table 3-19 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

	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%
Avg.	$144,352	$140,204	$4,148	3%

Net Revenue Adequacy

To put the 2010 net revenue results in perspective, net revenues are compared to the annual, levelized fixed costs for each technology. The MMU reevaluated the fixed costs for all three new entry plant configurations for 2010.[36] The estimated, 20-year levelized fixed costs[37] are $131,044 per installed MW-year for the new entrant CT plant,[38] $175,250 per installed MW-year for the new entrant CC plant and $465,455 per installed MW-year for the new entrant CP plant. Levelized fixed costs increased for all three technologies. Table 3-20 shows the 20-year levelized costs for each technology for the period 2005 through 2010.[39] The increased costs of constructing generation facilities from 2005 through 2008 are the result of a combination of factors, including increased worldwide demand in recent years. The estimated levelized fixed costs for both 2009 and 2010 show smaller increases than in prior years.

In this section, net revenue includes net revenue from the Real-Time Energy Market, from the Capacity Market and from any applicable ancillary service.

36 The MMU began evaluating fixed costs for all three technologies in 2005. In the following tables and figures, the 20-year levelized fixed costs from 2005 are used as a proxy for the preceding years.

37 Annual fixed costs may vary by location. The fixed costs presented here are associated with a location in the EMAAC LDA and are meant to serve as a baseline for comparison.

38 This analysis was performed for the MMU by Pasteris Energy, Inc. The annual costs were based on a 20-year project life, 50/50 debt-to-equity financing with a target internal rate of return (IRR) of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 15-year modified accelerated cost-recovery schedule (MACRS) for the CT plant and 20-year MACRS for the CC and CP plants. A general annual rate of cost inflation of 2.5 percent was utilized in all calculations.

39 The figures in Table 3-20 represent the annual cost per MW per year if total costs were levelized over the 20-year life cycle of the plant. These fixed costs of construction are specific to the PJM Eastern Mid-Atlantic Region.

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Table 3-20 New entrant 20-year levelized fixed costs (By plant type (Dollars per installed MW-year))

	2005 20-Year Levelized Fixed Cost	2006 20-Year Levelized Fixed Cost	2007 20-Year Levelized Fixed Cost	2008 20-Year Level-ized 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

In 2010, under the economic dispatch scenario, average net revenue from the PJM Real-Time Energy Market, the Capacity Market and the Ancillary Service Markets for a new entrant CT were $94,619 per installed MW-year. The associated operating costs were between $60 and $65 per MWh, based on a design heat rate of 10,500 Btu per kWh and a VOM rate of $7.46 per MWh.[40] The average PJM net revenue in 2010 would not have covered the fixed costs of a new CT. As shown in Table 3-21, the only year when average PJM net revenue was sufficient to cover fixed costs for a new CT was 1999.

Table 3-21 CT 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2010

	20-Year Levelized Fixed Cost	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$72,207	$74,537	103%
2000	$72,207	$30,946	43%
2001	$72,207	$63,462	88%
2002	$72,207	$28,260	39%
2003	$72,207	$10,566	15%
2004	$72,207	$8,543	12%
2005	$72,207	$10,437	14%
2006	$80,315	$14,948	19%
2007	$90,656	$48,530	54%
2008	$123,640	$50,532	41%
2009	$128,705	$55,939	43%
2010	$131,044	$94,619	72%
Average	$88,317	$40,943	46%

Table 3-22 includes the 20-year levelized fixed cost in 2010 for a new entrant CT, the economic dispatch net revenue for each zone in 2010 and average net revenue and average fixed costs for the period 1999 to 2010. There were two control zones with net revenues sufficient to cover 100 percent of the levelized fixed costs in 2010: BGE and Pepco control zones of the SWMAAC LDA, showing 100 and 106 percent recovery. Figure 3-3 summarizes the information in Table 3-22, showing the 2010 average net revenue for a new entrant CT, the zonal net revenue for the

40 The analysis used the daily gas costs and associated production costs for CTs and CCs. Heat rates for the CT, CC and CP are cited for an ambient temperature of 50 degrees and rounded to the nearest hundredth.

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period 1999 to 2010 and the levelized 2010 fixed cost for a new entrant CT. The extent to which net revenues cover the levelized fixed costs of investment in the CT technology is significantly dependent on location, which affects both energy and capacity revenue. Figure 3-4 shows total net revenues for the new entrant CT by market for 2010. Total net revenues in 2010 are higher than the twelve year average for all control zones, and this is largely due to RPM capacity revenue which comprises a significant portion of total revenue for the CT technology. Figure 3-5 shows zonal net revenue for the new entrant CT by LDA with the applicable yearly levelized fixed costs for the period 1999-2010. In 2008, 2009 and 2010 there were multiple zones with sufficient revenues to cover the fixed costs of investment in a new CT.

Table 3-22 CT 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): Calendar years 1999 to 2010

	2010			12-Year Average (1999-2010)		
	Net Revenue	20-Year Levelized Cost	Percent Recovered	Net Revenue	20-Year Levelized Cost	Percent Recovered
AECO	$111,894	$131,044	85%	$56,729	$88,317	64%
AEP	$61,376	$131,044	47%	$27,562	$88,317	31%
AP	$95,611	$131,044	73%	$35,134	$88,317	40%
BGE	$130,476	$131,044	100%	$59,223	$88,317	67%
ComEd	$59,089	$131,044	45%	$28,529	$88,317	32%
DAY	$60,787	$131,044	46%	$27,408	$88,317	31%
DLCO	$67,534	$131,044	52%	$39,371	$88,317	45%
Dominion	$99,387	$131,044	76%	$50,636	$88,317	57%
DPL	$110,964	$131,044	85%	$53,790	$88,317	61%
JCPL	$107,113	$131,044	82%	$52,346	$88,317	59%
Met-Ed	$107,488	$131,044	82%	$44,601	$88,317	51%
PECO	$104,501	$131,044	80%	$49,814	$88,317	56%
PENELEC	$84,833	$131,044	65%	$34,930	$88,317	40%
Pepco	$139,437	$131,044	106%	$62,102	$88,317	70%
PPL	$101,106	$131,044	77%	$41,247	$88,317	47%
PSEG	$104,847	$131,044	80%	$50,958	$88,317	58%
RECO	$99,907	$131,044	76%	$47,394	$88,317	54%
PJM	$94,619	$131,044	72%	$40,943	$88,317	46%

Figure 3-3 New entrant CT real-time 2010 net revenue, twelve-year average net revenue and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year): Calendar years 1999 to 2010

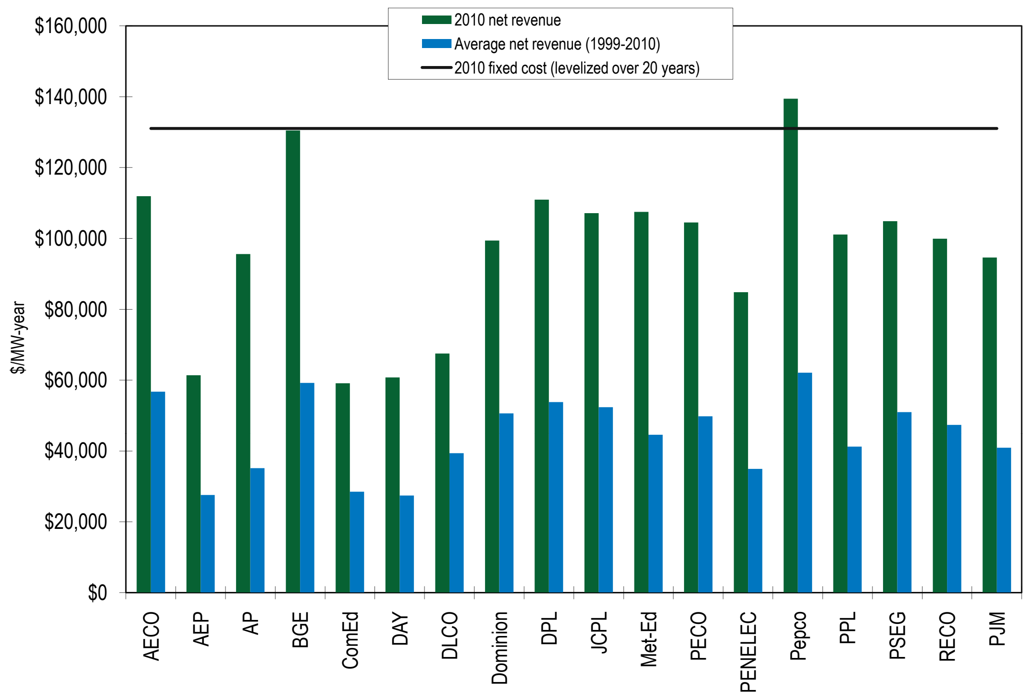

Figure 3-4 New entrant CT zonal real-time 2010 net revenue by market and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year)

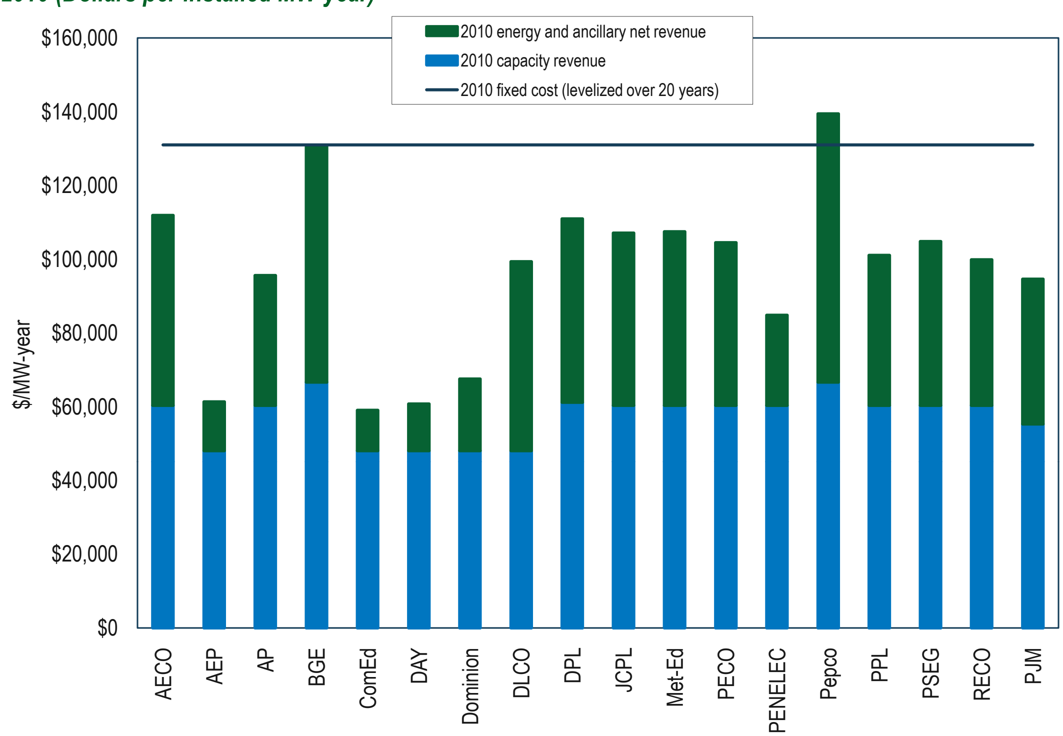

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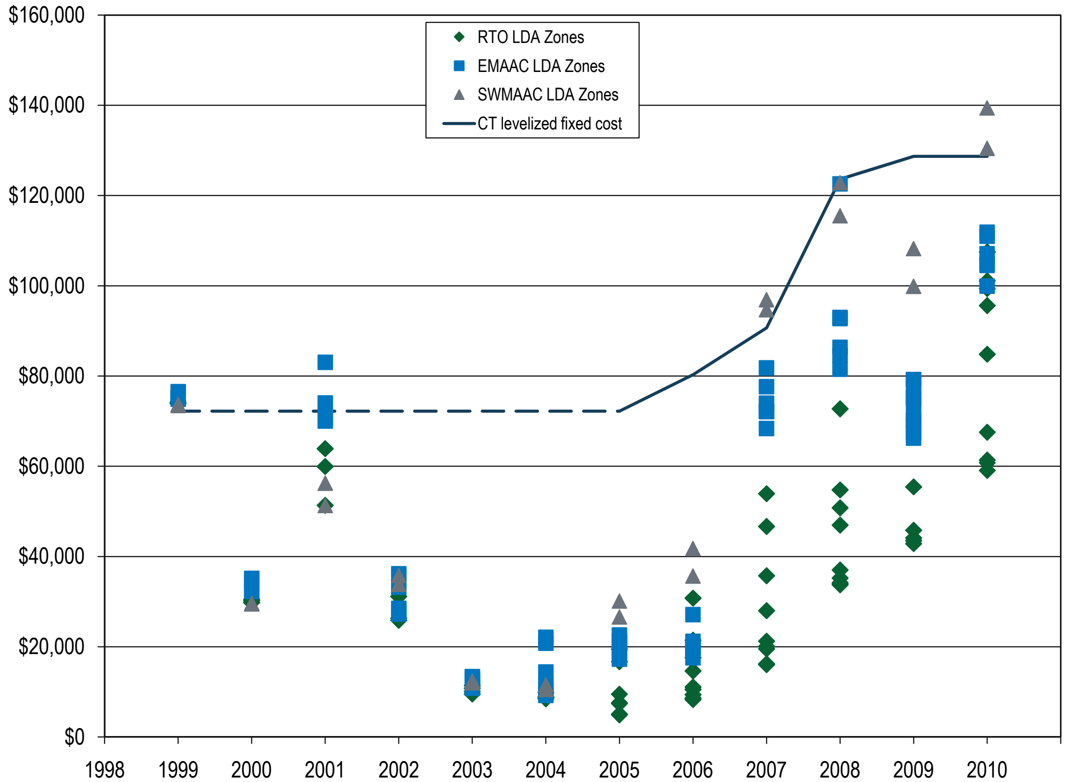
Figure 3-5 New entrant CT real-time net revenue and 20-year levelized fixed cost as of 2010 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2010



New Entrant Combined Cycle

In 2010, under the economic dispatch scenario, average net revenue from the PJM Real-Time Energy Market, the Capacity Market and the Ancillary Service Markets for a new entrant CC were $149,912 per installed MW-year. The associated operating costs were between $35 and $40 per MWh, based on a design heat rate of 6,900 Btu per kWh, average daily delivered natural gas prices of $5.02 per MBtu and a VOM rate of $3.23 per MWh. The resulting PJM average net revenue is less than the 20-year levelized fixed cost. Table 3-23 shows the PJM average CC net revenue and associated levelized fixed costs for the period 1999 to 2010. The only year when average PJM net revenue was sufficient to cover the associated 20-year levelized fixed costs for a new entrant CC was 1999, but some zonal net revenues were sufficient to cover the fixed costs for a new CC in several other years.

Table 3-23 CC 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2010

	20-Year Levelized Fixed Cost	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$93,549	$100,700	108%
2000	$93,549	$47,592	51%
2001	$93,549	$86,670	93%
2002	$93,549	$52,272	56%
2003	$93,549	$35,591	38%
2004	$93,549	$35,785	38%
2005	$93,549	$40,817	44%
2006	$99,230	$49,529	50%
2007	$143,600	$100,809	70%
2008	$171,361	$103,928	61%
2009	$173,174	$81,376	47%
2010	$175,250	$130,061	74%
Avg.	$118,122	$72,094	61%

Table 3-24 compares the 20-year levelized fixed cost in 2010 for a new entrant CC to the economic dispatch net revenue for each zone in 2010, along with average net revenue for the period 1999 to 2010 and average fixed costs. The average PJM net revenue is not enough to cover the levelized fixed costs. There are four zones that show more than adequate net revenue to cover 100 percent of the levelized fixed costs of a CC in 2010: AECO, BGE, DPL and Pepco. Figure 3-6 summarizes the information in Table 3-24, showing the 2010 net revenue for a new entrant CC, the average net revenue for the period 1999 to 2010 by zone and the levelized 2010 capital cost for a new entrant CC.[41] The extent to which net revenues cover the levelized fixed costs of investment in the CC technology is significantly dependent on location, which affects both energy and capacity revenue. Figure 3-7 shows total net revenues for the new entrant CC by market for 2010. Total net revenues in 2010 are higher than the twelve year average for all control zones, and this is largely due to RPM capacity revenue which comprises a significant portion of total revenue for the CC technology. Figure 3-8 shows zonal net revenue for the new entrant CC by LDA with the applicable yearly levelized fixed costs for the period 1999-2010. In 2007, 2008 and 2010 there were multiple zones with sufficient revenues to cover the fixed costs of investment in a new CC, and the two SWMAAC zones show sufficient revenues in each of the three years.

41 The fixed costs associated with the EMAAC LDA are meant to serve as a baseline for comparison.

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Table 3-24 CC 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): Calendar years 1999 to 2010

	2010			12-Year Average (1999-2010)		
	Net Revenue	20-Year Levelized Cost	Percent Recovered	Net Revenue	20-Year Levelized Cost	Percent Recovered
AECO	$175,900	$175,250	100%	$103,506	$118,122	88%
AEP	$98,280	$175,250	56%	$51,940	$118,122	44%
AP	$152,516	$175,250	87%	$73,565	$118,122	62%
BGE	$199,355	$175,250	114%	$103,738	$118,122	88%
ComEd	$87,686	$175,250	50%	$54,767	$118,122	46%
DAY	$97,600	$175,250	56%	$51,510	$118,122	44%
DLCO	$101,473	$175,250	58%	$80,625	$118,122	68%
Dominion	$162,324	$175,250	93%	$95,987	$118,122	81%
DPL	$175,605	$175,250	100%	$95,074	$118,122	80%
JCPL	$170,893	$175,250	98%	$96,902	$118,122	82%
Met-Ed	$167,178	$175,250	95%	$83,806	$118,122	71%
PECO	$164,909	$175,250	94%	$90,268	$118,122	76%
PENELEC	$134,761	$175,250	77%	$64,538	$118,122	55%
Pepco	$214,688	$175,250	123%	$108,477	$118,122	92%
PPL	$157,856	$175,250	90%	$78,033	$118,122	66%
PSEG	$168,625	$175,250	96%	$98,551	$118,122	83%
RECO	$158,836	$175,250	91%	$101,984	$118,122	86%
PJM	$149,912	$175,250	86%	$73,748	$118,122	62%

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Figure 3-6 New entrant CC real-time 2010 net revenue, twelve-year average net revenue and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year): Calendar years 1999 to 2010

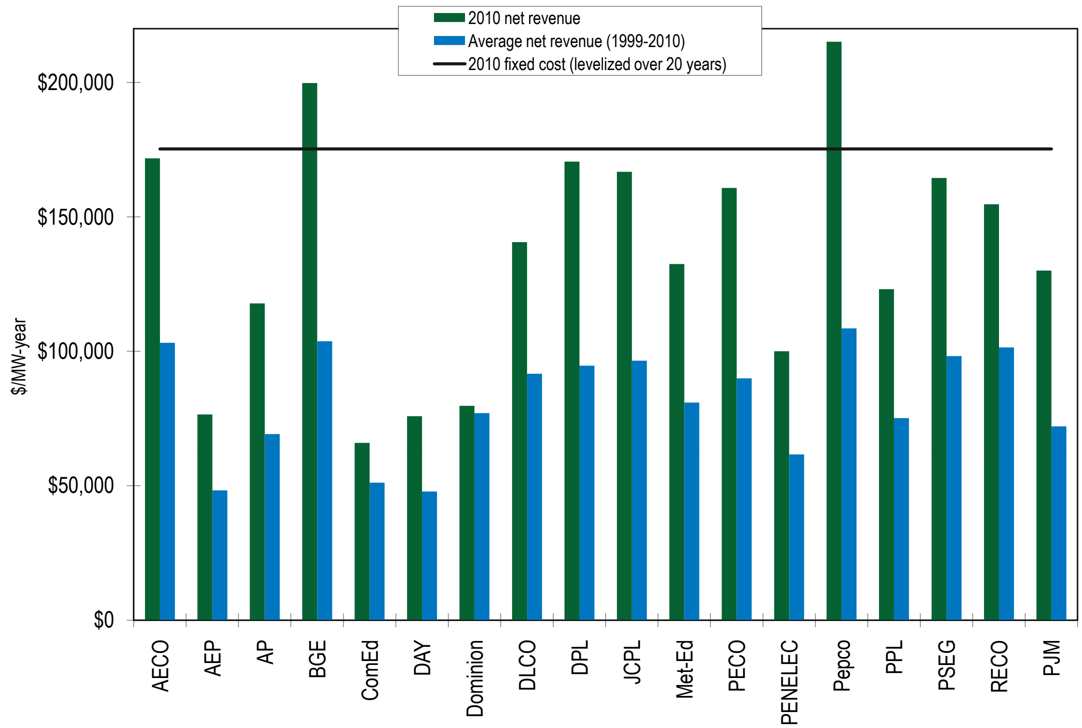

Figure 3-7 New entrant CC zonal real-time 2010 net revenue by market and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year)

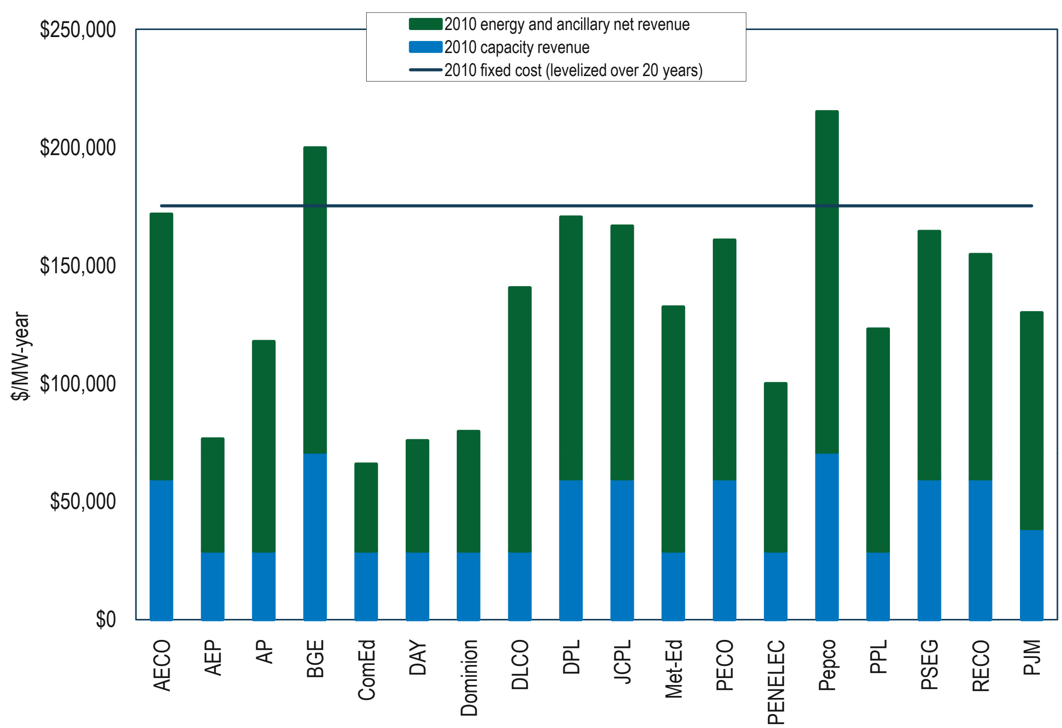

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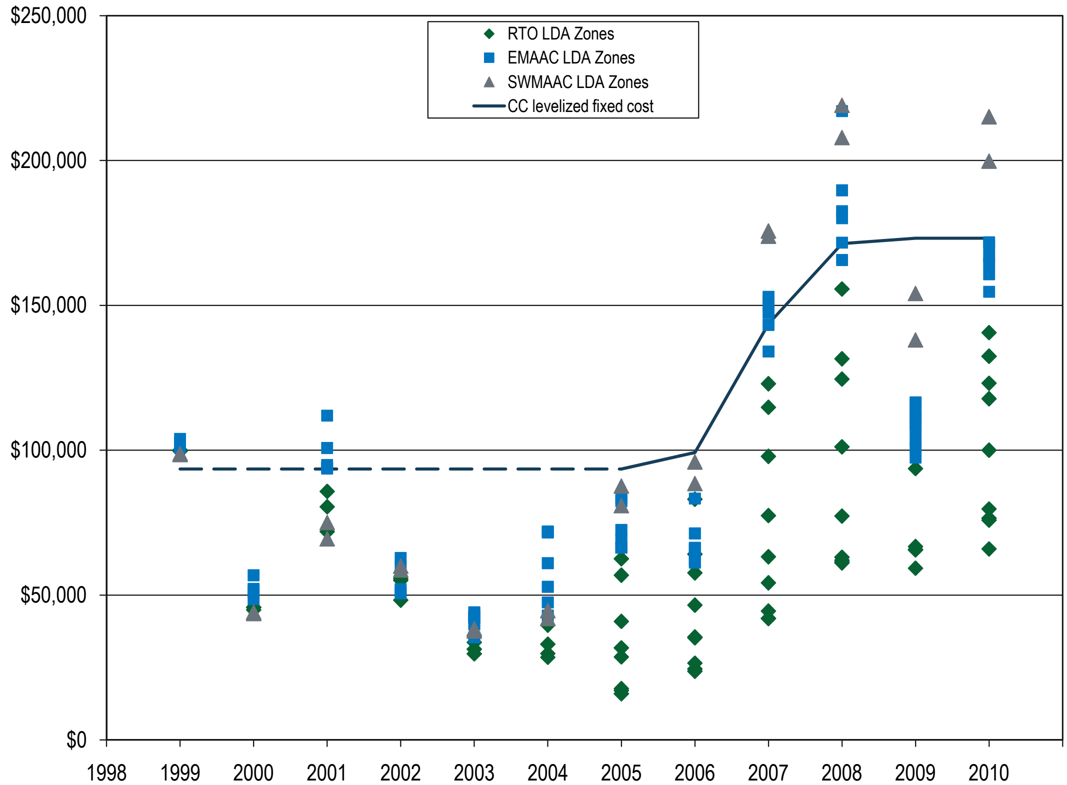
Figure 3-8 New entrant CC real-time net revenue and 20-year levelized fixed cost as of 2010 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2010



New Entrant Coal Plant

In 2010, under the economic dispatch scenario, average PJM net revenue from the Real-Time Energy Market, the Capacity Market and the Ancillary Service Markets for a new entrant CP was $185,644 per installed MW-year. The associated operating costs were between $30 and $35 per MWh, based on a design heat rate of 9,100 Btu per kWh and a VOM rate of $3.07 per MWh.[42]

Table 3-25 shows the PJM average CP net revenue and associated levelized fixed costs for the period 1999 to 2010. For the period, the resulting PJM average net revenue is less than the 20-year levelized fixed cost. The only year when average PJM net revenue was sufficient to cover the levelized fixed costs for a new entrant CP was 2005. However, several zonal net revenues were sufficient to cover the fixed costs for a new CP in 2005 and two zonal net revenues were sufficient to cover fixed costs in 2007. Average 2010 net revenue for a CP shows a significant increase from 2009 reflecting the higher average energy price levels in PJM and the more substantial impact of energy market net revenues for the CP technology.

42 The analysis used the prompt coal costs and associated production costs for CPs.

Table 3-25 CP 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2010

	20-Year Levelized Fixed Cost	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$208,247	$118,022	57%
2000	$208,247	$134,564	65%
2001	$208,247	$129,271	62%
2002	$208,247	$112,131	54%
2003	$208,247	$169,509	81%
2004	$208,247	$133,124	64%
2005	$208,247	$228,430	110%
2006	$267,792	$182,461	68%
2007	$359,750	$277,284	77%
2008	$492,780	$218,144	44%
2009	$446,550	$94,968	21%
2010	$465,455	$185,644	40%
Avg.	$290,838	$165,296	57%

Table 3-26 compares the 20-year levelized fixed cost in 2010 for a new entrant CP to the economic dispatch net revenue for each zone in 2010, along with average net revenue for the period 1999 to 2010 and average fixed costs. There were no control zones with sufficient net revenue to cover the levelized fixed costs of a new entrant CP in 2010. Figure 3-9 summarizes the information in Table 3-26, showing the 2010 net revenue for a new entrant CP, the average net revenue for the period 1999 to 2010 by zone and the levelized 2010 capital cost for a new entrant CP.[43] For every zone, 2010 energy net revenues for a CP are higher than 2009, and, for most zones, capacity revenues are higher.[44] The extent to which net revenues cover the levelized fixed costs of investment in the CP technology is significantly dependent on location, which affects both energy and capacity revenue as well as fuel costs. Figure 3-10 shows total net revenue for the new entrant coal plant by market for 2010. Total net revenues in 2010 are lower than the twelve year average for all control zones, and this is driven by lower energy price levels and lower energy net revenues, which comprise a significant portion of total revenue for the CP technology. Figure 3-12 shows zonal net revenue for the new entrant CP by LDA with the applicable yearly levelized fixed costs for the period 1999 to 2010.

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Table 3-26 CP 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): Calendar years 1999 to 2010

	2010			12-Year Average (1999-2010)		
	Net Revenue	20-Year Levelized Cost	Percent Recovered	Net Revenue	20-Year Levelized Cost	Percent Recovered
AECO	$222,251	$465,455	48%	$211,191	$290,838	73%
AEP	$115,311	$465,455	25%	$135,331	$290,838	47%
AP	$171,154	$465,455	37%	$189,830	$290,838	65%
BGE	$166,399	$465,455	36%	$200,014	$290,838	69%
ComEd	$166,017	$465,455	36%	$154,052	$290,838	53%
DAY	$136,491	$465,455	29%	$133,900	$290,838	46%
DLCO	$134,104	$465,455	29%	$150,098	$290,838	52%
Dominion	$201,844	$465,455	43%	$208,148	$290,838	72%
DPL	$221,754	$465,455	48%	$203,677	$290,838	70%
JCPL	$216,909	$465,455	47%	$202,037	$290,838	69%
Met-Ed	$211,816	$465,455	46%	$186,569	$290,838	64%
PECO	$210,457	$465,455	45%	$196,187	$290,838	67%
PENELEC	$186,033	$465,455	40%	$166,015	$290,838	57%
Pepco	$237,947	$465,455	51%	$212,113	$290,838	73%
PPL	$186,998	$465,455	40%	$180,408	$290,838	62%
PSEG	$197,234	$465,455	42%	$205,048	$290,838	71%
RECO	$210,649	$465,455	45%	$235,922	$290,838	81%
PJM	$185,644	$465,455	40%	$165,296	$290,838	57%

Figure 3-9 New entrant CP real-time 2010 net revenue, twelve-year average net revenue and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year): Calendar years 1999 to 2010

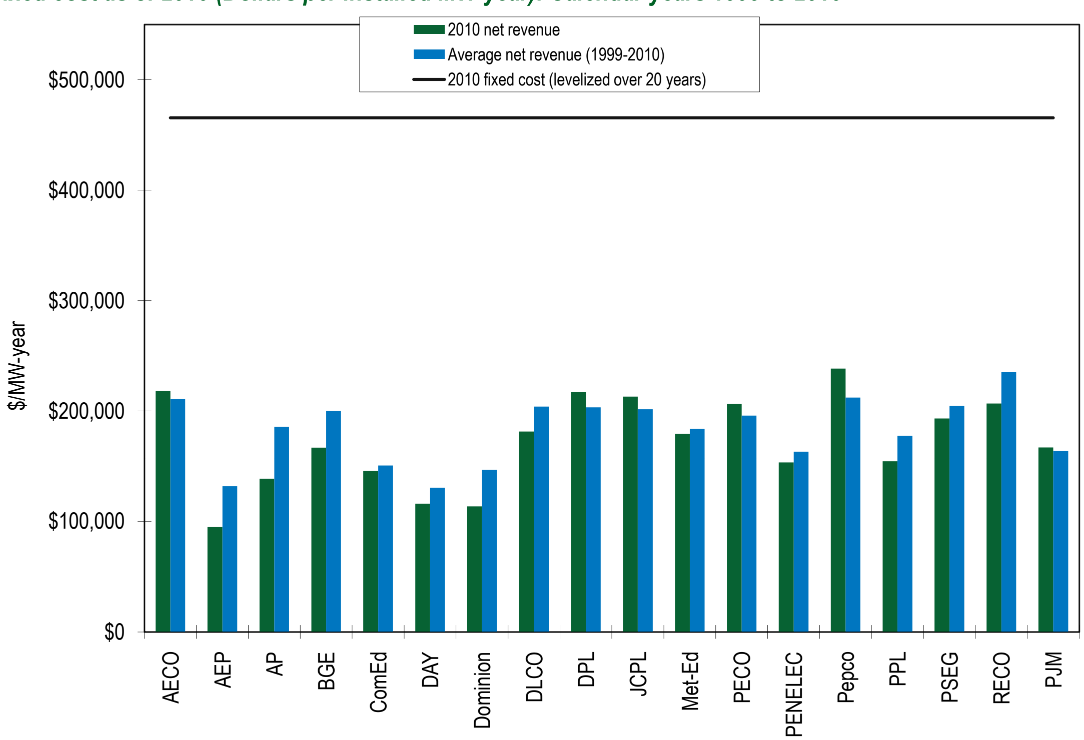


Figure 3-10 New entrant CP zonal real-time 2010 net revenue by market and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year)

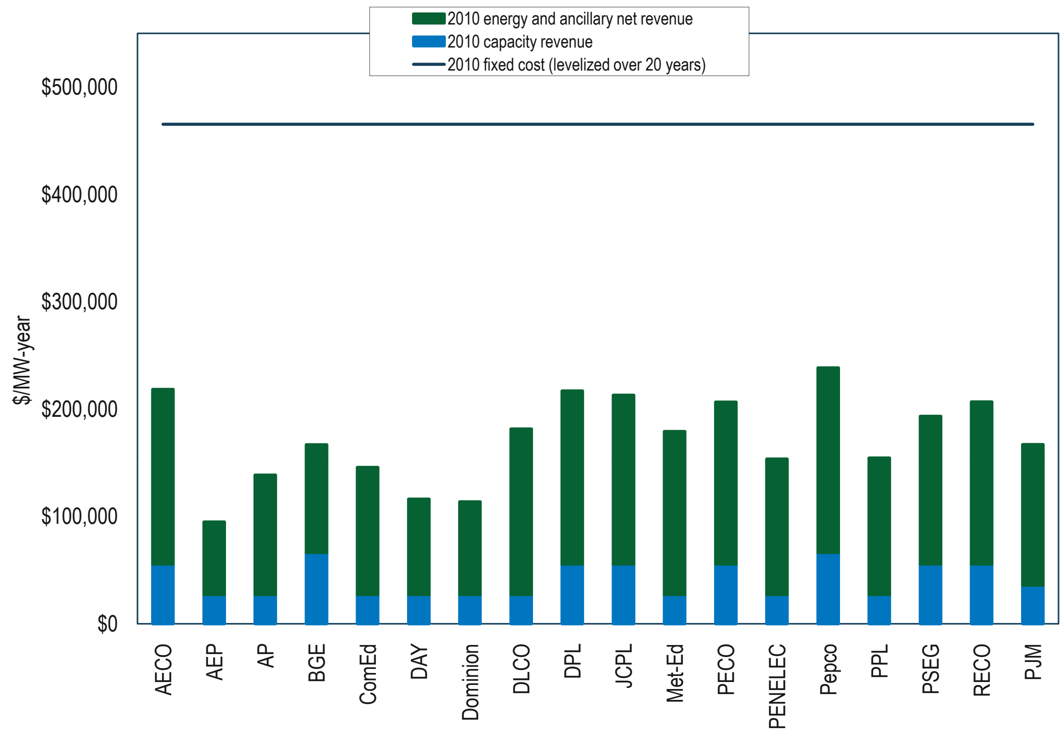
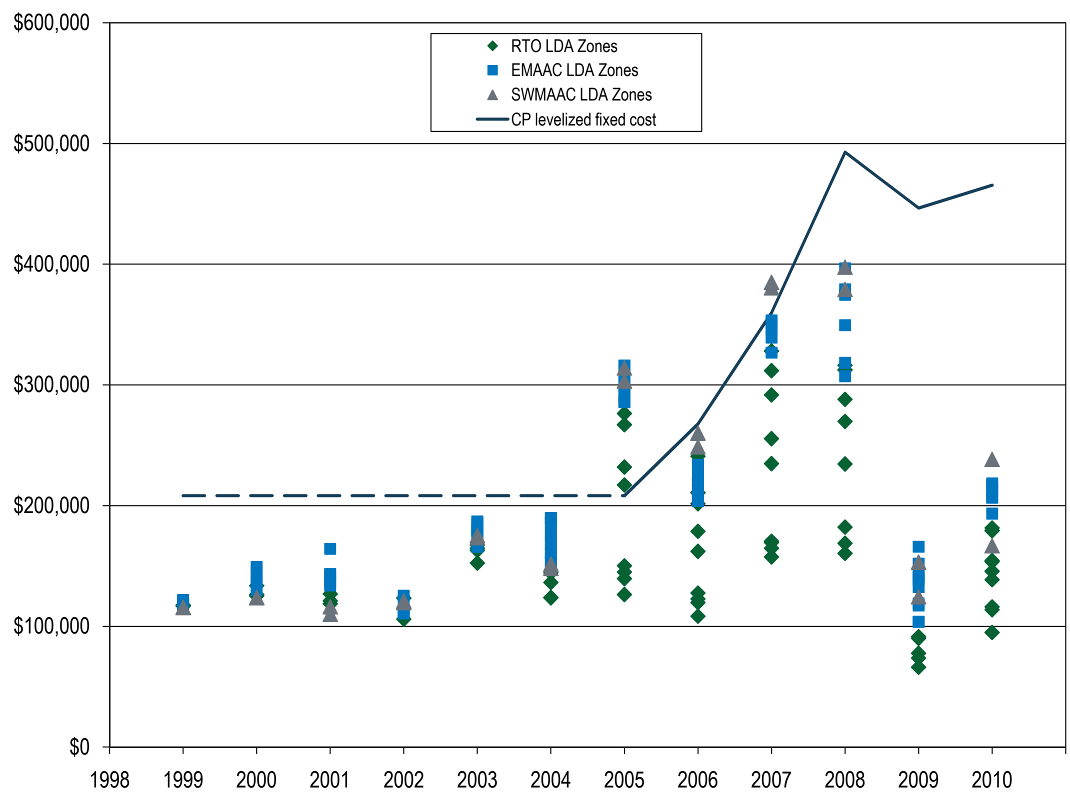


Figure 3-11 New entrant CP real-time net revenue and 20-year levelized fixed cost as of 2010 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2010



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Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the fixed costs of investing in new generating resources, 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. Analysis of 2010 net revenue indicates that the contribution of capacity revenue from RPM has a more significant effect on the incentive to invest in a new entrant CT or CC than other technologies. The profitability of new entrant peaking units, specifically, is substantially impacted by the local capacity market clearing price. Capacity market revenue is a smaller proportion of total net revenue for a new entrant coal plant, thus, the incentive to invest in a new entrant CP is less dependent on capacity revenues and more dependent on energy prices, input costs and energy net revenues.

The net revenue for a new generation resource varied significantly with the input fuel type and the efficiency of the reference technology. The delivered price of coal increased more than the delivered price of natural gas in most zones, as the price of low sulfur coal increased by 13 percent while the price of natural gas increased by 11.4 percent.[45] As a result, the natural gas fired power plants, particularly the more efficient combined cycle, show higher percentage increases in energy net revenues from 2010 than the coal-fired power plant. The net revenues in BGE zone of the SWMAAC LDA were approximately adequate to cover the annualized fixed costs for both the new entrant CT and CC, and the net revenues in Pepco zone were more than adequate to cover the annualized fixed costs for both the new entrant CT and CC.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental energy cost units and therefore tend to be marginal in the energy market and set prices in the energy market, when they run. When this occurs, CT energy market net revenues are small 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. There were relatively few high demand days in 2009 but in 2010, high demand days were more frequent. Scarcity revenues in the energy market also contribute to covering fixed costs, when they occur, but scarcity revenues are not a predictable and systematic source of net revenue. In the PJM design, the balance of the net revenue required to cover the fixed costs of peaking units comes from the Capacity Market. However, there may be a lag in Capacity Market prices which either offsets the reduction in energy market revenues or exacerbates the reduction in energy market revenues. Capacity Market prices are a function of a three year historical average net revenue offset which can be an inaccurate estimate of actual net revenues in the current operating year. In 2010, Capacity Market prices and revenues were relatively high, which had a substantial impact on the profitability of investing in CTs and CCs. Energy net revenues increased significantly in all PJM control zones, and capacity market prices increased for most PJM control zones. As a result, there were some zones that, when both energy revenues and capacity revenues are considered, showed revenue adequacy for a new entrant CT or CC in 2010.

The net revenue performance of combined cycle units (CCs) was comparable to that of CTs. CCs, like CTs, burn gas, but are more efficient than CTs and have higher fixed costs than CTs. Thus, as clearing prices set by CTs decline, net revenues from the Energy Market decline for CCs. However, in 2010, and with the spread between the delivered price of natural gas and the delivered price of coal decreasing in some months, for some zones, there are a number of hours in which the CC has lower generating costs than the CP.[46] Across zones, the average number of hours during which a

45 The spread between changes in coal prices and natural gas prices is particularly pronounced in the first and fourth quarters. In the third quarter, natural gas prices increased more in comparison to third quarter 2009 than coal prices, however, annual averages still show coal price increases exceeded price increases for natural gas.

46 The number of hours for which the incremental costs for a new entrant CC are lower than for the new entrant CP vary by zone as a result of zone specific estimates of delivered natural gas and coal costs, and, is generally higher for eastern zones where there are significant delivery costs associated with coal.

CC had lower generating costs than a CP was 2,059; for zones in MAAC LDA, the average number of hours was 2,411; and for zones in the rest of the RTO, the average number of hours was 1,413.

Coal units (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. However, when less efficient coal units are on the margin net revenues are higher for more efficient coal units. Coal units also received higher net revenues as a result of CTs setting prices based on gas costs. But, with natural gas prices increasing at a slower rate in some months than coal prices, these inframarginal energy revenues were lower than in prior years.

The returns earned by investors in generating units are a direct function of net revenues, the cost of capital, and the fixed costs associated with the generating unit. Positive returns may be earned at less than the annualized fixed costs, although the returns are less than the target. A sensitivity analysis was performed to determine the impact of changes in net revenue on the return on investment for a new generating unit. The internal rate of return (IRR) was calculated for a range of 20-year levelized net revenue streams, using 20-year levelized fixed costs from Table 3-20. Levelized net revenues were modified and the IRR calculated. A $7,500 per MW-year sensitivity was used for the CT; a $10,000 per MW-year sensitivity was used for the CC; and a $30,000 per MW-year sensitivity was used for the CP generator. The results are shown in Table 3-27.[47]

Table 3-27 Internal rate of return sensitivity for CT, CC and CP generators

	CT		CC		CP	
	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR
Sensitivity 1	$136,205	13.5%	$183,174	13.5%	$495,455	13.7%
Base Case	$128,705	12.0%	$173,174	12.0%	$465,455	12.0%
Sensitivity 2	$121,205	10.4%	$163,174	10.4%	$435,455	10.3%
Sensitivity 3	$113,705	8.7%	$153,174	8.8%	$405,455	8.4%
Sensitivity 4	$106,205	6.9%	$143,174	7.1%	$375,455	6.5%
Sensitivity 5	$98,705	4.9%	$133,174	5.3%	$345,455	4.4%
Sensitivity 6	$91,205	2.7%	$123,174	3.4%	$315,455	2.1%

Additional sensitivity analyses were performed for the CT and the CC technologies for the debt to equity ratio; the term of the debt financing; and the costs of interconnection. Table 3-28 shows the levelized annual revenue requirements associated with a range of debt to equity ratios holding the 12 percent IRR constant. The base case assumes 50/50 debt to equity ratio. As the percent of equity financing decreases, the levelized annual revenue required to earn a 12 percent IRR falls. Table 3-29 shows the levelized annual revenue requirements associated with various terms for the debt financing, assuming a 50/50 debt to equity ratio and 12 percent rate of return. As the term of the debt financing decreases, more net revenue is required annually to maintain a 12 percent rate of return.

47 This analysis was performed for the MMU by Pasteris Energy, Inc. The annual costs were based on a 20-year project life, 50/50 debt-to-equity financing with a target IRR of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 15-year modified accelerated cost-recovery schedule (MACRS) for the CT plant and 20-year MACRS for the CC and CP plants. A general annual rate of cost inflation of 2.5 percent was utilized in all calculations.

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Table 3-28 Debt to equity ratio sensitivity for CT and CC assuming 20 year debt term and 12 percent internal rate of return

	CT		CC	
	Equity as a percentage of total financing (%)	Levelized annual revenue requirement	Equity as a percentage of total financing (%)	Levelized annual revenue requirement
Sensitivity 1	60%	$139,446	60%	$186,000
Sensitivity 2	55%	$135,245	55%	$180,627
Base Case	50%	$131,044	50%	$175,250
Sensitivity 3	45%	$126,843	45%	$169,880
Sensitivity 4	40%	$122,642	40%	$164,505
Sensitivity 5	35%	$118,439	35%	$159,132
Sensitivity 6	30%	$114,238	30%	$153,758

Table 3-29 Debt term sensitivity for CT and CC assuming 50/50 debt to equity ratio and 12 percent internal rate of return

	CT		CC	
	Term of debt in years	Levelized annual revenue requirement	Term of debt in years	Levelized annual revenue requirement
Sensitivity 1	30	$117,871	30	$158,432
Sensitivity 2	25	$122,861	25	$164,790
Base Case	20	$131,044	20	$175,250
Sensitivity 3	15	$137,917	15	$184,045
Sensitivity 4	10	$147,032	10	$195,703

Table 3-30 shows the impact of a range of assumed interconnection costs on the levelized annual revenue requirement for the CT and the CC technologies. Interconnection costs vary significantly by location across PJM and even within PJM zones and can significantly impact the profitability of investing in peaking and midmerit generation technologies in a specific location. The impact on the annualized revenue requirements is more substantial for CTs than for CCs as interconnection costs are a larger proportion of overall project costs for CTs and as the new entrant CC has a higher energy output over which to spread the costs than the new entrant CT.

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Table 3-30 Interconnection cost sensitivity for CT and CC

	CT			CC		
	Capital Cost ($000)	Percent of total capital cost	Annualized Revenue Requirement ($/ICAP-Year)	Capital Cost ($000)	Percent of total capital cost	Annualized Revenue Requirement ($/ICAP-Year)
Sensitivity 1	$0	0.0%	$127,825	$0	0.0%	$172,422
Sensitivity 2	$3,759	1.2%	$129,436	$5,475	0.8%	$173,838
Base Case	$7,518	2.5%	$131,044	$10,951	1.6%	$175,250
Sensitivity 3	$11,278	3.7%	$132,652	$16,426	2.4%	$176,670
Sensitivity 4	$15,037	5.0%	$134,260	$21,902	3.2%	$178,084
Sensitivity 5	$18,796	6.2%	$135,868	$27,377	3.9%	$179,500
Sensitivity 6	$22,555	7.4%	$137,476	$32,852	4.7%	$180,916
Sensitivity 7	$50,000	16.5%	$149,216	$50,000	7.2%	$185,350
Sensitivity 8	$75,000	24.7%	$159,911	$75,000	10.8%	$191,814
Sensitivity 9	$100,000	33.0%	$170,606	$100,000	14.4%	$198,278

Actual Net Revenue

The analysis of net revenues in this section is based on actual net revenues for actual units operating in PJM. Net revenues from energy and capacity markets are compared to avoidable costs to determine the extent to which the revenues from PJM markets provide sufficient incentive for continued operations in PJM Markets. Avoidable costs are the costs which must be paid each year in order to keep a unit operating. Avoidable costs are less than total fixed costs, which include the return on and of capital, and more than marginal costs, which are the purely short run incremental costs of producing energy. It is rational for an owner to continue to operate a unit if it is covering its avoidable costs and therefore contributing to covering fixed costs. It is not rational for an owner to continue to operate a unit if it is not covering and not expected to cover its avoidable costs. As a general matter, under those conditions, retirement of the unit is the logical option. Thus, this comparison of actual net revenues to avoidable costs is a measure of the extent to which units in PJM may be at risk of retirement.

The definition of avoidable costs, based on the RPM rules, includes both avoidable costs and the annualized fixed costs of investments required to maintain a unit as a capacity resource (APIR). When actual net revenues are compared to actual avoidable costs, the actual avoidable costs include APIR when unit owners have included APIR in unit offers. This affects the interpretation of the conclusions. Existing APIR is a sunk cost and a rational decision about retirement would ignore such sunk costs. Potential APIR is not a sunk cost and a rational decision about retirement would consider the expected probability of recovering the costs of such new investments over the remaining life of the unit.

The MMU calculated unit specific energy and ancillary service net revenues for several technology classes. These net revenues were compared to avoidable costs to determine the extent to which PJM Energy and Ancillary Service Markets alone provide sufficient incentive for continued operations in PJM Markets. Energy and Ancillary Service revenues were then combined with the actual capacity revenues, and compared to actual avoidable costs to determine the extent to which the Capacity Market revenues covered any shortfall between energy and ancillary net revenues and avoidable costs. The comparison of the two results is an indicator of the significance of the role of the capacity market in maintaining the viability of existing generating units.

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Actual energy net revenues include Day-Ahead and balancing energy revenues, less submitted or estimated operating costs, as well as any applicable Day-Ahead or Balancing Operating Reserve Credits. Ancillary service revenues include actual unit credits for regulation services, spinning reserves and black start capability, in addition to actual or class average reactive revenues determined by actual FERC filings.

The MMU calculated average avoidable costs in dollars per MW-year for each quartile based on actual submitted Avoidable Cost Rate (ACR) data for units within a quartile associated with the most recent 2009/2010 and 2010/2011 RPM Auctions.[48] For units that did not submit ACR data, the default ACR was used. Avoidable costs were calculated for calendar year 2010 using the 2009/2010 avoidable cost data for 151 days and the 2010/2011 delivery year avoidable for 214 days.

An estimated annual avoidable cost rate for nuclear units was developed by Pasteris Energy, Inc from publicly available information and used to determine an avoidable cost proxy for all nuclear units.[49] While avoidable costs for other technologies are quartile specific averages based on unit specific avoidable costs, the nuclear avoidable cost rate represents a class average, consistent for all nuclear units both within and across quartiles.

The RPM capacity market design provides supplemental signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability. For this analysis, unit specific capacity revenues associated with the 2009/2010 and 2010/2011 delivery years, reflecting commitments made in Base Residual Auctions (BRA) and subsequent Incremental Auctions, net of any performance penalties, were added to unit specific energy and ancillary net revenues to determine total revenue from PJM Markets. Any unit with a significant portion of installed capacity designated as FRR committed was excluded from the analysis.[50] For units exporting capacity, the applicable Base Residual Auction (BRA) clearing price was applied, which may understate actual revenues, since units may bid an export price into the auction as an opportunity cost and provide capacity to the market with the higher price.

Net revenues were analyzed for most technologies for which avoidable costs are developed in the RPM, including three classes of combined cycle plants, six classes of combustion turbine plants and two classes of coal plants.[51] In addition, net revenues were analyzed for diesel units, run of river hydro plants, nuclear plants, and oil-fired and gas-fired steam units.

The underlying analysis was done on a unit specific basis, using individual unit actual net revenues and individual unit avoidable costs. Table 3-31 provides a summary of results, with average net revenues and associated recovery of average avoidable costs from energy markets and average total revenues and associated recovery of average avoidable costs from all markets, by technology class, as well as the total installed capacity associated with each technology analyzed. The class average energy and ancillary net revenues for the Frame F CC and Frame F CT and for the nuclear and run of river hydro technologies were more than sufficient to recover class average avoidable costs. The class average energy and ancillary net revenues for the first and second generation

48 If a unit submitted updated ACR data for an incremental auction for either the 2009/2010 or the 2010/2011 delivery year, that data was used instead of the ACR data submitted for the Base Residual Auction.

49 Data from the Nuclear Energy Institute (NEI) website (http://www.nei.org/) was used to develop an avoidable cost rate based on 2009 information, which was escalated through 2010. The NEI shows in a table titled U.S. Electric Production Costs and Components that the average non-fuel O&M cost for a nuclear power plant in 2009 was $14.60/MWh. This includes costs related to labor, material & supplies, contractor services, licensing fees, and miscellaneous costs such as employee expenses and regulatory fees and insurance. Property tax costs which were not included in the NEI value were obtained from public information and were $0.72/MWh and was added to the NEI value. The NEI value included VOM which is estimated at $2.00/MWh and this value was subtracted from the NEI value. Accordingly, the final adjusted avoidable cost is $13.32 in 2009. To determine 2010 costs, general 2009 costs were escalated at 2.5 percent to 2010. Plant O&M was escalated using the Handy-Whitman July 1 Index for "Total Nuclear Production Plant." The 2010 avoidable cost is $13.72/MWh.

50 The MMU cannot assess the risk of FRR designated units because the incentives associated with continued operations for these units are not transparent and are not aligned with PJM Market incentives. For the same reasons, units with significant FRR commitments are excluded from the analysis of units potentially facing significant capital expenditures associated with environmental controls.

51 Pumped storage units, wind and solar units, landfill gas burning units and municipal waste burning units were excluded from the analysis. Combined cycle units of two on one or three on one Frame F technology were combined to create a single technology class with a greater sample size. Waste coal units were combined with the sub-critical coal units to create a single technology class with a greater sample size.

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aero frame CT and LM 6000 aero frame CT were approximately sufficient to recover class average avoidable costs. The class average energy and ancillary net revenues for the Frame B CT, the third generation Pratt & Whitney aero frame CT, the diesel, oil-fired or gas-fired steam technologies and both coal technologies were not sufficient to recover class average avoidable costs. However, class average total revenues, including capacity revenues, were more than sufficient to recover class average avoidable costs for all technologies.

Table 3-31 Class average net revenue from energy and ancillary markets and associated recovery of class average avoidable costs and total revenue from all markets and associated recovery of class average avoidable costs

Technology	Total Installed Capacity (ICAP)	Class average energy and ancillary net revenue ($/MW-year)	Class average recovery of class average avoidable costs from energy revenue	Class average energy net revenue and capacity revenue ($/MW-year)	Class average recovery from all markets of class average avoidable costs
CC - NUG Cogeneration Frame B or E Technology	1,329	$25,941	67%	$85,531	220%
CC - Three on One Frame E Technology	4,225	$57,354	415%	$110,253	797%
CC - Two or Three on One Frame F Technology	12,677	$44,790	273%	$102,745	627%
CT - First & Second Generation Aero (P&W FT 4)	3,620	$11,927	104%	$70,370	616%
CT - First & Second Generation Frame B	4,466	$5,709	49%	$65,718	560%
CT - Second Generation Frame E	5,913	$15,115	193%	$67,286	859%
CT - Third Generation Aero (GE LM 6000)	1,774	$19,048	100%	$75,808	397%
CT - Third Generation Aero (P&W FT- 8 TwinPak)	1,550	$8,884	87%	$62,437	615%
CT - Third Generation Frame F	9,298	$23,307	279%	$74,870	895%
Diesel	241	$5,946	62%	$67,212	699%
Hydro	1,933	$198,114	1159%	$256,524	1501%
Nuclear	29,208	$267,121	238%	$325,204	289%
Oil or Gas Steam	9,656	$6,859	22%	$67,205	217%
Sub-Critical Coal	25,524	$72,322	99%	$126,690	173%
Super Critical Coal	19,053	$70,199	76%	$126,366	137%

The actual unit specific energy and ancillary net revenues, avoidable costs and capacity revenues underlying the class averages shown in Table 3-31 incorporate a wide range of results. In order to illustrate this underlying variability while preserving confidentiality of unit specific information, the data are aggregated and summarized by quartile.[52] Within each technology, quartiles were established based on the distribution of total energy net revenue received per installed MW-year. These quartiles remain constant throughout the analysis. Table 3-32 shows average energy and ancillary service net revenues by quartile for select technology classes.

52 Several technologies, including the CC NUG Cogeneration Frame B or E, the three on one Frame E, the Pratt & Whitney third generation aero frame, are included in Table 3-32 but excluded from the analysis by quartile due to confidentiality concerns based on the number of units. Similarly, in tables analyzing by technology by quartiles, for some technologies and some quartiles, if minimal data requirements were not met, the tables show "NA". However, these technologies are represented and quartiles included in the proportion of units at risk shown in Table 3-37.

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Table 3-32 Average energy and ancillary service net revenue by quartile for select technologies for calendar year 2010

Technology	First quartile average energy and ancillary net revenue ($/MW-year)	Second quartile average energy and ancillary net revenue ($/MW-year)	Third quartile average energy and ancillary net revenue ($/MW-year)	Fourth quartile average energy and ancillary net revenue ($/MW-year)
CC - Two or Three on One Frame F Technology	$18,793	NA	$45,274	$77,446
CT - First & Second Generation Aero (P&W FT 4)	$1,434	$4,435	$8,182	$32,821
CT - First & Second Generation Frame B	$372	$2,267	$4,405	$15,635
CT - Second Generation Frame E	$1,632	$4,294	$8,693	$44,032
CT - Third Generation Aero (GE LM 6000)	$2,999	$8,488	$16,045	$46,000
CT - Third Generation Frame F	$3,017	$8,200	$19,847	$58,469
Diesel	($1,085)	$1,630	$3,675	$16,613
Hydro	$87,840	$147,889	$194,925	$346,919
Nuclear	NA	$228,569	$319,729	$349,903
Oil or Gas Steam	($1,629)	$935	$4,430	$22,259
Sub-Critical Coal	$13,325	$55,848	$77,138	$140,688
Super Critical Coal	NA	$55,691	$80,902	$119,414

The first quartiles for the diesel and oil or gas-fired steam technologies show negative net energy revenues. This means that some of these units operated in PJM energy markets at a net loss and that the resulting average energy and ancillary service net revenue for the lowest 25 percent of units is negative. This results, for example, when a unit runs during unprofitable hours independent of PJM dispatch. For some older units, this may occur because of an inability to follow PJM dispatch. In other cases, a unit may have an incentive to run during hours when LMP is lower than operating costs because it is receiving revenues from outside PJM markets, via a bilateral agreement.[53]

Unit specific avoidable costs were averaged for each quartile and compared to the quartile average net energy revenues in Table 3-32. Table 3-33 shows the percentage recovery of quartile avoidable cost using the quartile average energy and ancillary service net revenue. The average energy net revenues for the first three quartiles are not adequate to recover avoidable costs for several of the older CT technologies and for the diesel technology and the average energy net revenues are not adequate to recover avoidable costs in any quartile for oil-fired or gas-fired steam units. However, the newer Frame F CT and CC technologies show average energy net revenues greater than average avoidable costs for the second, third and fourth quartiles. For sub-critical and super critical coal plants, the second quartile average avoidable cost recoveries are 70.5 percent and 64.7 percent. For super critical coal plants, the fourth quartile, which is the highest 25 percent of coal plants in energy and ancillary net revenue, shows a lower recovery of average avoidable costs than the third quartile. This is because the fourth quartile has higher average avoidable costs than does the third quartile. The average energy net revenues for the nuclear and hydro technologies are greater than the quartile average avoidable cost rate for each quartile.

53 For units that operated with a net loss in energy markets for calendar year 2010 and that operated more than 100 hours, for any hour that the unit was operating at a loss and not following dispatch, that hourly loss was set to zero to prevent units with bilateral contracts or out of market incentives to run at a loss from biasing average net revenues. This assumption affected less than 60 units and did not result in any changes in conclusions about risk of retirement.

Table 3-33 Avoidable cost recovery by quartile from energy and ancillary service net revenue for select technologies for calendar year 2010

Technology	First quartile recovery of avoidable costs	Second quartile recovery of avoidable costs	Third quartile recovery of avoidable costs	Fourth quartile recovery of avoidable costs
CC - Two or Three on One Frame F Technology	146.7%	NA	216.1%	409.6%
CT - First & Second Generation Aero (P&W FT 4)	11.7%	50.5%	88.1%	215.3%
CT - First & Second Generation Frame B	3.8%	20.9%	28.3%	146.2%
CT - Second Generation Frame E	20.9%	54.8%	112.5%	555.7%
CT - Third Generation Aero (GE LM 6000)	16.7%	44.1%	83.0%	231.4%
CT - Third Generation Frame F	34.6%	94.9%	248.9%	717.2%
Diesel	(12.0%)	18.0%	32.5%	183.4%
Hydro	680.1%	775.8%	1,076.3%	1,908.7%
Nuclear	NA	203.4%	284.5%	311.4%
Oil or Gas Steam	(5.9%)	2.8%	14.8%	67.7%
Sub-Critical Coal	20.9%	70.5%	115.7%	168.8%
Super Critical Coal	NA	64.7%	150.3%	73.1%

Differences in energy net revenue within technology classes reflect differences in incremental costs which are a function of plant efficiencies, input fuels, variable operating and maintenance (VOM) expenses and emission rates, as well as differences in location which affect both the LMP and delivery costs associated with input fuels. The quartile average net revenues for diesel units, the oil or gas-fired steam technology, and several of the older CT technologies reflect both units burning natural gas and units burning oil distillates. The geographical distribution of units for a given technology class across the PJM footprint determines individual unit price levels and thus significantly affects average energy net revenue for that technology class. For example, the quartile average energy and ancillary service revenues for the first and second generation Frame B CT technology, which range from $372 per MW-year and 3.8 percent recovery of avoidable costs to $15,635 per MW-year and 146.2 percent recovery, reflect average net revenues from units with heat rates ranging from 12,000 Btu/kWh to greater than 17,000 Btu/kWh, from units that burn natural gas or oil distillates and units that are spread among 15 different PJM Control Zones.

Table 3-34 shows average revenue from all PJM Markets by the same quartiles established for energy and ancillary service net revenues in Table 3-32.

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Table 3-34 Average total net revenue by quartile for select technologies for calendar year 2010

Technology	First quartile average total revenue ($/MW-year)	Second quartile average total net revenue ($/MW-year)	Third quartile average total net revenue ($/MW-year)	Fourth quartile average total net revenue ($/MW-year)
CC - Two or Three on One Frame F Technology	$73,586	NA	$108,508	$137,834
CT - First & Second Generation Aero (P&W FT 4)	$60,928	$64,604	$66,752	$88,474
CT - First & Second Generation Frame B	$57,611	$61,490	$60,573	$82,961
CT - Second Generation Frame E	$57,641	$56,341	$60,861	$92,711
CT - Third Generation Aero (GE LM 6000)	$60,627	$60,065	$69,797	$109,652
CT - Third Generation Frame F	$53,729	$57,081	$74,333	$110,548
Diesel	$57,822	$57,680	$66,126	$83,022
Hydro	$152,496	$206,753	$245,947	$405,957
Nuclear	NA	$283,662	$382,987	$412,232
Oil or Gas Steam	$58,876	$57,846	$65,870	$84,458
Sub-Critical Coal	$67,412	$108,316	$132,680	$196,000
Super Critical Coal	NA	$109,875	$128,693	$182,360

Table 3-35 shows the average avoidable cost recovery from all PJM markets by the same quartiles. Capacity payments in calendar year 2010 range from approximately $52,700 in the unconstrained RTO Control zones to $73,100 in the SWMAAC LDA. The result is that for the CC technology and both CT technologies, after capacity payments are considered, each quartile average total revenue far exceeded quartile average avoidable costs, and nearly all units experienced full recovery of average avoidable costs.

In some years, for some technologies, capacity payments significantly exceeded the avoidable costs. As a result of energy market conditions, many CC and CT units received sufficient revenue from the energy market to cover avoidable costs, and, once capacity revenues were considered, total revenues were well in excess of avoidable costs. For example, the third and fourth quartile average net revenue for the combined cycle and combustion turbine Frame F technologies were sufficient to cover avoidable costs before capacity revenues are considered. Average total net revenues, including capacity, for the third and fourth quartiles for the CC technology, and, for all quartiles for the CT technology, are several times greater than the quartile average avoidable costs.

While the average total revenues for the all quartiles of sub-critical and supercritical coal units are sufficient to cover avoidable costs, the two coal technologies generally show lower average recovery of avoidable costs than CTs and CCs. Avoidable costs for coal plants are considerably higher than for CTs and CCs, and revenues received from the capacity market make up a smaller portion of avoidable costs. As a result, the profitability of coal units is more dependent upon net revenues received in the energy market.

Table 3-35 Avoidable cost recovery by quartile from all PJM Markets for select technologies for calendar year 2010

Technology	First quartile recovery of avoidable costs	Second quartile recovery of avoidable costs	Third quartile recovery of avoidable costs	Fourth quartile recovery of avoidable costs
CC - Two or Three on One Frame F Technology	574.5%	NA	517.9%	729.1%
CT - First & Second Generation Aero (P&W FT 4)	498.7%	736.3%	718.9%	580.5%
CT - First & Second Generation Frame B	592.7%	565.9%	388.6%	775.7%
CT - Second Generation Frame E	736.6%	718.8%	787.5%	1,170.0%
CT - Third Generation Aero (GE LM 6000)	338.5%	312.2%	361.2%	551.7%
CT - Third Generation Frame F	615.5%	660.3%	932.2%	1,356.1%
Diesel	638.2%	636.7%	585.4%	916.4%
Hydro	1,180.7%	1,084.6%	1,358.1%	2,233.5%
Nuclear	NA	252.4%	340.8%	366.9%
Oil or Gas Steam	214.0%	175.0%	219.4%	256.7%
Sub-Critical Coal	105.8%	136.7%	199.0%	235.1%
Super Critical Coal	NA	127.7%	239.0%	111.6%

Quartile averages can be affected by outliers, and do not indicate the proportion of actual units in PJM not covering avoidable costs. Table 3-36 shows the proportion of units with full recovery of avoidable costs from energy markets and from all markets for calendar years 2009 and 2010.[54] In both years, some units for all technologies, other than hydro and nuclear, do not achieve full recovery of avoidable costs through energy markets alone. A substantial portion of Cogeneration units, all CT technologies, oil or gas-fired steam units, and coal plants do not achieve full recovery of avoidable costs through energy markets alone.

54 Units that provided notice of deactivation in 2010 and units that are designated reliability must run (RMR) were excluded from this analysis. Additionally, any unit with a significant portion of installed capacity designated as FRR committed was excluded from the analysis.

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Table 3-36 Proportion of units recovering avoidable costs from energy and ancillary markets as well as total markets for calendar years 2009 and 2010

	2009		2010	
Technology	Units with full recovery from Energy Markets	Units with full recovery from all markets	Units with full recovery from Energy Markets	Units with full recovery from all markets
CC - NUG Cogeneration Frame B or E Technology	0%	100%	30%	100%
CC - Three on One Frame E Technology	54%	100%	85%	100%
CC - Two or Three on One Frame F Technology	83%	100%	93%	100%
CT - First & Second Generation Aero (P&W FT 4)	6%	100%	32%	100%
CT - First & Second Generation Frame B	2%	100%	22%	99%
CT - Second Generation Frame E	0%	100%	42%	100%
CT - Third Generation Aero (GE LM 6000)	16%	100%	32%	100%
CT - Third Generation Aero (P&W FT- 8 TwinPak)	0%	100%	33%	100%
CT - Third Generation Frame F	25%	100%	62%	100%
Diesel	12%	96%	13%	100%
Hydro	100%	100%	100%	100%
Nuclear	93%	100%	100%	100%
Oil or Gas Steam	3%	92%	3%	92%
Sub-Critical Coal	30%	75%	52%	82%
Super Critical Coal	35%	82%	50%	82%

For the first and second generation CT technologies and the third generation aero technologies, less than 50 percent of the units in PJM received sufficient revenue from the energy market to recover avoidable costs in both years analyzed, but RPM capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs. For the combined cycle technology, the proportion of units recovering avoidable costs through energy market revenue was below 50 percent in both years for the cogeneration technology, and above 50 percent in both years for the more efficient frame E and F technologies. Capacity revenues were sufficient in both years to provide full recovery for all combined cycle units showing less than full recovery from energy market revenue. For the oil or gas-fired steam technology, approximately three percent of units received sufficient revenue from the energy market to recover avoidable costs in both years analyzed, and, in both years, when capacity revenues were considered, total revenues were sufficient for 92 percent to recover avoidable costs. In 2010, the small proportion of oil or gas fired steam units and Frame B CTs not recovering avoidable costs after capacity revenues represent approximately 720 MW. These units are characterized by higher than class average forced outage rates, which affect both energy and capacity revenues, as well as higher than class average avoidable costs, in some cases associated with capital expenditures to improve reliability.

For both the CT technologies and the CC technology, RPM revenue has provided an adequate supplemental revenue stream to incent continued operations in PJM for most units that do not recover 100 percent of fixed costs through energy market revenue.

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A significant number of sub-critical and supercritical coal units did not recover avoidable costs from energy market revenues alone in 2009 and 2010. In addition seven percent of nuclear units did not recover the class average nuclear avoidable cost rate from energy market revenues alone in 2009. With significantly higher avoidable costs than CCs and CTs and typically lower operating costs per MWh, the profitability of operating coal and nuclear units relies more heavily on energy market revenues.

A number of sub-critical and supercritical coal units did not recover avoidable costs even after capacity revenues are considered. These units are considered at risk of retirement.

Energy market net revenues are a function of energy prices and operating costs, which are a function of the cost of inputs and plant efficiencies. Avoidable costs are a function of technology, unit size and age of units and, in some cases, unit specific investments needed to maintain or enhance reliability or to comply with environmental regulations.

Table 3-37 shows characteristics of the subset of coal units with less than 100 percent recovery of avoidable costs after capacity revenues in 2010, compared to coal plants with greater than or equal to 100 percent recovery. The total installed capacity associated with coal units that did not cover their avoidable costs in 2010 was 6,769 MW, of which, 6,021 MW were located in the MAAC region. The average size of coal plants that did not cover avoidable costs was 225.6 MW, compared to 282.1 for coal plants that did cover avoidable costs. These units were, on average, less efficient. These units had a class average heat rate of approximately 11,430 Btu/kWh and average operating costs of $43.08/MWh compared to 10,870 btu/kWh and $29.92/MWh for coal plants with full recovery. A subset of these units run less often and operate as mid-merit or even peaking units in the supply stack. They are called on during periods of high LMP and may continue to operate in unprofitable hours due to more severe operating constraints compared to the CT and CC technologies. This subset of coal plants did not recover avoidable costs from energy and capacity revenues.

Units that did not cover avoidable costs generally sold capacity in RPM auctions, but some showed reduced capacity market revenues which may be attributable to partial clearing in Base Residual Auctions (BRA), high outage rates affecting the unforced capacity level that can be offered, or performance penalties associated with nonperformance. In addition, units that did not cover avoidable costs tended to have higher avoidable costs, and some showed significant levels of capital expenditures represented in Avoidable Project Investment Rate (APIR). It is possible that these units cleared at a level below 2010 avoidable cost recovery due to the lag in market revenues used to calculate offer caps associated with each delivery year which led to an offer cap that understated the annual recovery needed in 2010 from the RPM, or, these units may have been offered at a price below the avoidable cost based offer cap, including APIR. Such offers are rational, for example, if project costs are considered sunk, or if the project life is longer than the PJM defined recovery period for the calculation of the avoidable cost rate. In either case, these units may be at a lower risk of retirement than units under recovering avoidable costs exclusive of the recovery of capital investments.

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Table 3-37 Profile of coal units not recovering avoidable costs from all PJM Market net revenues for 2010

Technology	Coal plants with full recovery of avoidable costs	Coal plants with less than full recovery of avoidable costs
Total Installed Capacity	37,808	6,769
Installed Capacity within MAAC	12,978	6,021
Avg. Installed Capacity (ICAP)	282.1	225.6
Avg. Age of Plant (Years)	40	50
Avg. Heat Rate (Btu/kWh)	10,872	11,429
Avg. Run Hours (Hours)	6,505	3,847
Avg. Avoidable Costs	$61,748	$145,904
Avg. Incremental Cost per MWh	$29.92	$43.08

There were 93 coal units analyzed in 2010 with capacity less than or equal to 200 MW. Of those units, 20 did not cover their avoidable costs and three were close to not covering their avoidable costs. The risk of deactivation for these units depends on the degree to which revenues from all markets are less than avoidable costs. Table 3-38 shows the installed capacity (MW) associated with various levels of recovery for coal plants with less than or just over 100 percent recovery. Units accounting for 2,763 MW are recovering less than 65 percent of avoidable costs and units accounting for 4,862 MW are recovering less than 75 percent of avoidable costs.

Table 3-38 Installed capacity associated with various levels of avoidable cost recovery: Calendar year 2010

Groups of coal plants by percent recovery of avoidable cost	Installed Capacity (MW)	Percent of Total
0% - 65%	2,763	30.9%
65% - 75%	2,099	23.5%
75% - 90%	818	9.1%
90% - 100%	1,089	12.2%
100% - 115%	2,178	24.3%
Total	8,947	100.0%

Analysis of 2010 actual net revenues indicates that, for several technologies, there is a significant proportion of units not receiving sufficient net revenue in the PJM Energy Market to cover avoidable costs. For the CT, CC, diesel and oil-fired or gas-fired steam technologies, capacity revenue from RPM provides a sufficient supplement for units to fully recover avoidable costs. In 2010, a year of higher energy revenues compared to 2009, nuclear units and run of river hydro units did not require supplemental revenues from the capacity market in order to recover avoidable costs. In 2010, despite higher load levels and, generally higher price levels relative to operating costs, some coal-fired units in PJM did not fully recover avoidable costs even with capacity revenues.

Impact of Environmental Rules

Environmental rules may affect decisions about investments in existing units, investment in new units and decisions to retire units. There are pending regulations that would require significant capital expenditures on environmental controls for existing units. These capital expenditures, if required, would significantly impact the profitability of existing coal-fired units. Existing units facing these capital expenditures may be retired if it is not expected that the units will recover the associated costs through a combination of energy or capacity revenue. The extent to which capital expenditures affect an individual unit's offer in the capacity market depends upon the size of the unit, the level of investment required, the life and recovery rate of the investment, avoidable costs, and the expected net revenue.

The MMU analyzed the impact that pending environmental regulations regarding SO_2 and NO_x emissions may have on existing coal plants in the PJM footprint, given calendar year 2010 energy and capacity net revenues.[55] Units lacking controls for either NO_x emissions, SO_2 emissions, or both were identified as units at risk of significant capital expenditure on environmental control technologies. Table 3-39 shows the number of units and associated installed capacity lacking controls for either NO_x emissions, SO_2 emissions, or both. Approximately 75 units accounting for 14,388 MW of installed capacity may be at risk of facing significant capital expenditures associated with environmental controls.

Table 3-39 Units lacking controls for either NO_x emission rates, SO_2 emission rates, or both as of January 2010

Characteristics	Coal plants without NOx controls in place	Coal plants without SO2 controls in place	Coal plants without NOx and without SO2 controls in place	Total
Number of units	4	63	8	75
Total installed capacity (ICAP)	212	13,543	633	14,388

Table 3-40 shows attributes of coal plants with controls in place for both NO_x and SO_2 emissions compared to units that lack controls for either NO_x emissions, SO_2 emissions, or both. Of those 14,388 MW associated with plants that lack at least one control technology, 4,835 MW, or 34 percent, are located within MAAC, while 9,552 MW, or 66 percent are located in the rest of the RTO. About 12,105 MW, or 84 percent, are associated with plants online for more than 40 years and 5,359 MW, or 37 percent, are associated with coal plants less than 200 MW in size. Additionally, of the 14,388 MW of installed capacity lacking at least one control technology, 1,451 MW are associated with plants that did not fully recover avoidable costs in 2010.

55 FRR committed units are excluded from this analysis since they receive compensation out of PJM Markets.

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Table 3-40 Attributes of units lacking controls for either NO_x emission rates, SO_2 emission rates, or both as of January, 2010

Characteristics	Coal plants with both NOx and SO2 controls in place	Coal plants lacking controls for either NOx or SO2
Units	89	75
Total installed capacity (ICAP)	30,189	14,388
ICAP within MAAC	14,163	4,835
ICAP in rest of RTO	16,026	9,552
ICAP associated with plants older than 40 years	13,811	12,105
ICAP associated with small coal plants (200 MW or less)	4,322	5,359
ICAP associated with medium-sized coal plants (between 200 and 500 MW)	5,457	3,603
ICAP associated with large coal plants (500 MW or greater)	19,910	5,426
ICAP associated with 100 percent recovery of avoidable costs	24,872	12,936
ICAP associated with less than 100 percent recovery of avoidable costs	5,318	1,451

The MMU estimated the increase in avoidable costs, including APIR, associated with project investments for units in Table 3-40 lacking controls for NO_x emissions, SO_2 emissions, or both, as a base case. A second case was developed to represent stricter NO_x emission controls, in which some units with some earlier or less effective forms of environmental controls are required to invest in Selective Catalytic Reduction (SCR) technologies for NO_x control. In both cases, the MMU estimated an associated avoidable project investment recovery (APIR) rate using a 0.450 annual capital recovery rate factor (CRF), since it is assumed to be mandatory environmental capital expenditure, and estimated for each unit, the increase in energy or capacity revenues required for project investment recovery in 2010.[56] Figure 3-12 shows the amount of installed capacity associated with various levels of required increases in total revenues. Table 3-41 summarizes the information in Figure 3-12. Approximately 14,300 MW in the base case and 19,100 MW in the second case require an increase in energy or capacity revenue in order to cover projected avoidable costs. Approximately 13,000 MW in the base case and 14,300 MW in the second case require at least $400/MW-day or $152,880/MW-year; approximately 5,500 MW in the base case and 9,900 MW in the sensitivity require at least $500/MW-day or $184,310/MW-year.

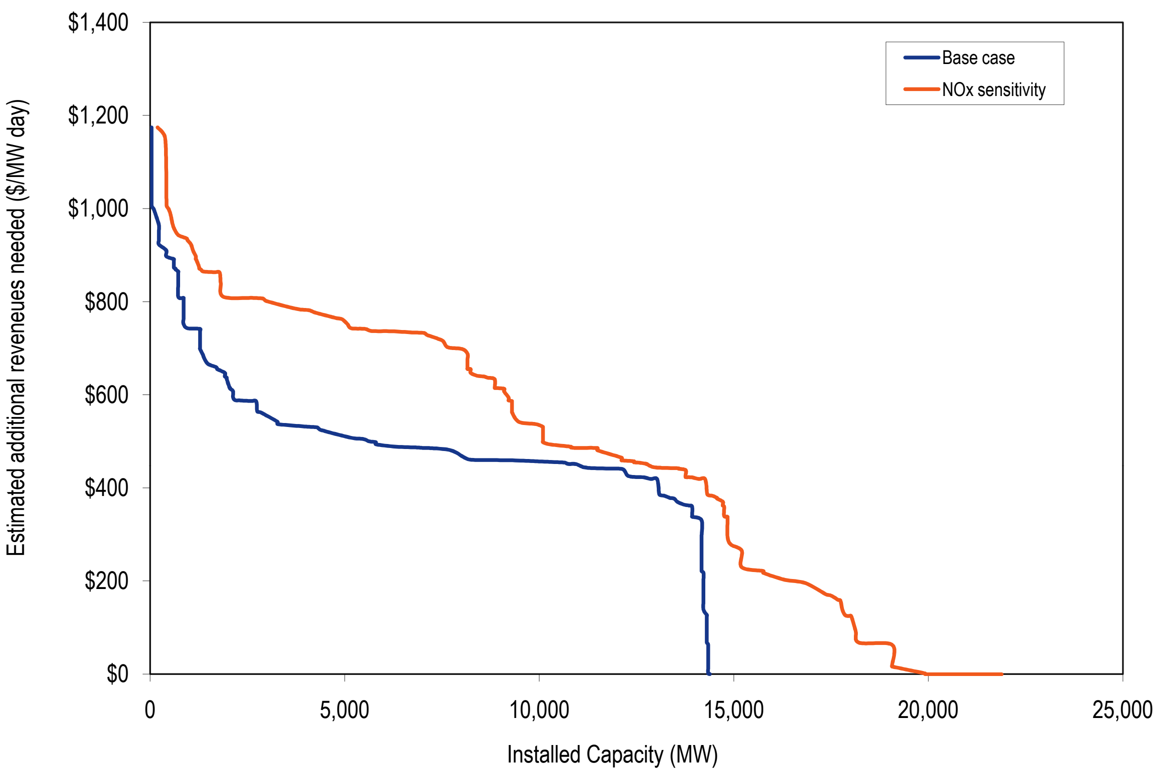
This analysis is not intended to forecast future energy or capacity prices or avoidable costs. It represents the various levels of shortfall, based on actual energy and capacity revenues in 2010, which would have been incurred if project investments associated with environmental controls were to have been recovered in 2010, assuming unit specific emission requirements and the recovery by the mandatory CRF defined in the PJM Tariff for avoidable project investment recovery. Actual owners in PJM may choose to account for project recovery internally over a longer project life than the applicable CRF allows and may therefore offer in to RPM below the calculated avoidable cost based offer cap. In this case, units may be achieving target returns yet show under recovery of calculated avoidable cost rates. If under recovery of avoidable costs including project investment rates is expected after energy and capacity revenues are considered, the decision to deactivate the unit rather than to make significant investments in environmental controls would be an economically rational decision.

56 Attachment DD, section 6.8 (a) of the PJM Tariff defines the applicable CRF used in avoidable cost calculations.

Table 3-41 Total installed capacity associated with estimated levels of additional revenue needed for recovery of project investment associated with environmental controls

Ranges of additional revenue needed ($/MW-day)	Installed capacity (ICAP) associated base case	Cumulative installed capacity (ICAP) associated with base case	Installed capacity (ICAP) associated with NOx sensitivity	Cumulative installed capacity (ICAP) associated with NOx sensitivity
$0	43	43	2,816	2,816
$1 - $99	121	164	1,050	3,867
$100 - $199	50	214	1,706	5,573
$200 - $299	0	214	1,560	7,133
$300 - $399	1,143	1,357	489	7,621
$400 - $499	7,554	8,911	4,352	11,973
$500 - $599	3,420	12,331	815	12,788
$600 - $799	1,336	13,666	6,107	18,894
$800 or greater	721	14,388	2,990	21,884

Figure 3-12 Total installed capacity associated with estimated levels of additional revenue needed for full project investment recovery in 2010



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Existing and Planned Generation

Installed Capacity and Fuel Mix

In calendar year 2010, PJM installed capacity declined from 167,853.8 MW on January 1 to 166,512.1 MW on December 31, a decrease of 1,341.7 MW or 0.8 percent, and the fuel mix also shifted slightly. Installed capacity includes net capacity imports and exports and can vary on a daily basis.

Installed Capacity

On January 1, 2010, PJM installed capacity was 167,853.8 MW (Table 3-42).[57] Over the next five months, unit retirements, facility reratings plus import and export shifts resulted in a decrease in installed capacity to 167,400.7 MW on May 31, 2010.[58]

Table 3-42 PJM installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2010

	1-Jan-10		31-May-10		1-Jun-10		31-Dec-10	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	68,382.1	40.7%	68,155.5	40.7%	67,991.1	40.8%	68,007.0	40.8%
Gas	49,238.8	29.3%	48,991.4	29.3%	48,424.5	29.0%	48,513.8	29.1%
Hydroelectric	7,921.9	4.7%	7,923.5	4.7%	7,923.5	4.8%	7,954.5	4.8%
Nuclear	30,611.9	18.2%	30,599.3	18.3%	30,619.0	18.4%	30,552.2	18.3%
Oil	10,700.1	6.4%	10,649.4	6.4%	10,645.5	6.4%	10,193.6	6.1%
Solid waste	672.1	0.4%	672.1	0.4%	672.1	0.4%	680.1	0.4%
Wind	326.9	0.2%	409.5	0.2%	481.1	0.3%	610.9	0.4%
Total	167,853.8	100.0%	167,400.7	100.0%	166,756.8	100.0%	166,512.1	100.0%

At the beginning of the new planning year on June 1, 2010, installed capacity decreased by 643.9 MW to 166,756.8, a 0.4 percent decrease in total PJM capacity over the May 31 level.

On December 31, 2010, PJM installed capacity was 166,512.1 MW.[59]

Energy Production by Fuel Source

In 2010, coal units provided 49.3 percent, nuclear units 34.6 percent, gas 11.7 percent, oil 0.4 percent, hydroelectric 2.0 percent, waste 0.7 percent and wind 1.2 percent of total generation (Table 3-43). Compared to calendar year 2009, generation from coal units increased 3.5 percent, and generation from nuclear units increased 2.1 percent. Generation from natural gas units increased 28.4 percent, and from oil units 106.8 percent.

57 Percents shown in Table 3-42 and Table 3-43 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables

58 The capacity described in this section is the summer installed capacity rating of all PJM generation capacity resources, as entered into the eRPM system, regardless of whether the capacity cleared in the RPM auctions.

59 Wind-based resources accounted for 610.9 MW of installed capacity in PJM on December 31, 2010. This value represents approximately 13 percent of wind nameplate capability in PJM. PJM administratively reduces the capabilities of all wind generators to 13 percent of nameplate capacity when determining the system installed capacity because wind resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind resources will be calculated using actual data in place of the 87 percent reduction. There are additional wind resources not reflected in this total because they are energy only resources and do not participate in the PJM Capacity Market. The wind capacity in this section is the full nameplate capacity, unless otherwise noted.

Table 3-43 PJM generation (By fuel source (GWh)): Calendar year 2010[60]

	2009 GWh	Percent	2010 GWh	Percent	Change in Output
Coal	349,818.2	50.5%	362,075.4	49.3%	3.5%
Nuclear	249,392.3	36.0%	254,534.1	34.6%	2.1%
Gas	67,218.9	9.7%	86,265.5	11.7%	28.3%
Natural Gas	65,848.2	9.5%	84,570.1	11.5%	28.4%
Landfill Gas	1,368.5	0.2%	1,695.0	0.2%	23.9%
Biomass Gas	2.2	0.0%	0.5	0.0%	(78.9%)
Hydroelectric	14,123.0	2.0%	14,384.4	2.0%	1.9%
Wind	5,489.7	0.8%	8,812.8	1.2%	60.5%
Waste	5,664.7	0.8%	5,356.6	0.7%	(5.4%)
Solid Waste	4,147.0	0.6%	4,157.5	0.6%	0.3%
Miscellaneous	1,517.7	0.2%	1,199.1	0.2%	(21.0%)
Oil	1,568.1	0.2%	3,243.2	0.4%	106.8%
Heavy Oil	1,383.7	0.2%	2,748.3	0.4%	98.6%
Light Oil	162.9	0.0%	446.9	0.1%	174.3%
Diesel	14.4	0.0%	32.3	0.0%	123.9%
Kerosene	7.1	0.0%	15.7	0.0%	120.8%
Jet Oil	0.0	0.0%	0.1	0.0%	51.9%
Solar	3.5	0.0%	5.7	0.0%	64.7%
Battery	0.3	0.0%	0.3	0.0%	18.9%
Total	693,278.7	100.0%	734,678.2	100.0%	6.0%

Planned Generation Additions

Net revenues provide incentives to build new generation to serve PJM markets. While these incentives operate with a significant lag time and are based on expectations of future net revenue, the amount of planned new generation in PJM reflects investors' perception of the incentives provided by the combination of revenues from the PJM Energy, Capacity and Ancillary Service Markets. At the end of 2010, 76,415 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of approximately 167,000 MW in 2010. Although it is clear that not all generation in the queues will be built, PJM has added capacity annually since 2000 (Table 3-44).[61]

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

61 The capacity additions are new MW by year, including full nameplate capacity of solar and wind facilities and are not net of retirements or deratings.

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Table 3-44 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 to 2010[62]

	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

PJM Generation Queues

Generation request queues are groups of proposed projects. Queue A was open from February 1997 through January 1998; Queue B was open from February 1998 through January 1999; Queue C was open from February 1999 through July 1999 and Queue D opened in August 1999. After Queue D, a new queue was opened every six months. Queue W was active through January 31, 2011.

Capacity in generation request queues for the nine year period beginning in 2010 and ending in 2018 decreased by 310 MW from 76,725 MW in 2009 to 76,415 MW in 2010, or zero percent (Table 3-45).[63] Queued capacity scheduled for service in 2010 decreased from 22,734 MW to 11,585 MW, or 49 percent. Queued capacity scheduled for service in 2011 decreased from 15,873 MW to 13,793 MW, or 13 percent. The 76,415 MW includes generation with scheduled in-service dates in 2010 and units still active in the queue with in-service dates scheduled before 2010, listed at nameplate capacity, although these units are not yet in service.

62 The capacity described in this table refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.
63 See the *2009 State of the Market Report for PJM* (March 11, 2010), pp. 179-180, for the queues in 2009.

Table 3-45 Queue comparison (MW): Calendar years 2010 vs. 2009

	MW in the Queue 2009	MW in the Queue 2010	Year-to-Year Change (MW)	Year-to-Year Change
2010	22,734	11,585	(11,149)	(49%)
2011	15,873	13,793	(2,080)	(13%)
2012	11,053	13,261	2,207	20%
2013	6,350	11,244	4,894	77%
2014	13,439	13,888	449	3%
2015	3,091	5,960	2,869	93%
2016	950	1,350	400	42%
2017	1,640	2,140	500	30%
2018	1,594	3,194	1,600	100%
Total	76,725	76,415	(310)	(0%)

Table 3-46 shows the amount of capacity active, in-service, under construction or withdrawn for each queue since the beginning of the Regional Transmission Expansion Plan (RTEP) Process and the total amount of capacity that had been included in each queue.[64]

64 Projects listed as active have been entered in the queue and the next phase can be under construction, in-service or withdrawn. At any time, the total number of projects in the queues is the sum of active projects and under-construction projects.

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Table 3-46 Capacity in PJM queues (MW): At December 31, 2010[65, 66]

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	17,637	18,432
F Expired 31-Jan-01	0	52	0	3,093	3,145
G Expired 31-Jul-01	0	486	630	21,679	22,795
H Expired 31-Jan-02	0	703	0	8,422	9,124
I Expired 31-Jul-02	0	103	0	4,904	5,007
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	4,128	4,632
N Expired 31-Jan-05	1,377	2,143	173	6,713	10,407
O Expired 31-Jul-05	1,678	1,346	411	4,137	7,572
P Expired 31-Jan-06	853	1,798	1,132	4,918	8,701
Q Expired 31-Jul-06	1,759	963	3,329	8,563	14,614
R Expired 31-Jan-07	5,312	649	820	16,234	23,015
S Expired 31-Jul-07	3,137	1,549	1,233	14,975	20,893
T Expired 31-Jan-08	11,411	607	754	14,845	27,617
U Expired 31-Jan-09	9,329	196	592	24,696	34,812
V Expired 31-Jan-10	13,076	64	134	3,704	16,979
W Expires 31-Jan-11	19,062	0	32	3,685	22,780
Total	67,014	26,533	9,401	214,459	317,408

Data presented in Table 3-46 show that through 2010, 48.0 percent of total in-service capacity from all the queues was from Queues A and B and an additional 8.2 percent was from Queues C, D and E.[67] As of December 31, 2010, 31.8 percent of the capacity in Queues A and B has been placed in service, and 8.4 percent of all queued capacity has been placed in service.

The data presented in Table 3-47 show that for successful projects there is an average time of 756 days between entering a queue and the in-service date. The data also show that for withdrawn projects, there is an average time of 443 days between entering a queue and completion or exiting. For each status, there is substantial variability around the average results.

65 The *2010 State of the Market Report for PJM* contains all projects in the queue including reratings of existing generating units and energy only resources.
66 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.
67 The data for Queue W include projects through December 31, 2010.

Table 3-47 Average project queue times (days): At December 31, 2010

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	756	613	0	4,420
In-Service	773	641	0	3,287
Suspended	2,301	736	890	3,849
Under Construction	1,155	900	0	4,370
Withdrawn	443	528	0	3,186

Distribution of Units in the Queues

A more detailed examination of the queue data permits some additional conclusions. The geographic distribution of generation in the queues shows that new capacity is being added disproportionately in the west, and includes a substantial amount of wind capacity.

Table 3-48 shows the RTEP projects under construction or active as of December 31, 2010, by unit type and control zone. Most of the steam projects (84.4 percent of the MW) and most of the wind projects (94.5 percent of the MW) are outside the Eastern MAAC (EMAAC)[68] and Southwestern MAAC (SWMAAC)[69] locational deliverability areas (LDAs).[70] Of the total capacity additions, only 16,084 MW or 21.0 percent are projected to be in EMAAC, while 2,572 MW or 3.4 percent are projected to be constructed in SWMAAC. Of total capacity additions, only 23,330 MW, or 30.5 percent of capacity, is being added inside MAAC zones. Overall, 75.6 percent of capacity is being added outside EMAAC and SWMAAC, and 69.5 percent of capacity is being added outside EMAAC, SWMAAC and WMAAC.

Wind projects account for approximately 38,301 MW of capacity or 50.1 percent of the capacity in the queues and combined-cycle projects account for 16,541 MW of capacity or 21.6 percent of the capacity in the queues.[71] Wind projects account for 3,423 MW of capacity in MAAC LDAs, or 14.7 percent. While there are no wind projects in the SWMAAC LDA, in the EMAAC LDA wind projects account for 2,079 MW of capacity, or 12.9 percent.

68 EMAAC consists of the AECO, DPL, JCPL, PECO and PSEG Control Zones.
69 SWMAAC consists of the BGE and Pepco Control Zones.
70 See the *2010 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for a map of PJM LDAs.
71 Since wind resources cannot be dispatched on demand, PJM rules previously required that the unforced capacity of wind resources be derated to 20 percent until actual generation data are available. Beginning with Queue U, PJM derates wind resources to 13 percent. Based on the derating of 38,301 MW of wind resources, the 76,415 MW currently active in the queues would be reduced to 43,093 MW.

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Table 3-48 Capacity additions in active or under-construction queues by control zone (MW): At December 31, 2010

	Battery	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Total
AECO	0	1,255	766	17	0	0	1,117	665	1,414	5,233
AEP	0	1,845	593	7	170	84	142	2,219	12,715	17,776
AP	32	958	0	6	78	0	463	772	1,340	3,649
BGE	0	29	0	30	0	1,640	0	132	0	1,831
ComEd	20	1,680	1,038	65	23	750	39	1,366	17,172	22,152
DAY	0	0	0	2	112	0	40	12	1,740	1,906
DLCO	0	0	0	0	0	91	0	0	0	91
DPL	0	929	109	0	0	0	244	43	645	1,969
Dominion	0	2,685	595	13	30	1,839	137	302	1,910	7,511
JCPL	0	2,605	27	33	0	0	938	0	0	3,603
Met-Ed	23	650	9	31	0	24	152	10	0	899
PECO	0	663	37	5	0	510	41	0	0	1,257
PENELEC	0	0	65	23	0	0	142	90	883	1,204
Pepco	0	725	0	6	0	0	10	0	0	741
PPL	20	0	139	10	143	1,600	165	33	461	2,571
PSEG	0	2,518	1,077	0	0	79	284	45	20	4,022
Total	95	16,541	4,454	250	555	6,617	3,913	5,689	38,301	76,415

There are potentially significant implications for future congestion, the role of firm and interruptible gas supply and natural gas supply infrastructure, if older steam units in the EMAAC and SWMAAC LDAs are replaced by units burning natural gas. Table 3-49 shows that in the EMAAC LDA, gas burning unit types account for 62.1 percent of the capacity additions. Steam additions (coal) account for about 4.6 percent of the MW and solar projects account for 16.3 percent of the MW in the queue for the EMAAC LDA. Nuclear and gas capacity comprise 93.1 percent of the MW capacity additions in the SWMAAC LDA. The wind capacity in this section is reported at nameplate capacity and not reduced to 13 percent of nameplate.

Table 3-49 Capacity additions in active or under-construction queues by LDA (MW): At December 31, 2010[72]

	Battery	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Total
EMAAC	0	7,969	2,016	56	0	589	2,623	753	2,079	16,084
SWMAAC	0	754	0	36	0	1,640	10	132	0	2,572
WMAAC	43	650	213	65	143	1,624	459	133	1,344	4,673
Non-MAAC	52	7,168	2,226	94	413	2,764	820	4,671	34,878	53,085
Total	95	16,541	4,454	250	555	6,617	3,913	5,689	38,301	76,415

72 WMAAC consists of the Met-Ed, PENELEC, and PPL Control Zones.

Table 3-50 shows existing generation by unit type and control zone. Existing steam (mainly coal and residual oil) and nuclear capacity is distributed across control zones.

A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue (Table 3-48) 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.

Table 3-50 Existing PJM capacity 2010[73] (By zone and unit type (MW))

	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	516	10,742
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	1,358	52	0	0	3	3,572	0	4,985
DLCO	0	101	188	0	6	1,777	0	1,239	0	3,311
DPL	0	376	2,496	96	0	0	0	1,919	0	4,887
Dominion	0	3,173	3,853	161	3,558	3,494	0	8,484	0	22,723
External	0	974	1,574	0	70	439	0	9,470	185	12,712
JCPL	0	1,192	1,423	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	517	8,181
Pepco	0	230	1,325	12	0	0	0	4,706	0	6,273
PPL	0	956	1,362	63	571	2,375	0	5,532	217	11,075
PSEG	0	2,921	2,860	0	5	3,553	58	2,535	0	11,932
Total	1	21,772	31,392	711	7,890	31,753	64	88,048	4,440	186,071

Table 3-51 shows the age of PJM generators by unit type. As most steam units in PJM are from 30 to 50 years old, it appears likely that significant and disproportionate retirements of steam units will occur within the next 10 to 20 years, particularly if stricter environmental regulations make steam units more costly to operate. While steam units comprise 47.3 percent of all current MW, steam units 40 years of age and older comprise 84.6 percent of all MW 40 years of age and older and 92.5 percent of such MW if hydroelectric is excluded from the total. Approximately 7,458 MW of steam units 40 years of age and older are located in EMAAC and SWMAAC, or 19.1 percent of all steam units 40 years and older.

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

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Table 3-51 PJM capacity (MW) by age

Age (years)	Battery	CC	CT	Diesel	Hydroelectric	Nuclear	Steam	Solar	Wind	Total
Less than 10	1	17,307	18,684	377	10	0	1,372	64	4,440	42,254
10 to 20	0	4,206	4,448	126	49	0	6,081	0	0	14,910
20 to 30	0	158	490	38	3,509	16,186	9,807	0	0	30,187
30 to 40	0	101	5,269	39	435	14,953	31,657	0	0	52,454
40 to 50	0	0	2,501	128	2,480	615	24,289	0	0	30,012
50 to 60	0	0	0	4	348	0	13,338	0	0	13,690
60 to 70	0	0	0	0	32	0	1,356	0	0	1,388
70 to 80	0	0	0	0	314	0	149	0	0	463
80 to 90	0	0	0	0	486	0	0	0	0	486
90 to 100	0	0	0	0	200	0	0	0	0	200
100 and over	0	0	0	0	27	0	0	0	0	27
Total	1	21,772	31,392	711	7,890	31,753	88,048	64	4,440	186,071

Table 3-52 shows the effect that the new generation in the queues would have on the existing generation mix, assuming that all non-hydroelectric generators in excess of 40 years of age retire by 2018. The expected role of gas-fired generation depends largely on projects in the queues and continued retirement of coal-fired generation. In 2018, CC and CT generators would account for 54.4 percent of EMAAC generation, an increase of 10.0 percentage points from 2010 levels. Accounting for the fact that about 940 MW of steam units over 40 years old are gas-fired, the result would be an increase in the proportion of gas-fired capacity in EMAAC from about 47 percent to about 54 percent. The proportion of gas-fired capacity in EMAAC would increase to 56.7 percent if the derating to 13 percent of nameplate for wind capacity is reflected, meaning that the effective capacity additions are 14,276 MW.

Without the planned coal-fired capability in EMAAC, new gas-fired capability would represent 65.1 percent of all new capability in EMAAC and 73.8 percent when the derating of wind capacity is reflected.

There is a planned addition of 1,640 MW of nuclear capacity in SWMAAC. Without the planned nuclear capability in SWMAAC, new gas-fired capability would represent 80.8 percent of all new capability in the SWMAAC. In 2018, this would mean that CC and CT generators would comprise 29.1 percent of total capability in SWMAAC.

In Non-MAAC zones, if older units retire, a substantial amount of coal-fired generation would be replaced by wind generation if the units in the generation queues are constructed.[74] In these zones, 92.2 percent of all generation 40 years or older is steam (primarily coal).With the retirement of these units in 2018, wind farms would comprise 27.2 percent of total capacity in Non-MAAC zones, if all queued capacity is built.

74 Non-MAAC zones consist of the AEP, AP, ComEd, DAY, DLCO, and Dominion Control Zones.

Table 3-52 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2018[75]

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%	0	1	0.0%
	Combined Cycle	0	0.0%	7,041	20.5%	7,969	15,011	33.6%
	Combustion Turbine	955	12.2%	8,224	23.9%	2,016	9,284	20.8%
	Diesel	49	0.6%	150	0.4%	56	156	0.4%
	Hydroelectric	2,042	26.0%	2,047	6.0%	0	2,047	4.6%
	Nuclear	615	7.8%	8,676	25.2%	589	8,651	19.4%
	Solar	0	0.0%	61	0.2%	2,623	2,685	6.0%
	Steam	4,192	53.4%	8,164	23.8%	753	4,725	10.6%
	Wind	0	0.0%	8	0.0%	2,079	2,087	4.7%
	EMAAC Total	7,853	100.0%	34,372	100.0%	16,084	44,646	100.0%
SWMAAC	Combined Cycle	0	0.0%	230	1.9%	754	984	9.3%
	Combustion Turbine	540	14.2%	2,165	18.3%	0	1,625	15.3%
	Diesel	0	0.0%	19	0.2%	36	55	0.5%
	Nuclear	0	0.0%	1,705	14.4%	1,640	3,345	31.5%
	Solar	0	0.0%	0	0.0%	10	10	0.1%
	Steam	3,267	85.8%	7,732	65.2%	132	4,597	43.3%
	SWMAAC Total	3,807	100.0%	11,851	100.0%	2,572	10,617	100.0%
WMAAC	Battery	0	0.0%	0	0.0%	43	43	0.2%
	Combined Cycle	0	0.0%	2,956	12.6%	650	3,606	16.6%
	Combustion Turbine	296	4.3%	2,054	8.8%	213	1,971	9.1%
	Diesel	35	0.5%	125	0.5%	65	154	0.7%
	Hydroelectric	444	6.5%	1,096	4.7%	143	1,238	5.7%
	Nuclear	0	0.0%	3,180	13.6%	1,624	4,804	22.2%
	Solar	0	0.0%	0	0.0%	459	459	2.1%
	Steam	6,042	88.6%	13,256	56.6%	133	7,346	33.9%
	Wind	0	0.0%	734	3.1%	1,344	2,078	9.6%
	WMAAC Total	6,817	100.0%	23,399	100.0%	4,673	21,657	100.0%
Non-MAAC	Battery	0	0.0%	0	0.0%	52	52	0.0%
	Combined Cycle	0	0.0%	11,545	9.9%	7,168	18,713	13.2%
	Combustion Turbine	709	2.6%	18,949	16.3%	2,226	20,466	14.4%
	Diesel	48	0.2%	418	0.4%	94	463	0.3%
	Hydroelectric	1,401	5.0%	4,747	4.1%	413	3,758	2.7%
	Nuclear	0	0.0%	18,192	15.6%	2,764	20,956	14.8%
	Solar	0	0.0%	3	0.0%	820	823	0.6%
	Steam	25,632	92.2%	58,896	50.6%	4,671	37,935	26.8%
	Wind	0	0.0%	3,699	3.2%	34,878	38,576	27.2%
	Non-MAAC Total	27,790	100.0%	116,449	100.0%	53,085	141,744	100.0%
All Areas	Total	46,267		186,071		76,415	218,663	

75 Percents shown in Table 3-52 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

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Characteristics of Wind Units

Table 3-53 shows the capacity factor of wind units in PJM. In 2010, the capacity factor of wind units in PJM was 27.4 percent. Wind units that were capacity resources had a capacity factor of 27.9 percent and an installed capacity of 3,371 MW. Wind units that were classified as energy only had a capacity factor of 25.0 percent and an installed capacity of 1,069 MW. Much of this wind capacity does not appear in the Capacity Market, as wind capacity in RPM is derated to 13 percent of nameplate capacity, and energy only resources are not included.

Table 3-53 Capacity factor of wind units in PJM, Calendar year 2010

Type of Resource	Capacity Factor	Total Hours	Installed Capacity (MW)
Energy-Only Resource	25.0%	102,819	1,069
Capacity Resource	27.9%	292,651	3,371
All Units	27.4%	395,470	4,440

Beginning June 1, 2009, PJM rules allowed units to submit negative price offers. Table 3-54 presents data on negative offers by wind units. Wind units were the only unit types to make negative offers. On average, 664.6 MW of wind were offered daily at a negative price. Wind units with negative offers were marginal in 1,287 separate five minute intervals, or 1.22 percent of all intervals. On average, 1,541.0 MW of wind were offered daily. Overall, wind units were marginal in 1,682 separate five minute intervals, or 1.60 percent of all intervals.

Table 3-54 Wind resources in real time offering at a negative price in PJM, Calendar year 2010

	Average MW Offered	Intervals Marginal	Percent of Intervals
At Negative Price	664.6	1,287	1.22%
All Wind	1,541.0	1,682	1.60%

Wind output differs from month to month, based on weather conditions. Figure 3-13 shows the average hourly real time generation of wind units in PJM, by month. On average, wind generation was highest in October, November, and December, and lowest in June, July, and August. The highest average hour, 1,735.2 MW, occurred in December, and the lowest average hour, 257.2 MW, occurred in July. Wind output in PJM is generally higher in off-peak hours and lower in on-peak hours.

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Figure 3-13 Average hourly real-time generation of wind units in PJM, Calendar year 2010

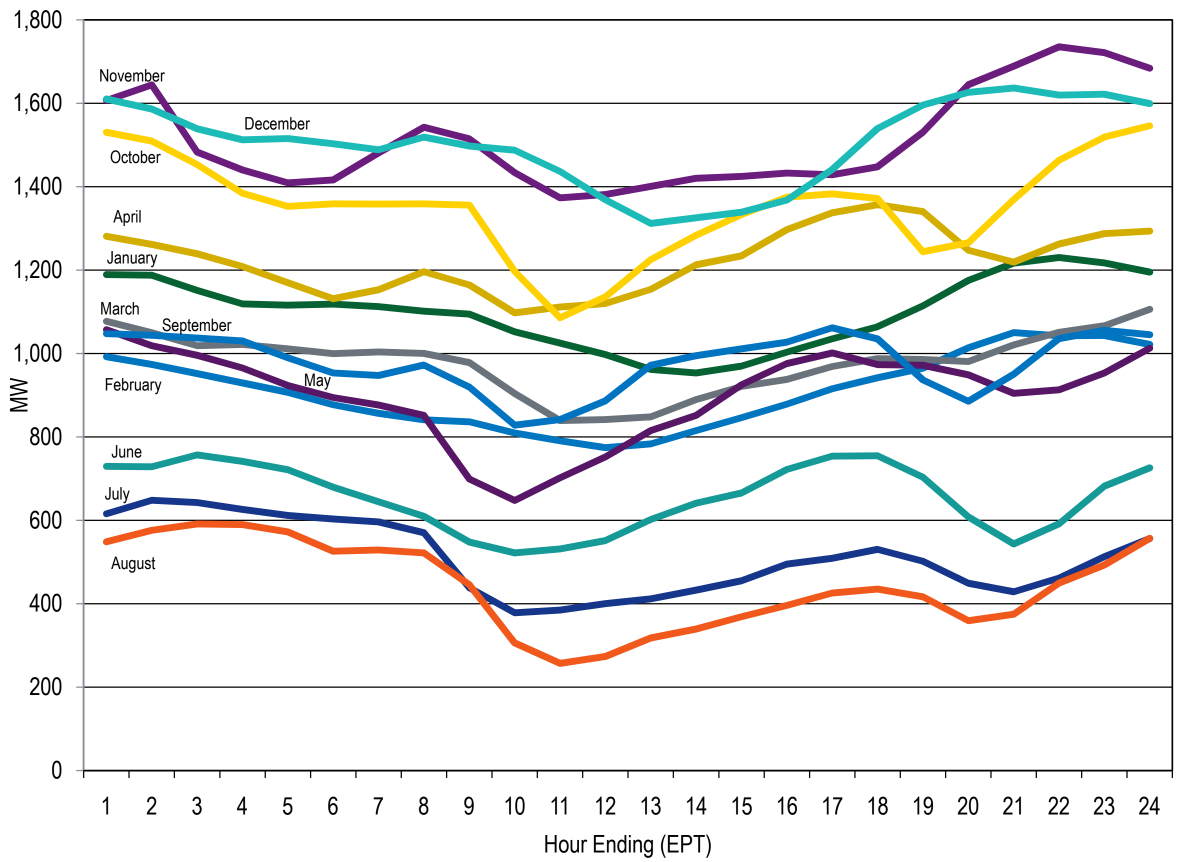

Table 3-55 shows the generation and capacity factor of wind units in each month of 2010. Capacity factors of wind units vary substantially by month. The highest capacity factor of wind units was 35.7 percent in January, and the lowest capacity factor was 12.1 percent in August, a difference of 23.6 percentage points. Overall, the capacity factor in winter months was higher than that of summer months. New wind farms came on line throughout 2010, and are included in this analysis as they were added.

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Table 3-55 Capacity factor of wind units in PJM by month, Calendar year 2010[76]

Month	Generation (MWh)	Capacity Factor
January	818,423.9	35.7%
February	612,044.4	28.6%
March	727,819.1	29.5%
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%

Table 3-56 shows the seasonal capacity factor of wind units in PJM, as well as the seasonal average hourly wind generation and seasonal average hourly load for on peak and off peak periods. The on peak winter capacity factor was 31.4 percent while the on peak summer capacity factor was 17.8 percent. The off peak winter capacity factor was 2.2 percentage points higher than during the on peak period, while the off peak summer capacity factor was 2.4 percentage points higher than during the on peak period.

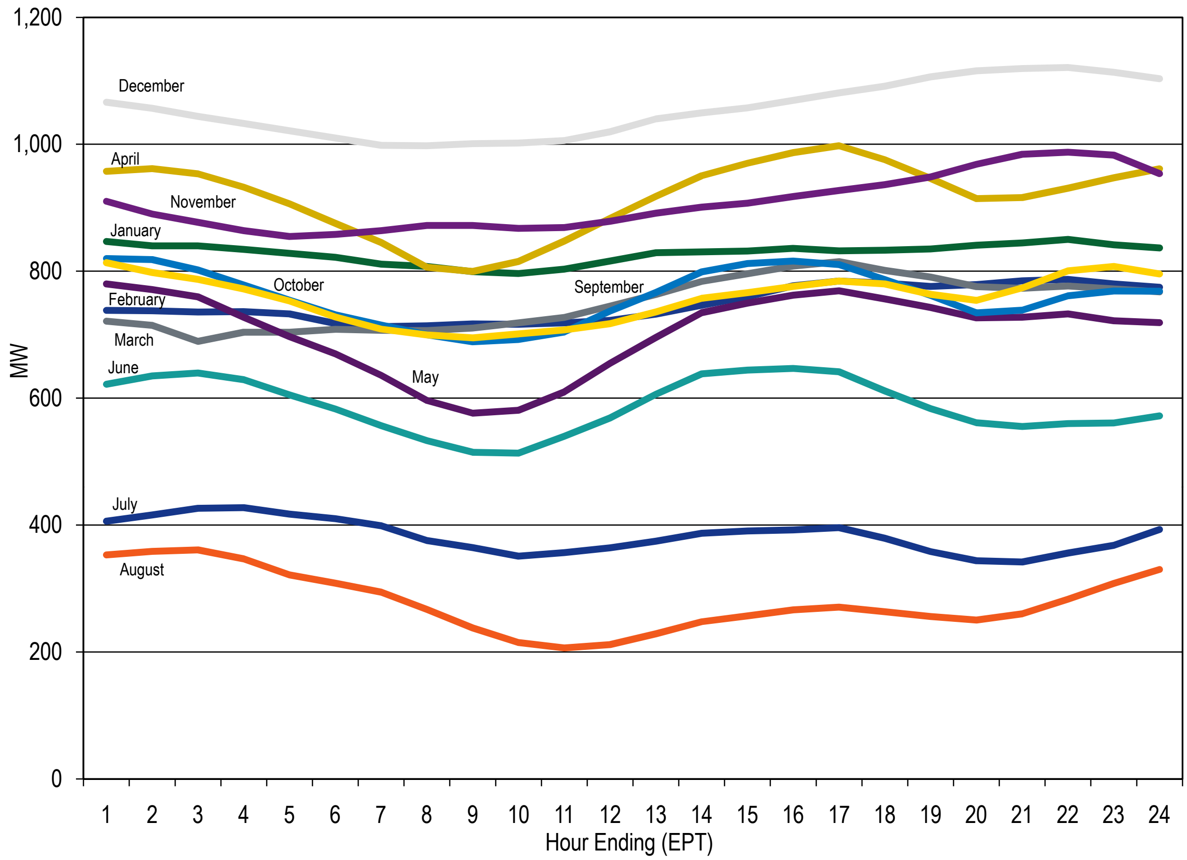
Table 3-56 Peak and off-peak seasonal capacity factor, average wind generation (MWh), and PJM load (MWh): Calendar year 2010

		Winter	Spring	Summer	Fall	Annual
Peak	Capacity Factor	31.4%	34.5%	17.8%	32.3%	26.2%
	Average Wind Generation	1,093.1	1,188.6	650.8	1,357.7	961.6
	Average Load	88,262.4	73,871.4	95,159.1	76,305.2	87,919.6
Off-Peak	Capacity Factor	33.6%	36.5%	20.2%	35.5%	28.5%
	Average Wind Generation	1,161.1	1,257.9	736.7	1,493.0	1,045.3
	Average Load	77,105.8	59,326.6	74,018.2	63,372.1	72,056.0

Wind units that are capacity resources are required, like all capacity resources, to offer the energy associated with their cleared capacity in the Day-Ahead Energy Market. In addition, the owners of wind resources have the flexibility to offer the non-capacity related wind energy at their discretion. Figure 3-14 shows the average hourly day-ahead time generation of wind units in PJM, by month.

76 Capacity factor shown in Table 3-55 is based on all hours in 2010.

Figure 3-14 Average hourly day-ahead generation of wind units in PJM, Calendar year 2010



Output from wind turbines displaces output from other generation types. This displacement affects the output of marginal units in PJM. The magnitude and type of effect on marginal unit output will depend on the level of the wind turbine output, its location, the time of the output and its duration. One measure of this displacement is based on the mix of marginal units when wind is producing output. Figure 3-15 shows the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real time wind generation through 2010. This provides, on an hourly average basis, potentially displaced marginal unit MW by fuel type in 2010. Wind output varies daily, and on average is about 248 MW lower from peak average output (2300 EPT) to lowest average output (1000 EPT). This is not an exact measure because it is not based on a redispatch of the system without wind resources. One result is that wind appears as the displaced fuel at times when wind resources were on the margin. In effect this means that there was no displacement for those hours.

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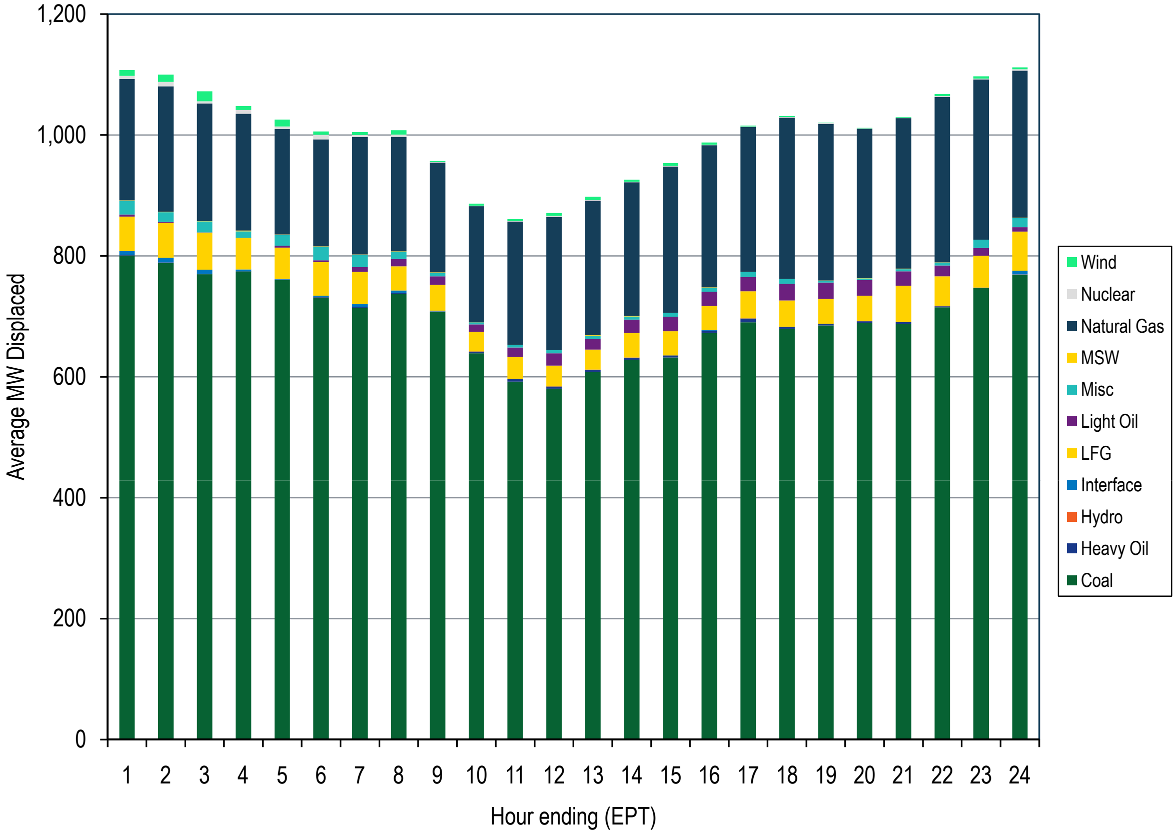
Figure 3-15 Marginal fuel at time of wind generation in PJM, Calendar year 2010



Environmental Regulatory Impacts

Emission Allowances Trading

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities. Under RGGI, each state has its own CO_2 Budget Trading Program that has been implemented through state regulations based on a common set of reciprocal rules that allow the ten individual state programs to function as a single regional compliance market for CO_2 allowances. Starting in 2009, the RGGI rules require that qualifying power generators hold allowances sufficient to cover their total CO_2 emissions over each three year compliance period. Qualifying power generators can purchase their allowances for the compliance period directly from the quarterly auctions held before and during the compliance period, or from holders of allowances from previous auctions. Additional allowances can be made available via RGGI state approved qualifying offset projects, although offset allowances can make up only a limited portion of a regulated power plant's compliance obligation. The current maximum allowable contribution of CO_2 offset allowances to a power generation facility's compliance obligation is 3.3 percent of emissions per compliance period. The cap on the contribution of CO_2 offset allowances can be raised to 5 percent or to 10 percent if the calendar year average price of CO_2 allowances exceeds annual Consumer Price Index (CPI) adjusted stage 1 ($7) or stage 2 ($10) trigger prices, respectively.

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Since September 25, 2008, a total of ten auctions have been held for 2009-2011 compliance period allowances, and eight auctions have been held for 2012-2014 compliance period allowances. Table 3-57 shows the RGGI CO_2 auction clearing prices and quantities for the ten 2009-2011 compliance period auctions held as of the end of calendar year 2010. The weighted average allowance auction price for the 2009-2011 compliance period auctions held from September 2008 through the 2010 calendar year was $2.40. Auction prices within the 2010 calendar year for the 2009-2011 compliance period peaked at $2.07 in March 10, 2010. Subsequent 2010 calendar year auctions for the 2009-2011 compliance period saw the clearing price fall, with the last auctions of the year, both the September 10, 2010 auction and the December 1, 2010 auction, providing the lowest auction price of the year at $1.86 an allowance. This price, $1.86 per allowance, is the current price floor for RGGI auctions, as determined in the first RGGI auction. The average 2010 spot price for a 2009-2011 compliance period allowance was $2.00 per ton. Monthly average spot prices for the 2009-2011 compliance period varied during the year, peaking in January at $2.17 per ton and declining to $1.88 per ton by December, slightly above the auction's price floor of $1.86 on December 1, 2010.

Figure 3-16 shows average, daily settled prices for NOx and SO_2 emission within PJM. In 2010, seasonal NOx prices were 61.6 percent lower than in 2009. SO_2 prices were 70.1 percent lower in 2010 than in 2009. Figure 3-16 also shows the average, daily settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances. RGGI allowances are required by generation in participating RGGI states. This includes PJM generation located in Delaware, Maryland, and New Jersey.

Figure 3-16 Spot average emission price comparison: Calendar years 2009 to 2010

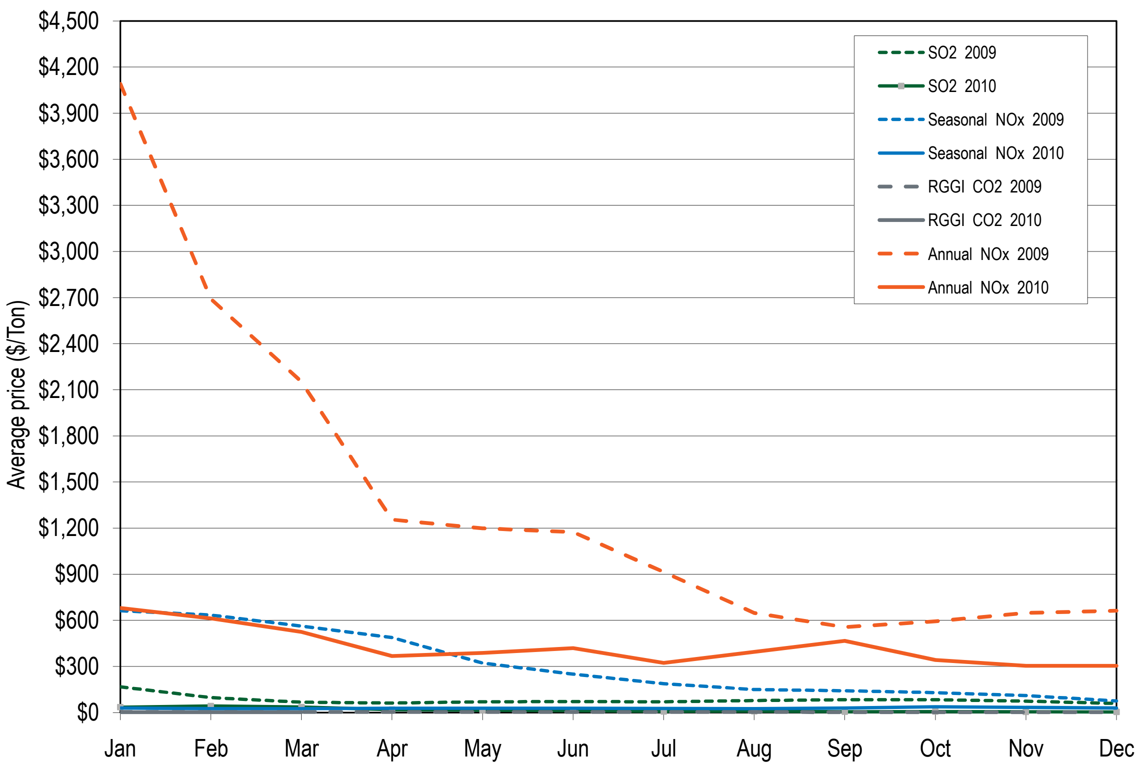

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Table 3-57 RGGI CO_2 allowance auction prices and quantities: 2009-2011 Compliance Period

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

Federal Regulation of Air Pollution

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA),[77] which, among other things, comprehensively regulates air emissions by establishing acceptable levels of and regulating emissions of hazardous air pollutants. EPA issues technology based standards for major sources and certain area sources of emissions.[78] In recent years, the EPA has been actively defining and tightening its standards and considering potential mechanisms, such as cap and trade, to facilitate meeting those standards. EPA actions have and are expected to continue to affect the costs to build and operate generating units in PJM which in turn affect wholesale energy prices and capacity prices.

Control of NO_x and SO_2 Emissions Allowances

The CAA requires States to attain and maintain compliance with fine particulate matter and ozone national ambient air quality standards (NAAQS). The CAA requires each State to prohibit emissions that significantly interfere with the ability of another State to meet NAAQS.[79] The EPA has sought to promulgate default Federal rules to achieve this objective.

The EPA's initial effort is the Clean Air Interstate Rule (CAIR). CAIR requires upwind states to implement control measures to reduce emissions of NO_x and SO_2 and created an optional interstate cap and trade program for these pollutants. CAIR went into effect across the 28 eastern states and the District of Columbia on January 1, 2009, mandating emissions cuts of NO_x. Mandates for SO_2 emissions commenced on January 1, 2010.

The U.S. Court of Appeals for the District of Columbia Circuit found CAIR unlawful under the CAA, but allowed CAIR to remain in effect while the EPA developed its replacement.[80] On July 6, 2010, the EPA proposed replacement regulations to reduce interstate transport of emissions.[81] One of

77 42 U.S.C. § 7401 et seq. (2000),
78 EPA defines "major sources" as a stationary source or group of stationary sources that emit or have the potential to emit 10 tons per year or more of a hazardous air pollutant or 25 tons per year or more of a combination of hazardous air pollutants. An "area source" is any stationary source that is not a major source.
79 CAA § 110(a)(2)(D)(i)(I).
80 *See North Carolina v. Environmental Protection Agency, et al.*, 531 F.3d 896 (D.C. Cir. 2008), *reh'g granted in part*, 550 F.3d 1176 (DC Cir. 2008).
81 *See* Proposed Rule, *Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone*, EPA Docket No. RIN 2060-AP50, 75 Fed. Reg. 45210 ("Proposed Rule").

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the Court's concerns about CAIR was its creation of a multi-state market to meet reduction targets regionally contrary to the state by state reductions mandated under CAA Title I.[82]

The EPA's new rule, known as the Clean Air Transport Rule (CATR), currently is subject to an administrative notice and comment proceeding, and a final rule is expected in July, 2011. The EPA has proposed to sunset CAIR after 2011, which means that allowances allocated for periods post 2011 "should not be usable for any purpose."[83]

CATR would reduce power plant emissions of SO_2 and NO_x to meet state by state emission reductions targets. The EPA anticipates that power plants will take steps such as (i) operating already installed pollution control equipment more frequently, (ii) installing new control equipment, and (iii) using lower sulfur coal in order to achieve compliance. The emission reductions are scheduled to begin in 2012, within one year after the rule is finalized. All PJM states are included in the 28 states that would be required to reduce both annual SO_2 and NO_x emissions.

The CAA requires EPA to review and, if appropriate, revise the air quality criteria for the primary (health-based) and secondary (welfare-based) NAAQs every five years. The NAAQS are the targets to which compliance mechanisms such the CATR are directed. A final rule on SO_2 primary NAAQS was published June 22, 2010 (Docket No. EPA-HQ-OAR-2007-0352). The EPA has initiated proceedings to review secondary NAAQS for NO_x and SO_2 (Docket No. EPA-HQ-OAR-2007-1145) and primary and secondary NAAQS for Ozone (O_3) (Docket No. EPA-HQ-OAR-2008-0699). Proposed rules are expected to issue, respectively, in July, 2011 and May, 2013.

Emissions Control of Hazardous Air Pollutants

Section 112 of the CAA requires the EPA to promulgate emissions control standards, known as the National Emission Standards for Hazardous Air Pollutants (NESHAP), from both new and existing area and major sources. There are at least three NESHAP rulemakings in progress that will impact operations at various classes of generating units.

On July 9, 2004, the EPA proposed a rule in Docket No. EPA-HQ-OAR-2002-0058, that would finalize emission standards for boilers and process heaters located at major sources, including "fossil fuel-fired units less than 25 megawatts and all utility boilers firing a non-fossil fuel that is not a solid waste."[84] A major source of hazardous air pollutants is defined as any stationary source or group of stationary sources within a contiguous area and under common control that emits or has the potential to emit, considering physical and operational design, in the aggregate, 10 tons per year or more of any single hazardous air pollutant or 25 tons per year or more of multiple pollutants. Sources that emit levels less than these amounts are known as area sources. Under the Urban Air Toxic Strategy, some types of area sources will have also have air toxic standards.

The CAA requires the standards to reflect the maximum degree of reduction in hazardous air pollutant emissions that is achievable taking into consideration the cost of achieving the emissions reductions, any non air quality health and environmental impacts, and energy requirements. This level of control is commonly referred to as the Maximum Achievable Control Technology (MACT).

82 531 F.3d at 906–908.
83 Proposed Rule at 45337.
84 Proposed Rule, *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters*, 75 Fed. Reg. 32006, 32016 (June 4, 2010).

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The MACT floor is the minimum control level allowed for NESHAP and ensures that all major hazardous air pollutant emission sources achieve the level of control already achieved by the better-controlled and lower-emitting sources in each category.

On July 9, 2004, the EPA proposed a rule in Docket No. EPA-HQ-OAR-2006-0790, that would establish national emission standards for control of hazardous air pollutants from two area source categories, one of which is industrial boilers, including those in electric generating units.[85] A final rule is under review from the OMB, and is expected in January 2011. The rule covers area source boilers that burn coal, oil, biomass, or secondary "non-waste" materials, but not natural gas. The rule aims to reduce emissions of a number of toxic air pollutants including mercury, other metals,[86] and organic air toxics. The standards for area sources must be technology-based. Standards for area sources can be based on either generally available control technology (GACT), or MACT.

EPA is also required under a consent decree to issue a notice of proposed rulemaking no later than March 16, 2011, in a proceeding to promulgate MACT specifically applicable to coal- and oil-fired electric utility steam generating units. A final rule is due by November 16, 2011 in Docket Nos. EPA-HQ-OAR-2009-0234 and EPA-HQ-OAR-2005-0031. Implementation would occur three years later, which would occur in the 2014/2015 Delivery Year.

Permitting/Prevention of Significant Deterioration

In 2007, the U.S. Supreme Court overruled EPA's determination that it was not authorized to regulate green house gas emissions under the CAA and remanded the matter to EPA to determine whether green house gases endanger public health and welfare.[87] On December 7, 2009, the EPA determined that green house gases, in including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, endanger public health and welfare.[88]

On May 13, 2010, the EPA issued a rule addressing green house gases (GHG) from the largest stationary sources, including power plants.[89] The Prevention of Significant Deterioration and Title V programs under the CAA impose certain permitting requirements on sources of pollutants. The EPA began phased implementation of this rule on January 2, 2011. Affected facilities will be required to include GHGs in their permit if they increase net GHG emissions by at least 75,000 tons per year (tpy) CO_2 equivalent and also significantly increase emissions of at least one non-GHG pollutant.[90] In July 2011, the rule expands to cover all new facilities with GHG emissions of at least 100,000 tpy and modifications at existing facilities that would increase GHG emissions by at least 75,000 tpy.[91] These permits must demonstrate the use of best available control technology (BACT) to minimize GHG emission increases when facilities are constructed or significantly modified.[92]

Standards of Performance for New Stationary Resources

On December 23, 2010, the EPA entered a settlement agreement to resolve the States and other litigants request for performance standards and emission guidelines for GHG emissions under

85 Proposed Rule, *National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers; Proposed Rule*, 75 Fed. Reg. 31896 (June 4, 2010).
86 Includes antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, phosphorus, and selenium.
87 *Massachusetts v. EPA*, 549 U.S. 497 (2007)
88 *See Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, 74 Fed. Reg. 66496, 66497 (December 15, 2009).
89 EPA, Final Rule, *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule*, Docket ID No. EPA–HQ–OAR–2009–0517, 75 Fed. Reg. 31514.
90 *Id.* at 31516.
91 *Id.*.
92 *Id.* at 31520.

Sections 111(b) and (d) of the CAA. The EPA agreed to issue a notice of proposed rulemaking by July 26, 2011, and a final rule by May 26, 2012. The new rule will amend the standards of performance for electric utility steam generating units codified in EPA regulations to address regulation of GHG.[93]

Clean Water Regulations

The EPA has initiated a rulemaking proceeding (EPA-HQ-OW-2008-0667) to ensure that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impacts, as required under Section 316(b) of the Clean Water Act (CWA). EPA expects to issue a proposed rule in March, 2011.

Emission Controlled Capacity in the PJM Region

Due to environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. Environmental regulations may affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls.

Coal and heavy oil have the highest SO_2 emission rates, while natural gas and light oil have low to negligible SO_2 emission rates. Many coal steam units in PJM have installed FGD (flue-gas desulfurization) technology to reduce SO_2 emissions from coal steam units. Of the current 76,220.7 MW of coal steam capacity in PJM, 48,946.7 MW of capacity, 64.2 percent, has some form of FGD technology. Table 3-58 shows emission controls by unit type, of fossil fuel units in PJM.

Table 3-58 SO_2 emission controls (FGD) by unit type (MW), as of December 31, 2010

	SO2 Controlled	No SO2 Controls	Total	Percent Controlled
Coal Steam	48,946.7	27,274.0	76,220.7	64.2%
Combined Cycle	0.0	21,542.4	21,542.4	0.0%
Combustion Turbine	0.0	31,519.2	31,519.2	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	48,946.7	91,515.0	140,461.7	34.8%

NO_x emission controlling technology is used by nearly all fossil fuel unit types. Coal steam, combined cycle, combustion turbine, and non-coal steam units in PJM have NO_x controls. Of current fossil fuel units in PJM, 127,420.9 MW, or 90.7 percent, of 140,461.7 MW of capacity in PJM, have emission controls for NO_x. Table 3-59 shows NO_x emission controls by unit type of fossil fuel units in PJM.

93 See 40 CFR Part 60.

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Table 3-59 NO_x emission controls by unit type (MW), as of December 31, 2010

	NOx Controlled	No NOx Controls	Total	Percent Controlled
Coal Steam	74,122.9	2,097.8	76,220.7	97.2%
Combined Cycle	21,392.4	150.0	21,542.4	99.3%
Combustion Turbine	26,097.5	5,421.7	31,519.2	82.8%
Diesel	0.0	342.4	342.4	0.0%
Non-Coal Steam	5,808.1	5,028.9	10,837.0	53.6%
Total	127,420.9	13,040.8	140,461.7	90.7%

Coal steam units in PJM generally have particulate controls. Typically, technologies such as electrostatic precipitators (ESP) or baghouses are used to reduce particulate matter in coal steam units. In PJM, 74,621.7 MW, 97.9 percent, of all coal steam unit MW, have some type of particulate emissions control technology. Table 3-60 shows particulate emission controls by unit type of fossil fuel units in PJM.

Table 3-60 Particulate emission controls by unit type (MW), as of December 31, 2010

	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	21,542.4	21,542.4	0.0%
Combustion Turbine	0.0	31,519.2	31,519.2	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%

Renewable Portfolio Standards

Many PJM jurisdictions have enacted legislation to require that a defined percentage of utilities' load be served by renewable resources, for which there are many standards and definitions. These are typically known as Renewable Portfolio Standards, or RPS. As of 2010, Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards, ranging from 0.02 percent of all load served in North Carolina, to 7.41 percent of all load served in New Jersey. Virginia has enacted a voluntary renewable portfolio standard. Indiana, Kentucky, and Tennessee have enacted no renewable portfolio standards.

Under the proposed standards, a substantial amount of load in PJM is required to be served by renewable resources by 2020. As Table 3-61 shows, New Jersey will require 20.37 percent of load to be served by renewable resources, the most stringent standard of all PJM jurisdictions. Typically, renewable generation earns renewable energy credits (also known as alternative energy credits), or RECs, when they generate. These RECs are bought by utilities and load serving entities to fulfill the requirements for renewable generation. Standards for renewable portfolios differ from jurisdiction to jurisdiction, for example, Illinois requires only utilities to purchase renewable energy credits, while Pennsylvania requires all load serving entities to purchase renewable energy credits (known as alternative energy credits in Pennsylvania).

Renewable energy credit markets are markets related to the production and purchase of wholesale power, but are not subject to FERC regulation or any other market regulation or oversight. RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not recognized as part of PJM markets. Revenues from RECs markets are in addition to revenues earned from the sale of the same MWh in PJM markets. Many jurisdictions allow various types of renewable resources to earn multiple RECs per MWh, though typically one REC is equal to one MWh. For example, West Virginia allows one credit each per MWh from generation from "alternative energy resources" such as waste coal or pumped-storage hydroelectric, but allows two credits each per MWh of electricity generated by "renewable energy resources", which includes resources such as wind, solar, and run-of-river hydroelectric. PJM Environmental Information Services (EIS), an unregulated subsidiary of PJM, operates the Generation Attribute Tracking System (GATS), which is used by many jurisdictions to track these renewable energy credits. The MMU recommends that renewable energy credit markets be brought into PJM markets as RECs are an increasingly critical component of regulated wholesale energy prices.

Table 3-61 Renewable standards of PJM jurisdictions to 2020[94,95]

Jurisdiction	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Delaware	5.50%	7.00%	8.50%	10.00%	11.50%	13.00%	14.50%	16.00%	18.00%	20.00%	20.00%
Indiana	No Standard										
Illinois	5.00%	6.00%	7.00%	8.00%	9.00%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%
Kentucky	No Standard										
Maryland	5.53%	7.50%	9.00%	10.70%	12.80%	13.00%	15.20%	15.60%	18.30%	17.70%	18.00%
Michigan			<10.00%	<10.00%	<10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
New Jersey	7.41%	8.30%	9.21%	10.14%	11.10%	12.07%	13.08%	14.10%	16.16%	18.25%	20.37%
North Carolina	0.02%	0.02%	3.00%	3.00%	3.00%	6.00%	6.00%	6.00%	10.00%	10.00%	10.00%
Ohio	5.00%	1.00%	1.50%	2.00%	2.50%	3.50%	4.50%	5.50%	6.50%	7.50%	8.50%
Pennsylvania	6.70%	9.20%	9.70%	10.20%	10.70%	11.20%	13.70%	14.20%	14.70%	15.20%	15.70%
Tennessee	No Standard										
Virginia	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%
Washington, D.C.	5.50%	6.00%	6.50%	7.00%	7.50%	8.00%	8.00%	8.00%	8.00%	8.00%	8.50%
West Virginia						10.00%	10.00%	10.00%	10.00%	10.00%	15.00%

Many PJM jurisdictions have also added requirements for the purchase of specific renewable resource technologies, specifically solar resources. These solar requirements are included in the standards shown in Table 3-61, but must be met by solar RECs only. Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, D.C., all have a requirement for the proportion of load served by solar units by 2020.[96] Michigan, Virginia, and West Virginia have no specific solar standard. In 2010, the most stringent standard in PJM was New Jersey's, requiring 0.22 percent of load to be served by solar resources. As Table 3-62 shows, by 2020, the most stringent standard will be Delaware's which requires at least 2.01 percent of load to be served by solar.

94 This analysis shows the total standard of renewable resources in all PJM jurisdictions, including Tier I and Tier II resources.

95 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.

96 Pennsylvania and Delaware allow only solar photovoltaic resources to fulfill the jurisdiction's solar requirement.

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Table 3-62 Solar renewable standards of PJM jurisdictions to 2020

Jurisdiction	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Delaware	0.02%	0.05%	0.10%	0.20%	0.35%	0.56%	0.80%	1.11%	1.55%	2.01%	2.01%
Indiana	No Standard										
Illinois			0.00%	0.12%	0.27%	0.60%	0.69%	0.78%	0.87%	0.96%	1.05%
Kentucky	No Standard										
Maryland	0.03%	0.05%	0.10%	0.20%	0.30%	0.40%	0.50%	0.55%	0.90%	1.20%	1.50%
Michigan	No Solar Standard										
New Jersey	0.22%	0.31%	0.39%	0.50%	0.62%	0.77%	0.93%	1.18%	1.33%	1.57%	1.84%
North Carolina	0.02%	0.07%	0.07%	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%
Ohio	0.01%	0.03%	0.06%	0.09%	0.12%	0.15%	0.18%	0.22%	0.26%	0.30%	0.34%
Pennsylvania	0.01%	0.02%	0.03%	0.05%	0.08%	0.14%	0.14%	0.25%	0.29%	0.34%	0.39%
Tennessee	No Standard										
Virginia	No Solar Standard										
Washington, D.C.	0.03%	0.38%	0.07%	0.08%	0.10%	0.13%	0.16%	0.19%	0.23%	0.28%	0.33%
West Virginia	No Solar Standard										

Some PJM jurisdictions have also added specific requirements to their renewable portfolio standards for other technologies. The standards shown in Table 3-63 are also included in the base standards. Illinois requires that a percentage of utility load be served by wind farms, starting at 3.75 percent in 2010 and escalating to 13.13 percent in 2020. Maryland, New Jersey, Pennsylvania[97], and Washington D.C. all have "Tier 2" or "Class 2" standards, which allow specific technology types, such as waste coal units in Pennsylvania, to qualify for renewable energy credits. North Carolina also requires a certain amount of power generated using swine waste and poultry waste to fulfill their renewable portfolio standards, while New Jersey requires 2,164 GWh of solar generation by 2020 (Table 3-63).

Table 3-63 Additional renewable standards of PJM jurisdictions to 2020

Jurisdiction		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Illinois	Wind Requirement	3.75%	4.50%	5.25%	6.00%	6.75%	7.50%	8.63%	9.75%	10.88%	12.00%	13.13%
Maryland	Tier II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	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
North Carolina	Swine Waste			0.07%	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)			170	700	900	900	900	900	900	900	900
Pennsylvania	Tier II Standard	4.20%	6.20%	6.20%	6.20%	6.20%	6.20%	8.20%	8.20%	8.20%	8.20%	8.20%
Washington, D.C.	Tier 2 Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.00%	1.50%	1.00%	0.50%	0.00%

97 Pennsylvania Tier II credits includes energy derived from waste coal, distributed generation systems, demand-side management, large-scale hydropower, municipal solid waste, generation from wood pulping process, and integrated combined coal gasification technology.

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PJM jurisdictions include various methods to comply with required renewable portfolio standards. If an LSE is unable to comply with the renewable portfolio standards required by the LSE's jurisdiction, LSEs may make alternative compliance payments, with varying standards. These alternative compliance payments are a way to make up any shortfall between the RECs required by the state and those the LSE actually purchased. In New Jersey, solar alternative compliance payments are $639 per MWh. Pennsylvania requires that the alternative compliance payment for solar credits be 200 percent of the average market value of solar RECs sold in the RTO. Compliance methods differ from jurisdiction to jurisdiction. For example, Illinois requires that 50 percent of the renewable portfolio standard be met through alternative compliance payments. Table 3-64 shows the alternative compliance standards in PJM jurisdictions, where such standards exist. These alternative compliance methods can have a significant impact on the traded price of RECs.

Table 3-64 Renewable alternative compliance payments in PJM jurisdictions: 2010

Jurisdiction	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$400.00
Indiana	No standard		
Illinois	$15.28		
Kentucky	No standard		
Maryland	$40.00	$15.00	$400.00
Michigan	No specific penalties		
New Jersey	$50.00		$639.00
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 3-65 shows generation by jurisdiction and renewable resource type in 2010. This includes only units that would qualify for REC credits by primary fuel type, including waste coal, battery, and pumped-storage hydroelectric, which can qualify for Pennsylvania Tier II credits if they are located in the PJM footprint. Wind units account for 8,812.8 GWh of 17,087.9 Tier I GWh, or 51.6 percent, in the PJM footprint. As shown in Table 3-65, 42,442.1 GWh were generated by resources that were primarily renewable, including both Tier II and Tier I renewable credits, of which, Tier I type resources accounted for 40.3 percent.

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Table 3-65 Renewable generation by jurisdiction and renewable resource type (GWh): Calendar year 2010

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	44.7	0.0	0.0	0.0	0.0	0.0	0.0	44.7	89.3
Indiana	0.0	0.0	0.0	44.8	0.0	0.0	0.0	2,153.7	2,198.5	2,198.5
Illinois	0.0	148.2	0.0	0.0	0.0	17.1	0.0	3,822.9	3,971.1	3,988.1
Kentucky	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	0.0	68.2	0.0	1,667.8	0.0	615.3	0.0	15.0	1,751.1	2,366.3
Michigan	0.0	32.1	0.0	66.1	0.0	0.0	0.0	0.0	98.2	98.2
New Jersey	0.0	298.6	515.4	18.1	1.5	1,435.3	0.0	11.5	329.7	2,280.3
North Carolina	0.0	0.0	0.0	674.7	0.0	0.0	0.0	0.0	674.7	674.7
Ohio	0.0	38.8	0.0	137.3	3.2	0.0	0.0	0.0	179.3	179.3
Pennsylvania	0.3	876.9	2,391.2	2,090.7	1.0	2,443.1	10,685.5	1,875.5	4,844.0	20,364.2
Tennessee	0.0	0.0	0.0	0.0	0.0	308.8	0.0	0.0	0.0	308.8
Virginia	0.0	187.9	4,904.0	915.5	0.0	1,149.7	0.0	0.0	1,103.4	7,157.2
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	959.0	0.0	0.0	888.6	934.2	1,893.2	2,781.8
Total	0.3	1,695.5	7,810.5	6,573.9	5.7	5,969.3	11,574.1	8,812.8	17,087.9	42,442.1

Table 3-66 shows the capacity of renewable resources in PJM by jurisdiction, as defined by primary or alternative fuel types being renewable.[98] This analysis includes various coal and natural gas units that have a renewable fuel as a secondary fuel, and thus are able to earn renewable energy credits. Pennsylvania has the largest amount of renewable capacity in PJM, 8,131.3 MW, or 32.1 percent of the total renewable capacity. New Jersey has the highest amount of solar capacity in PJM, 58.4 MW, or 91.4 percent of the total solar capacity. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 2,998.1 MW, or 67.5 percent of the total wind capacity.

98 Defined by fuel type, or a generator being registered in PJM GATS. Includes only units that are interconnected to the PJM system.

Table 3-66 PJM renewable capacity by jurisdiction (MW), on December 31, 2010

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	70.0	1,623.9
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	3,537.7	4.5	0.0	18.0	0.0	46.0	2.5	0.0	0.0	0.0	3,608.7
Pennsylvania	1.0	0.0	199.4	2,240.3	0.0	2,575.0	664.9	3.0	280.0	1,418.9	748.8	8,131.3
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	3,915.7	493.8	4,276.3	117.0	6,563.0	2,898.7	63.9	976.1	1,548.9	4,439.9	25,294.3

Table 3-67 shows renewable capacity registered in the PJM Generation Attribute Tracking System (GATS), a system operated by PJM EIS, that are not PJM units. This includes solar capacity of 302.4 MW of which 204.2 MW is in New Jersey. These resources can also earn renewable energy credits, and can be used to fulfill the renewable portfolio standards in PJM jurisdictions. All capacity shown in Table 3-67 is registered in PJM GATS, and may sell renewable energy credits through PJM EIS. Some of this capacity is located in jurisdictions outside PJM, but that may qualify for specific renewable energy credits in some jurisdictions. This includes both behind-the-meter generation located inside PJM, and generation connected to other RTOs outside PJM.

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Table 3-67 Renewable capacity by jurisdiction, non-PJM units registered in GATS[99,100] (MW), on December 31, 2010

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	8.5	0.0	0.1	8.6
Illinois	0.0	8.7	97.8	0.0	0.0	0.0	10.4	0.0	302.5	419.5
Indiana	0.0	0.0	19.2	0.0	679.1	0.0	0.1	0.0	0.0	698.5
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	13.5	10.0	0.0	28.5
Michigan	0.0	0.0	37.0	0.0	0.0	0.0	0.0	20.0	0.0	57.0
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	23.8	204.2	0.0	0.2	264.7
New York	0.0	179.9	0.0	0.0	0.0	0.0	0.2	0.0	0.0	180.2
North Carolina	0.0	225.0	5.3	0.0	0.0	0.0	1.9	0.0	0.0	232.2
Ohio	607.0	1.0	42.4	52.6	45.0	0.0	18.5	109.3	9.7	885.5
Pennsylvania	0.0	0.2	5.4	4.8	85.5	0.3	41.3	0.0	0.0	137.5
Tennessee	0.0	0.0	3.2	0.0	0.0	0.0	0.0	0.0	0.0	3.2
Virginia	0.0	12.5	14.8	0.0	0.0	0.0	2.4	318.1	0.0	347.9
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	1.0
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	9.0	0.0	0.0	0.0	0.0	0.1	44.6	0.0	53.7
Total	607.0	438.4	282.7	57.4	809.6	24.1	302.4	590.0	458.6	3,570.2

Scarcity and Scarcity Pricing

In electricity markets, scarcity means that demand, plus reserve requirements, is nearing the limits of the available capacity of the system. Under the current PJM rules, high prices, or scarcity pricing, result from high offers by individual generation owners for specific units when the system is close to its available capacity. These offers give the aggregate energy supply curve its steep upward sloping tail.[101] As demand increases and units with higher markups and higher offers are required to meet demand, prices increase. As a result, positive markups and associated high prices on high-load days may be the result of appropriate scarcity pricing rather than market power.

The energy market alone frequently does not directly or sufficiently value some of the resources needed to provide for reliability. That is the reason for the development of administrative scarcity pricing mechanisms such as the Reliability Pricing Model (RPM) capacity market and the scarcity pricing mechanism in the energy market.

99 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.
100 See "Renewable Generators Registered in GATS" <https://gats.pjm-eis.com/myModule/rpt/myrpt.asp?r=228> (Accessed January 25, 2011).
101 See *2010 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part I," at Figure 2-1, "Average PJM aggregate supply curves: Summers 2009 and 2010."

Designation of Maximum Emergency MW

During extreme system conditions when PJM declares Maximum Emergency Alerts, the PJM tariff specifies that capacity can only be designated as maximum emergency if the capacity has limitations on its availability because of environmental limitations, fuel limitations, emergency conditions at the unit or it represents temporary capacity additions obtained by operating the unit past its normal limits.[102,103] The intent of the rule regarding maximum emergency designation is to ensure that only capacity with a clearly defined issue limiting its economic availability is defined as maximum emergency MW which can be made available, at PJM direction, to maintain the system during emergency conditions.

Declarations of a Hot/Cold Weather Alerts also affect declarations of Maximum Emergency Capacity under the rules.[104,105] A Hot/Cold Weather Alert indicates conditions that require that combustion turbine (CT) and steam units with limited fuel availability be removed from economic availability and made available as emergency only capacity.[106] The Hot/Cold Weather Alert rule regarding Maximum Emergency capacity declarations, as outlined in Manual 13, is consistent with the Maximum Emergency Alert rule and its intent. While the Maximum Emergency Alert rule limits maximum emergency designations to capacity with limited availability during extreme system conditions, the Hot/Cold Weather Alert rule defines specific availability limitations which require that capacity be defined as maximum emergency during extreme system conditions.

The indicated references are the only place in the tariff that there is a clear definition of maximum emergency status. The analysis suggests that some MW are inappropriately designated as maximum emergency at times of declared Maximum Emergency Alerts. The analysis also suggests that some MW are designated as maximum emergency at times other than declared Maximum Emergency Alerts, which do not meet this definition. Such designations could be considered a form of withholding. There should be a clear definition of maximum emergency status that applies throughout the tariff.

There are incentives to keep capacity incorrectly designated as maximum emergency. Capacity designated as maximum emergency is considered as available, not on outage, even during the peak five hundred hours of the year defined in RPM. Capacity designated as maximum emergency is substantially less likely to be dispatched than capacity with an economic offer on high load days.

102 See PJM Tariff, 6A.1.3 Maximum Emergency Offer Limitations pp. 1839-1840 . Effective Date: 9/17/2010 See PJM. "Manual 13: Emergency Operations," Revision: 42 (Effective January 24, 2010), pp. 69.

103 See PJM. "Manual 13: Emergency Operations," Revision: 42 (Effective January 24, 2010), p. 69: "On days when PJM has declared, prior to 1800 hours on the day prior to the operating day, a Maximum Emergency Generation Alert for the entire PJM Control Area or for specific Control Zones or Scarcity Pricing Regions, the only units for which all of part of their capability may be designated as Maximum Emergency are those that meet the criteria described above. Should PJM declare a Maximum Generation Alert during the operating day for which the alert is effective, generation owners will be responsible for removing any unit availability from the Maximum Generation category that does not meet the above criteria within 4 hours of the issuance of the alert. PJM will make a mechanism available to participants by which they may inform PJM of their generating capability that meets the above criteria and indicate which of the criteria it meets." See also PJM Tariff, 6A.1.3 Maximum Emergency Offer Limitations pp. 1839-1840.

104 The purpose of the Hot Weather Alert is to prepare personnel and facilities for extreme hot and/or humid weather conditions which may cause capacity requirements/unit unavailability to be substantially higher than forecast are expected to persist for an extended period. In general, a Hot Weather alert can be issued on a Control Zone basis, if projected temperatures are to exceed 90 degrees with high humidity for multiple days. See PJM. "Manual 13: Emergency Operations," Revision: 42 (Effective January 24, 2010, p 41.

105 The purpose of the Cold Weather Alert is to prepare personnel and facilities for expected extreme cold weather conditions. As a general guide when the forecasted weather conditions approach minimum or actual temperatures for the Control Zone fall near or below ten degrees Fahrenheit. PJM can initiate a Cold Weather Alert at higher temperatures if PJM anticipates increased winds or if PJM projects a portion of gas fired capacity is unable to obtain spot market gas during load pick-up periods (refer to Inter RTO Natural Gas Coordination Procedure below). PJM will generally initiate a Cold Weather Alert on a Control Zone basis. See PJM. "Manual 13: Emergency Operations," Revision: 42 (Effective January 24, 2010, p 39.

106 See PJM. "Manual 13: Emergency Operations," Revision: 42 (Effective January 24, 2010, pp 37-38. CTs burning oil, kerosene or diesel with less than 16 hours of remaining fuel are considered to be fuel limited during a Hot Weather Alert. CTs burning gas with less than 8 hours of daily fuel allowance are considered to be fuel limited during a Hot Weather Alert. Steam units with less than 32 hours of fuel in inventory are considered to be fuel limited during a Hot Weather Alert.

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Given these incentives to keep capacity incorrectly designated as maximum emergency under normal system conditions, the rules regarding maximum emergency designations are expected to result in a decrease in the level of capacity designated as maximum emergency during Maximum Emergency Alerts because MW designated as maximum emergency, which do not have to meet a clear standard at other times, must comply with the tariff definition of maximum emergency during Maximum Emergency Alerts. The pattern of daily average maximum emergency levels before and during Maximum Emergency Alerts is generally consistent with this expectation. Figure 3-17 shows that declared maximum emergency MW fell, from the previous day's levels, on July 7 and July 23 after Maximum Emergency Alert declarations. Capacity which was designated as maximum emergency prior to a declaration of Maximum Emergency Alerts but which did not meet this tariff definition was reported as on forced outage or as available economic capacity after such a declaration.

During Maximum Emergency Alert Days, capacity designated as maximum emergency was used to produce energy in every hour of each day, despite the fact that prices were below $500 and there were no PJM instructions to load the maximum emergency generation. This behavior suggests that a portion of MW designated as maximum emergency were used as economic MW by participants and were therefore incorrectly classified even during Maximum Emergency Alert Days.

There are incentives to increase declared outages and potential incentives to decrease declared outages during high demand periods. In fact, for each summer month in 2010, declared outage MW during Hot Weather Alerts were lower than the average declared outage MW in each summer month, although reductions in outage MW were offset to a minor extent (1.6 percent of MW) by increases in maximum emergency generation declarations.

Definitions

PJM's current administrative scarcity pricing mechanism is designed to recognize real- time scarcity in the Energy Market and to increase prices to reflect the scarcity conditions. Administrative scarcity pricing results when PJM takes identified emergency actions. The scarcity price is based on the highest offer of an operating unit. PJM takes emergency actions on a regional basis when a region of the PJM system is low on economic sources of energy and reserves. Such actions include voltage reductions,[107] emergency power purchases, manual load dump, and loading of maximum emergency generation.[108] These do not represent all of the emergency actions that are available to PJM operators, but the listed steps are defined in the PJM Tariff as the triggers for scarcity pricing events.[109]

This section defines scarcity to exist when the demand for power exceeds the capacity available to provide both energy and 10 minute synchronized reserves. There were no such scarcity events in 2010. This section defines a high-load day to exist when hourly real time demand, including a 30 minute reserve target, equals 95 percent or more of total, within-30 minute supply in the absence

107 A voltage reduction warning (not an action) is evidence that the system is running out of available resources. A voltage reduction warning "is implemented when the available synchronized reserve capacity is less than the synchronized reserve requirement, after all available secondary and primary reserve capacity (except restricted maximum emergency capacity) is brought to a synchronized reserve status and emergency operating capacity is scheduled from adjacent systems." See PJM. "Manual 13: Emergency Operations," Revision 42 (Effective January 24, 2010), p. 24. Note that curtailment of nonessential building load is implemented prior to, or at this same time as, a voltage reduction action.

108 See PJM. "Manual 13: Emergency Operations," Revision: 42 (Effective January 24, 2010), p. 29: "The PJM RTO is normally loaded according to bid prices; however, during periods of reserve deficiencies, other measures must be taken to maintain reliability."

109 See OATT, Sheet No. 402A.01.

of non market administrative intervention, on an hourly integrated basis over a two hour period.[110] There were eighteen high load days in June, July, August and September of 2010.

2010 Results: High-Load Days

While PJM did not declare scarcity conditions in 2010, there were a number of days when, on a local or regional basis, the PJM system experienced relatively high resource requirements. Table 3-68 provides a description of the maximum emergency alerts and actions that can be posted by PJM.

Table 3-68 Maximum Emergency Alerts and Actions

Event	Purpose
Maximum Emergency Alert	Day ahead notice that maximum emergency generation has been called into day ahead operating capacity
Maximum Emergency Generation Action Transmission Contingency Support	Real time notice that maximum emergency generation may be required to provide local contingency support
Maximum Emergency Generation Action	Real time notice that maximum emergency generation may be required for system support

Table 3-69 shows high load days, Hot Weather Alerts, Maximum Emergency Alerts and Maximum Emergency Actions for June through September. There was one high load day on which PJM took emergency generation actions (August 11, 2010), but the emergency generation action was to control for local, rather than regional or system-wide reliability issues, and did not trigger a scarcity event. There were two high load days for which Maximum Emergency Generation Alerts were declared. There were three Maximum Emergency Alert days in 2010, May 26, June 24 and August 24, which did not meet the definition of a high load day. From June through September, PJM declared thirty one Hot Weather Alert days. Nine of these days met the definition of a high load day.

110 See PJM. "Manual 13: Emergency Operations", Revision 42. Effective Date January 24, 2011. p 11. The thirty minute reserve target is the day-ahead operating reserve target based of a percentage of Day Ahead peak load.

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Table 3-69 High Load Hour, Hot Weather Alerts and Maximum Emergency Related Events: June through September 2010

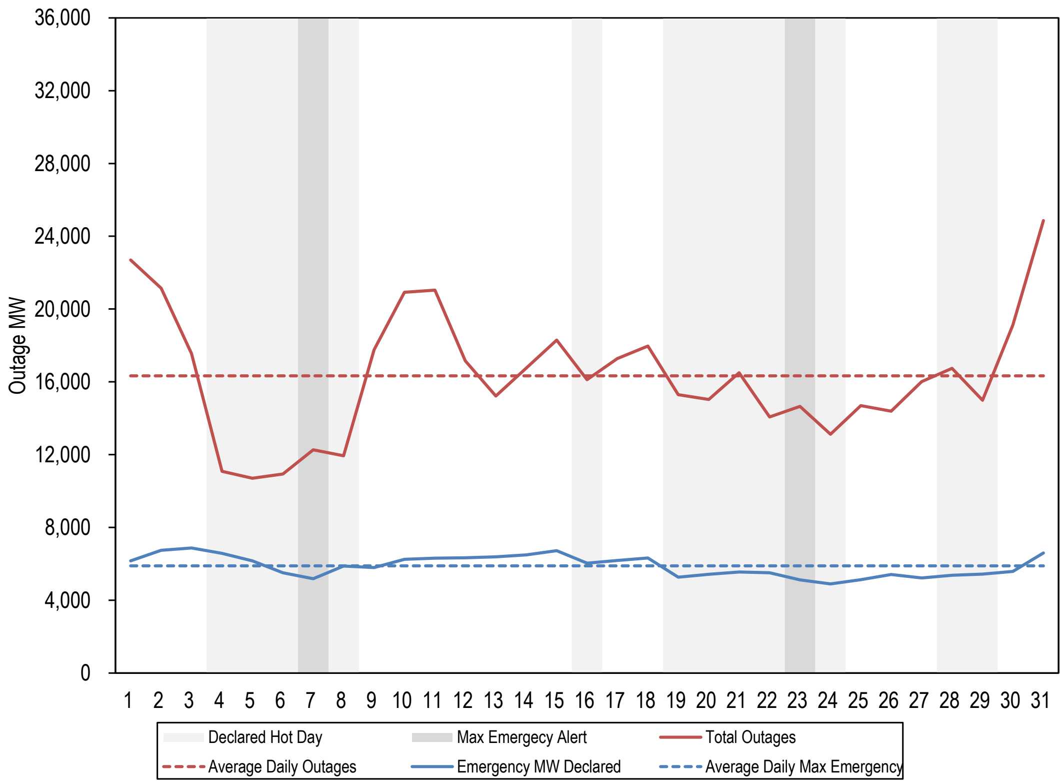
Dates	High Load Day (High Load Hours)	Hot Weather Alert	Maximum Emergency Generation Alert	Maximum Emergency Action Transmission Contigency Support	Maximum Emergency Generation Action
6/5/2010	2				
6/11/2010				PEPCO	
6/18/2010		Mid Atlantic and Southern			
6/20/2010		Mid Atlantic and Southern			
6/22/2010		PJMCA plus Southern			
6/23/2010	2	PJM			
6/24/2010		Mid Atlantic and Southern		AE (Atl City Elec) Sub Transmission Zone	
6/25/2010		Mid Atlantic and Southern			
6/26/2010		Mid Atlantic and Southern			
6/27/2010		Mid Atlantic and Southern			
6/28/2010		Mid Atlantic and Southern			
6/29/2010	2	Mid Atlantic and Southern			
7/4/2010		Mid Atlantic and Southern			
7/5/2010		AEP, AP, DAY, DLCO, OVEC, Mid Atlantic, Southern			
7/6/2010		AEP, AP, DAY, DLCO, OVEC, Mid Atlantic, Southern			
7/7/2010	2	AEP, AP, DAY, DLCO, OVEC, Mid Atlantic, Southern	Mid Atlantic Southern Region		
7/8/2010		AEP, AP, DAY, DLCO, OVEC, Mid Atlantic, Southern			
7/16/2010		Mid Atlantic and Southern			
7/19/2010		Mid Atlantic and Southern			
7/20/2010		Mid Atlantic and Southern			
7/21/2010	7	Mid Atlantic and Southern			
7/22/2010		Mid Atlantic and Southern			
7/23/2010	5	PJM	Mid Atlantic		
7/24/2010	3	PJM			
7/25/2010		Mid Atlantic, DOM			
7/27/2010	4				
7/28/2010	4	Mid Atlantic and Southern			
7/29/2010	4	Southern			
8/3/2010	2				
8/4/2010	4				
8/5/2010		Mid Atlantic, Southern			
8/9/2010	5				
8/10/2010	5	AEP, AP, DAY, DLCO, Mid Atlantic, Southern, DOM			
8/11/2010	5	Mid Atlantic, Southern			PEPCO
8/12/2010		Western			
8/27/2010	2				
8/30/2010		AP, DLCO, Mid Atlantic, Southern			
9/1/2010	4	AP, DLCO, Mid Atlantic, DOM			
9/2/2010	4	Mid Atlantic, Domininion			
9/23/2010		RTO	PJM: AP, BC, PEPCO		AP, BGE and PEPCO
9/24/2010		RTO	PJM RTO		AP, BGE and PEPCO

There were eighteen high load days, which must include two contiguous high load hours, from June through September, 2010, which included 66 high load hours. There were four additional days with one high load hour each, for a total of 70 high-load hours in 2010.

Seven of the eighteen high load days of 2010 and 29 of the 70 high load hours in 2010 occurred in July. Figure 3-17 shows, for July, the daily and monthly average outage MW and the daily and monthly average maximum emergency MW. Emergency MW are measured as declared maximum emergency capacity offers plus any actual generation in excess of declared maximum emergency capacity in any hour. For example, a 100 MW generator has 10 MW of its offered capacity listed as emergency MW in its offer curve. If the generator produced 102 MWh of output in one hour, it would be counted as 12 MW of emergency MW in that hour. The same unit would be counted as offering 10 MW of emergency when it was not operating. Figure 3-17 also shows the days for which PJM declared Hot Weather Alerts and days for which PJM declared Maximum Emergency Generation Alerts in July. Hot Weather Alerts and Maximum Emergency Generation Alerts are declared in advance of the operating day.

Despite a nuclear outage (Salem 1) in July, outage levels in the Hot Weather Alert period, July 4 through July 8, were lower than the July average.

Figure 3-17 July daily average outage and maximum emergency MW vs. July average outage and maximum emergency MW by day



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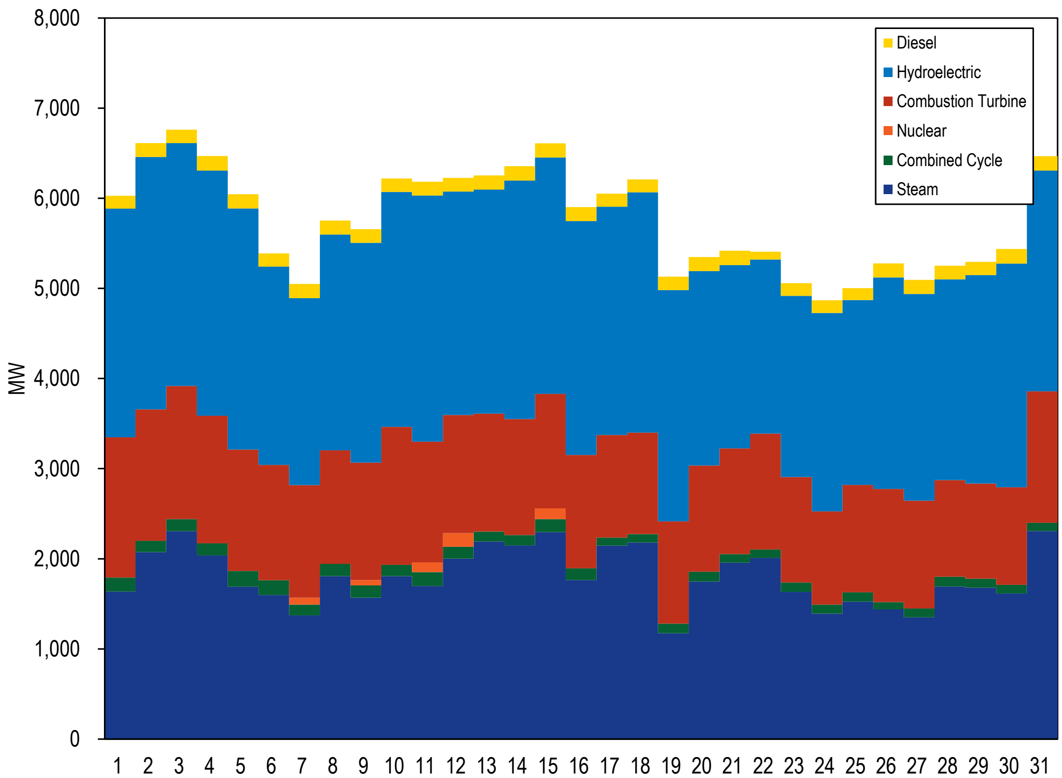
July 7 and July 23 were both Maximum Emergency Alert Days. Figure 3-18 shows average hourly declared emergency MW by day and by technology type for July. Hourly average emergency MW did fall slightly on July 7 and July 23 relative to the prior day's emergency MW. Figure 3-18 shows that steam units had the greatest variance in the total maximum emergency MW in July. Steam resources showed the largest decline in maximum emergency MW in the five day Hot Day period from July 4 through July 8. Figure 3-17 and Figure 3-18 show that behavior on both July 7 and July 23 was consistent with PJM market rules regarding maximum emergency MW declarations during a Maximum Emergency Alert. Maximum emergency MW declarations on both days were lower than the previous day's declarations levels on an aggregate basis. The same aggregate behavior was observed on September 23 and September 24, two other days with Maximum Emergency Alerts.

Figure 3-18 Average hourly declared emergency MW by day and by source: July 2010



On July 7, a Maximum Emergency Alert Day, units produced energy from maximum emergency MW in every hour of the day, ranging from 46 MWh in hour 0500 to 740 MWh of energy in hour 1900, despite the fact that hourly integrated prices were below $500 and there were no PJM instructions to load the maximum emergency generation. Including energy from MW in excess of economic or emergency MW offers, from 591 (hour 0400) to 1,746 (hour 2000) MWh of energy was produced from maximum emergency capacity on July 7. This behavior suggests that a portion of MW designated as maximum emergency were used as economic MW by participants and were therefore incorrectly classified even during Maximum Emergency Alert Days when the tariff definition of maximum emergency applies.

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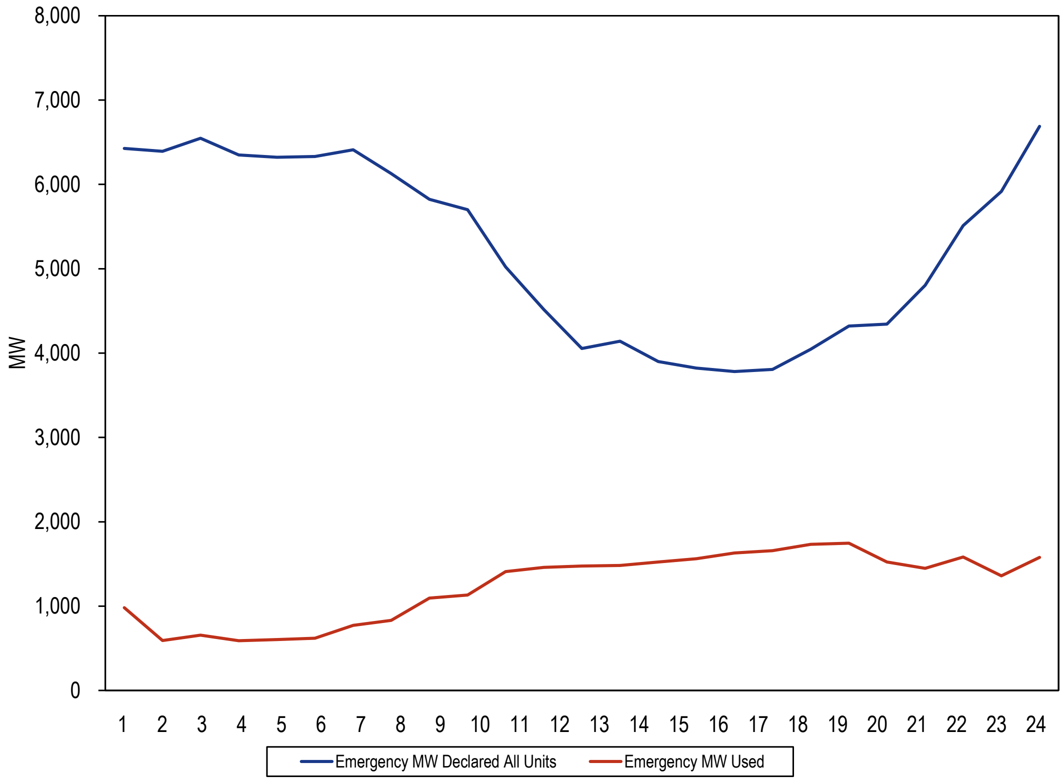
Figure 3-19 shows, by hour, the total emergency MW declared and total emergency MW used to produce energy on July 7. Steam units produced, on an hourly average basis, 57 percent of the energy from emergency MW on July 7.

The intent of the rule regarding maximum emergency designation is to permit capacity with extremely limited short run availability for specific reasons to not offer or run even during a Maximum Emergency Alert so that it can be made available, at PJM direction, to maintain system reliability during designated emergency conditions.

The actual energy output from emergency MW on July 7 suggests that a substantial amount of capacity designated as maximum emergency MW did not behave in a manner consistent with the rule. Despite the fact that no Maximum Emergency Generation Action was declared on July 7, Figure 3-19, shows that on July 7 these maximum emergency MW were being used to provide energy in every hour and at hourly integrated prices below $500. This behavior suggests that a portion (11.9 percent on average) of MW designated as maximum emergency were used as economic MW by participants and were therefore incorrectly classified even during Maximum Emergency Alert Days.

Figure 3-19 July 7 hourly declared emergency MW, hourly emergency MW



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Operating Reserve

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, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges.

From the perspective of those participants paying operating reserve charges, these costs are an unpredictable and unhedgeable component of the total cost of energy in PJM. While reasonable operating reserve charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level of operating reserve charges is as low as possible consistent with the reliable operation of the system and that the allocation of operating reserve charges reflects the reasons that the costs are incurred.

The level of total operating reserve credits and corresponding charges increased in 2010 by 74.6 percent compared to 2009, to a total of $569,062,688. This was primarily the result of a large increase in the amount of balancing operating reserve credits. The increase in operating reserve credits was the result of a number of factors including the increase in summer and winter load, the increase in fuel costs and the related increases in generator offer prices, LMP and congestion in 2010.

The level of operating reserve credits paid to specific units depends on the level of the unit's energy offer, the unit's operating parameters and the decisions of PJM operators. Operating reserve credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start units or to keep units operating even when hourly LMP is less than the offer price including energy, startup and no-load offers. PJM continues to review and measure daily operating reserve performance, to analyze issues and resolve them in a timely manner, to make better information more readily available to dispatchers and to emphasize the impact of dispatcher decisions on operating reserve charge levels.

New rules governing the payment of operating reserve credits and the allocation of operating reserve charges became effective on December 1, 2008. The new Operating Reserve Construct will be referred to as the new rules and the prior Operating Reserve Construct will be referred to as the old rules.[111]

Credit and Charge Categories

Operating reserve credits include day-ahead, synchronous condensing and balancing operating reserve categories**.** Total operating reserve credits paid to PJM participants equal the total operating reserve charges paid by PJM participants. Table 3-70 shows the categories of credits and charges and their relationship. The bottom half of this table shows how credits are allocated under the new operating reserve construct. Table 3-71 shows the different types of deviations.

111 See the *2009 State of the Market Report for PJM*, Volume II, Section 3, "Energy Market Part 2".

Table 3-70 Operating reserve credits and charges

Credits Received	Charges Paid
Day ahead:	Day-ahead demand
Day-Ahead Energy Market	Decrement bids
Day-ahead import transactions	Day-ahead export transactions
Synchronous condensing	Real-time load
	Real-time export transactions
Balancing:	
Balancing energy market	Real-time deviations
Lost opportunity cost	from day-ahead schedules
Real-time import transactions	
Balancing Energy Market Credits Received	**Balancing Energy Market Charges Paid**
(RTO, Eastern Region, Western Region)	Real-time load
Reliability Credits	Real-time export transactions
Deviation Credits	Real-time deviations
	from day-ahead schedules

Table 3-71 Operating reserve deviations

	Deviations	
Day ahead		Real time
Day-ahead decrement bids	Demand (Withdrawal)	Real-time load
Day-ahead load	(RTO, East, West)	Real-time sales
Day-ahead sales		Real-time export transactions
Day-ahead export transactions		
Day-ahead increment offers	Supply (Injection)	Real-time purchases
Day-ahead purchases	(RTO, East, West)	Real-time import transactions
Day-ahead import transactions		
Day-ahead scheduled generation	Generator (Unit)	Real-time generation

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Day-Ahead Credits and Charges

Day-ahead operating reserve credits consist of Day-Ahead Energy Market and day-ahead import transaction credits. The rules governing these credits and associated charges were not modified in the new rules.

The day-ahead operating reserve charges that result from paying total day-ahead operating reserve credits are allocated daily to PJM members in proportion to the sum of their cleared day-ahead demand, decrement bids and day-ahead exports. Table 3-74 shows monthly day-ahead operating reserve charges for calendar years 2009 and 2010.

Synchronous Condensing Credits and Charges

Synchronous condensing credits are provided to eligible synchronous condensers for real-time condensing and energy use costs if PJM dispatches them for purposes other than synchronized reserve, post-contingency constraint control or reactive services.[112] The rules governing these credits and associated charges were not modified in the new rules.

The operating reserve charges that result from paying operating reserve credits for synchronous condensing are allocated daily to PJM members in proportion to the sum of their real-time load and real-time export transactions. Table 3-74 shows monthly synchronous condensing charges for calendar years 2009 and 2010.

Balancing Credits and Charges

Balancing operating reserve credits consist of balancing energy market credits, lost opportunity cost credits, and real-time import transaction credits. Balancing operating reserve credits are paid to generation resources that operate at PJM's request if market revenues are less than the resource's offer. Lost opportunity cost credits are paid to generation resources when their output is reduced at PJM's request for reliability purposes from their economic or self-scheduled output level. Balancing operating reserve credits are paid to real-time import transactions, if market revenues are less than the offer. Balancing operating reserve credits are also paid to cancelled pool-scheduled resources, to resources providing quick start reserve and to resources performing annual, scheduled black start tests.

112 "Manual 28: Operating Agreement Accounting," Revision 46 (October 1, 2010).

Table 3-72 Balancing operating reserve allocation process

	Reliability Credits	Deviation Credits
RTO	**1.) Reliability Analysis:** Conservative Operations and for TX constraints 500kV & 765kV **2.) Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 500kV & 765kV	**1.) Reliability Analysis:** Load + Reserves and for TX constraints 500kV & 765kV **2.) Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 500kV & 765kV
East	**1.) Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	**1.) Reliability Analysis:** Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV
West	**1.) Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	**1.) Reliability Analysis:** Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV

Table 3-72 shows the allocation process for balancing operating reserves. Credits are assigned to units during two periods, the reliability analysis and the Real-Time Market. During PJM's reliability analysis, performed after the Day-Ahead Market is cleared, credits are allocated for conservative operations and to meet real-time load. Conservative operations means that units are committed due to conditions that warrant conservative actions to ensure the maintenance of system reliability. Such conditions include hot and cold weather alerts. The resultant credits are defined as reliability credits and are allocated to real-time load plus exports. Units are committed to operate in real time to augment the physical units committed in the Day-Ahead Market in order to meet the forecasted real-time load plus the operating reserve requirement. The resultant credits are defined as deviation credits and are allocated to supply, demand, and generator deviations.

In the Real-Time Market, credits are also allocated for reliability or to meet load. Credits are paid to units that are called on by PJM and in which the LMP is not greater than or equal to the unit's offer for at least four five-minute intervals of at least one clock hour while the unit was running at PJM's direction. These are defined as Reliability Credits and are allocated to real-time load plus exports. Balancing operating reserve credits earned by all other units operated at PJM's direction in real time where the LMP is greater than or equal to the unit's offer for at least four five-minute intervals of at least one clock hour are defined as deviation credits and are allocated to real-time supply, demand, and generator deviations from day-ahead schedules.

Credits are allocated regionally based on whether a unit was called on for a transmission constraint and the voltage level of the constraint. Credits associated with transmission constraints that are 500kV or 765kV are assigned to RTO credits while credits associated with constraints of all other voltages are assigned to regional credits.

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Credit and Charge Results

Overall Results

Table 3-73 shows total operating reserve credits from 1999 through 2010.[113,114] Total operating reserve credits increased by 74.6 percent in 2010 from 2009. Table 3-73 shows the ratio of total operating reserve credits to the total value of PJM billings.[115] This ratio increased from 1.2 percent in 2009 to 1.6 percent in 2010. This is the highest this ratio has been since 2005, and is the first annual increase since 2004.

Table 3-73 Total day-ahead and balancing operating reserve credits: Calendar years 1999 to 2010

	Total Operating Reserve Credits	Annual Credit Change	Operating Reserve as a Percent of Total PJM Billing	Day-Ahead $/MWh	Day-Ahead Change	Balancing $/MWh	Balancing Change
1999	$133,897,428	NA	7.5.%	NA	NA	NA	NA
2000	$216,985,147	62.1%	9.6%	0.341	NA	0.535	NA
2001	$290,867,269	34.0%	8.7%	0.275	(19.5%)	1.070	100.2%
2002	$237,102,574	(18.5%)	5.0%	0.164	(40.4%)	0.787	(26.4%)
2003	$289,510,257	22.1%	4.2%	0.226	38.2%	1.197	52.0%
2004	$414,891,790	43.3%	4.8%	0.230	1.7%	1.236	3.3%
2005	$682,781,889	64.6%	3.0%	0.076	(66.9%)	2.758	123.1%
2006	$322,315,152	(52.8%)	1.5%	0.078	2.6%	1.331	(51.7%)
2007	$459,124,502	42.4%	1.5%	0.057	(27.0%)	2.331	75.1%
2008	$429,253,836	(6.5%)	1.3%	0.084	48.0%	2.113	(9.3%)
2009	$325,842,346	(24.1%)	1.2%	0.120	42.3%	1.1100*	(47.5%)
2010	$569,062,688	74.6%	1.6%	0.113	(5.7%)	2.3103*	108.1%

Table 3-73 shows the average day-ahead operating reserve credits per MWh (or the charge rate) for each full year since the introduction of the Day-Ahead Energy Market. The day-ahead operating reserve rate decreased $0.0068 per MWh or 5.7 percent from $0.1201 per MWh in 2009 to $0.1133 per MWh in 2010. The balancing operating reserve rate increased $1.2003 per MWh, or 108.1 percent, from $1.1100 per MWh in 2009 to $2.3103 per MWh in 2010. The balancing rates of $2.3103 per MWh for 2010 and $1.1100 for 2009 (as indicated with asterisk) represent what the rate would have been if calculated under the old operating construct rules, taking each day's total balancing operating reserve credits, and dividing by total demand, supply, and generator deviations. This was derived by taking all regional reliability and deviation credits for the day and dividing by total PJM supply, demand, and generator deviations, netted across the RTO rather than zone, hub, or interface. The rates shown in the table are the averages of the daily rates across the year.

113 Table 3-73 includes all categories of credits as defined in Table 3-68 and includes all PJM Settlements billing adjustments. Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of operating reserves. The billing data reflected in this report were the current figures on January 14, 2011.

114 An Energy Market that clears based on market-based generator offers was initiated on April 1, 1999. The 1999 total includes Energy Market operating reserve credits for three months based on generators' cost-based offers and for nine months based on generators' market-based offers. The Day-Ahead Energy Market opened on June 1, 2000. Operating reserve credits for 1999 and the first five months of 2000 include only those credits paid in the balancing energy market. Since June 1, 2000, operating reserve credits have included credits for both day-ahead and balancing.

115 See the *2010 State of the Market Report for PJM*, Volume II, Section 7, "Congestion," at Table 7-1, "Total annual PJM congestion (Dollars (Millions)): Calendar years 2003 to 2010," for the value of PJM billings during the period indicated.

Total operating reserve charges in 2010 were $569,062,688, up from the total of $325,842,346 in 2009. Table 3-74 compares monthly operating reserve charges by category for calendar years 2009 and 2010. The overall increase of 74.6 percent in 2010 is comprised of a 4.5 percent decrease in day-ahead operating reserve charges, a 71.1 percent decrease in synchronous condensing charges and a 109.1 percent increase in balancing operating reserve charges. The day-ahead operating reserve charges proportion of total operating reserve charges decreased by 13.2 percentage points to 15.9 percent, the synchronous condensing charges proportion decreased 0.7 percentage points to 0.1 percent, and the balancing charges proportion increased 13.8 percentage points to 83.9 percent.

Table 3-74 Monthly operating reserve charges: Calendar years 2009 and 2010

	2009 Charges				2010 Charges			
	Day-Ahead	Synchronous Condensing	Balancing	Total	Day-Ahead	Synchronous Condensing	Balancing	Total
Jan	$9,260,150	$1,328,814	$30,116,725	$40,705,689	$10,281,351	$50,022	$40,472,496	$50,803,869
Feb	$7,434,068	$839,679	$16,548,988	$24,822,735	$11,425,494	$14,715	$22,346,529	$33,786,738
Mar	$9,549,963	$108,664	$26,025,562	$35,684,189	$8,836,886	$122,817	$16,823,288	$25,782,991
Apr	$6,998,364	$19,929	$13,251,273	$20,269,566	$7,633,141	$93,253	$22,870,495	$30,596,889
May	$6,024,108	$5,543	$15,490,257	$21,519,908	$5,127,307	$131,600	$39,144,404	$44,403,311
Jun	$6,722,329	$0	$19,339,846	$26,062,175	$3,511,264	$33,923	$56,989,229	$60,534,415
Jul	$8,210,636	$38,643	$17,728,976	$25,978,255	$4,601,788	$88,136	$63,190,853	$67,880,778
Aug	$7,697,174	$1	$21,164,586	$28,861,761	$3,622,670	$66,535	$41,690,612	$45,379,817
Sep	$6,057,598	$13,611	$13,471,368	$19,542,577	$8,433,892	$27,971	$40,637,086	$49,098,949
Oct	$7,046,301	$0	$17,026,425	$24,072,727	$7,719,744	$1,543	$30,433,986	$38,155,273
Nov	$8,617,280	$22,639	$12,888,600	$21,528,519	$6,556,715	$29,674	$20,020,310	$26,606,698
Dec	$11,323,263	$117,573	$25,353,409	$36,794,245	$12,951,879	$59,954	$83,021,125	$96,032,958
Total	$94,941,235	$2,495,097	$228,406,015	$325,842,346	$90,702,132	$720,142	$477,640,414	$569,062,688
Share of Annual Charges	29.1%	0.8%	70.1%	100.0%	15.9%	0.1%	83.9%	100.0%

Table 3-75 shows the amount and percentages of regional balancing charge allocations across PJM for 2010. The largest share of charges was paid by RTO demand deviations. The regional balancing charges allocation table does not include charges attributed for lost opportunity cost credits, cancelled pool-scheduled resources, resources providing quick start reserve and resources performing annual, scheduled black start tests.

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Table 3-75 Regional balancing charges allocation: Calendar year 2010[116]

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	$42,122,972 12.6%	$1,689,055 0.5%	$43,812,027 13.1%	$102,864,673 30.7%	$48,547,311 14.5%	$32,906,726 9.8%	$184,318,710 54.9%	$228,130,737 68.0%
East	$46,474,131 13.9%	$1,712,870 0.5%	$48,187,002 14.4%	$15,404,606 4.6%	$6,727,200 2.0%	$3,852,121 1.1%	$25,983,926 7.7%	$74,170,928 22.1%
West	$19,829,984 5.9%	$862,677 0.3%	$20,692,661 6.2%	$6,916,779 2.1%	$3,022,844 0.9%	$2,577,253 0.8%	$12,516,876 3.7%	$33,209,536 9.9%
Total	$108,427,088 32.3%	$4,264,602 1.3%	$112,691,690 33.6%	$125,186,058 37.3%	$58,297,355 17.4%	$39,336,099 11.7%	$222,819,512 66.4%	$335,511,201 100%

Deviations

Categories

Under the old rules, all operating reserve charges that resulted from paying balancing operating reserve credits were allocated daily to PJM members in proportion to their real-time hourly deviations from cleared quantities in the Day-Ahead Market, netted across the RTO. Table 3-74 shows monthly balancing operating reserve charges for calendar years 2009 and 2010. Under the new rules, only credits allocated to generators defined to be operating to control for deviations on the system are charged to deviations. Deviations fall into three categories, demand, supply and generator deviations, and are calculated on an hourly basis. Supply and demand deviations are netted separately for each participant by zone, hub, or interface, and totaled for the day. Each category of deviation is calculated separately and a PJM member may have deviations in all three categories.

- **Demand.** Hourly deviations in the demand category equal the absolute value of the difference between: a) the sum of cleared decrement bids plus cleared, day-ahead load plus day-ahead exports scheduled through the Enhanced Energy Scheduler (EES);[117] and b) the sum of real-time load plus real-time sales scheduled through eSchedules[118] plus real-time exports scheduled through the EES.

- **Supply.** Hourly deviations in the supply category equal the absolute value of the difference between: a) the sum of the cleared increment offers plus day-ahead imports scheduled through EES; and b) the sum of the real-time bilateral transactions scheduled through eSchedules plus real-time imports scheduled through EES.

- **Generator.** Hourly deviations in the generator category equal the absolute value of the difference between: a) a unit's cleared, day-ahead generation; and b) a unit's hourly, integrated real-time generation. More specifically, a unit has calculated deviations for an hour if the hourly integrated real-time output is not within 5 percent of the hourly day-ahead schedule; the hourly integrated real-time output is not within 10 percent of the hourly integrated desired output; or

116 The total charges shown in Table 3-75 do not equal the total balancing charges shown in Table 3-74 because the totals in Table 3-74 include lost opportunity cost, cancellation, and local charges while the totals in Table 3-75 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.

117 The Enhanced Energy Scheduler is a PJM application used by participants to schedule import and export transactions.

118 PJM's eSchedules is an application used by participants for internal bilateral transactions.

the unit is not eligible to set LMP for at least one five-minute interval during an hour. Deviations are calculated for individual units, except where netting at a bus is permitted.

- **Netting.** Demand and supply deviations are netted by zone, hub, or interface in which they occur. For example, a negative deviation in a zone can be offset by a positive deviation that occurs in that zone. The sum of each organization's netted deviations by zone, hub, or interface is categorized into either the eastern or western region, depending on where the zone, hub, or interface is located. The RTO region is the sum of an organization's eastern and western region deviations, plus deviations that occurred at hubs that include buses in both regions. Generators that deviate from real-time dispatch may offset deviations by another generator at the same bus. The set of generators that are allowed to be netted must be electrically equivalent at the bus, and owned by the same participant.

- An organization's total daily balancing operating reserve charges are equal to the sum of the three deviation categories, by region, for the day, multiplied by the regional daily balancing operating reserve rates.

Allocation

Under the new rules, a subset of defined balancing reserve charges are assigned to deviations and deviations are separated into RTO and regional categories. Table 3-76 shows monthly real-time deviations for demand, supply and generator categories for 2009 and 2010. These deviations are the sum of all the regional deviations. Total deviations summed across the demand, supply, and generator categories were higher in 2010 than 2009 by 9,825,957 MWh. Demand deviations increased by 12.8 percent, supply deviations decreased by 11.1 percent, and generator deviations increased by 13.6. From 2009 to 2010, the share of total deviations in the demand category increased by 3.6 percentage points, the share of supply deviations decreased by 4.9 percentage points, and the share of generator deviations increased by 1.2 percentage points.

Effective December 1, 2008, new rules governing the calculation of generator deviations were implemented. Under the old rules, a generator was considered to deviate if the unit was operating at an actual output that was more than 10 percent from the PJM desired MW, or if they were operating at an output that was 5 percent, or 5 MW from their day-ahead schedule. Under the new rules, the ramp limited desired (RLD) MW is used instead to determine the unit's desired MW. This RLD MW is the achievable MW based on the UDS ramp rate.[119] The goal of this rule change was to further incent generators to follow PJM dispatch instruction in order to increase market efficiency, and improve reliability. Additionally, a deviation from a generator may offset a deviation from another generator if they are connected to the same electrically equivalent bus, and are owned by the same participant.

119 Manual 28: *Operating Agreement Accounting* Section 5: Operating Reserve Accounting 5.2.1

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Table 3-76 Monthly balancing operating reserve deviations (MWh): Calendar years 2009 and 2010

	2009 Deviations				2010 Deviations			
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)
Jan	9,128,112	5,575,170	2,630,917	17,334,199	9,439,465	5,707,965	2,698,568	17,845,998
Feb	7,044,702	4,153,575	2,107,229	13,305,505	7,675,656	5,332,236	2,456,048	15,463,940
Mar	7,214,090	4,352,550	2,409,507	13,976,146	8,101,950	5,138,264	2,264,951	15,505,165
Apr	6,873,427	3,836,896	2,275,153	12,985,477	7,006,983	4,668,407	2,132,045	13,807,435
May	6,958,699	5,184,983	2,382,351	14,526,033	9,004,034	4,228,004	2,416,103	15,648,141
Jun	8,569,879	4,603,052	2,635,991	15,808,922	10,936,989	3,964,478	3,174,230	18,075,697
Jul	9,233,511	5,129,409	2,243,337	16,606,257	10,928,408	3,847,011	3,412,498	18,187,917
Aug	9,961,944	5,425,344	2,427,539	17,814,827	9,747,045	3,417,328	3,188,437	16,352,810
Sep	7,972,378	4,171,876	2,109,506	14,253,759	9,480,237	3,587,356	2,524,213	15,591,806
Oct	7,028,775	4,543,635	2,203,723	13,776,133	7,170,712	2,913,554	2,368,303	12,452,569
Nov	6,742,675	4,248,221	2,193,013	13,183,910	7,606,971	2,860,054	2,485,153	12,952,178
Dec	8,301,680	4,682,157	3,113,047	16,096,884	10,069,627	4,027,236	3,513,489	17,610,352
Total	95,029,874	55,906,867	28,731,313	179,668,054	107,168,079	49,691,893	32,634,039	189,494,011
Share of Annual Deviations	52.9%	31.1%	16.0%	100.0%	56.6%	26.2%	17.2%	100.0%

Real-time load, real-time exports, and deviations in each region are shown in Table 3-77. RTO deviations are classified as the sum of eastern and western deviations, plus deviations from hubs that span multiple regions.[15]

Table 3-77 Regional charges determinants (MWh): Calendar year 2010

	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	697,390,682	28,285,676	725,676,358	107,168,079	49,691,893	32,634,039	189,494,011	915,170,369
East	381,897,104	14,877,468	396,774,572	66,283,874	31,674,848	17,028,384	114,987,106	511,761,678
West	315,493,578	13,408,208	328,901,786	40,576,952	17,936,701	15,605,655	74,119,308	403,021,094

The MMU has analyzed the impact of the new rules which net supply and demand deviations by zone, hub, or interface, and net generator deviations at the same electrically equivalent bus. Under the new netting rules, total deviations in 2010 were 12,817,998 MWh, 7.3 percent higher than if they had been calculated under the old rules. In order to isolate the impact of the netting changes, the analysis did not take into account the changes made for ramp limited desired MW. Under the new netting rules, demand deviations were 9,380,066 MWh higher, supply deviations were 3,599,194 MWh higher, and generator deviations were 161,261 MWh lower, in 2010, than if they had been calculated under the old rules. Table 3-78 shows the monthly impacts of netting deviations for each category.

Table 3-78 Monthly impacts on netting deviations: Calendar year 2010

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	8,243,822	9,439,465	1,195,643	5,143,977	5,707,965	563,988	2,709,298	2,698,568	(10,730)
Feb	6,833,397	7,675,656	842,259	4,988,991	5,332,236	343,245	2,462,260	2,456,048	(6,212)
Mar	7,347,674	8,101,950	754,276	4,765,342	5,138,264	372,922	2,269,634	2,264,951	(4,683)
Apr	6,252,224	7,006,983	754,758	4,018,539	4,668,407	649,868	2,146,341	2,132,045	(14,296)
May	8,196,632	9,004,034	807,403	3,703,829	4,228,004	524,175	2,429,552	2,416,103	(13,448)
Jun	10,076,412	10,936,989	860,577	3,591,018	3,964,478	373,460	3,188,180	3,174,230	(13,949)
Jul	10,094,282	10,928,408	834,126	3,644,685	3,847,011	202,326	3,434,716	3,412,498	(22,219)
Aug	9,072,262	9,747,045	674,784	3,287,880	3,417,328	129,448	3,199,527	3,188,437	(11,089)
Sep	8,727,517	9,480,237	752,721	3,403,670	3,587,356	183,686	2,528,532	2,524,213	(4,319)
Oct	6,587,772	7,170,712	582,940	2,843,181	2,913,554	70,373	2,394,899	2,368,303	(26,595)
Nov	7,120,018	7,606,971	486,954	2,852,925	2,860,054	7,129	2,491,869	2,485,153	(6,716)
Dec	9,236,002	10,069,627	833,625	3,848,661	4,027,236	178,575	3,540,494	3,513,489	(27,005)
Total	97,788,014	107,168,079	9,380,066	46,092,699	49,691,893	3,599,194	32,795,300	32,634,039	(161,261)

Table 3-79 shows the summary for each category of deviations under the old rules and the new rules.

Table 3-79 Summary of impact on netting deviations: Calendar year 2010

	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Total Deviations (MWh)
Old Rules (No Netting)	97,788,014	46,092,699	32,795,300	176,676,013
New Rules (Netting)	107,168,079	49,691,893	32,634,039	189,494,011
Difference	9,380,066	3,599,194	(161,261)	12,817,998

Balancing Operating Reserve Charge Rate

Under the new balancing operating reserve cost allocation rules, PJM calculates six separate balancing rates, a reliability rate for each region, and a deviation rate for each region. The reliability rates are equal to the total reliability credits divided by real-time load plus exports. The deviation rates are calculated as the total deviation credits divided by the sum of the demand, supply, and generation deviations. RTO rates are based on RTO credits, while the regional rates are based on regional credits. See Table 3-72 for how these credits are allocated.

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Figure 3-20 shows the daily RTO reliability and deviation balancing operating reserve rates for 2010. The average daily RTO deviation rate for 2010 was $0.9116 per MWh, while the average daily RTO reliability rate was $0.0579 per MWh. The largest daily rate occurred on December 15, 2010, when the RTO deviation rate was $13.1590 per MWh.

Figure 3-20 Daily RTO reliability and deviation balancing operating reserve rates ($/MWh): Calendar year 2010

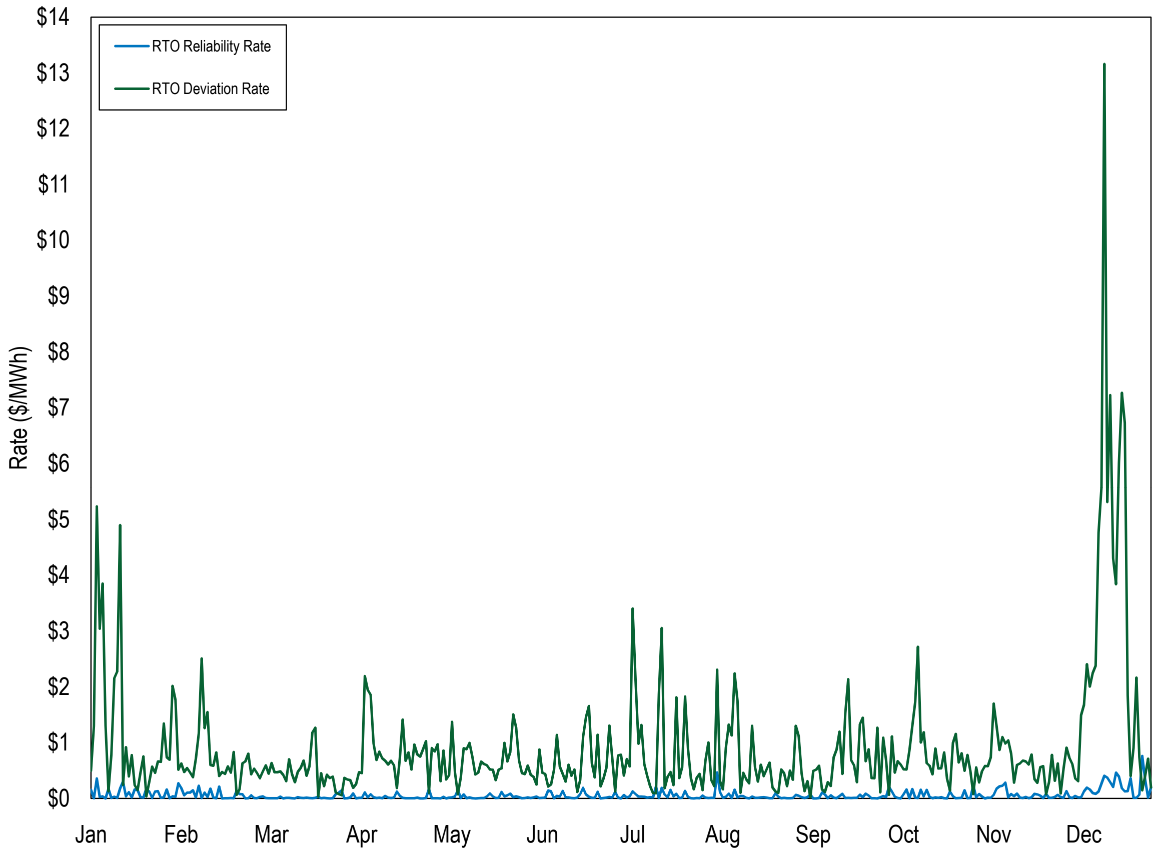

Figure 3-21 shows the daily regional reliability and deviation rates for 2010.

Figure 3-21 Daily regional reliability and deviation rates ($/MWh): Calendar year 2010

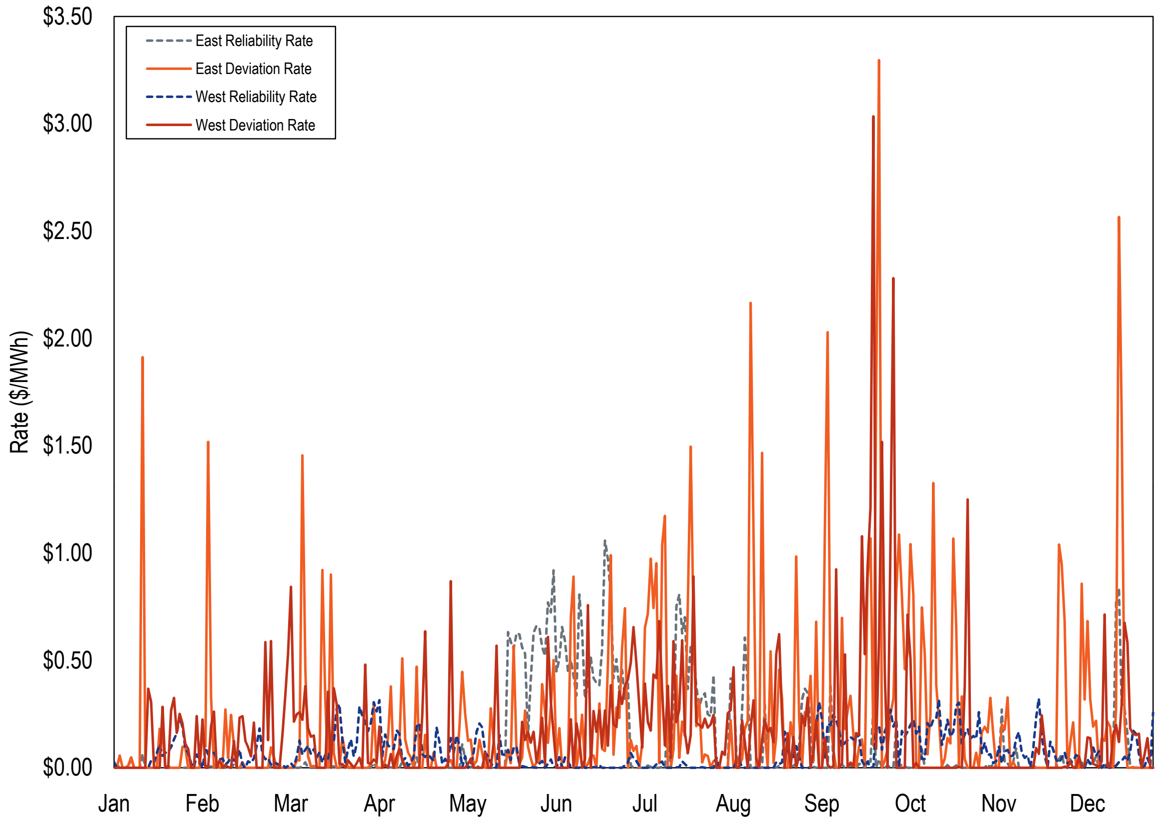

Table 3-80 shows the rates for each region in each category. Regional reliability rates are higher than the RTO reliability rate. The RTO deviation rate is substantially higher than the regional deviation rates.

Table 3-80 Regional balancing operating reserve rates ($/MWh): Calendar year 2010

	Reliability ($/MWh)	Deviations ($/MWh)
RTO	0.058	0.912
East	0.108	0.225
West	0.070	0.161

Operating Reserve Credits by Category

Figure 3-22 shows that 79.4 percent of total operating reserve credits were in the balancing energy market category, which includes the balancing generator, real-time transactions, and lost opportunity cost credits.

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Figure 3-22 Operating reserve credits: Calendar year 2010

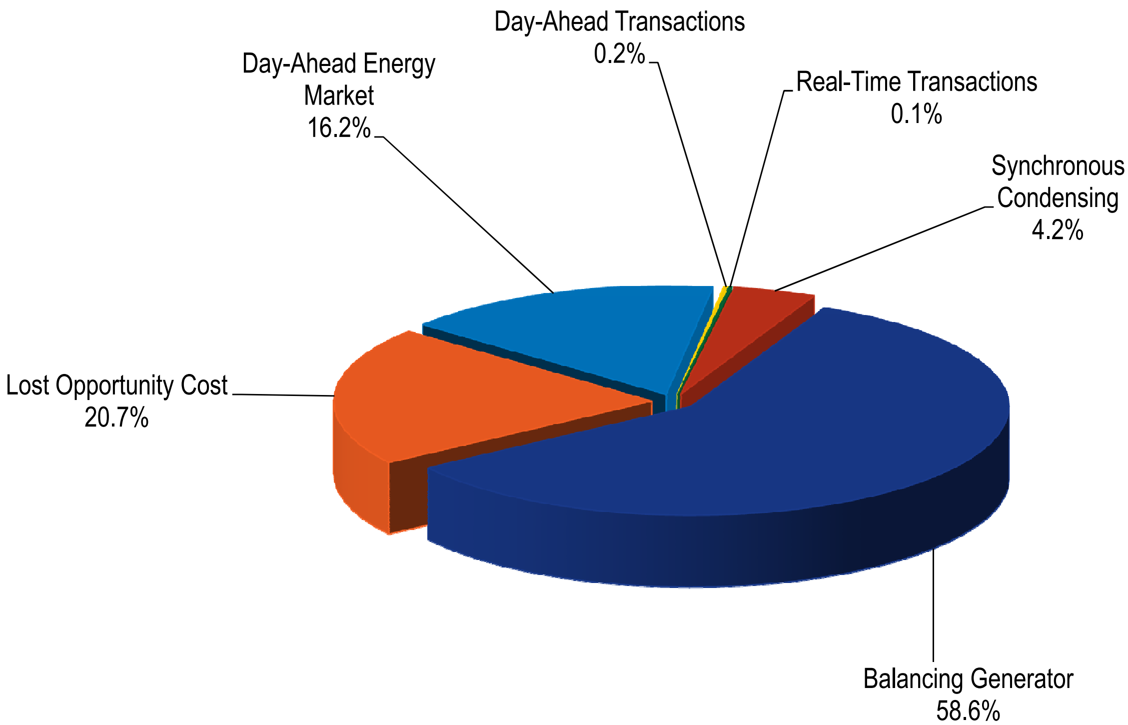

Table 3-81 shows the monthly totals for each type of credit for 2010. The winter months of 2010, which include January, February, November, and December, accounted for 36.2 percent of operating reserve credits for the year, while the summer months, which include May, June, July and August, accounted for 38.2 percent, and the shoulder months 25.6 percent. These credits do not equal the total amount of charges paid of $569,062,688. The difference of $18,407,371 was operating reserve billing adjustments made by PJM directly to participants' bills.[120]

120 PJM Settlements makes offline adjustments for credits to participants on a continuous basis, and these adjustments are not classified in one of the reported categories.

Table 3-81 Credits by month (By operating reserve market): Calendar year 2010[121]

	Day-Ahead Generator	Day-Ahead Transactions	Synchronous Condensing	Balancing Generator	Balancing Transactions	Lost Opportunity Cost	Total
Jan	$10,199,534	$81,816	$50,022	$34,146,809	$0	$3,333,858	$47,812,040
Feb	$11,382,585	$42,910	$14,715	$17,778,182	$77,139	$1,712,235	$31,007,765
Mar	$8,831,771	$5,115	$122,817	$13,931,307	$15,603	$1,971,841	$24,878,454
Apr	$7,633,141	$0	$93,253	$17,089,233	$0	$4,531,810	$29,347,437
May	$5,117,845	$9,462	$131,600	$23,339,866	$1,236	$15,665,943	$44,265,953
Jun	$3,469,143	$42,121	$33,923	$38,816,038	$196,537	$15,681,736	$58,239,499
Jul	$3,974,505	$627,284	$88,136	$36,965,861	$0	$23,571,309	$65,227,095
Aug	$3,391,194	$231,476	$66,535	$24,130,734	$0	$15,010,705	$42,830,644
Sep	$8,248,826	$185,065	$27,971	$26,086,355	$0	$13,876,042	$48,424,259
Oct	$7,719,743	$0	$1,543	$22,431,618	$4,053	$7,998,315	$38,155,272
Nov	$6,491,210	$65,505	$29,674	$16,412,647	$251,730	$3,355,934	$26,606,700
Dec	$12,951,611	$268	$59,954	$51,284,168	$22,546,342	$7,017,855	$93,860,198
Total	$89,411,108	$1,291,023	$720,142	$322,412,819	$23,092,640	$113,727,584	$550,655,317
Share of Credits	16.2%	0.2%	0.1%	58.6%	4.2%	20.7%	100.0%

Characteristics of Credits and Charges

Types of Units

Table 3-82 shows the distribution of credits by unit type and type of operating reserve. (Each row sums to 100 percent.)

Table 3-82 Credits by unit types (By operating reserve market): Calendar year 2010

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Total
Combined Cycle	33.5%	0.0%	61.1%	5.4%	$128,185,049
Combustion Turbine	2.0%	0.4%	58.5%	39.1%	$173,770,791
Diesel	2.5%	0.0%	83.1%	14.4%	$761,532
Hydro	0.0%	0.0%	100.0%	0.0%	$1,322,714
Landfill	0.0%	0.0%	0.0%	100.0%	$18,038,251
Nuclear	0.0%	0.0%	0.0%	100.0%	$3,155,919
Steam	21.4%	0.0%	69.9%	8.7%	$200,804,340
Wind Farm	0.0%	0.0%	100.0%	0.0%	$233,059

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

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Table 3-83 shows the distribution of credits for each type of operating reserves received by each unit type. (Each column sums to 100 percent.) Combined-cycle units and conventional steam units received 96.2 percent of the day-ahead generator credits. Combustion turbines received 100 percent of the synchronous condensing credits.

Table 3-83 Credits by operating reserve market (By unit type): Calendar year 2010

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost
Combined Cycle	48.1%	0.0%	24.3%	6.1%
Combustion Turbine	3.8%	100.0%	31.5%	59.8%
Diesel	0.0%	0.0%	0.2%	0.1%
Hydro	0.0%	0.0%	0.4%	0.0%
Landfill	0.0%	0.0%	0.0%	15.9%
Nuclear	0.0%	0.0%	0.0%	2.8%
Steam	48.1%	0.0%	43.5%	15.4%
Wind Farm	0.0%	0.0%	0.1%	0.0%
Total	$89,411,108	$720,142	$322,412,819	$113,727,584

Economic and Noneconomic Generation

Economic generation includes units producing energy at an offer price less than or equal to the LMP at the unit. Noneconomic generation includes units that are producing energy but at an offer price higher than the LMP at the unit. Balancing generator operating reserve credits are allocated on a segmented basis for each unique period that a unit operates, rather than an hour to hour basis. Therefore it is possible for a unit to have a segment during which some hours are economic and some hours are noneconomic. For example, if a unit is turned on to control a constraint, it would be considered economic at that time if the unit set the price in the constrained area or was inframarginal. However, if that unit needs to satisfy a minimum runtime because of physical operating characteristics, the unit may become noneconomic for the remainder of its runtime. Noneconomic and economic status may also change when units are run through the overnight hours in order to be available for morning load pickups.

The MMU analyzed the hours for which a unit received balancing generator operating reserve credits to determine which units are economic and noneconomic. Each hour was first determined to be economic or noneconomic based solely on the unit's hourly energy offer. The hourly energy offer does not include the hourly no-load cost or any applicable startup cost. A unit could be economic for every hour during a segment, but still receive balancing generator operating reserve credits because LMP revenue did not cover the additional startup and hourly no-load costs.

Table 3-84 shows the number of economic and noneconomic hours for each unit type. For example, of the 32,507 hours in which combined cycle units were paid balancing generator operating reserve credits, the LMP at the unit was higher than its real-time energy offer in 19,562 hours, or 60.2 percent of the time.

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Table 3-84 Economic vs. noneconomic hours: Calendar year 2010

Unit Type	Economic Hours	Economic Hours Percentage	Noneconomic Hours	Noneconomic Hours Percentage	Total Hours
Combined Cycle	19,562	60.2%	12,945	39.8%	32,507
Combustion Turbine	16,888	33.4%	33,641	66.6%	50,529
Diesel	1,011	31.7%	2,182	68.3%	3,193
Steam	57,536	78.7%	15,590	21.3%	73,126

Geography of Balancing Credits and Charges

Table 3-85 and Table 3-86 compare the share of balancing operating reserve charges paid by generators and balancing operating reserve credits paid to generators in the Eastern Region and the Western Region. Generation charges are defined in these tables as the allocation of charges paid by generators due to generator deviations from day-ahead schedules or not following PJM dispatch.[122] On average, 49.7 percent of balancing generator charges and 49.7 percent of lost opportunity cost charges were paid by generators deviating in the Eastern Region while these generators received 78.4 percent of all balancing generator credits and 83.2 percent of all lost opportunity cost credits. Table 3-85 and Table 3-86 also show generator credits and charges as shares of total operating reserve credits and charges.

Table 3-85 Monthly balancing operating reserve charges and credits to generators (Eastern Region): Calendar year 2010

	Unit Deviation Charges	Unit Deviation LOC Charges	Total Unit Deviation Charges	Balancing Generator Credit	LOC Credit	Total Balancing Credit
Jan	$1,913,490	$249,304	$2,162,794	$29,069,084	$2,730,988	$31,800,072
Feb	$1,069,496	$138,378	$1,207,873	$14,194,451	$1,375,982	$15,570,433
Mar	$591,204	$125,590	$716,795	$8,223,758	$1,399,277	$9,623,035
Apr	$904,242	$342,520	$1,246,763	$12,334,741	$3,370,088	$15,704,830
May	$919,969	$1,219,952	$2,139,922	$17,804,209	$13,869,787	$31,673,995
Jun	$1,335,181	$1,454,729	$2,789,910	$33,707,188	$14,552,023	$48,259,211
Jul	$2,254,298	$2,323,868	$4,578,166	$30,003,084	$19,048,045	$49,051,129
Aug	$1,575,868	$1,449,154	$3,025,022	$18,782,501	$10,495,220	$29,277,721
Sep	$1,199,555	$971,724	$2,171,280	$17,115,023	$12,709,146	$29,824,169
Oct	$1,399,801	$763,452	$2,163,252	$15,514,301	$7,391,601	$22,905,901
Nov	$934,410	$314,847	$1,249,257	$12,632,087	$2,966,149	$15,598,237
Dec	$5,370,588	$648,599	$6,019,187	$43,530,775	$4,659,867	$48,190,642
Avg.	49.7%	49.7%	49.7%	78.4%	83.2%	79.7%

122 The Eastern Region contains the BGE, Dominion, PENELEC, Pepco, Met-Ed, PPL, JCPL, PECO, DPL, PSEG, RECO, and AECO Control Zones. The Western Region includes the AEP, AP, ComEd, DLCO, and DAY Control Zones.

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Table 3-86 Monthly balancing operating reserve charges and credits to generators (Western Region): Calendar year 2010

	Unit Deviation Charges	Unit Deviation LOC Charges	Total Unit Deviation Charges	Balancing Generator Credit	LOC Credit	Total Balancing Credit
Jan	$1,971,007	$263,791	$2,234,797	$5,077,725	$602,870	$5,680,596
Feb	$998,751	$132,679	$1,131,430	$3,583,730	$336,253	$3,919,983
Mar	$756,085	$166,509	$922,594	$5,707,549	$572,564	$6,280,114
Apr	$1,099,662	$393,474	$1,493,136	$4,754,491	$1,161,722	$5,916,213
May	$935,038	$1,196,289	$2,131,327	$5,535,658	$1,796,157	$7,331,815
Jun	$1,233,687	$1,360,809	$2,594,496	$5,108,850	$1,129,713	$6,238,563
Jul	$1,883,906	$1,998,293	$3,882,198	$6,962,777	$4,523,264	$11,486,041
Aug	$1,478,290	$1,641,533	$3,119,823	$5,348,233	$4,515,485	$9,863,718
Sep	$1,573,967	$1,208,792	$2,782,759	$8,971,332	$1,166,896	$10,138,228
Oct	$1,060,568	$698,071	$1,758,639	$6,917,317	$606,714	$7,524,031
Nov	$880,641	$326,613	$1,207,254	$3,780,560	$389,785	$4,170,344
Dec	$5,822,566	$736,978	$6,559,544	$7,753,394	$2,357,989	$10,111,382
Avg.	50.3%	50.3%	50.3%	21.6%	16.8%	20.3%

Table 3-87 shows that on average, generator charges were 9.6 percent of all operating reserve charges and generator credits were 78.6 percent of all operating reserve credits. In 2009, generator charges were 8.4 percent of all charges, and generator credits were 68.7 percent of all credits.

Table 3-87 Percentage of unit credits and charges of total credit and charges: Calendar year 2010

	Total Unit Deviation Charges Percent of Total Operating Reserve Charges	Total Unit Credits Percent of Total Operating Reserve Credits
Jan	8.6%	78.4%
Feb	6.9%	62.9%
Mar	6.4%	63.9%
Apr	9.0%	73.7%
May	9.6%	88.1%
Jun	8.9%	93.6%
Jul	12.3%	92.8%
Aug	13.5%	91.4%
Sep	10.1%	82.5%
Oct	10.3%	79.8%
Nov	9.1%	74.3%
Dec	10.6%	62.1%
Avg.	9.6%	78.6%

Impacts of Revised Operating Reserve Rules

Review of Impact on Regional Balancing Operating Reserve Charges

The MMU has analyzed the net impact of allocating a proportion of balancing operating reserve credits to real-time load and exports. Credits that are received by generators that operate for reliability purposes are now paid as charges by organizations with real-time load and exports. Credits that are received by generators that operate for deviation purposes are still paid as charges by organizations that have deviations. The purpose of this rule change was to reallocate a portion of the balancing operating reserve charges to those requiring additional resources to maintain system reliability, real-time load and exports, and away from those creating deviations. The MMU calculated what balancing operating reserve charges would have been under the old rules and compared it to what actually happened in 2010.

Total reliability and deviation balancing operating reserve credits were $335,511,201 in 2010.[123] This is a 93.5 percent increase from 2009, which totaled $173,349,483. Table 3-88 shows each category of credits by region.

Table 3-88 Regional balancing operating reserve credits: Calendar year 2010

	Reliability Credits	Deviation Credits	Total Credits
RTO	$43,812,027	$184,318,710	$228,130,737
East	$48,187,002	$25,983,926	$74,170,928
West	$20,692,661	$12,516,876	$33,209,536
Total	$112,691,690	$222,819,512	$335,511,201

Table 3-89 shows the total amount of deviations in the demand, supply, and generator categories for 2010.

Table 3-89 Total deviations: Calendar year 2010

	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total
Total (MWh)	107,168,079	49,691,893	32,634,039	189,494,011

Under the old operating reserve rules, total charges for a day would have been applied to each organization's demand, supply, and generator deviations to calculate total charges.

For comparative purposes only, the old balancing rate in Table 3-90 was calculated as the total credits in Table 3-88 divided by total deviations in Table 3-89, or $335,511,201/189,494,011 MWh, a rate of $1.7706 per MWh. The MMU derived the rates on a daily basis and recalculated organizational charges.

123 Only balancing generator charges were in this analysis. The charges shown in this section do not include lost opportunity cost, cancellation, or local charges.

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Table 3-90 Charge allocation under old operating reserve construct: Calendar year 2010

	Demand Deviations	Supply Deviations	Generator Deviations	Total
Total (MWh)	107,168,079	49,691,893	32,634,039	189,494,011
Balancing Rate ($/MWh)	1.771	1.771	1.771	1.771
Charges ($)	$189,747,902	$87,982,658	$57,780,641	$335,511,201

Under the new operating reserve rules, rates are calculated separately for reliability and deviation categories in the Eastern, Western, and RTO Regions, resulting in six balancing rates. The Eastern and Western reliability rates are calculated by taking each region's daily reliability credits and dividing by each region's real-time load and exports. These regional rates are then charged to each organization's regional real-time load and exports. The RTO reliability rate is calculated by taking the total RTO reliability rates for the day and dividing it by the sum of eastern and western real-time load and exports. This rate is then charged to the sum of an organization's eastern and western real-time load and exports. Regional deviation credits are charged to the sum of demand, supply, and generator deviations for each region in which they occur (deviations at hubs that span both regions apply to RTO deviations).[124] Total RTO deviations are the sum of the eastern deviations, western deviations, and the deviations at hubs that span both regions.

For 2010, charges were actually allocated as shown in Table 3-91. For comparative purposes only, the reliability and deviation rates in the table are the annual credits divided by either real-time load and exports or total deviations ($43,812,027 / 725,676,358 = 0.0604, the RTO reliability rate). The charges are calculated based on the actual daily rates.

Table 3-91 Actual regional credits, charges, rates and charge allocation (MWh): Calendar year 2010

	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	$43,812,027	725,676,358	0.060	$43,812,027	$184,318,710	189,494,011	0.973	$184,318,710	$228,130,737
East	$48,187,002	396,774,572	0.121	$48,187,002	$25,983,926	115,064,099	0.226	$25,983,926	$74,170,928
West	$20,692,661	328,901,786	0.063	$20,692,661	$12,516,876	74,189,868	0.169	$12,516,876	$33,209,536
Total	$112,691,690	725,676,358	NA	$112,691,690	$222,819,512	189,494,011	NA	$222,819,512	$335,511,201

The difference between the charges based on the old operating reserve rules (Table 3-90) and the actual charges allocated under the current rules is shown in Table 3-90, separated by deviation type. The total amount of charges reallocated from the demand, supply, and generator deviations is equal to the amount of total reliability charges.

124 Only two hubs span across both the eastern and western regions: the Dominion Hub and the Western Int. Hub.

Table 3-92 Difference in total operating reserve charges between old rules and new rules: Calendar year 2010

	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	$189,747,902	$87,982,658	$57,780,641	$335,511,201
Charges (Current)	$108,427,088	$4,264,602	$112,691,690	$125,186,058	$58,297,355	$39,336,099	$222,819,512
Difference	$108,427,088	$4,264,602	$112,691,690	($64,561,844)	($29,685,303)	($18,444,542)	($112,691,690)

An increase of $112,691,690 of charges was assigned to real-time load and exports for 2010. Real-time load paid an additional $108,427,088, while real-time exports paid an additional $4,264,602. These increases were matched by a decrease of $64,343,546 in charges to demand deviations, a decrease of $29,548,082 in charges to supply deviations, and a decrease of $18,764,061 in charges to generator deviations. Reliability charges accounted for 33.6 percent of total balancing operating reserve charges.

Impact on decrement bids and incremental offers

The MMU has estimated the impact of the new balancing operating reserve rules on the allocation of charges to virtual activity. The level of virtual activity that was not otherwise netted out was calculated by organization for increment offers and decrement bids. All organizational deviations were grouped into regions. "Total Increment Offers" and "Total Decrement Bids", shown in Table 3-93, is the sum of cleared virtual activity for 2010. "Adjusted Increment Offer Deviations" and "Adjusted Decrement Bid Deviations" are the net deviations for each type of virtual trade that were not offset by other positions, such as load, sales, purchases, exports, or imports. For example if a participant has the following position: in the Day-Ahead Market, a 100 MWh decrement bid, 50 MWh load, 10 MWh sale, and a 5 MWh export transaction, and in the Real-Time Market, a 55 MWh load, a 5 MWh sale, and a 5 MWh export transaction. The additional 5 MWh of real-time load, and deficiency of 5 MWh of real-time sales offset each other, leaving a 100 MWh net deviation from the decrement bid.

Table 3-93 Total virtual bids and amount of virtual bids paying balancing operating charges (MWh): Calendar year 2010

Month	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
Feb	8,323,844	11,828,781	2,004,162	2,234,045
Mar	8,032,429	11,159,303	2,150,898	2,594,826
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

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In order to determine what these deviation charges would have been under the old balancing operating reserve rules, balancing operating reserve rates were determined for each day. Balancing operating reserve credits paid to generators were recalculated using the old rules that evaluated units over the entire 24 hours for each day. The new rules evaluate units by operating segments within a day. Supply, demand, and generator deviations were recalculated by netting participants' deviations across the RTO. The new rules net supply and demand deviations by zone, hub, or interface, and net generator deviations by bus, provided they are electrically equivalent and owned by the same participant. Generator deviations were not adjusted for changes in regard to the use of ramp-limited desired MW under the current rules. The resulting daily balancing operating reserve rate was determined by dividing balancing operating reserve credits by supply, demand, and generator deviations, then adding the daily lost opportunity cost rate.

Total charges were calculated for each company using this balancing rate and the sum of their adjusted increment offer and decrement bids. The resulting total amount of charges that would have been paid by virtual activity in 2010 was $132,741,464. Under the current rules, this charge is $106,719,600. The monthly differences can be seen in Table 3-94.

Table 3-94 Comparison of balancing operating reserve charges to virtual bids: Calendar year 2010

Month	Charges Under Old Rules	Charges Under Current Rules	Difference
Jan	$12,525,384	$10,190,867	($2,334,517)
Feb	$5,319,874	$3,936,420	($1,383,454)
Mar	$4,797,076	$3,468,829	($1,328,248)
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)

The net result is that virtual offers and bids paid $26,021,864 less in operating reserve charges as a result of the change in rules than they would have paid under the old rules. These charges were paid by real time load and exports. A summary showing this breakdown for each region is shown in Table 3-95.

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Table 3-95 Summary of impact on virtual bids under balancing operating reserve allocation: Calendar year 2010

Region	Adjusted Increment Offer Deviations (MWh)	Adjusted Decrement Bid Deviations (MWh)	Total Adjusted Virtual Deviations (MWh)	Balancing Rate Old Rules ($/MWh)	Balancing Rate Current Rules ($/MWh)	Charges Under Old Rules	Charges Under Current Rules	Differerence
RTO	23,609,817	35,212,727	58,822,544	2.17	1.53	$132,741,464	$94,844,415	($37,897,048)
East	14,596,342	20,413,754	35,010,096	0.00	0.16	$0	$8,056,742	$8,056,742
West	8,933,131	14,491,720	23,424,851	0.00	0.00	$0	$3,818,443	$3,818,443

Segmented Make Whole Payments

Under the old operating reserve rules, balancing operating reserves for units were evaluated over the entire 24-hour period of the day. Under the new rules:[125]

> "Balancing Operating Reserve credits are calculated by operating segment within an Operating Day. A resource will be made whole for the duration of the greater of the day-ahead schedule or minimum run time (minimum down time for demand resources) and made whole separately for the block of hours it is operated at PJM's direction in excess of the greater of the day-ahead schedule or minimum run time (minimum down time for demand resources). Startup costs (shut down costs for demand resources), as applicable, will be included in the segment represented by the longer of the day-ahead schedule or minimum run time (minimum down time for demand resources)."

The primary intent of this rule was to provide incentives for generating units to follow PJM dispatch after the end of their day-ahead schedule or minimum run time and to provide incentives to offer flexible schedules and to follow dispatch when economic.

The MMU analyzed the impact of segmented make whole payments on balancing operating reserves. The MMU compared what balancing credits would have been for each unit for each day under the old rules to what the credits were under the new rules. As a result of the introduction of segmented make whole payments in place of 24 hour make whole payments, balancing operating credits were $26,262,054 higher, or 5.2 percent, from December 1, 2008 through December 31, 2010. The total increase for the calendar year 2010 was $18,087,648, or 6.0 percent. Table 3-96 provides a breakdown of monthly differences between the two methods of calculation since December 2008.

125 Manual 28: *Operating Agreement Accounting* Section 5: Operating Reserve Accounting 5.2.1

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Table 3-96 Impact of segmented make whole payments: December 2008 through December 2010

Year	Month	Balancing Credits Under Old Rules	Balancing Credits Under New Rules	Difference
2008	Dec	$17,879,706	$18,564,627	$684,920
2009	Jan	$24,958,891	$26,413,119	$1,454,228
2009	Feb	$13,834,755	$14,391,550	$556,795
2009	Mar	$21,434,893	$22,200,141	$765,248
2009	Apr	$10,532,594	$10,741,260	$208,666
2009	May	$13,499,668	$13,813,209	$313,541
2009	Jun	$15,111,383	$16,058,545	$947,162
2009	Jul	$14,657,498	$15,414,023	$756,525
2009	Aug	$14,467,711	$15,602,754	$1,135,043
2009	Sep	$10,293,949	$10,576,618	$282,669
2009	Oct	$14,337,978	$14,605,878	$267,900
2009	Nov	$8,889,163	$9,091,845	$202,682
2009	Dec	$19,403,859	$20,002,885	$599,026
2010	Jan	$32,982,105	$33,924,489	$942,385
2010	Feb	$17,321,317	$17,609,133	$287,815
2010	Mar	$13,458,120	$13,672,172	$214,052
2010	Apr	$16,441,644	$17,036,058	$594,414
2010	May	$21,854,306	$23,455,721	$1,601,415
2010	Jun	$36,297,521	$38,885,349	$2,587,828
2010	Jul	$32,251,623	$37,053,630	$4,802,007
2010	Aug	$21,867,024	$24,335,171	$2,468,147
2010	Sep	$24,293,196	$25,686,790	$1,393,593
2010	Oct	$21,839,101	$22,478,455	$639,354
2010	Nov	$15,795,391	$16,238,383	$442,991
2010	Dec	$49,180,164	$51,293,810	$2,113,646
Total		$502,883,559	$529,145,613	$26,262,054

Table 3-97 shows the effect of segmented make whole payments on each type of unit that received balancing operating reserve credits for the period from December 1, 2008 through December 31, 2010. "Number of Unit-Days" in the table is the count of units that received balancing credits each day, summed across the entire year. For example, an average of 26 combined-cycle units received credits for each day of the year (9,482 / 365 = 26). The average daily amount received in credits for a unit for each method of calculation was analyzed to show the impact of an average day for each type of unit. The last three columns in the table show the total difference in credits for the time period across each unit type.

Table 3-97 Impact of segmented make whole payments (By unit type): Calendar year 2010

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	9,482	$7,608	$8,254	$646	$72,138,362	$78,262,392	$6,124,030
Large Frame Combustion Turbine (135 - 180 MW)	3,885	$9,129	$10,143	$1,015	$35,465,394	$39,406,789	$3,941,395
Medium Frame Combustion Turbine (30 - 65 MW)	9,827	$3,491	$3,834	$342	$34,309,724	$37,673,652	$3,363,928
Medium-Large Frame Combustion Turbine (65 - 125 MW)	2,947	$5,884	$6,365	$481	$17,340,058	$18,757,970	$1,417,912
Petroleum/Gas Steam (Pre-1985)	1,171	$59,386	$60,537	$1,151	$69,541,058	$70,888,358	$1,347,300
Sub-Critical Coal	29,988	$1,737	$1,763	$26	$52,100,107	$52,880,369	$780,262
Petroleum/Gas Steam (Post-1985)	2,328	$2,472	$2,778	$306	$5,754,062	$6,466,904	$712,842
Small Frame Combustion Turbine (0 - 29 MW)	3,690	$1,691	$1,779	$88	$6,240,408	$6,564,842	$324,434
Diesel	4,561	$123	$139	$16	$559,413	$634,601	$75,188
Super-Critical Coal	9,044	$1,104	$1,104	$0	$9,982,209	$9,982,565	$357
Hydro	768	$196	$196	$0	$150,717	$150,717	$0

From December 1, 2008, through December 31, 2009, combined-cycles received nearly 50 percent of the increase in segmented make-whole payments, and combustion turbines 37.9 percent. In 2010, combustion turbines received 50.0 percent of this increase, and combined-cycles 33.9 percent (Table 3-98). This is a result of the increased dispatch in 2010 related to higher loads which led to the overall increase of balancing operating reserve credits paid to combustion turbines in 2010 (Table 3-82 and Table 3-83). Under the old rules, combustion turbines would have been paid $93,355,584, and with segmented make whole payments, the units received $102,403,253, a total difference of $9,047,669, or a 9.7 percent increase.

Table 3-98 Share of balancing operating reserve increases for segmented make whole payments (By unit type): December 2008 through December 2010

Unit Type	Share of Increase
Combustion Turbines	50.0%
Combined-Cycle	33.9%
Steam	15.7%
Diesel	0.4%
Hydro	0.0%

Unit Operating Parameters

The use of restrictive operating parameters to exercise market power and inflate operating reserve credits was addressed, based on the MMU's analysis and positions, in the revised operating reserve rules. The MMU's prior analyses indicated that operating reserve credits may result from the submission of artificially restrictive, unit-specific operating parameters.[126] The MMU also pointed out that restrictive operating parameters can interact with unit-specific markups to increase operating reserve payments to units.

126 See the *2009 State of the Market Report for PJM*, Volume II, "Section 3, Energy Market, Part 2" at "Operating Reserve."

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The new operating reserves rules addressed the parameter issue by establishing a parameter limited schedule (PLS) that helps prevent the use of restrictive operating parameters when units have local market power. Table 3-99 shows the parameter limited matrix for periods that are currently effective.[127]

Table 3-99 Unit Parameter Limited Schedule Matrix

Unit Type	Minimum Run Time (Hours)	Minimum Down Time (Hours)	Maximum Daily Starts	Maximum Weekly Starts	Turn Down Ratio
Petroleum/Gas Steam (Pre-1985)	8 or Less	7 or Less	1 or More	7 or More	3 or More
Petroleum/Gas Steam (Post-1985)	5.5 or Less	3.5 or Less	2 or More	11 or More	2 or More
Combined-Cycle	6 or Less	4 or Less	2 or More	11 or More	1.5 or More
Sub-Critical Coal	15 or Less	9 or Less	1 or More	5 or More	2 or More
Super-Critical Coal	24 or Less	84.0	1 or More	2 or More	1.5 or More
Small Frame and Aero Combustion Turbine (0 - 29 MW)	2 or Less	2 or Less	2 or More	14 or More	1 or More
Medium Frame and Aero Combustion Turbine (30 - 65 MW)	3 or Less	2 or Less	2 or More	14 or More	1 or More
Medium-Large Frame Combustion Turbine (65 - 125 MW)	5 or Less	3 or Less	2 or More	14 or More	1 or More
Large Frame Combustion Turbine (135 - 180 MW)	5 or Less	4 or Less	2 or More	14 or More	1 or More

Units may request exceptions to the values in the matrix. The MMU analyzed the frequency with which these exceptions affected market outcomes. The only units included in the analysis were units put on their cost schedule after failing the TPS test. There were 568 events, affecting 58 unique units, when a unit with a PLS exception was capped and received balancing operating reserve credits (Table 3-100). The number of events occurring in 2010 more than doubled from the period December 1, 2008 through December 31, 2009, during which 216 events, and 44 unique units, were capped while receiving credits.

Table 3-100 Units receiving credits from a parameter limited schedule: December 2008 through December 2010

Unit Type	Number of Units	Observations
Combined-Cycle	4	11
Large Frame Combustion Turbine (135 - 180 MW)	10	105
Medium-Large Frame Combustion Turbine (65 - 125 MW)	10	152
Petroleum/Gas Steam (Pre-1985)	5	15
Sub-Critical Coal	28	284
Super-Critical Coal	1	1

127 See PJM "Parameter Limited Schedule Matrix," for parameter levels at <http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/20080916-parameter-limited-schedule-matrix.ashx> (104 KB).

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Issues in Operating Reserves

Market Power Issues

The exercise of market power by units that are paid operating reserve credits has contributed to the level of operating reserve charges paid by PJM members. The inflexible operating parameter issue was addressed by the introduction of new PJM rules implementing parameter limited schedules.

Markup

The MMU analyzed the top 10 units receiving operating reserve credits to determine the contribution that markup makes to operating reserve payments.[128] The markup for the top 10 units averaged 33.8 percent in 2010. The markup for the top 10 units is a weighted average, weighted by generator output when operating reserve credits are paid.

The generation owner with the largest share of operating reserve credits had a weighted average markup of 0.0 percent in 2010. The generation owners with the second and third largest share (22.8 and 22.8 percent each) had a weighted-average markup of 16.3 percent and 76.5 percent.

Concentration of Operating Reserve Credits

There remains a high degree of concentration in the units and companies receiving operating reserve credits. This concentration appears to result from a combination of unit operating characteristics and PJM's persistent need for operating reserves in particular locations.

The concentration of operating reserve credits is first examined by analyzing the characteristics of the top 10 units receiving operating reserve credits. The focus on the top 10 units is illustrative.

The concentration of operating reserve credits remains high, but decreased in 2010 compared to 2009. As Table 3-101 shows, the top 10 units receiving total operating reserve credits, which make up less than one percent of all units in PJM's footprint, received 33.2 percent of total operating reserve credits in 2010, compared to 37.1 percent in 2009. The top 20 units received 42.2 percent of total operating reserve credits in 2010 and 46.0 percent in 2009. In 2010, the top generation owner received 24.9 percent of the total operating reserve credits paid, a decrease from 2009, when the top generation owner received 32.8 percent of the total operating reserve credits.

128 Markup is calculated as [(Price – Cost)/Cost] where cost represents the cost-based offer as defined in PJM "Manual 15: Cost Development Guidelines," Revision 11 (December 2, 2009). As a result, the markups here are not directly comparable to those calculated as [(Price – Cost)/Price].

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Table 3-101 Top 10 operating reserve revenue units (By percent of total system): Calendar years 2001 to 2010

	Top 10 Units Credit Share	Percent of Total PJM Units
2001	46.7%	1.8%
2002	32.0%	1.5%
2003	39.3%	1.3%
2004	46.3%	0.9%
2005	27.7%	0.8%
2006	29.7%	0.8%
2007	29.7%	0.8%
2008	18.8%	0.8%
2009	37.1%	0.8%
2010	33.2%	0.8%

Table 3-102 shows the distribution of operating reserve credits to units by zone. The top three zones accounted for 63.5 percent of the total. The PSEG Control Zone had the largest share of credits with 25.2 percent, the Dominion Control Zone was the second highest with 19.2 percent, and the Pepco Control Zone was third with a 19.1 percent share.

Table 3-102 Unit operating reserve credits for units (By zone): Calendar year 2010

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	$671,820	$5,514	$2,197,947	$3,905,127	$6,780,409	1.3%
AEP	$2,870,042	$13,296	$40,332,870	$3,704,606	$46,920,814	8.9%
AP	$2,027,358	$0	$6,426,335	$8,054,017	$16,507,710	3.1%
BGE	$8,956,887	$0	$12,312,645	$522,499	$21,792,031	4.1%
ComEd	$1,580,732	$4,080	$9,486,213	$6,808,692	$17,879,718	3.4%
DAY	$211,857	$0	$2,225,821	$328,481	$2,766,159	0.5%
DLCO	$2,634,354	$0	$11,030,377	$263,615	$13,928,345	2.6%
Dominion	$5,725,788	$0	$40,320,399	$54,819,450	$100,865,636	19.2%
DPL	$3,768,620	$10,337	$12,471,215	$2,119,131	$18,369,303	3.5%
JCPL	$2,887,195	$0	$7,851,450	$879,855	$11,618,499	2.2%
Met-Ed	$433,474	$0	$2,524,121	$805,995	$3,763,590	0.7%
PECO	$2,253,955	$2,095	$8,290,005	$2,552,626	$13,098,681	2.5%
PENELEC	$621,324	$27,409	$1,512,030	$5,416,639	$7,577,402	1.4%
Pepco	$8,614,205	$0	$77,353,307	$14,720,240	$100,687,751	19.1%
PPL	$429,429	$0	$8,230,711	$2,686,247	$11,346,387	2.2%
PSEG	$45,724,070	$657,410	$79,847,372	$6,140,365	$132,369,216	25.2%
RECO	$0	$0	$0	$0	$0	0.0%
External	$0	$0	$0	$0	$0	0.0%
Total	$89,411,108	$720,142	$322,412,819	$113,727,584	$526,271,654	100.0%

Table 3-103 rank orders the top 10 units receiving total operating reserve credits, and the top 10 organizations receiving total operating reserve credits. The organization ranked number one does not necessarily own the unit that is ranked number one. The unit that received the most total operating reserve credits received $43,439,277 for 2010, or 8.3 percent of the total operating reserve credits paid to all units, compared to 12.7 percent for the top unit of 2009. The cumulative distribution column shows that the top 10 units had a 33.2 percent share of the total operating reserve credits in 2010. The top organization had a 24.9 percent share of the total credits, or $131,269,636, compared to 32.8 percent in 2009. The top 10 organizations receiving credits had a cumulative share of 83.1 percent.

Table 3-103 Top 10 units and organizations receiving total operating reserve credits: Calendar year 2010

	Units			Organizations		
Rank	Total Credit	Total Credit Share	Total Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$43,439,277	8.3%	8.3%	$131,269,636	24.9%	24.9%
2	$31,556,899	6.0%	14.3%	$97,277,079	18.5%	43.4%
3	$21,543,721	4.1%	18.3%	$62,600,022	11.9%	55.3%
4	$18,256,867	3.5%	21.8%	$37,756,657	7.2%	62.5%
5	$14,332,143	2.7%	24.5%	$25,523,773	4.8%	67.3%
6	$13,921,639	2.6%	27.2%	$21,725,470	4.1%	71.5%
7	$13,399,983	2.5%	29.7%	$20,941,025	4.0%	75.5%
8	$6,284,703	1.2%	30.9%	$18,484,418	3.5%	79.0%
9	$6,186,466	1.2%	32.1%	$13,949,799	2.7%	81.6%
10	$5,556,922	1.1%	33.2%	$7,749,082	1.5%	83.1%

Table 3-104 rank orders the top 10 units receiving day-ahead operating reserve credits, and the top 10 organizations receiving day-ahead operating reserve credits. The top unit received $19,218,254, or 21.5 percent of the total day-ahead generator credits, which is nearly identical with 2009. The second unit had a 12.3 percent share, which when combined with the top unit was 33.8 percent of the total credits. The top organization in 2010 received 51.0 percent of the day-ahead credits, compared to 48.9 percent in 2009. The top 10 organizations received 90.3 percent of the day-ahead credits.

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Table 3-104 Top 10 units and organizations receiving day-ahead generator credits: Calendar year 2010

	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	$19,218,254	21.5%	21.5%	$45,588,536	51.0%	51.0%
2	$10,979,961	12.3%	33.8%	$9,200,533	10.3%	61.3%
3	$8,237,693	9.2%	43.0%	$7,569,378	8.5%	69.7%
4	$3,596,128	4.0%	47.0%	$4,721,875	5.3%	75.0%
5	$3,418,695	3.8%	50.8%	$3,233,156	3.6%	78.6%
6	$3,165,849	3.5%	54.4%	$3,157,821	3.5%	82.2%
7	$2,573,784	2.9%	57.3%	$2,315,364	2.6%	84.8%
8	$2,315,364	2.6%	59.8%	$2,182,215	2.4%	87.2%
9	$2,119,032	2.4%	62.2%	$1,470,017	1.6%	88.8%
10	$1,555,872	1.7%	64.0%	$1,271,978	1.4%	90.3%

Table 3-105 rank orders the top 10 units receiving synchronous condensing credits, and the top 10 organizations receiving synchronous condensing credits. This market remains even more highly concentrated the operating reserve credits overall, as the top organization received 91.3 percent of synchronous condensing credits, up from 89.4 percent in 2009.

Table 3-105 Top 10 units and organizations receiving synchronous condensing credits: Calendar year 2010

	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	$55,449	7.7%	7.7%	$657,410	91.3%	91.3%
2	$54,979	7.6%	15.3%	$27,409	3.8%	95.1%
3	$52,148	7.2%	22.6%	$14,309	2.0%	97.1%
4	$51,860	7.2%	29.8%	$13,296	1.8%	98.9%
5	$47,298	6.6%	36.3%	$4,080	0.6%	99.5%
6	$43,700	6.1%	42.4%	$2,095	0.3%	99.8%
7	$37,144	5.2%	47.6%			
8	$34,526	4.8%	52.4%			
9	$32,934	4.6%	56.9%			
10	$31,449	4.4%	61.3%			

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Table 3-106 rank orders the top 10 units receiving balancing generator credits, and the top 10 organizations receiving balancing generator credits. The top organization received 24.5 percent of total credits, down from 29.3 percent in 2009. The top ten organizations received a total of 87.4 percent of all the balancing generator credits.

Table 3-106 Top 10 units and organizations receiving balancing generator credits: Calendar year 2010

	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	$32,448,468	10.1%	10.1%	$78,884,956	24.5%	24.5%
2	$21,542,992	6.7%	16.7%	$56,452,837	17.5%	42.0%
3	$17,918,553	5.6%	22.3%	$49,475,085	15.3%	57.3%
4	$12,365,767	3.8%	26.1%	$33,453,646	10.4%	67.7%
5	$12,302,180	3.8%	30.0%	$16,516,178	5.1%	72.8%
6	$9,977,020	3.1%	33.0%	$16,311,940	5.1%	77.9%
7	$6,094,250	1.9%	34.9%	$15,007,623	4.7%	82.5%
8	$4,616,286	1.4%	36.4%	$6,063,758	1.9%	84.4%
9	$4,119,971	1.3%	37.6%	$5,254,273	1.6%	86.0%
10	$3,805,134	1.2%	38.8%	$4,459,378	1.4%	87.4%

Table 3-107 rank orders the top 10 units receiving lost opportunity cost credits, and the top 10 organizations receiving lost opportunity cost credits. The top organization received 35.4 percent of the total lost opportunity cost credits and 80.9 percent were received by the top 10 organizations.

Table 3-107 Top 10 units and organizations receiving lost opportunity cost credits: Calendar year 2010

	Units			Organizations		
Rank	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution
1	$4,577,153	4.0%	4.0%	$40,232,616	35.4%	35.4%
2	$4,567,656	4.0%	8.0%	$18,458,356	16.2%	51.6%
3	$3,598,190	3.2%	11.2%	$7,751,095	6.8%	58.4%
4	$3,288,209	2.9%	14.1%	$6,138,734	5.4%	63.8%
5	$3,097,224	2.7%	16.8%	$3,913,969	3.4%	67.3%
6	$2,702,194	2.4%	19.2%	$3,657,338	3.2%	70.5%
7	$2,691,504	2.4%	21.6%	$3,444,927	3.0%	73.5%
8	$2,597,591	2.3%	23.8%	$3,415,707	3.0%	76.5%
9	$2,557,217	2.2%	26.1%	$2,899,720	2.5%	79.1%
10	$2,494,927	2.2%	28.3%	$2,120,795	1.9%	80.9%

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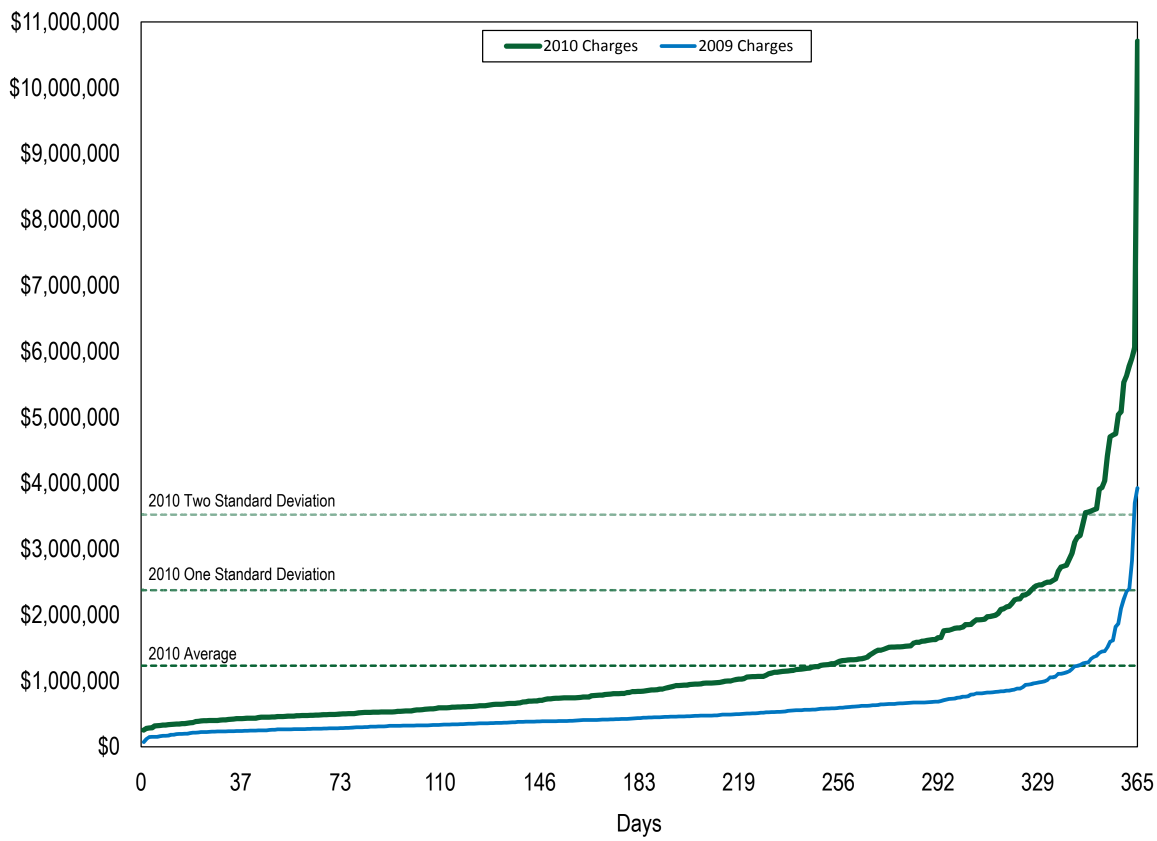
Increased Operating Reserve Charges

Summary

Operating reserve charges in 2010 increased 74.6 percent overall when compared to 2009, including a 120.0 percent increase in balancing generator credits. Total balancing generator credits for 2010 totaled $449,325,457, compared to $204,229,481 in 2009. Figure 3-23 shows the distribution of daily balancing generator credits for 2010 and 2009. The distribution curve for 2010 is higher for each day of the year, and starts to diverge towards the upper end of the distribution. The highest level of balancing generator credits paid for one day in 2010 was $10,707,778, compared to $3,927,226 in 2009. Figure 3-23 shows that the average daily balancing credits paid to generators was $1,231,103, with a standard deviation of $1,145,882. Only 22 days in 2009, or 6.0 percent of the days in the year, had daily balancing operating reserve credits paid to generators higher than the average daily payment in 2010.

Figure 3-23 Balancing Generator Credits Daily Distribution: Calendar year 2010 and 2009



Causes

Weather is one of the primary drivers of load in PJM. The summer of 2010 had higher than average temperatures across the PJM region. PJM hourly average real-time load increased in 2010 by 4.7 percent from 2009. Increases in demand require more generators to operate for longer periods of time. PJM declared Hot Weather Alerts on 36 days. This may result in extra generators being scheduled in order to meet the expected loads. A period of consecutive days with high temperatures requires more generating units to remain online for long periods of time. Increased forced outages result.

Table 3-108 shows the MWh loss from outages in 2010 and 2009. This includes planned, maintenance, and forced outages. MWh loss is the MW reduction of the outage multiplied by length in hours of the outage. The MWh lost due to outages increased by 13,464,130 MWh, or 5.5 percent, in 2010. Lengthy outages from large baseload coal units to make long-term improvements occurred in 2010, resulting in the increase of MWh lost.

Table 3-108 Loss of MWh from outages: Calendar year 2009 and 2010

Unit Type	2009 MWh Loss	2010 MWh Loss	MWh Loss Difference
Steam	157,405,677	173,295,820	15,890,143
Combined Cycle	26,419,761	29,524,036	3,104,275
Combustion Turbine	18,100,396	19,063,448	963,052
Other	10,451,976	8,712,275	(1,739,701)
Nuclear	31,498,585	26,744,946	(4,753,639)
Total	243,876,395	257,340,525	13,464,130

Fuel prices play a major role in the overall level of operating reserve credits to generators. Fuel prices are the largest and most volatile component of a units' daily offers. Eastern and western natural gas prices were 12.3 and 11.0 percent higher in 2010 than in 2009. Light fuel No. 2 oil and heavy fuel No. 6 oil prices were 29.3 and 32.3 percent higher in 2010 than in 2009.[129] Natural gas prices are relatively volatile prices. There are 13 major pipelines serving the PJM region. Transco pipeline pricing points Zone 5, Zone 6 Non New York, and Zone 6 New York, and the Texas Eastern M3 pricing point, have the most volatile natural gas prices of the pipelines and associated delivery zones. There are a large group of generators served by these pipelines that are located in high load areas of PJM. During periods of extreme cold, typically when temperatures reach 10 degrees Fahrenheit or less, these pipelines charge a premium for gas, which can be as high as three times the non premium price. When offers increase, the cost to operate units increases and credits paid to generators increase. Table 3-109 compares the minimum, maximum, average, and standard deviation of daily delivery prices ($/MMBtu) for Transco Zone 5, Zone 6 Non New York, and Zone 6 New York, Texas Eastern M3 zone, and all other pricing points used for PJM generator offers.

Table 3-109 Natural Gas Pipeline and Zone Delivery Price Summary: Calendar Year 2010[21]

Year	Pricing Points	Min	Max	Mean	Std. Dev
2010	Transco and Texas Eastern M3	$5.19	$20.34	$3.28	$1.89
2010	Other Pricing Points	$4.45	$7.94	$2.85	$0.74

129 Fuel data reported in this analysis are the average of daily fuel price indices in the PJM footprint. All data from Platts.

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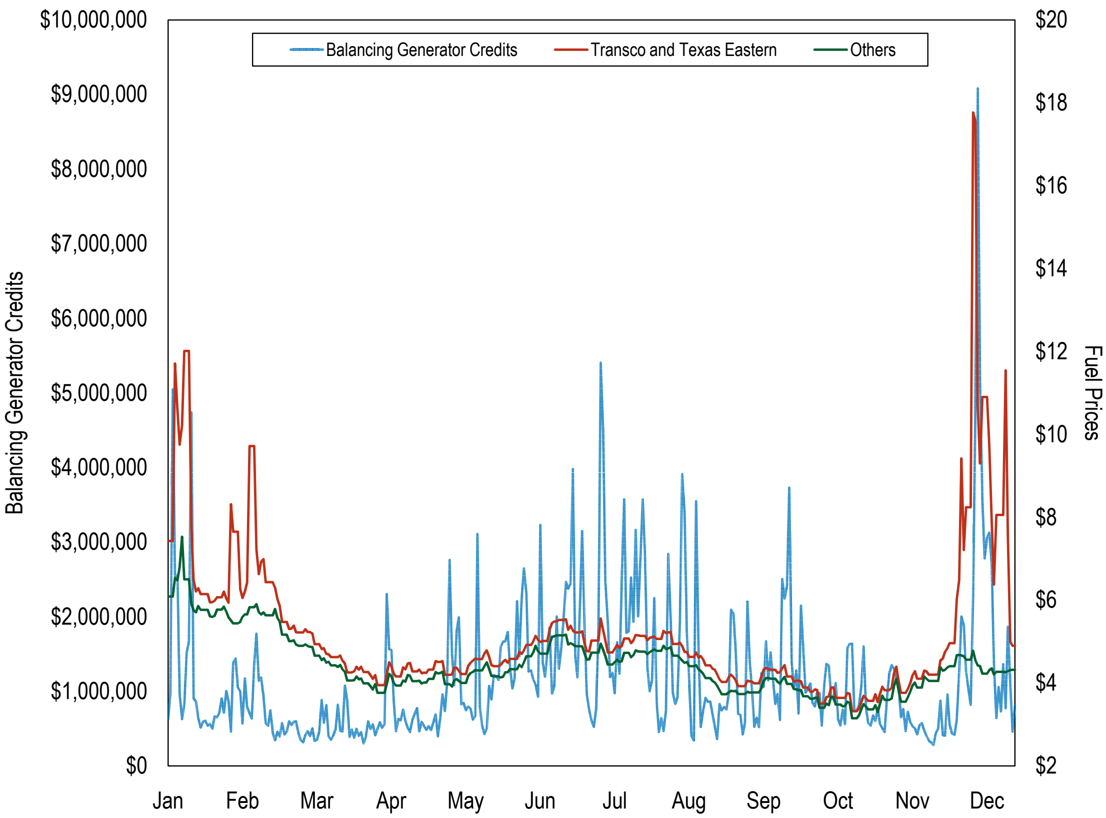
On December 13th, 2010, PJM issued a Cold Weather Alert, during which PJM notified generation owners to be prepared to call in additional staff to prepare all generating units to run for the morning pickup. As a result of the increased number of out of merit units, and high natural gas prices, balancing operating reserve credits received during the period from December 13 through December 22, 2010, which accounts for 2.7 percent of the days of the year, were $56,595,618.00, or 12.6 percent of all operating reserve credits for the year.

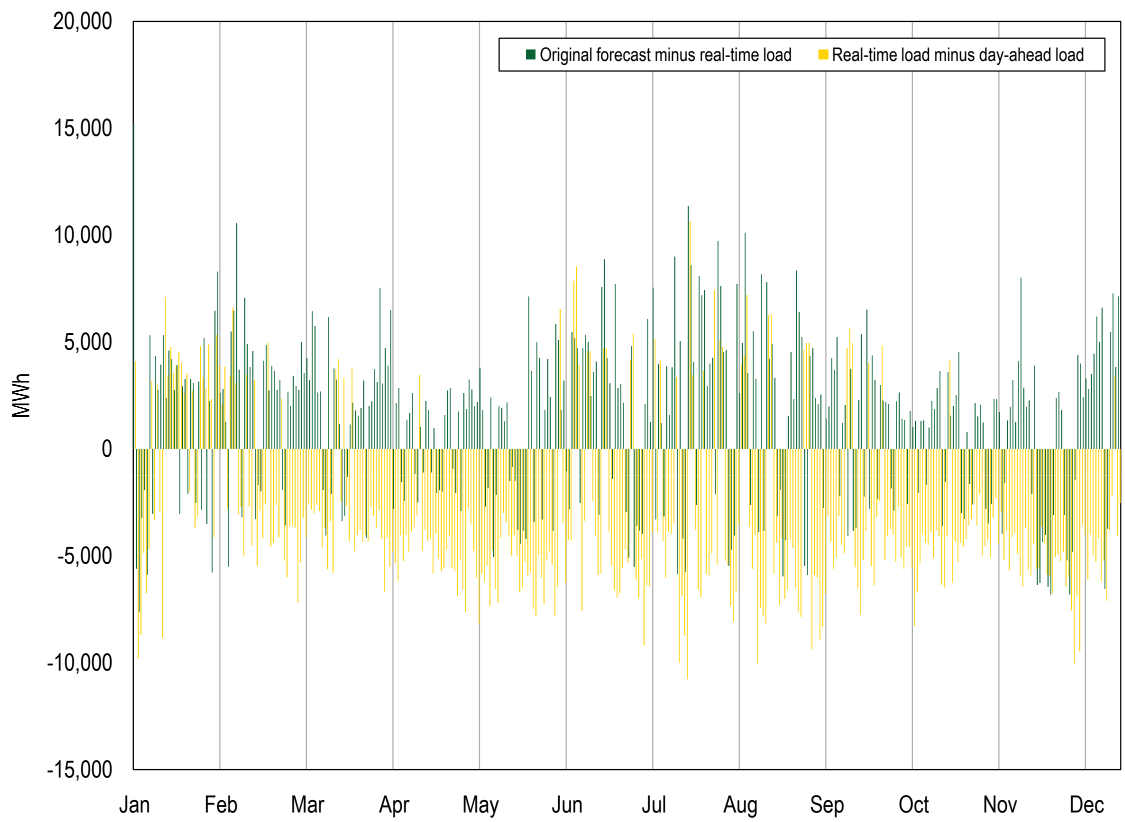
Figure 3-24 shows the average daily spot price ($/MMBtu) for various natural gas pricing points serving the PJM territory. The "Transco and Texas Eastern" group are the Transco Zone 5, Zone 6 Non New York, Zone 6 New York, and the Texas Eastern M3 prices, and the "Others" group are all other pricing points used for PJM generator offers.

Figure 3-24 Daily Natural Gas Pipeline and Zone Delivery Prices: Calendar year 2010



Forecasting load also plays a role in the level of operating reserves paid to generators. Over-forecasting or under-forecasting could result in running units uneconomically. For example, if Day-Ahead load is over-forecasted, additional generators may be scheduled in the Day-Ahead Market. If they are not needed during the operational day, generators can receive cancellation costs. If a unit has a day-ahead schedule and is started at a specific hour in order to meet real-time load, but is not needed during the operational day, they must remain online to satisfy minimum runtimes, and be made whole for the entire period. Short-term forecasts are also updated throughout the operating day. If short-term forecasts are high, and PJM instructed additional units to start that are no longer needed, they will remain on to satisfy minimum runtimes. These units are frequently combustion turbines running on natural gas or oil. When load is under-forecasted, PJM must dispatch units during the operating day that can start quickly to adjust for the unexpected load. Again, these are frequently combustion turbines running on natural gas or oil. Figure 3-25 shows the daily maximum hourly difference between the original PJM forecasted load and the actual real-time load, and the daily maximum hourly difference of the actual real-time load and day-ahead load. Original PJM forecasted load refers to the last forecast made on a day for real-time load the next operating day.

Figure 3-25 Actual Daily Loads and Forecasts: Calendar year 2010



The level of imports and exports is partially responsible for fluctuations in balancing operating reserve credits. Changes in tie flows can cause the redispatch of the system, and require generators to run out of economic merit order. Loop flow may also cause redispatch of the system, and require units to run out of economic merit order. Figure 3-26 shows hourly loop flows for some interfaces that had higher levels of loop flow activity in 2010.

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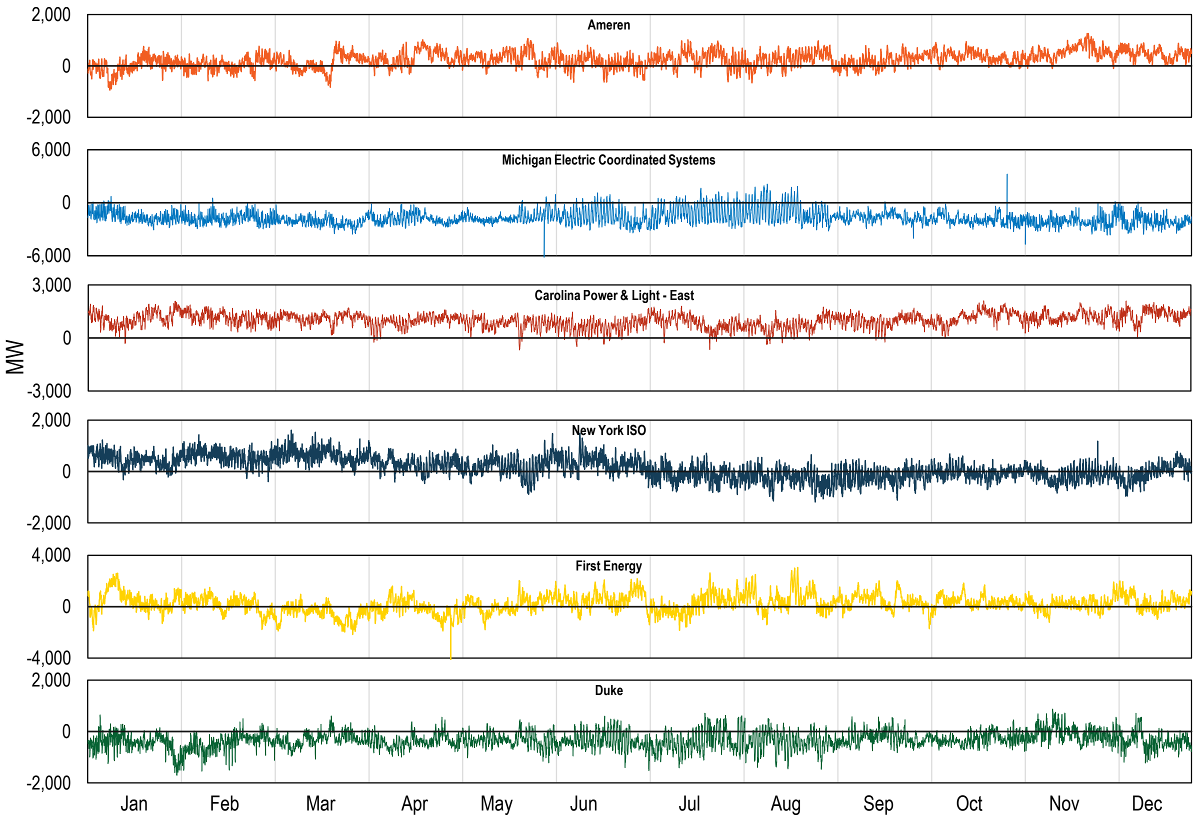
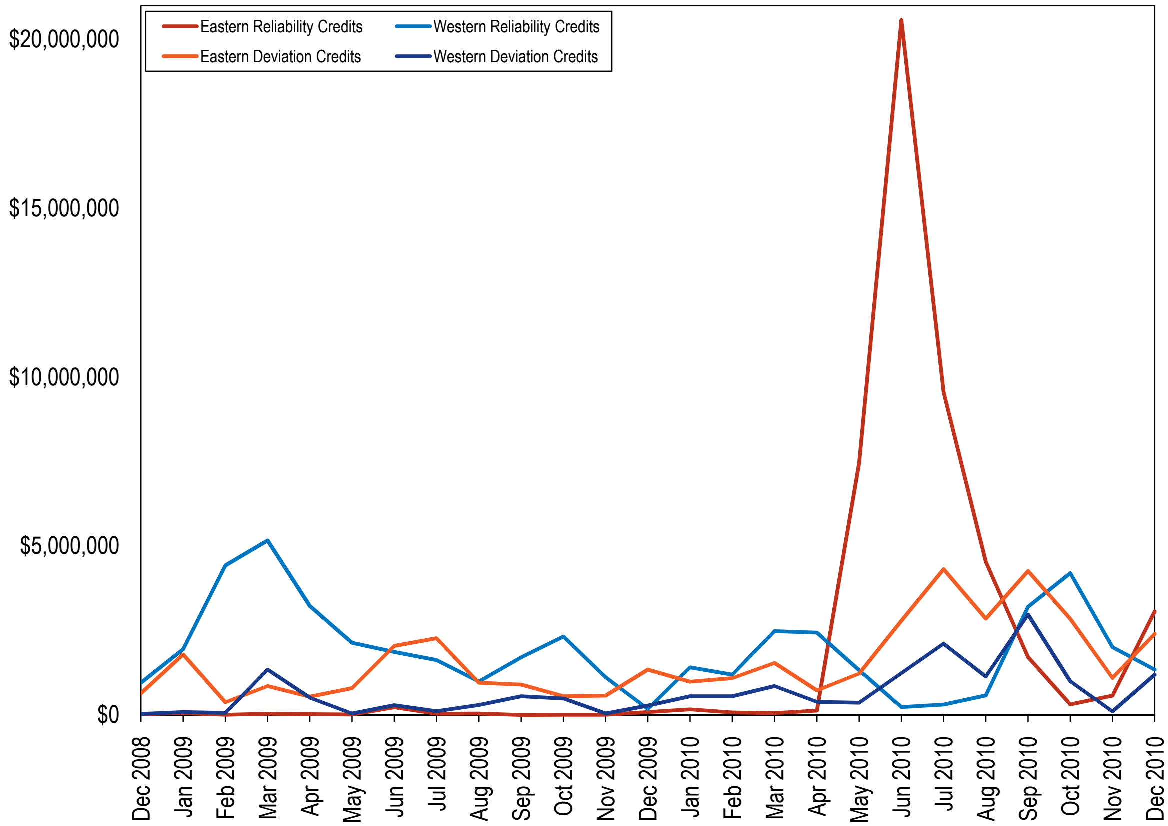
Figure 3-26 Hourly interface loop flows: Calendar year 2010



Eastern Reliability Credits

Figure 3-27 shows the regional reliability and regional deviation credits since the introduction of the new operating reserve rules.

Figure 3-27 Monthly regional reliability and deviations credits: December 2008 through December 2010



One of the purposes of the new operating reserve rules was to allocate reliability charges to those requiring additional resources to maintain system reliability, defined to be real-time load and exports. In 2010, the rule change had a significant impact on the categorization and corresponding allocation of balancing operating reserve charges. In 2010, $112,691,690 of reliability charges, which included $48,187,002 of Eastern reliability credits, were allocated to participants serving real-time load and exports, which would have been charged to supply, demand, and generator deviations under the prior rules. May, June, and July accounted for $37,587,708, or 78.0 percent of the Eastern reliability credits in 2010. Figure 3-28 shows the six categories of total balancing generator credits for each month in 2010.[130]

130 Credits in this figure do not include additional balancing operating reserve credits, such as lost opportunity cost.

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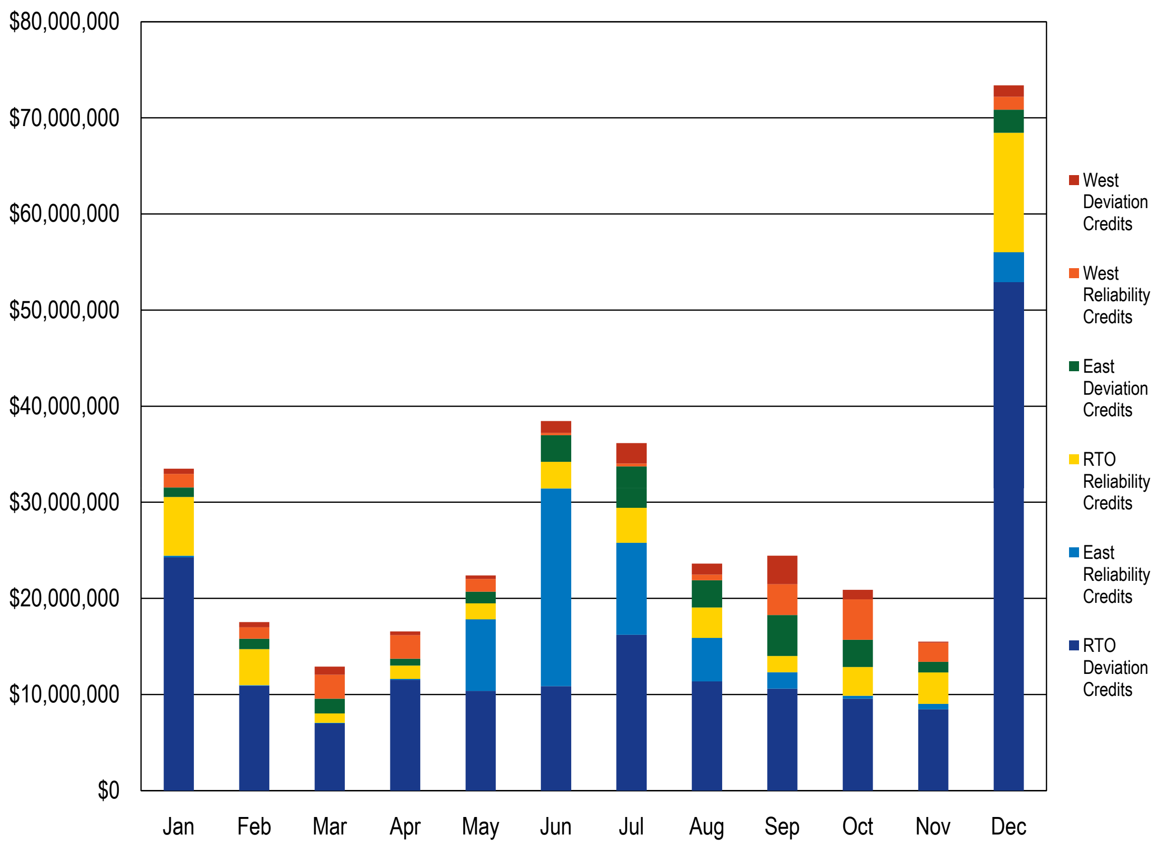
Figure 3-28 Monthly balancing operating reserve categories: Calendar year 2010



In mid May, maintenance work began on a 230kV line in the eastern region of PJM. This transmission outage, coupled with higher loads due to high temperatures in the region and the physical characteristics and operating parameters of the relevant units, required certain units to operate continuously in order to maintain system reliability. This continuous operation required significant balancing operating reserve credits to cover the offers of the units. The balancing operating reserve credits paid to these units were allocated to real-time load and exports. Table 3-110 shows the breakdown of these credits by month.

Table 3-110 Monthly balancing operating reserve categories: Calendar year 2010

Date	RTO Reliability Credits	East Reliability Credits	West Reliability Credits	RTO Deviation Credits	East Deviation Credits	West Deviation Credits
Jan	$6,119,792	$164,034	$1,408,756	$24,275,260	$980,832	$551,706
Feb	$3,730,998	$71,112	$1,192,894	$10,910,706	$1,085,923	$552,538
Mar	$981,402	$55,004	$2,480,550	$6,994,205	$1,537,198	$850,687
Apr	$1,375,806	$127,499	$2,436,919	$11,506,105	$721,388	$387,016
May	$1,650,356	$7,462,340	$1,320,404	$10,366,522	$1,225,542	$358,820
Jun	$2,765,366	$20,571,439	$229,942	$10,870,297	$2,786,236	$1,235,853
Jul	$3,649,811	$9,553,929	$305,048	$16,223,617	$4,312,914	$2,106,625
Aug	$3,157,164	$4,527,239	$576,921	$11,361,170	$2,850,328	$1,138,954
Sep	$1,706,764	$1,710,724	$3,200,795	$10,598,552	$4,260,925	$2,969,837
Oct	$2,971,034	$308,136	$4,199,921	$9,572,029	$2,842,250	$996,386
Nov	$3,259,804	$572,585	$2,002,226	$8,463,705	$1,096,254	$99,424
Dec	$12,445,498	$3,062,960	$1,338,284	$52,948,237	$2,392,579	$1,191,752
Total	$43,813,795	$48,187,002	$20,692,661	$184,090,404	$26,092,368	$12,439,598

Eastern reliability credits were a primary reason for the large increase in operating reserves in 2010. As seen in Figure 3-27, there was inconsistency in the regular pattern of operating reserves for the year. Total balancing generator credits increased 93.5 percent in 2010 to $335,511,201, up from $173,349,483 in 2009. Deviation credits increased 56.1 percent, or $80,095,925, while reliability credits increased 268.0 percent, or $82,065,794. The increase in reliability credits included a 10.3 percent decrease in western credits, a 520.4 percent increase in RTO credits, and a 9,584.1 percent increase in eastern credits. In 2009, eastern balancing generator credits were $497,589, while they were $48,187,002 in 2010. Table 3-109 shows the impact of the new rules on the allocation of these credits.

Table 3-111 Charges re-allocated to real-time load and exports: Calendar year 2009 and 2010

Credit Type	Region	2009	2010	Difference	Percentage Difference
Deviations	RTO	$125,850,691	$184,318,710	$58,468,019	46.5%
	East	$12,904,076	$25,983,926	$13,079,851	101.4%
	West	$3,968,820	$12,516,876	$8,548,056	215.4%
	Total	$142,723,586	$222,819,512	$80,095,925	56.1%
Reliability	RTO	$7,061,503	$43,812,027	$36,750,525	520.4%
	East	$497,589	$48,187,002	$47,689,413	9,584.1%
	West	$23,066,804	$20,692,661	($2,374,144)	(10.3%)
	Total	$30,625,896	$112,691,690	$82,065,794	268.0%
Total		$173,349,483	$335,511,201	$162,161,719	93.5%

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Dispatchable Transaction Credits

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. 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. Import dispatchable transactions receive the hourly integrated import pricing point LMP for the hours when energy flows. 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.

The $22,546,342 level of dispatchable transaction credits in December 2010 was unprecedented. From January of 2000 thru November 2010, the amount of balancing transaction credits in PJM totaled $3,854,605. This amount, received over the past 131 months, represents just 17.1 percent of the balancing transaction credits received in December 2010. Figure 3-29 shows the amount of balancing transaction credits received by all participants since the year 2000.

Figure 3-29 Monthly balancing transactions credits: 2000 through 2010

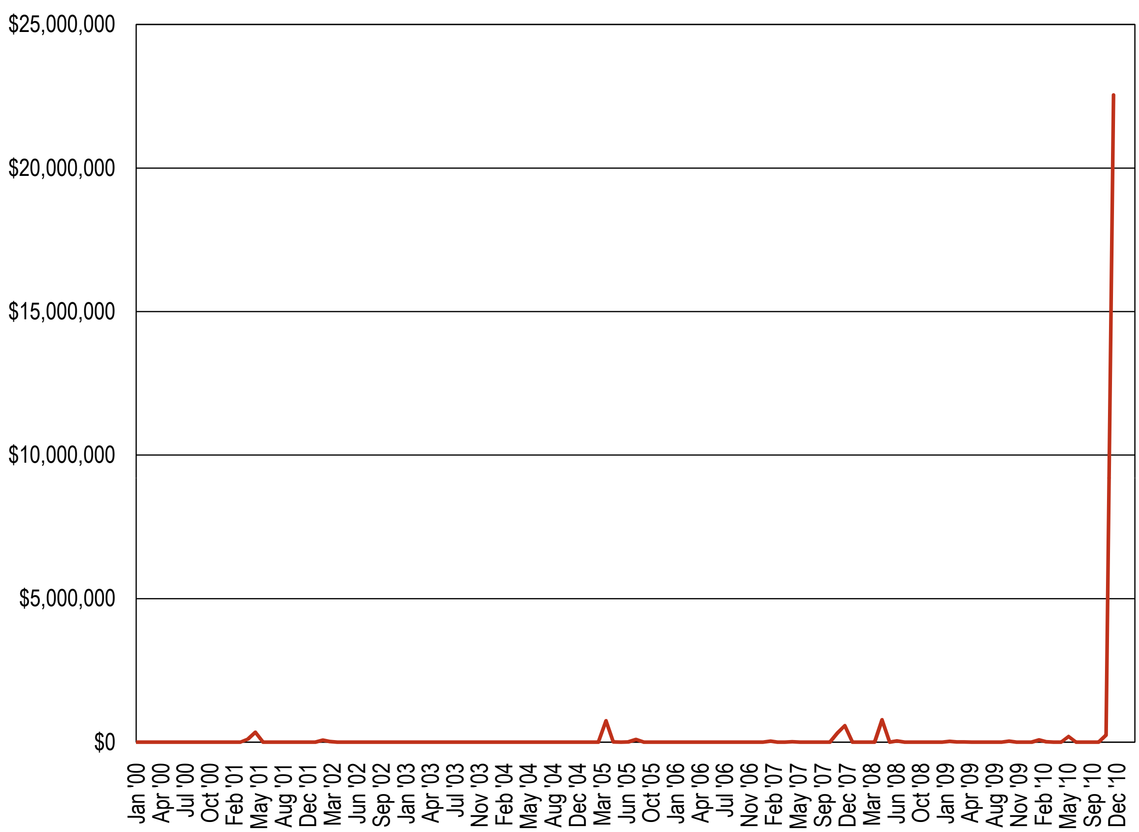

Table 3-112 shows the annual amount of balancing transaction credits since 2000. The amount of balancing transaction credits received in December of 2010 represents about 25 percent of all balancing operating reserve credits for the month, a percentage which is usually under 0.2 percent. Of this amount, 95.1 percent, or $21,438,881, was received by one market participant.

Table 3-112 Annual balancing transaction credits: 2000 through 2010

Year	Balancing Transaction Credit
2000	$0
2001	$0
2002	$98,065
2003	$0
2004	$1,146
2005	$857,550
2006	$8,826
2007	$966,213
2008	$827,633
2009	$91,293
2010	$23,092,640

The MMU recommends that dispatchable transactions be eliminated as an option for market participants. Alternatively, the MMU recommends that the evaluation of dispatchable transactions be modified from the manual process implemented today, and be included in the Generation Control Application (GCA) tool and modeled similar to a unit being bid with a one hour minimum run time. This will eliminate the potential for a dispatchable transaction to be loaded, and inadvertently continue to flow in subsequent hours where the transaction would not be economic, thus accruing a large amount of balancing operating reserve credits. Including dispatchable transactions in the GCA software would provide the most economic dispatch of PJM system resources.

Parameter-Limited Schedules

According to current rules, units are required to submit schedules with parameter limits consistent with the parameter limited schedule matrix for cost-based schedules and price-based parameter-limited schedules.[131] Units are placed on cost-based schedules when they are called on for transmission constraints and fail the TPS test, in which case they are then required to follow their parameter limits, as submitted with their cost-based schedules. In the case of a Maximum Generation Emergency alert, units are placed on a parameter-limited price-based schedule, in which the energy offers of their schedule may still be market based, but the operating parameters must adhere to their pre-defined parameter limits.

Price-based schedules are not required to follow any pre-defined parameter limits. This could allow participants to use price-based schedule parameters to exercise market power in order to receive

131 See PJM. "Manual 11: Energy & Ancillary Services Market Operations", Revision 45 (June 23, 2010), Section 2: Overview of the PJM Energy Markets 2.3.4.

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additional operating reserve credits. A generation owner could extend the minimum runtime of a unit prior to every weekend in order to ensure that the unit was running for PJM and receiving operating reserve credits rather than shutting down or self scheduling.

Units also offer more flexible parameters on the price-based schedule than the cost-based schedule at times. When this occurs it demonstrates that, contrary to the intent of parameter limited schedules, the unit is more flexible than reflected in its parameter limits.

The MMU also recommends that startup and notification time parameters for both cost based and price based offers be added to the list of parameters with required levels. This will prevent the submission of artificially long start and notification parameters which are designed to address economic issues with units rather than the physical issues that parameters are intended to address. Limits on these parameters will help ensure that capacity resources, paid for in RPM, meet their obligation to make legitimate and competitive offers in the Day-Ahead Market every day.

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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 and New Analysis

- Real-time net exports increased from -1,407 GWh in 2009 to -9,661 GWh in 2010, and day-ahead net exports decreased from -9,032.5 GWh in 2009 to -6,470.0 GWh in 2010.
- In 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 for a majority of hours in 2010, 58 percent between PJM and the Midwest ISO and 51 percent between PJM and NYISO.
- System loop flows increased from 2.2 percent for the calendar year 2009 to 5.2 percent for the calendar year 2010.
- PJM initiated fewer TLRs in 2010 (110 TLRs) than in 2009 (129 TLRs).
- The Midwest ISO and PJM filed a settlement agreement resolving all complaints regarding the management of the Joint Operating Agreement.
- The Commission supported an expedited timeline in the Broader Regional Market docket, and ordered interface pricing modifications and the development of a market-to-market congestion management protocol by the second quarter of 2011.
- The Commission conditionally accepted a Congestion Management Protocol between PJM and Progress Energy Carolinas.
- Changes to the marginal loss surplus allocation created opportunities for market participants to submit uneconomic transactions for the sole purpose of receiving an allocation of the marginal loss surplus. Customers entering uneconomic bids profited by $9.6 million after the cost of transmission as a result of the change in the allocation methodology.
- The daily volume of up-to congestion bids increased from approximately 600 bids per day, prior to the September 17, 2010 modification to the up-to congestion product that eliminated the requirement to procure transmission, to approximately 950 bids per day.
- Total uncollected congestion charges for 2010 were $3.3 million, a 379 percent increase from the 2009 total uncollected congestion charges of $688,547.
- Balancing operating reserve credits, allocated to real-time dispatchable import transactions, were approximately $24 million in 2010, an increase from the 2009 total of approximately $91,000.

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Summary Recommendations

- The MMU recommends that PJM modify a number of its transaction related rules to improve market efficiency, reduce operating reserves charges, reduce gaming opportunities and to make the markets more transparent. The MMU recommends changing the not willing to pay congestion product to eliminate uncollected congestions charges, eliminating internal source and sink bus designations for external energy transactions, eliminating or modifying the dispatchable transactions and up to congestion transactions products to reduce or eliminate gaming opportunities associated with the products.

- The MMU requests that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC.

- 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.

Overview

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In 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 -805 GWh.[1] Gross monthly import volumes averaged 3,496 GWh while gross monthly exports averaged 4,301 GWh.

- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In 2010, PJM was a net exporter of energy in the Day-Ahead Energy Market in all months except August, November and December. In the Day-Ahead Energy Market, monthly net interchange averaged -539 GWh. Gross monthly import volumes averaged 7,342 GWh while gross monthly exports averaged 7,881 GWh.

- **Aggregate Imports and Exports in the Day-Ahead versus the Real-Time Energy Market.** In 2010, gross imports in the Day-Ahead Energy Market were 210 percent of the Real-Time Energy Market's gross imports (111 percent for the calendar year 2009), gross exports in the Day-Ahead Energy Market were 183 percent of the Real-Time Energy Market's gross exports (127 percent for the calendar year 2009) and net interchange in the Day-Ahead Energy Market was 67 percent of net interchange in the Real-Time Energy Market (-9,661GWh in the Real-Time Energy Market and -6,470 GWh in the Day-Ahead Energy Market).

- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market in 2010, there were net exports at 16 of PJM's 21 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 70 percent of the total net exports:

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.

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PJM/New York Independent System Operator, Inc. (NYIS) with 30 percent, PJM/Neptune (NEPT) with 20 percent and PJM/MidAmerican Energy Company (MEC) with 20 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 55 percent of the total net PJM exports in the Real-Time Energy Market. Four PJM interfaces had net imports, with two importing interfaces accounting for 90 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 78 percent and PJM/LG&E Energy, L.L.C. (LGEE) with 12 percent.[2]

- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, there were net exports at 12 of PJM's 21 interfaces. The top four net exporting interfaces accounted for 92 percent of the total net exports: PJM/NYIS with 33 percent, PJM/western Alliant Energy Corporation (ALTW) with 25 percent, PJM/MidAmerican Energy Company (MEC) with 18 percent and PJM/NEPT with 16 percent. There are three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/LIND). Combined, these interfaces made up 50 percent of the total net PJM exports in the Day-Ahead Energy Market. Nine PJM interfaces had net imports in the Day-Ahead Energy Market, with two interfaces accounting for 78 percent of the total net imports: PJM/OVEC with 47 percent and PJM/Michigan Electric Coordinated System (MECS) with 31 percent.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and Midwest Independent System Operator (MISO) Interface Prices.** In 2010, the average price difference between the PJM/MISO Interface and the MISO/PJM Interface was consistent with the direction of the average flow. In 2010, the PJM average hourly Locational Marginal Price (LMP) at the PJM/MISO border was $33.33 while the Midwest ISO LMP at the border was $33.90, a difference of $0.57, while the average hourly flow in 2010 was -918 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 42 percent of hours of 2010. While the average hourly LMP difference at the PJM/MISO border was only $0.57, the average of the absolute value of the hourly difference was $11.64. For the hours when the direction of flows was not consistent with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MWh of flow, was $51.5 million at the PJM/MISO Interface.

- **PJM and New York ISO Interface Prices.** In 2010, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. In 2010, the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus was not consistent with the direction of the average flow. In 2010, the PJM average hourly LMP at the PJM/NYISO border was $47.64 while the NYISO LMP at the border was $44.69, a difference of $2.95, while the average hourly flow was -722 MW. (The negative sign means that the flow was an export from

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

PJM to NYISO, which is not consistent with the fact that the average PJM price was higher than the average NYISO price.) The direction of flows was consistent with price differentials in only 49 percent of the hours. While the average hourly LMP difference at the PJM/NYISO border was only $2.95, the average of the absolute value of the hourly difference was $14.74. For the hours when the direction of flows was not consistent with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MWh of flow, was $52.7 million at the PJM/NYIS Interface.

- **Neptune Underwater Transmission Line to Long Island, New York.** On July 1, 2007, a 65-mile direct current (DC) transmission line from Sayreville, New Jersey, to Nassau County on Long Island, via undersea and underground cable, was placed in service, providing a direct connection from PJM to the NYISO. This is a merchant 230 kV transmission line 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. In 2010, the average price difference between the PJM/Neptune price and the NYISO/Neptune price was consistent with the direction of the average flow. In 2010, the PJM average hourly LMP at the Neptune Interface was $51.40 while the NYISO LMP at the Neptune Bus was $58.08, a difference of $6.67, while the average hourly flow in 2010 was -544 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. While the average hourly LMP difference at the PJM/Neptune border was only $6.67, the average of the absolute value of the hourly difference was $23.30. For the hours when the direction of flows was not consistent with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MW of flow, was approximately $43.4 million at the PJM/NEPT Interface.

- **Linden Variable Frequency Transformer (VFT) Facility.** On November 1, 2009, the Linden VFT facility was placed in service, providing an additional 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.[3] The facility includes 350 feet of new 230 kV transmission line and 1,000 feet of new 345 kV transmission line, with a capacity of 300 MW. 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. In 2010, the average price difference between the PJM/Linden price and the NYISO/Linden price was consistent with the direction of the average flow. In 2010, the PJM average hourly LMP at the Linden Interface was $50.10 while the NYISO LMP at the Linden Bus was $51.58, a difference of $1.48, while the average hourly flow was -139 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 61 percent of the hours. While the average hourly LMP difference at the PJM/Linden border was only $1.48, the average of the absolute value of the hourly difference was $18.13. During all hours where flows did not align with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MW of flow, was approximately $8.8 million at the PJM/LIND Interface.

3 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.

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Operating Agreements with Bordering Areas

- **PJM and New York Independent System Operator, Inc. Joint Operating Agreement.**[4] 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 in 2010.

- **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 in 2010. 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. The MMU believes that this approach should be the minimum industry standard. This conceptual achievement, however, has not been matched by adequate attention to the details of its administration, which have resulted in multiple FERC filings by the Midwest ISO and PJM.

- **PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.**[5] 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 through 2010.

- **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**[6] 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 through 2010. As part of this agreement, both parties agreed to develop a formal Congestion Management Protocol (CMP). On February 2, 2010, PJM and PEC filed a revision to the JOA to include a CMP.[7] The MMU responded to the filing on February 23, 2010.[8]

- **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 Region) entered into a reliability coordination agreement. It provides for system and outage coordination, emergency procedures and the exchange of data.

4 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (September 14, 2007) (Accessed March 7, 2011) <http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/interconnection_agreements/nyiso_pjm_joa_final.pdf> (2,285 KB).

5 See "Congestion Management Process (CMP) Master" (May 1, 2008) (Accessed October 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20080502-miso-pjm-tva-baseline-cmp.ashx> (432 KB).

6 See "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (September 17, 2010) (Accessed March 7, 2011) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/progress-pjm-joint-operating-agreement.ashx> (2,983 KB).

7 See *PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc.* Docket No. ER10-713-000 (February 2, 2010).

8 See "Motion to Intervene and Comments of the Independent Market Monitor for PJM."Docket No. ER10-713-000 (February 25, 2010)

9 See "Adjacent Reliability Coordinator Coordination Agreement" (May 23, 2007) (Accessed October 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx> (528 KB).

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.** In 2010, 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. PJM manages loop flow using a combination of interface price signals, redispatch and TLR procedures.

  In 2010, net scheduled interchange was -6,778 GWh and net actual interchange was -6,425 GWh for a difference of 353 GWh or 5.2 percent (2.2 percent for the calendar year 2009).

  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 2009, the PJM/ Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows (-15,106 GWh in 2010 and -14,441 GWh for the calendar year 2009). The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows (4,015 GWh in 2010 and 3,840 GWh for the

10 111 FERC ¶ 61,228 (2005).

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calendar year 2009). 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.

- o **Loop Flows at PJM's Southern Interfaces.** The difference between scheduled and actual power flows at PJM's southern interfaces was significant in 2010. 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 -703 GWh and the actual flow was 3,312 GWh, a difference of 4,015 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 -421 GWh and the actual flow was 8,350 GWh, a difference of 8,771 GWh.

- **PJM Transmission Loading Relief Procedures (TLRs).** In 2010, PJM issued 110 TLRs of level 3a or higher. Of the 110 TLRs issued, 65 events were TLR level 3a, and the remaining 45 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 110 TLRs in 2010, compared to 129 in 2009, 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 TLRs.

- **Up-To Congestion.** In the period following the March 1, 2008, modifications to the up-to congestion bids (March 1, 2008, through December 31, 2010), the monthly average of up-to congestion bids increased from 3,027.1 GWh (for the period from January 1, 2006 through April 30, 2008) to 6,192.9 GWh. In June and July, there was a significant increase in the total up-to congestion bids. This increase in activity for up-to congestion transactions was the result of the allocation methodology for the marginal loss surplus.

- **Marginal Loss Surplus Allocation.** 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.

- **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.

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

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.** 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. The transparency of real-time LMPs and the reduction of the required notification period from 60 minutes to 20 minutes has eliminated the value that dispatchable transactions once provided market participants. Dispatchable transactions now only serve as a potential mechanism for receiving operating reserve credits.

  The MMU recommends that dispatchable transactions be eliminated as an option for market participants. Alternatively, the MMU recommends that the evaluation of dispatchable transactions be modified from the manual process implemented today, and be included in the Generation Control Application (GCA) tool and modeled in same way as a unit offer with a one hour minimum run time. This would eliminate the potential for a dispatchable transaction to be loaded and continue to flow in subsequent hours when the transaction is not economic, thus accruing balancing operating reserve credits, and would treat these transactions the same

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way that dispatchable units are treated. This would enhance the efficiency of PJM dispatch of system resources.

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 for 2010, including evolving transaction patterns, economics and issues. In 2010, PJM was a net exporter of energy and a large share of both import and export activity occurred at a small number of interfaces. Three interfaces accounted for 70 percent of the total real-time net exports and two interfaces accounted for 90 percent of the real-time net import volume. Four interfaces accounted for 92 percent of the total day-ahead net exports and two interfaces accounted for 78 percent of the day-ahead net import volume.

In 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 for a majority of hours, 58 percent between PJM and the Midwest ISO and 51 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.

Detailed Recommendations

- The MMU recommends that PJM modify a number of its transaction related rules to improve market efficiency, reduce operating reserves charges, reduce gaming opportunities and to make the markets more transparent.

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- The MMU recommends 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.

- The MMU recommends that dispatchable transactions be eliminated as an option for market participants.

- The MMU recommends that the up-to congestion transaction product be eliminated. Alternatively, the MMU recommends that PJM require all import and export up-to congestion transactions to pay day-ahead and balancing operating reserve charges.

- The MMU recommends that PJM eliminate all internal PJM buses for use in up-to congestion bidding.

- The MMU recommends that PJM modify the not willing to pay congestion product to address the issues of uncollected congestion charges. The MMU recommends charging market participants for any congestion incurred while such transactions are loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions to transactions at interfaces (wheeling transactions).

- The MMU recommends that the Enhanced Energy Scheduler (EES) application be modified to require that transactions be scheduled for a constant MW level over the entire 45 minutes as soon as possible.

- The MMU requests that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC.

- 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.

    - 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. PJM is engaged in preliminary discussions with both Midwest ISO and NYISO on interface pricing.

    - The MMU recommends that the PJM and Midwest ISO JOA be modified to eliminate payments between RTOs when such payments would result from the failure of generating units to respond to appropriate pricing signals.

    - The MMU recommends that the grandfathered Southeast and Southwest Interface pricing agreements be terminated, as the interface prices received for these agreements do not represent the economic fundamentals of locational marginal pricing.

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- The MMU recommends that PJM monitor, and adjust as necessary, the buses and weightings applied to the interfaces to ensure that the interface prices reflect ongoing changes in system conditions and that loop flows are accounted for on a dynamic basis.

Interchange Transaction Activity

Aggregate Imports and Exports

PJM was a monthly net exporter of energy in the Real-Time Energy Market in all months of 2010 (Figure 4-1, Figure 4-2 and Figure 4-3).[12,13] The total 2010 real-time net interchange of -9,661 GWh was greater than net interchange of -1,407 GWh in 2009. The peak month in 2010 for net exporting interchange was October, -1,335 GWh; in 2009 it had been June, -1,031 GWh. Monthly gross exports averaged 4,301 GWh and monthly gross imports averaged 3,496 GWh, for an average monthly net interchange of -805 GWh.

PJM was a net importer of energy in the Day-Ahead Energy Market in August, November and December of 2010, and a net exporter of energy in the remaining months. Total net interchange was -6,470 GWh. The peak month for net exporting interchange was April, -1,891 GWh. The peak month for net importing interchange was December, 1,603 GWh. Monthly gross exports averaged 7,881 GWh and monthly gross imports averaged 7,342 GWh, for an average monthly net interchange of -539 GWh.

Transactions in the Day-Ahead Energy Market create financial obligations to deliver in the Real-Time Energy Market and to pay operating reserve charges based on differences between the transaction MW in the Day-Ahead and Real-Time Energy Markets. In 2010, gross imports in the Day-Ahead Energy Market were 210 percent of the Real-Time Energy Market's gross imports (111 percent for the calendar year 2009), gross exports in the Day-Ahead Energy Market were 183 percent of the Real-Time Energy Market's gross exports (127 percent for the calendar year 2009) and net interchange in the Day-Ahead Energy Market was 67 percent of net interchange in the Real-Time Energy Market (-9,661 GWh in the Real-Time Energy Market and -6,470 GWh in the Day-Ahead Energy Market).

12 Calculated values shown in Section 4, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

13 The interchange values shown in Figure 4-1,Figure 4-2 and Figure 4-3, and Table 4-1 through Table 4-6 do not include dynamic schedules. Dynamic schedules are flows from generating units that are physically located in one balancing authority area but deliver power to another balancing authority area. The power from these units flows over the lines on which the actual flow at PJM's borders is measured. As a result, the net interchange in these figures and tables does not match the "Net Scheduled" values shown in Table 4-10.

Figure 4-1 PJM real-time scheduled imports and exports: Calendar year 2010

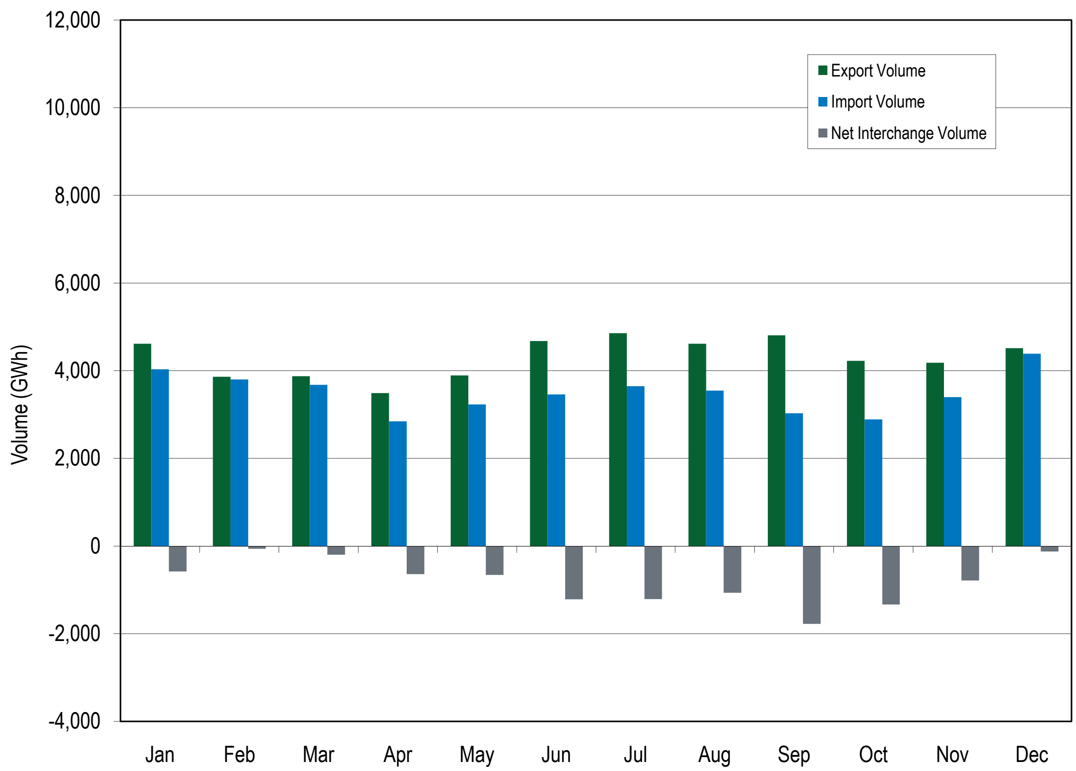

Figure 4-2 PJM day-ahead scheduled imports and exports: Calendar year 2010

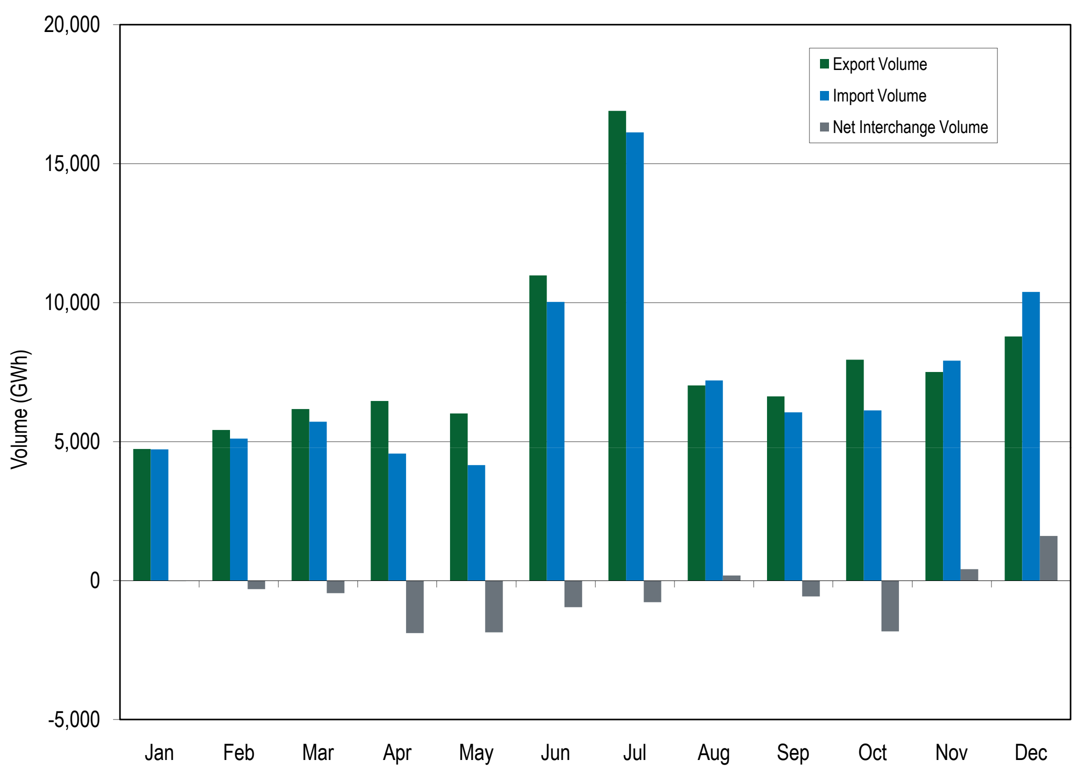

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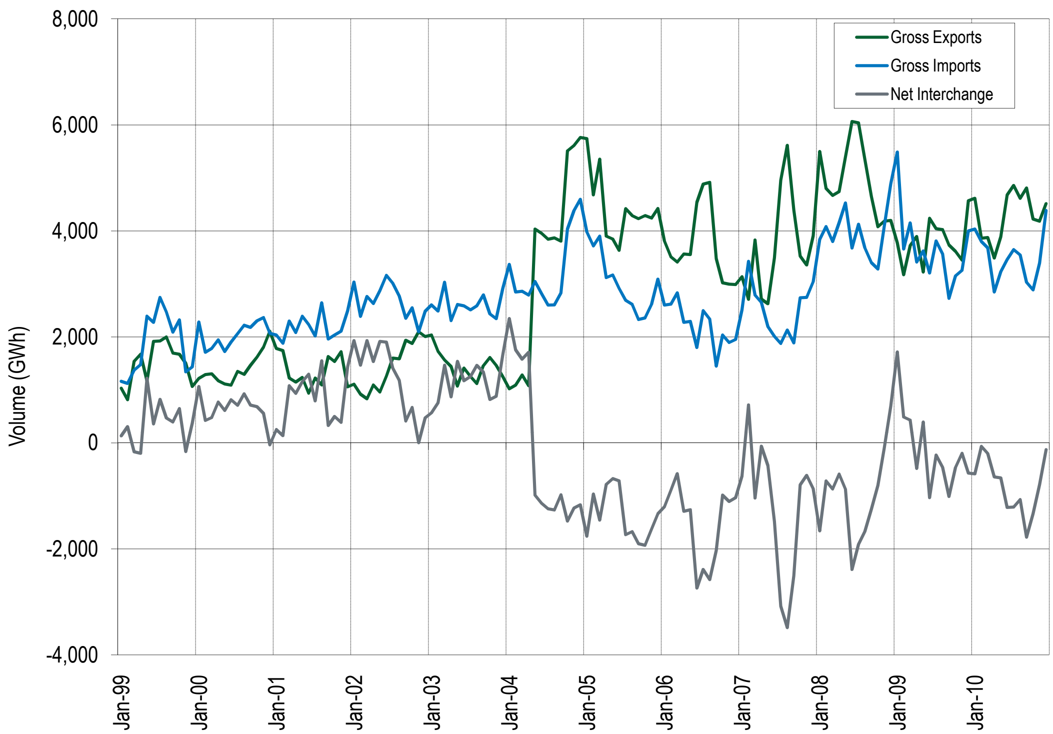
Figure 4-3 shows the real-time import and export volume for PJM from 1999 through 2010. PJM became a consistent net exporter of energy in 2004, coincident with the expansion of the PJM footprint, and has continued to be a net exporter in most months since that time.

Figure 4-3 PJM scheduled import and export transaction volume history: 1999 through December 2010



Interface Imports and Exports

In November of 2009, the Linden variable frequency transformer (VFT) facility was placed in service. As a result, a new interface was created, bringing the total number of interfaces between PJM and other balancing authorities to 21. The Linden (LIND) Interface and the Neptune (NEPT) Interface are separate from the NYIS Interface. However, all three are interfaces between PJM and the NYISO. Table 4-1 through Table 4-6 show the interchange totals at the individual interfaces with the NYISO, as well as with the NYISO as a whole. Similarly, the interchange totals at the individual interfaces between PJM and the Midwest ISO are shown, as well as with the Midwest ISO as a whole.

Total imports and exports are comprised of flows at each PJM interface. Net interchange in the Real-Time Market is shown by interface for 2010 in Table 4-1, while gross imports and exports are shown in Table 4-2 and Table 4-3. Net interchange in the Day-Ahead Energy Market is shown by interface for 2010 in Table 4-4, while gross imports and exports are shown in Table 4-5 and Table 4-6.

In 2010, there were net exports in the Real-Time Energy Market at 16 of PJM's 21 interfaces. (See Table 4-7 for active interfaces in 2010). The top three net exporting interfaces in the Real-Time Energy Market accounted for 70 percent of the total net exports: PJM/NYIS with 30 percent, PJM/NEPT with 20 percent and PJM/MEC with 20 percent of the net export volume. There are three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/LIND). Combined, these interfaces made up 55 percent of the total net PJM exports in the Real-Time Energy Market.

Figure 4-9 shows that PJM's PJM/NYIS average hourly interface price was $2.95 greater than the NYISO's NYIS/PJM Interface price. Net exports are not consistent with purchasing at a lower price and selling at a higher price. The flows were consistent with the price differentials in 49 percent of all hours in 2010. The PJM/NEPT flow averaged approximately -544 MW, and the PJM/LIND flow averaged approximately -139 MW for each hour through 2010. The PJM/NEPT Interface price was, on average lower than the NYIS/NEPT bus price ($51.40 in PJM vs. $58.08 in the NYISO). Similarly, the PJM/LIND Interface price averaged $50.10, while the NYISO/Linden bus price averaged $51.58. The average hourly flows at the PJM/NEPT and PJM/LIND Interfaces were consistent with the average price differentials in 2010. The scheduled flows at the PJM/NEPT Interface were consistent with the price differentials in only 64 percent of all hours in 2010, and the scheduled flows at the PJM/LIND Interface were consistent with the price differentials in only 61 percent of all hours in 2010.

In 2010, there were net exports in the Day-Ahead Energy Market at 12 of PJM's 21 interfaces. The top four exporting interfaces accounted for 92 percent of PJM's total net exports, PJM/NYIS with 33 percent, PJM/ALTW with 25 percent, PJM/MEC with 18 percent and PJM/NEPT with 16 percent. There are three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)). Combined, these interfaces made up 50 percent of the total net PJM exports in the Day-Ahead Energy Market.

There were net imports in the Real-Time Energy Market at four of PJM's interfaces. Two net importing interfaces accounted for 90 percent of PJM's net import volume, PJM/OVEC with 78 percent and PJM/LG&E Energy, L.L.C. with 12 percent of the net import volume.

Eleven shareholders own OVEC and share OVEC's generation output. Approximately 70 percent of the shares of ownership belong to load serving entities, or their affiliates, within the PJM footprint. The agreement requires delivery of approximately 70 percent of the generation output into the PJM footprint.[14] OVEC itself does not serve load, and therefore does not generally import energy. The nature of the ownership of OVEC and the location of its affiliates within the PJM footprint account for the large percentage of PJM's net interchange volume.

There were net imports in the Day-Ahead Energy Market at nine of PJM's 21 interfaces. The top two net importing interfaces accounted for 78 percent of PJM's total net imports, PJM/OVEC with 47 percent and PJM/MECS with 31 percent.

14 See "Ohio Valley Electric Corporation: Company Background." (Accessed January 24, 2010) <http://www.ovec.com/OVECHistory.pdf> (26 KB).

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Table 4-1 Real-time scheduled net interchange volume by interface (GWh): Calendar year 2010

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	(70.4)	(72.8)	(40.8)	(141.2)	(114.0)	(154.2)	(150.1)	(162.4)	(154.8)	(172.5)	(126.6)	(227.8)	(1,587.6)
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	219.7	92.2	(32.8)	(22.9)	123.6	(116.4)	(50.8)	(21.0)	(113.3)	(33.9)	(146.1)	52.0	(49.7)
EKPC	(65.5)	(99.2)	14.1	39.3	(0.2)	(19.5)	81.2	88.4	(43.5)	(32.1)	(63.2)	(79.9)	(180.1)
LGEE	31.9	144.5	29.7	44.1	116.8	130.0	160.3	103.4	185.4	290.7	262.4	252.3	1,751.5
MEC	(454.2)	(422.0)	(458.1)	(383.0)	(436.0)	(429.4)	(440.7)	(402.4)	(420.2)	(453.9)	(435.6)	(428.7)	(5,164.2)
MISO	(74.1)	512.4	510.7	8.1	188.5	(327.7)	(658.1)	(550.5)	(945.7)	(767.9)	(334.4)	(74.9)	(2,513.6)
ALTE	3.6	(9.5)	13.7	(7.1)	(0.7)	(66.2)	(90.3)	(46.3)	(116.0)	(64.5)	(62.1)	(146.2)	(591.6)
ALTW	(32.1)	(8.4)	1.4	(16.1)	(27.7)	(148.3)	(80.2)	(54.7)	(106.3)	(70.3)	(58.1)	(44.9)	(645.7)
AMIL	(141.6)	(85.5)	(63.5)	(25.6)	37.1	18.8	22.1	77.6	(7.4)	(12.8)	(11.8)	(30.7)	(223.3)
CIN	78.4	323.4	233.5	(112.2)	189.0	155.8	(37.8)	(52.3)	(333.5)	(307.7)	(70.4)	(54.4)	11.8
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(13.8)	(8.5)	0.0	0.0	(22.3)
FE	(117.4)	(60.2)	(70.6)	(114.3)	(142.5)	(173.5)	(182.1)	(211.3)	(86.1)	(86.9)	(96.5)	110.3	(1,231.1)
IPL	(28.4)	48.4	(4.6)	112.6	61.3	(61.2)	(177.9)	(121.3)	(170.1)	4.3	(8.3)	6.2	(339.0)
MECS	195.1	312.7	387.5	199.7	95.9	103.2	34.9	0.5	20.1	(101.2)	61.2	238.3	1,547.9
NIPS	(24.0)	(10.8)	(4.9)	(0.6)	(1.9)	(111.1)	(98.2)	(49.9)	(56.7)	(43.4)	(33.8)	(63.2)	(498.5)
WEC	(7.7)	2.3	18.2	(28.3)	(22.0)	(45.2)	(48.6)	(92.8)	(75.9)	(76.9)	(54.6)	(90.3)	(521.8)
NYISO	(1,307.0)	(1,039.9)	(1,109.6)	(950.3)	(1,334.9)	(1,257.1)	(1,003.0)	(1,029.6)	(1,219.8)	(1,145.5)	(1,143.5)	(963.0)	(13,503.2)
LIND	(146.0)	(125.5)	(115.7)	(75.8)	(89.8)	(100.4)	(99.2)	(63.6)	(113.0)	(114.0)	(95.1)	(106.5)	(1,244.6)
NEPT	(496.7)	(423.6)	(449.9)	(280.9)	(464.8)	(466.6)	(411.5)	(292.7)	(375.7)	(391.0)	(419.5)	(379.9)	(4,852.8)
NYIS	(664.3)	(490.8)	(544.0)	(593.6)	(780.3)	(690.1)	(492.3)	(673.3)	(731.1)	(640.5)	(628.9)	(476.6)	(7,405.8)
OVEC	1,176.9	943.0	1,018.8	854.0	805.9	1,001.9	781.7	1,004.6	931.1	947.2	1,149.0	1,198.8	11,812.9
TVA	(39.0)	(121.5)	(129.3)	(88.3)	(7.8)	(43.4)	69.0	(97.4)	2.7	32.5	50.6	144.9	(227.0)
Total	(581.7)	(63.3)	(197.3)	(640.2)	(658.1)	(1,215.8)	(1,210.5)	(1,066.9)	(1,778.1)	(1,335.4)	(787.4)	(126.3)	(9,661.0)

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Table 4-2 Real-time scheduled gross import volume by interface (GWh): Calendar year 2010

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	128.3	113.4	99.8	0.6	22.7	9.9	28.2	26.5	6.4	9.9	12.8	23.4	481.9
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	408.5	235.2	135.1	142.6	258.6	174.8	229.5	243.7	104.5	113.3	166.6	248.9	2,461.3
EKPC	15.8	3.0	53.9	58.1	34.8	36.6	88.9	104.2	22.6	10.2	9.7	7.8	445.6
LGEE	48.9	150.5	73.5	58.7	135.6	161.8	187.6	171.8	218.2	297.3	267.4	274.9	2,046.2
MEC	44.1	28.1	35.7	52.3	61.5	34.7	41.7	46.5	43.7	24.5	32.7	54.8	500.3
MISO	1,142.9	1,388.4	1,292.1	852.6	907.3	1,055.0	866.6	748.7	656.4	503.7	729.3	1,303.8	11,446.8
ALTE	30.0	8.0	28.9	2.4	9.4	1.0	1.3	6.7	3.3	9.4	4.2	0.0	104.6
ALTW	0.0	5.4	7.6	1.1	2.8	6.3	7.6	17.6	14.5	12.4	20.8	5.3	101.4
AMIL	23.5	49.2	39.2	45.6	55.0	37.1	33.3	88.8	17.3	11.6	9.6	20.2	430.4
CIN	500.9	555.4	454.8	227.2	364.7	551.6	366.0	314.9	216.4	149.9	343.6	507.9	4,553.3
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	181.6	207.6	205.4	156.0	147.5	162.3	176.9	150.8	218.3	186.5	178.8	333.1	2,304.8
IPL	47.1	116.7	16.2	115.9	113.5	71.8	16.0	1.5	4.3	8.2	4.6	26.4	542.2
MECS	304.3	385.9	475.1	283.7	181.5	185.2	215.2	150.5	170.9	122.3	156.9	408.9	3,040.4
NIPS	0.0	0.0	0.0	0.2	13.4	6.4	2.9	14.7	10.8	0.4	0.0	2.0	50.8
WEC	55.5	60.2	64.9	20.5	19.5	33.3	47.4	3.2	0.6	3.0	10.8	0.0	318.9
NYISO	934.4	901.2	922.5	765.7	890.8	916.1	1,184.7	1,084.6	916.6	896.8	884.9	1,010.0	11,308.3
LIND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	934.4	901.2	922.5	765.7	890.8	916.1	1,184.7	1,084.6	916.6	896.8	884.9	1,010.0	11,308.3
OVEC	1,176.9	943.0	1,018.8	854.0	805.9	1,001.9	781.7	1,004.6	931.1	947.2	1,149.0	1,226.7	11,840.8
TVA	134.6	35.7	47.7	63.0	115.6	67.9	237.4	116.4	131.8	85.1	142.9	237.4	1,415.5
Total	4,034.4	3,798.5	3,679.1	2,847.6	3,232.8	3,458.7	3,646.3	3,547.0	3,031.3	2,888.0	3,395.3	4,387.7	41,946.7

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Table 4-3 Real-time scheduled gross export volume by interface (GWh): Calendar year 2010

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	198.7	186.2	140.6	141.8	136.7	164.1	178.3	188.9	161.2	182.4	139.4	251.2	2,069.5
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	188.8	143.0	167.9	165.5	135.0	291.2	280.3	264.7	217.8	147.2	312.7	196.9	2,511.0
EKPC	81.3	102.2	39.8	18.8	35.0	56.1	7.7	15.8	66.1	42.3	72.9	87.7	625.7
LGEE	17.0	6.0	43.8	14.6	18.8	31.8	27.3	68.4	32.8	6.6	5.0	22.6	294.7
MEC	498.3	450.1	493.8	435.3	497.5	464.1	482.4	448.9	463.9	478.4	468.3	483.5	5,664.5
MISO	1,217.0	876.0	781.4	844.5	718.8	1,382.7	1,524.7	1,299.2	1,602.1	1,271.6	1,063.7	1,378.7	13,960.4
ALTE	26.4	17.5	15.2	9.5	10.1	67.2	91.6	53.0	119.3	73.9	66.3	146.2	696.2
ALTW	32.1	13.8	6.2	17.2	30.5	154.6	87.8	72.3	120.8	82.7	78.9	50.2	747.1
AMIL	165.1	134.7	102.7	71.2	17.9	18.3	11.2	11.2	24.7	24.4	21.4	50.9	653.7
CIN	422.5	232.0	221.3	339.4	175.7	395.8	403.8	367.2	549.9	457.6	414.0	562.3	4,541.5
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.8	8.5	0.0	0.0	22.3
FE	299.0	267.8	276.0	270.3	290.0	335.8	359.0	362.1	304.4	273.4	275.3	222.8	3,535.9
IPL	75.5	68.3	20.8	3.3	52.2	133.0	193.9	122.8	174.4	3.9	12.9	20.2	881.2
MECS	109.2	73.2	87.6	84.0	85.6	82.0	180.3	150.0	150.8	223.5	95.7	170.6	1,492.5
NIPS	24.0	10.8	4.9	0.8	15.3	117.5	101.1	64.6	67.5	43.8	33.8	65.2	549.3
WEC	63.2	57.9	46.7	48.8	41.5	78.5	96.0	96.0	76.5	79.9	65.4	90.3	840.7
NYISO	2,241.4	1,941.1	2,032.1	1,716.0	2,225.7	2,173.2	2,187.7	2,114.2	2,136.4	2,042.3	2,028.4	1,973.0	24,811.5
LIND	146.0	125.5	115.7	75.8	89.8	100.4	99.2	63.6	113.0	114.0	95.1	106.5	1,244.6
NEPT	496.7	423.6	449.9	280.9	464.8	466.6	411.5	292.7	375.7	391.0	419.5	379.9	4,852.8
NYIS	1,598.7	1,392.0	1,466.5	1,359.3	1,671.1	1,606.2	1,677.0	1,757.9	1,647.7	1,537.3	1,513.8	1,486.6	18,714.1
OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	27.9	27.9
TVA	173.6	157.2	177.0	151.3	123.4	111.3	168.4	213.8	129.1	52.6	92.3	92.5	1,642.5
Total	4,616.1	3,861.8	3,876.4	3,487.8	3,890.9	4,674.5	4,856.8	4,613.9	4,809.4	4,223.4	4,182.7	4,514.0	51,607.7

Table 4-4 Day-ahead net interchange volume by interface (GWh): Calendar year 2010

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	(89.3)	(111.3)	(114.7)	(122.2)	(108.3)	(134.2)	372.0	(119.5)	(70.8)	(129.3)	(206.7)	(141.3)	(975.6)
CPLW	10.2	(1.0)	1.0	(0.9)	(1.0)	(1.5)	6.7	2.0	5.6	7.9	4.6	19.7	53.3
DUK	161.4	38.4	8.6	12.6	72.5	23.2	(222.7)	(100.4)	29.2	17.2	64.5	65.6	170.1
EKPC	(1.5)	(5.9)	(3.4)	(0.2)	(1.4)	(3.0)	(4.5)	(3.5)	(0.1)	0.0	0.1	0.1	(23.3)
LGEE	1.0	5.3	0.0	(0.1)	1.4	(8.0)	(13.7)	(51.5)	(3.7)	0.9	0.0	0.0	(68.4)
MEC	(479.4)	(444.1)	(482.8)	(433.0)	(464.1)	(789.0)	(374.3)	(457.0)	(448.1)	(477.0)	(468.6)	(428.7)	(5,746.1)
MISO	282.3	(160.5)	(312.1)	(1,450.5)	(1,018.5)	550.4	3,478.1	820.5	79.0	(1,128.3)	983.6	2,083.3	4,207.3
ALTE	227.6	(257.5)	(136.2)	(302.4)	(711.0)	(168.0)	73.0	145.9	(9.0)	(403.9)	315.8	1,466.5	240.8
ALTW	(282.2)	(414.3)	(1,220.9)	(1,761.3)	(766.8)	(2,195.9)	(1,908.2)	(567.7)	68.1	437.3	663.7	273.4	(7,674.8)
AMIL	14.4	97.5	6.7	12.4	44.5	114.6	1.7	9.0	(1.3)	(6.4)	19.7	80.1	392.9
CIN	182.9	(60.8)	43.1	(70.3)	41.8	310.0	1,376.9	161.3	4.2	(215.5)	(11.0)	(88.6)	1,674.0
CWLP	0.0	0.0	0.0	0.0	(0.3)	0.0	(19.5)	0.0	(11.8)	(8.5)	0.0	0.0	(40.1)
FE	(70.5)	(20.7)	118.8	(72.4)	(79.3)	390.4	1,007.5	20.4	(218.3)	(519.1)	(112.7)	(107.6)	336.5
IPL	(53.4)	(18.4)	(44.7)	(8.5)	(42.0)	68.9	131.8	41.7	(41.0)	(54.2)	(44.8)	(131.3)	(195.9)
MECS	387.8	654.4	885.6	732.9	546.6	1,223.9	1,484.6	767.5	379.5	(263.9)	247.4	681.6	7,727.9
NIPS	(204.5)	(217.0)	(143.3)	(87.6)	(120.2)	(103.9)	394.9	(34.3)	(67.1)	(49.7)	(43.8)	(65.1)	(741.6)
WEC	80.2	76.3	178.8	106.7	68.2	910.4	935.4	276.7	(24.3)	(44.4)	(50.7)	(25.7)	2,487.6
NYISO	(969.0)	(912.0)	(825.4)	(752.7)	(1,017.9)	(1,657.9)	(4,727.8)	(904.8)	(894.0)	(945.2)	(948.1)	(973.6)	(15,528.4)
LIND	(21.1)	(18.3)	(53.2)	(11.4)	(15.3)	(12.0)	(24.7)	(9.9)	(53.2)	(50.8)	(47.9)	(66.3)	(384.1)
NEPT	(502.6)	(445.2)	(456.7)	(301.3)	(473.4)	(472.7)	(420.9)	(317.7)	(374.8)	(392.2)	(423.9)	(407.1)	(4,988.5)
NYIS	(445.3)	(448.5)	(315.5)	(440.0)	(529.2)	(1,173.2)	(4,282.2)	(577.2)	(466.0)	(502.2)	(476.3)	(500.2)	(10,155.8)
OVEC	1,074.0	1,243.3	1,300.5	917.1	679.0	1,058.2	1,045.7	978.5	711.5	740.6	853.3	970.1	11,571.8
TVA	(5.3)	37.8	(27.0)	(60.9)	(5.4)	7.7	(335.1)	16.4	18.0	87.4	127.9	7.8	(130.7)
Total	(15.6)	(310.0)	(455.3)	(1,890.8)	(1,863.7)	(954.1)	(775.6)	180.7	(573.4)	(1,825.8)	410.6	1,603.0	(6,470.0)

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Table 4-5 Day-ahead gross import volume by interface (GWh): Calendar year 2010

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	64.2	39.5	29.3	10.7	15.8	49.1	595.7	124.6	89.2	37.7	57.5	138.4	1,251.7
CPLW	15.6	0.6	1.8	0.0	1.4	0.8	6.7	2.0	7.1	8.5	4.7	19.7	68.9
DUK	176.3	96.2	48.1	40.2	107.2	77.8	139.9	112.9	108.6	66.2	105.1	135.0	1,213.5
EKPC	0.0	0.0	0.4	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.1	0.1	0.8
LGEE	1.0	5.4	0.0	0.0	1.8	0.5	1.4	6.5	2.2	12.1	2.4	0.0	33.3
MEC	18.8	5.6	12.2	18.6	70.2	158.8	247.8	33.6	20.7	1.4	0.0	56.5	644.2
MISO	2,400.5	2,738.3	3,112.5	2,678.8	2,251.6	7,455.1	12,488.8	4,596.2	3,905.6	3,782.4	5,158.0	7,350.2	57,918.0
ALTE	866.4	762.4	662.8	382.9	263.8	721.2	2,191.6	1,241.3	1,728.4	1,650.5	2,471.8	4,524.1	17,467.2
ALTW	72.0	67.2	72.4	53.6	40.2	345.7	896.3	257.6	542.7	863.2	1,014.1	464.7	4,689.7
AMIL	68.1	157.9	50.5	32.1	44.8	114.6	1.7	10.5	4.5	4.1	29.5	88.7	607.0
CIN	436.8	592.0	555.1	590.4	430.6	969.6	1,988.3	701.1	238.3	118.6	139.5	127.9	6,888.2
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	156.2	176.9	364.9	203.7	179.3	752.7	1,536.1	519.1	204.8	125.7	327.1	299.4	4,845.9
IPL	26.9	29.4	30.7	102.8	97.0	1,045.3	1,004.8	124.0	16.8	4.0	30.3	9.9	2,521.9
MECS	606.2	801.7	1,125.2	1,118.7	1,035.2	2,223.8	2,629.9	1,246.7	1,060.7	787.7	848.1	1,446.8	14,930.7
NIPS	28.6	19.5	24.3	33.1	26.9	292.1	1,115.1	84.5	19.3	45.0	93.0	154.7	1,936.1
WEC	139.3	131.3	226.6	161.5	133.8	990.1	1,125.0	411.4	90.1	183.6	204.6	234.0	4,031.3
NYISO	835.3	885.1	1,095.7	883.7	858.1	1,165.0	1,202.9	1,219.8	1,047.4	1,048.7	1,069.3	1,115.3	12,426.3
LIND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	835.3	885.1	1,095.7	883.7	858.1	1,165.0	1,202.9	1,219.8	1,047.4	1,048.7	1,069.3	1,115.3	12,426.3
OVEC	1,133.2	1,259.7	1,379.9	922.0	802.1	1,063.8	1,086.8	985.3	793.4	925.9	1,199.3	1,299.9	12,851.3
TVA	75.9	77.8	36.7	15.2	44.4	55.3	357.2	120.3	79.1	239.1	316.3	273.9	1,691.2
Total	4,720.8	5,108.2	5,716.6	4,569.2	4,152.6	10,026.2	16,127.4	7,201.2	6,053.3	6,122.0	7,912.7	10,389.0	88,099.2

Table 4-6 Day-ahead gross export volume by interface (GWh): Calendar year 2010

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	153.5	150.8	144.0	132.9	124.1	183.3	223.7	244.1	160.0	167.0	264.2	279.7	2,227.3
CPLW	5.4	1.6	0.8	0.9	2.4	2.3	0.0	0.0	1.5	0.6	0.1	0.0	15.6
DUK	14.9	57.8	39.5	27.6	34.7	54.6	362.6	213.3	79.4	49.0	40.6	69.4	1,043.4
EKPC	1.5	5.9	3.8	0.2	1.4	3.0	4.7	3.5	0.1	0.0	0.0	0.0	24.1
LGEE	0.0	0.1	0.0	0.1	0.4	8.5	15.1	58.0	5.9	11.2	2.4	0.0	101.7
MEC	498.2	449.7	495.0	451.6	534.3	947.8	622.1	490.6	468.8	478.4	468.6	485.2	6,390.3
MISO	2,118.2	2,898.8	3,424.6	4,129.3	3,270.1	6,904.7	9,010.7	3,775.7	3,826.6	4,910.7	4,174.4	5,266.9	53,710.7
ALTE	638.8	1,019.9	799.0	685.3	974.8	889.2	2,118.6	1,095.4	1,737.4	2,054.4	2,156.0	3,057.6	17,226.4
ALTW	354.2	481.5	1,293.3	1,814.9	807.0	2,541.6	2,804.5	825.3	474.6	425.9	350.4	191.3	12,364.5
AMIL	53.7	60.4	43.8	19.7	0.3	0.0	0.0	1.5	5.8	10.5	9.8	8.6	214.1
CIN	253.9	652.8	512.0	660.7	388.8	659.6	611.4	539.8	234.1	334.1	150.5	216.5	5,214.2
CWLP	0.0	0.0	0.0	0.0	0.3	0.0	19.5	0.0	11.8	8.5	0.0	0.0	40.1
FE	226.7	197.6	246.1	276.1	258.6	362.3	528.6	498.7	423.1	644.8	439.8	407.0	4,509.4
IPL	80.3	47.8	75.4	111.3	139.0	976.4	873.0	82.3	57.8	58.2	75.1	141.2	2,717.8
MECS	218.4	147.3	239.6	385.8	488.6	999.9	1,145.3	479.2	681.2	1,051.6	600.7	765.2	7,202.8
NIPS	233.1	236.5	167.6	120.7	147.1	396.0	720.2	118.8	86.4	94.7	136.8	219.8	2,677.7
WEC	59.1	55.0	47.8	54.8	65.6	79.7	189.6	134.7	114.4	228.0	255.3	259.7	1,543.7
NYISO	1,804.3	1,797.1	1,921.1	1,636.4	1,876.0	2,822.9	5,930.7	2,124.6	1,941.4	1,993.9	2,017.4	2,088.9	27,954.7
LIND	21.1	18.3	53.2	11.4	15.3	12.0	24.7	9.9	53.2	50.8	47.9	66.3	384.1
NEPT	502.6	445.2	456.7	301.3	473.4	472.7	420.9	317.7	374.8	392.2	423.9	407.1	4,988.5
NYIS	1,280.6	1,333.6	1,411.2	1,323.7	1,387.3	2,338.2	5,485.1	1,797.0	1,513.4	1,550.9	1,545.6	1,615.5	22,582.1
OVEC	59.2	16.4	79.4	4.9	123.1	5.6	41.1	6.8	81.9	185.3	346.0	329.8	1,279.5
TVA	81.2	40.0	63.7	76.1	49.8	47.6	692.3	103.9	61.1	151.7	188.4	266.1	1,821.9
Total	4,736.4	5,418.2	6,171.9	6,460.0	6,016.3	10,980.3	16,903.0	7,020.5	6,626.7	7,947.8	7,502.1	8,786.0	94,569.2

Transactions Basics

Interchange Transactions – Real-Time Energy Market

There are three steps required for market participants to enter external interchange transactions in PJM's Real-Time Energy Market. The steps are: acquisition of valid transmission via the Open Access Same Time Information System (OASIS); acquisition of available ramp via PJM's Enhanced Energy Scheduler system (EES); and the creation of a valid NERC Tag. In addition, the interchange request must pass the neighboring balancing authority checkout process in order for the request to be implemented. After a successful implementation of an external energy schedule, the energy will flow between balancing authorities. Such a transaction will continue to flow at its designated energy profile as long as the system can support it, it is deemed economic based on options set at the time of scheduling, or until the market participant chooses to curtail the transaction.

While the OASIS has a path component, this path only reflects the path of energy into or out of PJM to one neighboring balancing authority. The NERC Tag requires the complete path to be specified from the Generation Control Area (GCA) to the Load Control Area (LCA). This complete path is utilized by PJM to determine the interface pricing point which PJM will associate with the transaction.

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Interchange Transactions – Day-Ahead Energy Market

Entering external energy transactions in the Day-Ahead Energy Market requires fewer steps than the Real-Time Energy Market. Market participants need to acquire a valid, willing to pay congestion (WPC) OASIS reservation to prove that their day-ahead schedule could be supported in the Real-Time Energy Market.[15] Day-Ahead Energy Market schedules need to be cleared through the Day-Ahead Energy Market process in order to become an approved schedule. The Day-Ahead Energy Market transactions are financially binding, but will not physically flow. In the Day-Ahead Energy Market, a market participant is not required to acquire a ramp reservation, a NERC Tag, or to go through a neighboring balancing authority checkout process.

There are three types of day-ahead external energy transactions: Fixed; Up-to congestion; and Dispatchable.

A fixed Day-Ahead Energy Market transaction request means that the market participant agrees to be a price taker for the MW amount of the offer. There is no price associated with the request and the market participant agrees to take the day-ahead LMP at the associated import or export pricing point. If the market participant has met the required deadline and has acquired a valid willing-to-pay congestion OASIS reservation, a fixed day-ahead transaction request will be accepted in the Day-Ahead Energy Market. These approved transactions are a financial obligation. If the market participant does not provide a corresponding transaction in the Real-Time Energy Market, they are subject to the balancing market settlement.

To submit an up-to congestion offer, the market participant is required to submit an energy profile (start time, stop time and MW value) and specify the amount of congestion they are willing to pay. If, in the Day-Ahead Energy Market, congestion on the desired path is less than that specified, the up-to congestion request is approved. Approved up-to congestion offers are financial obligations.

Dispatchable transactions in the Day-Ahead Energy Market are similar to those in the Real-Time Energy Market in that they are evaluated against a floor or ceiling price at the designated import or export pricing point. For import dispatchable transactions, if the LMP at the interface clears higher than the specified bid, the transaction is approved. For export dispatchable transactions, if the LMP at the interface clears lower than the specified bid, the transaction is approved. As with fixed and up-to congestion transactions, cleared dispatchable transactions in the Day-Ahead Energy Market represent a financial obligation. If the market participant does not meet the commitment in the Real-Time Energy Market, they are subject to the balancing market settlement.

Source and Sink in the Real-Time Energy Market

Real-Time Energy Market transaction sources and sinks are determined through a combination of defaulted values and market participant selections.

- **Real-Time Energy Market Imports:** For a real-time import energy transaction, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS

15 On September 17, 2010, up-to congestion transactions no longer required a willing to pay congestion transmission reservation. Additional details can be found under the "Up-to Congestion" heading in this report.

reservation, the source defaults to the associated interface price as defined by the POR/POD path. For example, if the selected POR is TVA and the POD is PJM, the source would initially default to TVA's Interface pricing point (i.e. SouthIMP). At the time the energy is scheduled, if the GCA on the NERC Tag represents physical flow entering PJM at an interface other than the SouthIMP Interface, the source would then default to that new interface. The sink bus is selected by the market participant at the time the OASIS reservation is made, which can be any bus in the PJM footprint where LMPs are calculated, and does not change.

- **Real-Time Energy Market Exports:** For a real-time export energy transaction, when a market participant selects the POR and POD on their OASIS reservation, the sink defaults to the associated interface price as defined by the POR/POD path. For example, if the selected POR is PJM and the POD is TVA, the sink would initially default to TVA's Interface pricing point (i.e. SouthEXP). At the time the energy is scheduled, if the LCA on the NERC Tag represents physical flow leaving PJM at an interface other than the SouthEXP Interface, the sink would then default to that new interface. The source bus is selected by the market participant at the time the OASIS reservation is made, which can be any bus in the PJM footprint where LMPs are calculated, and does not change.

- **Real-Time Energy Market Wheels:** For a real-time wheel through energy transaction, when a market participant selects the POR and POD on their OASIS reservation, both the source and sink default to the associated interface prices as defined by the POR/POD path. For example, if the selected POR is TVA and the POD is NYIS, the source would initially default to TVA's Interface pricing point (i.e. SouthIMP), and the sink would initially default to NYIS's Interface pricing point (i.e. NYIS). At the time the energy is scheduled, if the GCA on the NERC Tag represents physical flow entering PJM at an interface other than the SouthIMP Interface, the source would then default to that new interface. Similarly, if the LCA on the NERC Tag represents physical flow leaving PJM at an interface other than the NYIS Interface, the sink would then default to that new interface.

Source and Sink in the Day-Ahead Energy Market

Day-Ahead Energy Market transaction sources and sinks are determined solely by the market participants.

- **Day-Ahead Energy Market Imports:** For day-ahead import energy transactions, the market participant chooses any import pricing point they wish to have associated with their transaction. This selection is made through the EES user interface. The sink bus is selected by the market participant at the time the OASIS reservation is made, which can be any bus in the PJM footprint where LMPs are calculated.

- **Day-Ahead Energy Market Exports:** For day-ahead export energy transactions, the market participant chooses any export pricing point they wish to have associated with their transaction. This selection is made through the EES user interface. The source bus is selected by the market participant at the time the OASIS reservation is made, which can be any bus in the PJM footprint where LMPs are calculated.

- **Day-Ahead Energy Market Wheels:** For day-ahead wheel through energy transactions, the market participant chooses any import pricing point and export pricing point they wish to have associated with their transaction. These selections are made through the EES user interface.

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Curtailment of Transactions

Once a transaction has been implemented, energy flows between balancing authorities. Transactions can be curtailed under several conditions, including economic and reliability considerations.

There are three types of economic curtailments: curtailments of dispatchable schedules, OASIS designation curtailments (willing to pay congestion or not willing to pay congestion), and market participant self-curtailments. System reliability curtailments are termed TLRs or transmission loading relief.

A dispatchable external energy transaction (also known as "real-time with price") is one in which the market participant designates a floor or ceiling price on their external transaction from which they would like the energy to flow. For example, an import dispatchable schedule specifies that the market participant only wishes to load the transaction if the LMP at the interface where the transaction is entering the PJM footprint reaches a specified limit (the minimum LMP at which they are willing to sell energy into PJM). An export dispatchable schedule specifies the maximum LMP at the interface where the market participant wishes to purchase energy from PJM.

PJM system operators evaluate dispatchable transactions 30 minutes prior to the start of every hour of the energy profile. If the system operator expects the floor (or ceiling) price to be realized over the next hour, they contact the market participant informing them that they are loading the transaction. Once loaded, the dispatchable transaction will run for the next hour. If the system operator does not feel that the transaction will be economic, they will elect to not load the transaction, or to curtail the dispatchable transaction at the top of the next hour if it has already been loaded. Dispatchable schedules can be viewed as a generation offer, with a minimum run time of one hour. For importing dispatchable transactions, if the resulting hourly integrated prices are such that the transaction should not have been loaded, the transaction will be made whole through operating reserve credits.

Not willing to pay congestion transactions should be curtailed if there is realized congestion between the designated source and sink.

Transactions utilizing spot import service will be curtailed if the interface price where the transaction enters PJM reaches zero.

A market participant may curtail their transactions. All self curtailments must be requested on 15 minute intervals. In order for PJM to approve a self curtailment request, there must be available ramp for the modification.

Interface Pricing

Interface pricing points differ from interfaces. (See Table 4-7 for a list of active interfaces in 2010. Figure 4-4 shows the approximate geographic location of the interfaces.)

Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the estimated electrical impact of the external power

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source on PJM tie lines, regardless of contract transmission path.[16] PJM establishes prices for transactions with external balancing authorities by assigning interface pricing points to individual balancing authorities based on the Generation Control Area and Load Control Area as specified on the NERC Tag. According to the *PJM Interface Price Definition Methodology* dynamic interface pricing calculations use actual system conditions to determine a set of weighting factors for each external pricing point in an interface price definition.[17] The weighting factors are determined in such a manner that the interface reflects actual system conditions. However, this analysis is an approximation given the complexity of the transmission network outside PJM and the dynamic nature of power flows. Transactions between PJM and external balancing authorities need to be priced at the PJM border. The challenge is to create interface prices, composed of external pricing points, which accurately represent flows between PJM and external sources of energy. The result is price signals that embody the underlying economic fundamentals across balancing authority borders.[18] Table 4-8 presents the interface pricing points used in 2010.

Table 4-7 Active interfaces: Calendar year 2010

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ALTE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
AMIL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CIN	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
EKPC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
FE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
IPL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LGEE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
TVA	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
WEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active

16 See "LMP Aggregate Definitions" (December 18, 2008) (Accessed January 15, 2010) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (1,369 KB). PJM periodically updates these definitions on its Web site. See <http://www.pjm.com>.

17 See "PJM Interface Pricing Definition Methodology." (September 29, 2006) (Accessed January 20, 2010) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20060929-interface-definition-methodology1.ashx> (33 KB).

18 See the *2007 State of the Market Report*, Volume II, Appendix D, "Interchange Transactions," for a more complete discussion of the development of pricing points.

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Figure 4-4 PJM's footprint and its external interfaces

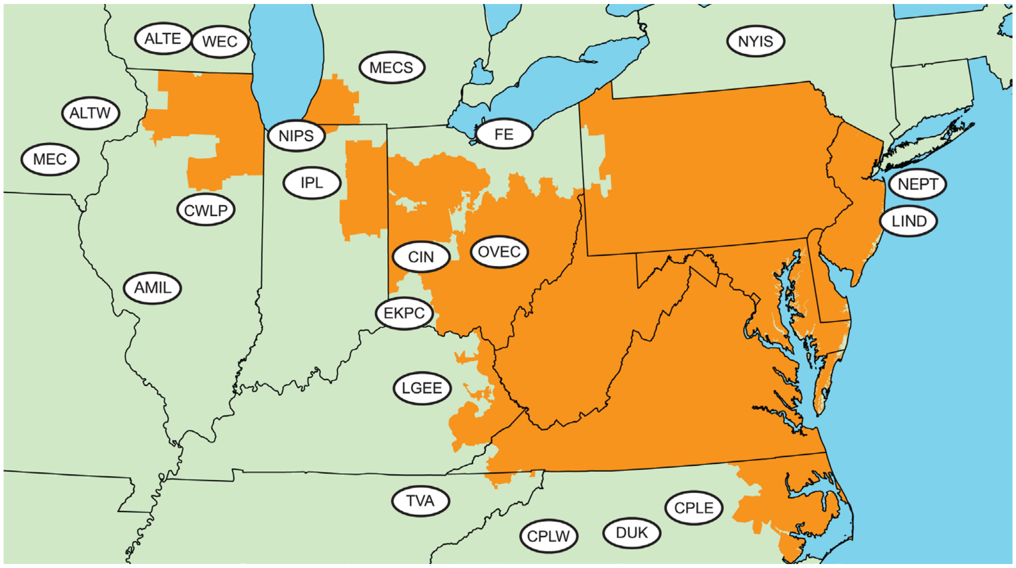

Table 4-8 Active pricing points: 2010

PJM 2010 Pricing Points				
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

In 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 for a majority of hours, 58 percent between PJM and the Midwest ISO and 51 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. PJM is engaged in preliminary discussions with both Midwest ISO and NYISO on interface pricing.

PJM and Midwest ISO Interface Prices

Both the PJM/MISO and the MISO/PJM Interface pricing points represent the value of power at the relevant border, as determined in each market. In both cases, the interface price is the price at which transactions are settled. For example, a transaction into PJM from the Midwest ISO would receive the PJM/MISO Interface price upon entering PJM, while a transaction into the Midwest ISO from PJM would receive the MISO/PJM Interface price. PJM and the Midwest ISO use network models to determine these prices and to ensure that the prices are consistent with the underlying electrical flows. PJM uses the LMP at nine buses[19] within the Midwest ISO to calculate the PJM/MISO Interface price, while the Midwest ISO uses prices at all of the PJM generator buses to calculate the MISO/PJM Interface price.[20]

Real-Time Prices

In 2010, the average price difference between the PJM/MISO Interface and the MISO/PJM Interface was consistent with the direction of the average flow. In 2010, the PJM average hourly Locational Marginal Price (LMP) at the PJM/MISO border was $33.33 while the Midwest ISO LMP at the border was $33.90, a difference of $0.57, while the average hourly flow in 2010 was -918 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 42 percent of hours of 2010. While the average hourly LMP difference at the PJM/MISO border was only $0.57, the average of the absolute value of the hourly difference was $11.64. For the hours when the direction of flows was not consistent with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MWh of flow, was $51.5 million at the PJM/MISO Interface.

19 See "LMP Aggregate Definitions" (December 18, 2008) (Accessed January 15, 2010) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (1,369 KB). PJM periodically updates these definitions on its web site. See <http://www.pjm.com>.

20 Based on information obtained from the Midwest ISO Extranet (January 15, 2010) <http://extranet.midwestiso.org>.

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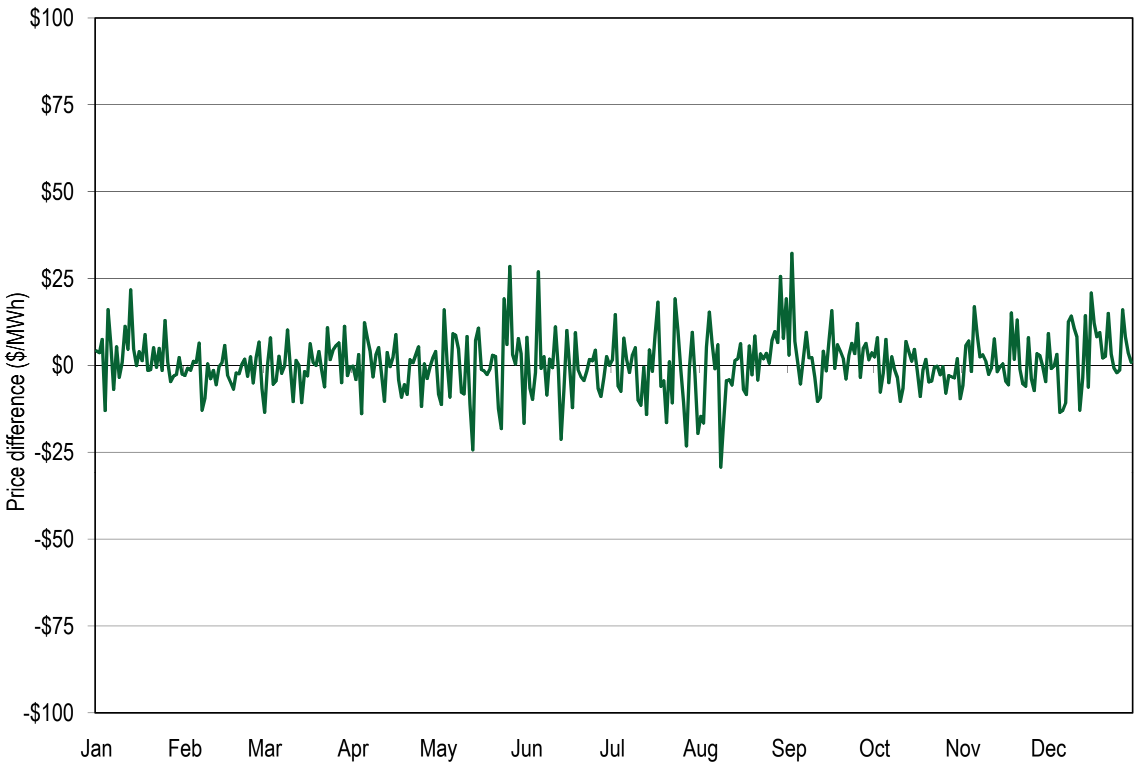
Figure 4-5 Real-time daily hourly average price difference (Midwest ISO Interface minus PJM/MISO): Calendar year 2010



The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 4-5). There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences.

In 2010, the difference between the real-time PJM/MISO Interface price and the real-time MISO/PJM Interface price fluctuated between positive and negative about eight times per day. The standard deviation of the hourly price was $18.37 for the PJM/MISO Interface price and $20.72 for the MISO/PJM Interface price. The standard deviation of the difference in interface prices was $20.50. The average of the absolute value of the hourly price difference was $11.64. Absolute values reflect price differences regardless of whether they are positive or negative.

The simple average interface price difference suggests that competitive forces prevent price deviations from persisting, although with a lag that permits substantial price differences in both directions.

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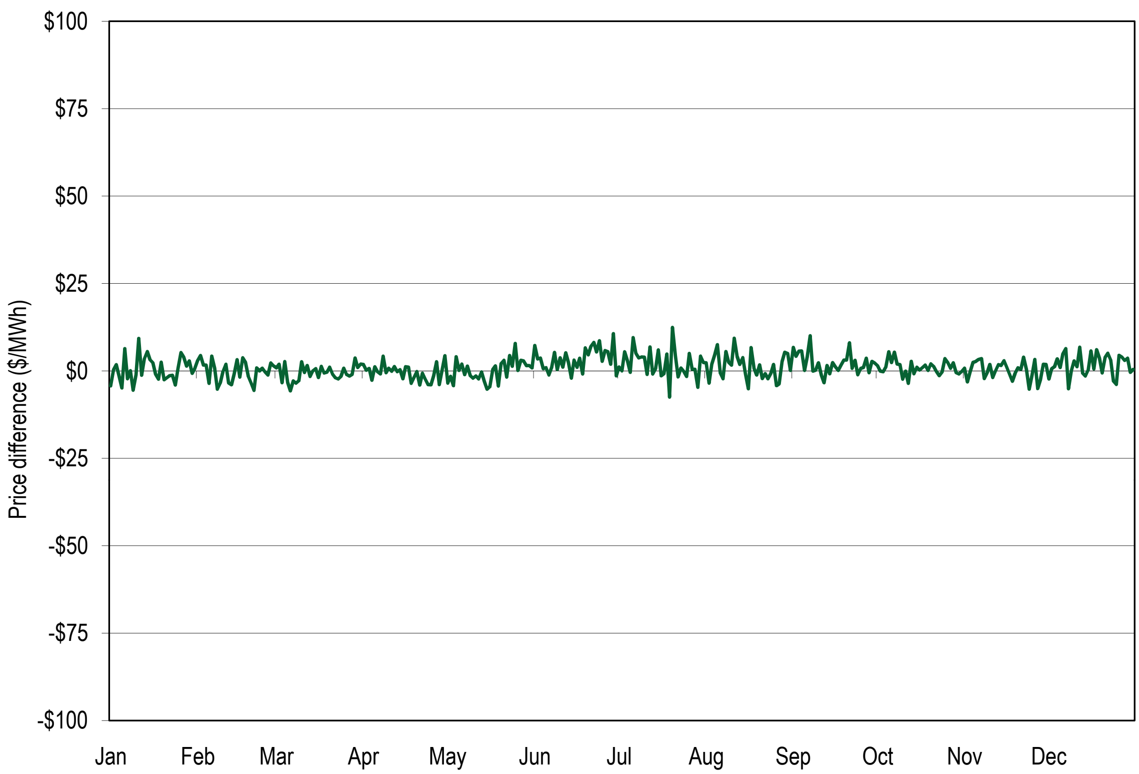
Day-Ahead Prices

The 2010 day-ahead hourly average interface prices for PJM/MISO and MISO/PJM were $34.83 and $33.87. The simple average difference between the day-ahead MISO/PJM Interface price and the PJM/MISO Interface was $0.96 in 2010 (Figure 4-6). In the Day-Ahead Energy Market, gross exports to the Midwest ISO were 53,710.7 GWh in 2010.

Figure 4-6 Day-ahead daily hourly average price difference (Midwest ISO interface minus PJM/MISO): Calendar year 2010



In 2010, the difference between the day-ahead PJM/MISO Interface price and the day-ahead MISO/PJM Interface price fluctuated between positive and negative about five times per day. The standard deviation of the hourly price was $13.05 for the PJM/MISO price and $13.89 for the MISO/PJM Interface price. The standard deviation of the difference in interface prices was $5.12. The average of the absolute value of the hourly price difference was $3.58.

PJM and NYISO Interface Prices

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in

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explaining the observed relationship between interface prices and inter-RTO/ISO power flows, and those price differentials.

PJM operators must verify all requested energy schedules with its neighboring balancing authorities. Only if the neighboring balancing authority agrees with the expected interchange will the transaction flow. If there is a disagreement in the expected interchange for any 15 minute interval, the system operators must work to resolve the difference. It is important that both balancing authorities enter the same values in their Energy Management Systems (EMS) to avoid inadvertent energy from flowing between balancing authorities.

With the exception of the NYISO, all neighboring balancing authorities handle transaction requests the same way as PJM (i.e. via the NERC Tag). This helps facilitate interchange transaction checkouts, as all balancing authorities are receiving the same information. While the NYISO also requires NERC Tags, they utilize their Market Information System (MIS) as their primary scheduling tool. The NYISO's Real-Time Commitment (RTC) tool evaluates all bids and offers each hour, and performs a least cost economic dispatch solution. This evaluation accepts or denies individual transactions in whole or in part. Upon market clearing, the NYISO implements NERC Tag adjustments to match the output of the RTC. PJM and the NYISO can verify interchange transactions once the NYISO Tag adjustments are sent and approved. The results of the adjustments made by the NYISO affect PJM operations, as the adjustments often cause large swings in expected ramp for the next hour.

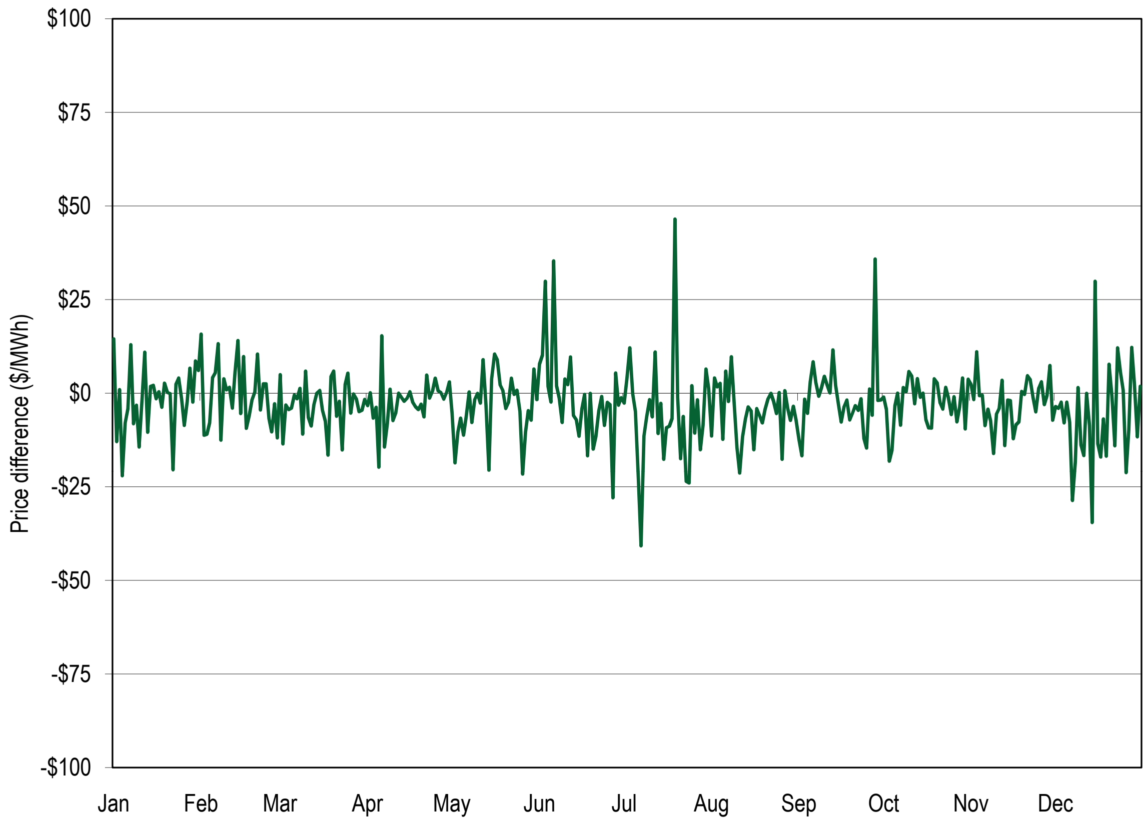
PJM's price for transactions with the NYISO (excluding those transactions across the Neptune and Linden lines), termed the NYIS Interface pricing point by PJM, represents the value of power at the PJM/NYISO border, as determined by the PJM market. PJM defines its NYIS Interface pricing point using two buses.[21] Similarly, the NYISO's price for transactions with PJM, termed the PJM proxy bus by the NYISO, represents the value of power at the NYISO/PJM border, as determined by the NYISO market. In the NYISO market, transactions are required to have a price associated with them. Import transactions are treated as generator offers at the NYISO/PJM proxy bus. Export transactions are treated as load bids. Competing bids and offers are evaluated along with the other NYISO resources and a proxy bus price is derived.

Real-Time Prices

In 2010, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. In 2010, the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus was not consistent with the direction of the average flow. In 2010, the PJM average hourly LMP at the PJM/NYISO border was $47.64 while the NYISO LMP at the border was $44.69, a difference of $2.95, while the average hourly flow was -722 MW. (The negative sign means that the flow was an export from PJM to NYISO, which is not consistent with the fact that the average PJM price was higher than the average NYISO price.) The direction of flows was consistent with price differentials in only 49 percent of the hours. While the average hourly LMP difference at the PJM/NYISO border was only $2.95, the average of the absolute value of the hourly difference was $14.74. For the hours when the direction of flows was not consistent with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MWh of flow, was $52.7 million at the PJM/NYIS Interface.

21 See "LMP Aggregate Definitions" (December 18, 2008) (Accessed January 15, 2010) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (1,369 KB). PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

Figure 4-7 Real-time daily hourly average price difference (NY proxy - PJM/NYIS): Calendar year 2010



The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 4-8). There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences.

The difference between the real-time PJM/NYIS Interface price and the real-time NYISO/PJM proxy bus price continued to fluctuate between positive and negative about eight times per day in 2010 as it has since 2003. The standard deviation of hourly price was $28.58 in 2010 for the PJM/NYIS Interface price and $31.84 in 2010 for the NYISO/PJM proxy bus price. The standard deviation of the difference in interface prices was $31.02 in 2010. The average of the absolute value of the hourly price difference was $14.74 in 2010. Absolute values reflect price differences without regard to whether they are positive or negative.

Day-Ahead Prices

The 2010 day-ahead hourly average PJM/NYIS Interface price and the NYISO/PJM proxy bus price were $46.53 and $48.11. The simple average difference between the day-ahead PJM/NYISO Interface price and the NYISO/PJM proxy bus price was $1.58 in 2010 (Figure 4-8). In the Day-Ahead Energy Market, the gross exports to the NYISO were 22,582.1 GWh in 2010.

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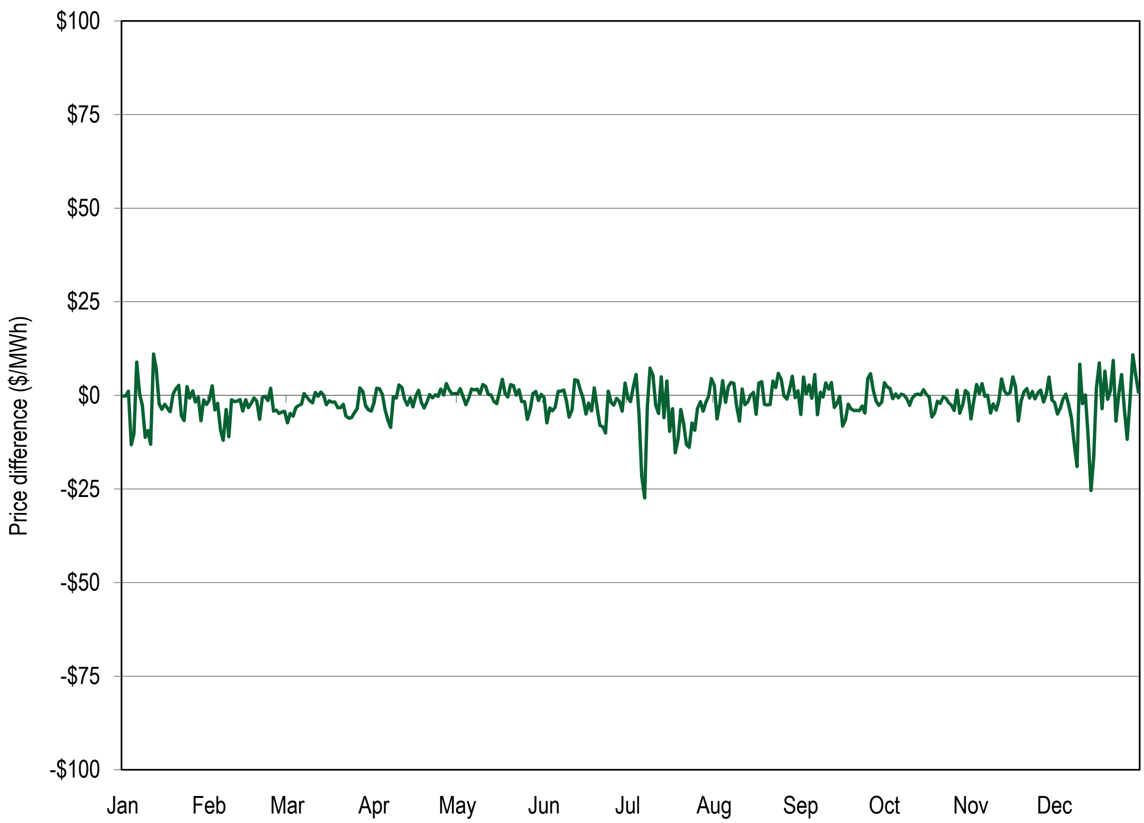
The difference between the day-ahead PJM/NYIS Interface price and the day-ahead NYISO/PJM proxy bus price fluctuated between positive and negative about four times per day in 2010. The standard deviation of hourly price was $20.08 in 2010 for the PJM/NYIS Interface price and $16.79 in 2010 for the NYISO/PJM proxy bus price. The standard deviation of the difference in interface prices was $7.09 in 2010. The average of the absolute value of the hourly price difference was $4.73 in 2010. Absolute values reflect price differences without regard to whether they are positive or negative.

Figure 4-8 Day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): Calendar year 2010



Summary of Interface Prices between PJM and Organized Markets

Some measures of the real-time and day-ahead PJM interface pricing with the Midwest ISO and with the NYISO are summarized and compared in Figure 4-9 and Figure 4-10, including average prices and measures of variability.

Figure 4-9 PJM, NYISO and Midwest ISO real-time border price averages: Calendar year 2010

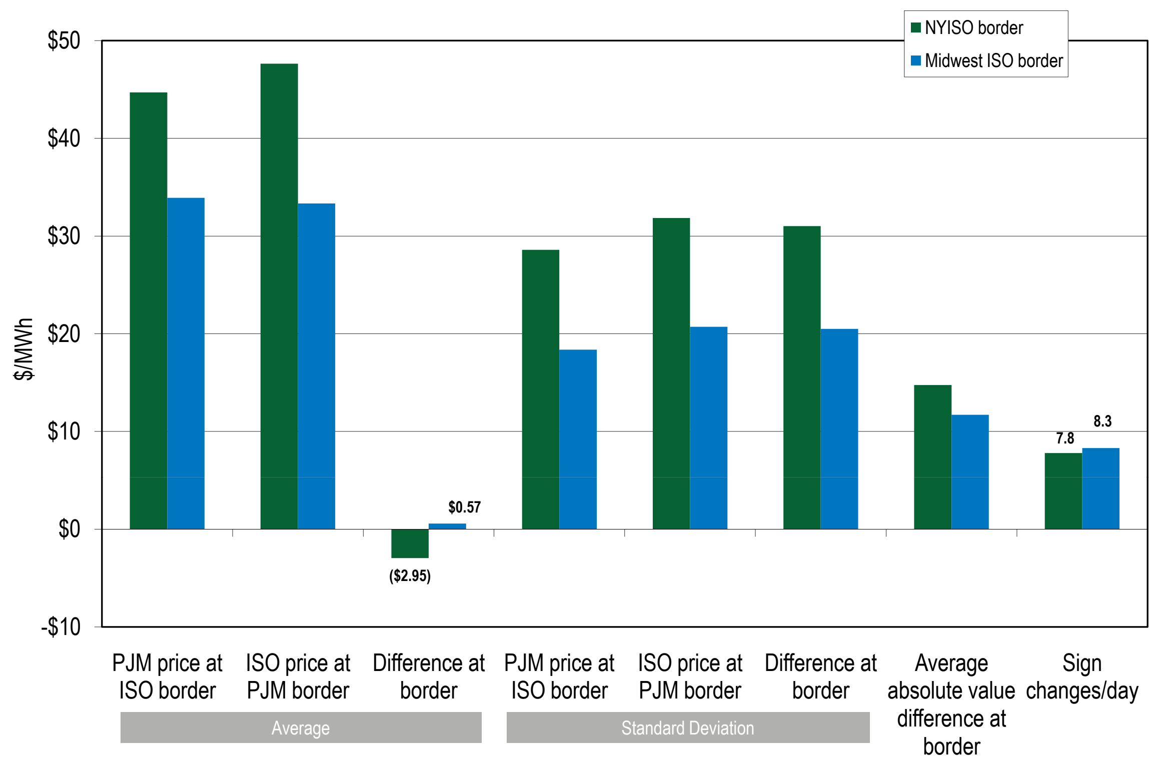
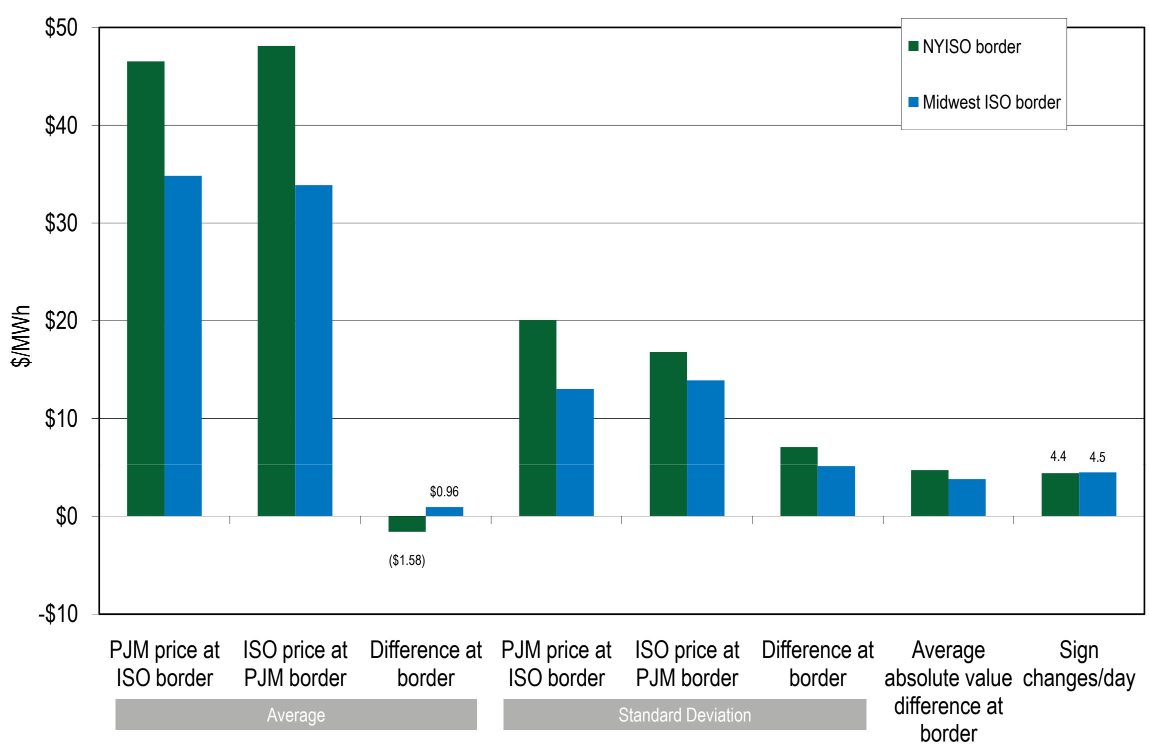


Figure 4-10 PJM, NYISO and Midwest ISO day-ahead border price averages: Calendar year 2010



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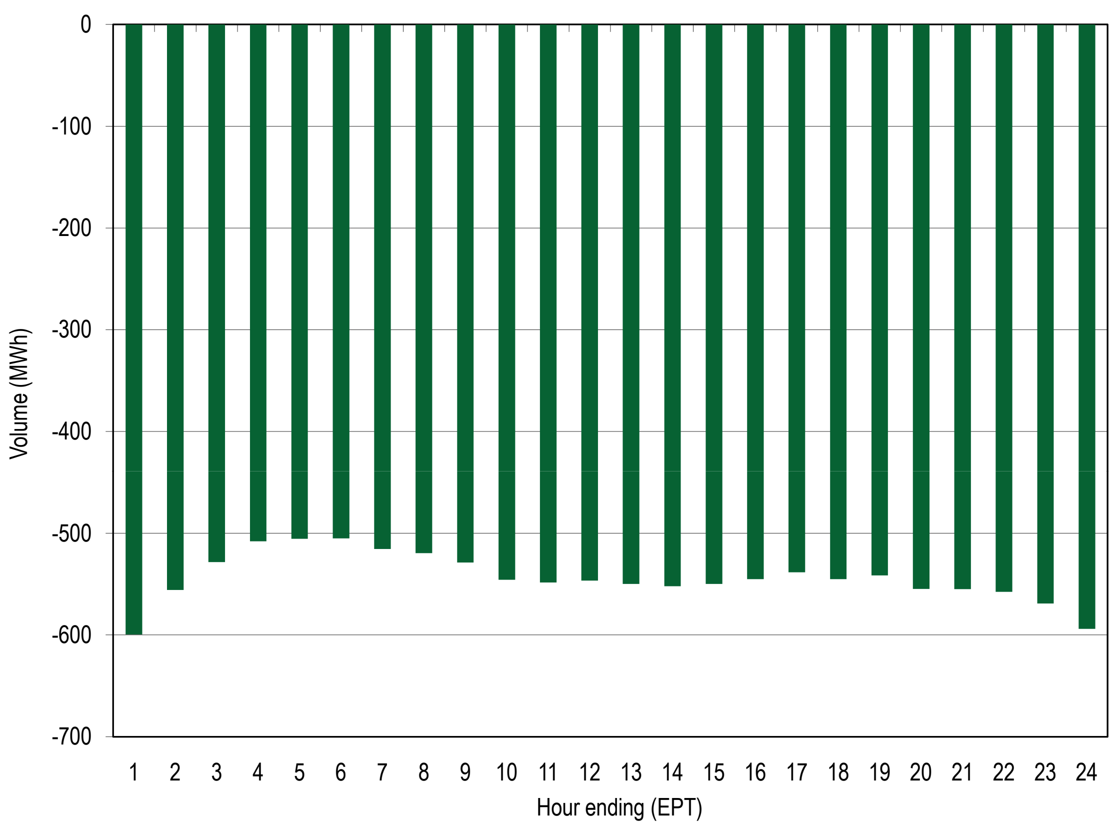
Neptune Underwater Transmission Line to Long Island, New York

On July 1, 2007, a 65-mile, DC transmission line from Sayreville, New Jersey, to Nassau County on Long Island via undersea and underground cable was placed in service, providing an additional connection between PJM and the NYISO. This is a merchant 230 kV transmission line with a capacity of 660 MW. While the Neptune line is a bidirectional facility, Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York. For 2010, the total real-time scheduled net exports on the Neptune line were 4,853 GWh while the day-ahead scheduled net exports were 4,989 GWh. Figure 4-11 shows the real-time average flow, by hour of the day, on the Neptune line for the calendar year 2010. In 2010, the average price difference between the PJM/Neptune price and the NYISO/Neptune price was consistent with the direction of the average flow. In 2010, the PJM average hourly LMP at the Neptune Interface was $51.40 while the NYISO LMP at the Neptune Bus was $58.08, a difference of $6.67, while the average hourly flow in 2010 was -544 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. While the average hourly LMP difference at the PJM/Neptune border was only $6.67, the average of the absolute value of the hourly difference was $23.30. For the hours when the direction of flows was not consistent with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MW of flow, was $43.4 million at the PJM/NEPT Interface.

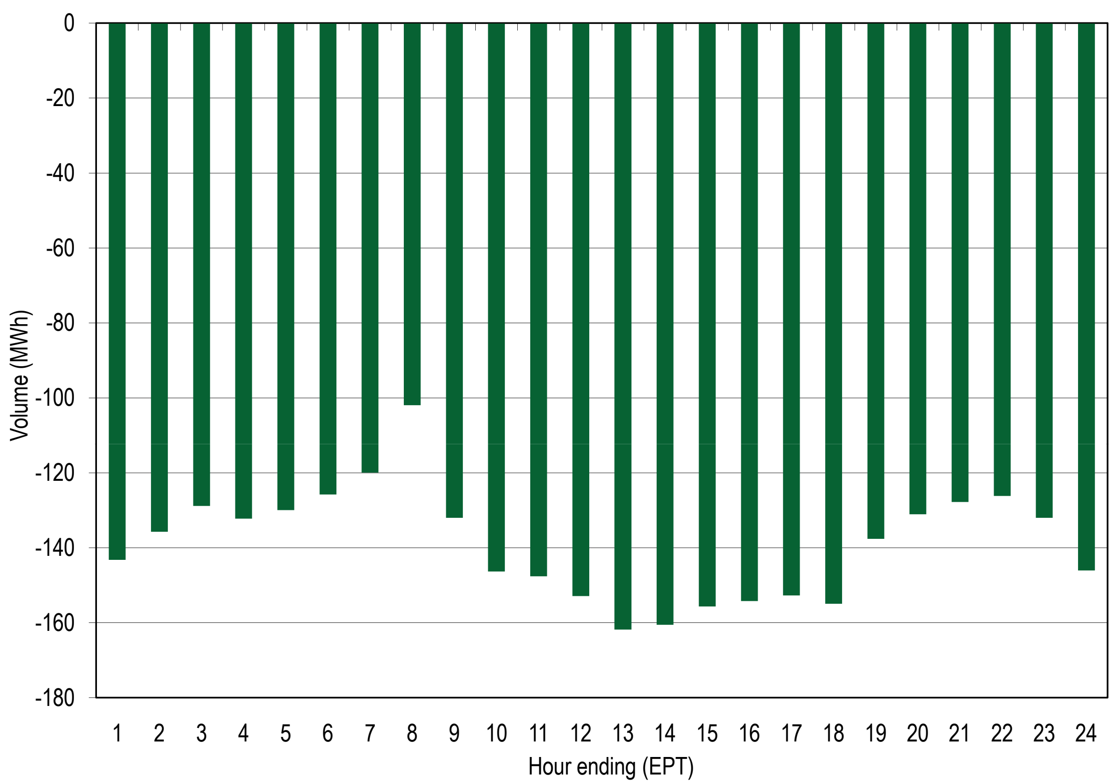
Figure 4-11 Neptune hourly average flow: Calendar year 2010



Linden Variable Frequency Transformer (VFT) facility

On November 1, 2009, the Linden VFT facility was placed in service, providing an additional connection between PJM and the NYISO. A variable frequency transformer is a technology which allows for fast responding continuous bidirectional power flow control, similar to that of a PAR. The facility includes 350 feet of new 230 kV transmission line and 1,000 feet of new 345 kV transmission line, with a capacity of 300 MW. 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. The basis for this limitation is unclear. Figure 4-12 shows the real-time average flow, by hour of the day, on the Linden line for the calendar year 2010. In 2010, the average price difference between the PJM/Linden price and the NYISO/Linden price was consistent with the direction of the average flow. In 2010, the PJM average hourly LMP at the Linden Interface was $50.10 while the NYISO LMP at the Linden Bus was $51.58, a difference of $1.48, while the average hourly flow was -139 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 61 percent of the hours. While the average hourly LMP difference at the PJM/Linden border was only $1.48, the average of the absolute value of the hourly difference was $18.13. During all hours where flows did not align with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MW of flow, was $8.8 million at the PJM/LIND Interface.

Figure 4-12 Linden hourly average flow: January through December 2010



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Operating Agreements with Bordering Areas

To improve reliability and reduce potential competitive seams issues, PJM and its neighbors have developed, and continue to work on, joint operating agreements. These agreements are in various stages of development and include a reliability agreement with the NYISO, an implemented operating agreement with the Midwest ISO, an implemented reliability agreement with TVA, an operating agreement with Progress Energy Carolinas, Inc., that is not yet fully implemented, and a reliability coordination agreement with VACAR South.

PJM and New York Independent System Operator Joint Operating Agreement (JOA)

On May 22, 2007, the JOA between PJM and the New York Independent System Operator (NYISO) became effective. This agreement was developed to improve reliability. It also formalizes 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 in 2010. By order issued July 16, 2009, the Commission directed the NYISO to "develop and file a report on long-term comprehensive solutions to the loop flow problem, including addressing interface pricing and congestion management, and any associated tariff revisions, within 180 days of the date of this order."[22] After working in collaboration with PJM, the Midwest ISO and the Ontario Independent Electricity System Operator (IESO), including an opportunity to comment by stakeholders and market monitors, the NYISO filed on January 12, 2010, a Report on Broader Regional Markets; Long-Term Solutions to Lake Erie Loop Flow.[23] On July 15, 2010, the Commission conditionally accepted the NYISO Report subject to the parties filing answers to the questions set forth in the order within 30 days of the date of the order.[24] The Commission requested that the parties provide additional evidence regarding the proposed solutions. On August 16, 2010, the NYISO provided their response to the July 15th Order.[25] On September 15, 2010, the Market Monitoring Unit (MMU) responded to the NYISO filing.[26] The MMU commented that the NYISO response lacked detail and focus in implementing solutions that could be implemented quickly, and continued to lack detailed and firm timelines for implementation. Additionally, the MMU questioned the curtailment priority granted to transactions scheduled on non-firm transmission when electing to purchase "buy-through of congestion" as well as the inability to implement a market to market congestion management agreement with PJM. Finally, the MMU provided comments and recommendations on implementing an interface pricing solution in the NYISO to mitigate the incentives to scheduling circuitous paths into and out of the NYISO. The MMU actively participated in the meeting of the Broader Regional Markets Group in Philadelphia on September 27, 2010, and continues to advocate in that process a joint operating agreement between NYISO and PJM that is equivalent to or better than the JOA between the Midwest ISO and PJM. On December 30, 2010, the Commission issued an Order on Rehearing and Compliance which indicated that they agreed with the MMU comments and directed the NYISO to make interface pricing revisions by the second quarter of 2011. Additionally, the Commission required that congestion management/market-to-market coordination for the Commission-jurisdictional RTO/ISOs be completed concurrently by the second quarter of 2011.[27]

22 128 FERC ¶ 61,049 (Ordering Para. B), *order on clarification*, 128 FERC ¶ 61,239.
23 See "Report on Broader Regional Markets: Long-Term Solutions to Lake Erie Loop Flow" Docket No. ER08-1281-004 (January 12, 2010)
24 See 132 FERC ¶ 61,031.
25 See "Response to Questions and Supplemental Report on Broader Regional Markets; Long-Term Solutions to Lake Erie Loop Flow" Docket No. ER08-1281-004 (August 16, 2010).
26 See "Comments of the Independent Market Monitor for PJM."Docket No. ER08-1281-004 (September 15, 2010).
27 See 133 FERC ¶ 61,276.

PJM and Midwest ISO Joint Operating Agreement

The market to market coordination between PJM and the Midwest ISO continued in 2010. Under the market to market rules, the organizations coordinate pricing at their borders. PJM and the Midwest ISO each calculate an LMP for its interface with the other organization. Both entities calculate LMPs using network models including distribution factor impacts. PJM uses nine buses within the Midwest ISO to calculate the PJM/MISO Interface pricing point LMP while the Midwest ISO uses all of the PJM generator buses in its model of the PJM system in its computation of the MISO/PJM Interface pricing point.

In 2009, the Midwest ISO requested that PJM review the components of the Congestion Management Protocol (CMP) to verify data accuracy. During this review, it was found that some data inputs to the market flow calculator were incorrect during the period from April 2005 through June 2009. The resulting inaccuracies in the market flow calculation meant that the Midwest ISO received less compensation than appropriate. While the errors in input data have been corrected for market to market activity moving forward, the Midwest ISO and PJM are currently in the process of calculating the shortfall. PJM reported an estimate of $77.5 million.[28]

Differences also emerged over how the parties are administering the JOA, such as the use by the Midwest ISO of proxy flowgates. The practice of inappropriately using proxy flowgates for market to market activity, if confirmed, measured and determined inconsistent with the JOA, would have meant that the Midwest ISO received more compensation than appropriate.

These matters went before the Commission in settlement proceedings.[29] Two settlement conferences were held on August 4, 2010, and November 3, 2010. The settling parties and interveners discussed the issues raised by the complaints in the proceedings, as well as other issues arising under the JOA that came to light during the course of the discussions, including a newly discovered error in the calculation of Firm Flow Entitlements (FFEs) under the JOA. As a result of the discussions conducted at the settlement conferences, the Midwest ISO and PJM reached a settlement resolving all issues in the proceeding. The settlement includes a dismissal of all complaints within the proceeding. Additionally, “Both parties further agree to release and discharge forever the other, its officers, directors, employees, members, successors, and assigns from any and all claims, demands, damages, amounts owed, actions, causes of actions, or suits of any kind or nature whatsoever, known or unknown, foreseen or unforeseen, that arose or could have arisen under the JOA for events that occurred prior to the date of the filing of this settlement.” The settlement agreement also includes an agreement to perform a comprehensive and inclusive “Baseline Review” by an independent third party of all of the Midwest ISO’s and PJM’s existing means and processes for implementing the market-to-market provisions of the JOA, including those pertaining to market-to-market settlements. Also, the settlement includes additional provisions outlining a change management process, a biennial review of process changes, enhanced access to data, limitations on claims and resettlements under the JOA and amendments to the JOA to implement a set of guiding principles and modifications to certain market-to-market procedures that facilitate effective coordination and avoid future disputes.[30] The MMU remains concerned that this disagreement over administration of the JOA will unduly detract from its ability to serve as the basis for moving forward industry practice for managing congestion and loop flows at system interfaces, but notes that the *Memorandum of Understanding* signed by PJM and the Midwest ISO on May

28 See “PJM/MISO Market Flow Calculation Error. “(September 10, 2009) (Accessed January 15, 2010) <http://www.pjm.com/committees-and-groups/committees/~/media/committees-groups/committees/mic/20090910/20090910-item-07-m2m-calculation-error.ashx> (49 KB).

29 See 131 FERC ¶ 61,284 (June 29, 2010).

30 See “Explanatory Statement” Docket No. EL10-45-000; Docket No. EL10-46-000; Docket No. EL10-60-000 (Consolidated) (January 4, 2011).

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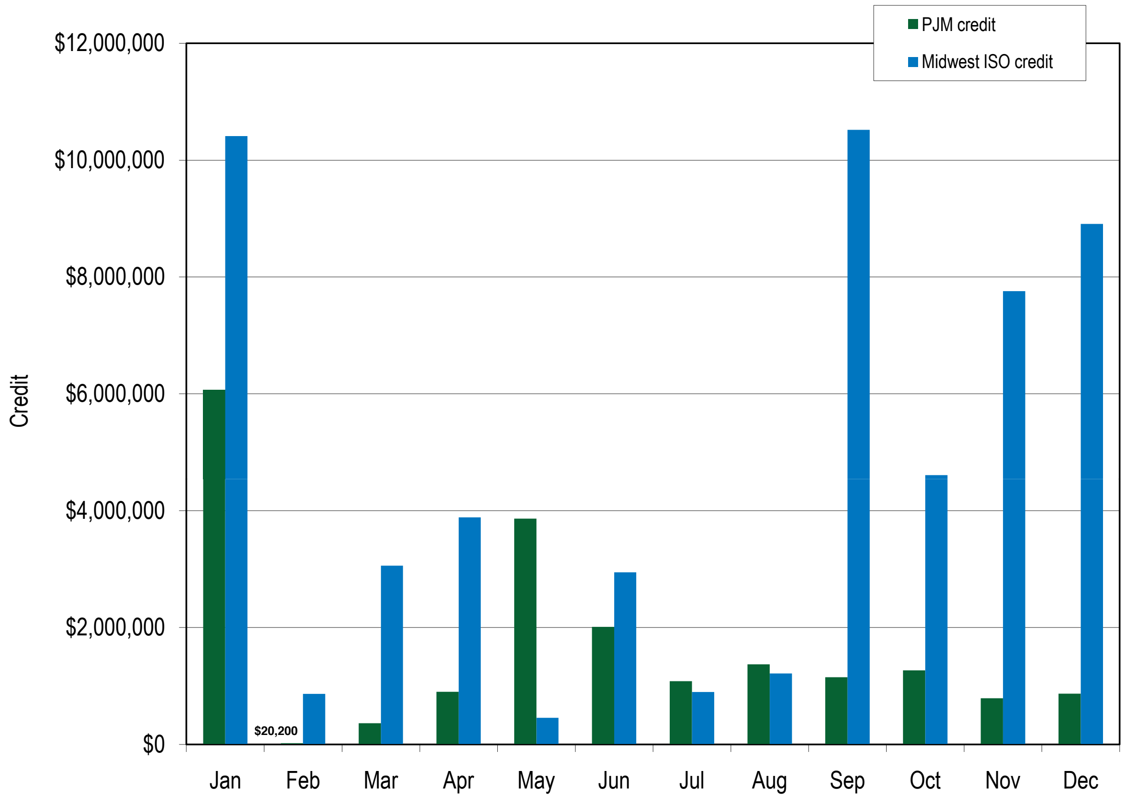
27, 2010 "reaffirms the value of the agreement and pledges continued cooperation to develop new practices to improve the interface between the two organizations."[31]

Generating units that do not respond to RTO dispatch signals may contribute to the need for PJM and the Midwest ISO to implement market to market redispatch and result in payments under the JOA. The MMU recommends that the JOA be modified to eliminate payments between RTOs when such payments would result from the failure of generating units to respond to appropriate pricing signals.

The market to market operations resulted both in the Midwest ISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. The Firm Flow Entitlement (FFE) represents the amount of historic flow that each RTO had created on each reciprocal coordinated flowgate (RCF) used in the market to market settlement process. The FFE establishes the amount of market flow that each RTO is permitted to create on the RCF before incurring redispatch costs during the market to market process. If the non-monitoring RTO's real-time market flow is greater than their FFE plus the approved MW adjustment from day-ahead coordination, then the non-monitoring RTO will pay the monitoring RTO based on the difference between their market flow and their FFE. If the non-monitoring RTO's real-time market flow is less than their FFE plus the approved MW adjustment from day-ahead coordination, then the monitoring RTO will pay the non-monitoring RTO for congestion relief provided by the non-monitoring RTO based on the difference between the non-monitoring RTO's market flow and their FFE. Figure 4-13 presents the monthly credits each organization received from redispatching for the other. A PJM credit is a payment by the Midwest ISO to PJM and a Midwest ISO credit is a payment by PJM to the Midwest ISO. The largest payments from PJM to the Midwest ISO in 2010 were the result of redispatch by the Midwest ISO to relieve congestion on the Crete-St Johns Tap 345 kV for the loss of Dumont-Wilton Center 765 kV line. Total PJM payments to the Midwest ISO in 2010 were approximately $55.5 million, a 22 percent increase from the 2009 level. The largest payments from the Midwest ISO to PJM in 2010 were the result of redispatch by PJM to relieve congestion on the Pleasant Prairie-Zion 345 kV for the loss of Zion-Arcadian 345 kV line. Total Midwest ISO payments to PJM were approximately $19.8 million, a 150 percent increase from the 2009 level.

31 See "PJM-MISO-MOU-May-2010" (May 27, 2010) (Accessed October 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/pjm-miso-mou-may-2010.ashx> (313 KB).

Figure 4-13 Credits for coordinated congestion management: Calendar year 2010



PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement (JRCA)

The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management and congestion relief among the wholesale electricity markets of the Midwest ISO and PJM and the service territory of TVA. The agreement continued to be in effect in 2010. Information-sharing among the parties enables each transmission provider to recognize and manage the effects of its operations on the adjoining systems. Additionally, the three organizations conduct joint planning sessions to ensure that improvements to their integrated systems are undertaken in a cost-effective manner and without adverse reliability impacts on any organization's customers.

PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement

On September 9, 2005, the FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. The agreement remained in effect through 2010. As part of this agreement, both parties agreed to develop a formal Congestion Management Protocol (CMP). On February 2, 2010, PJM and PEC filed a revision to the JOA to include a CMP.[32] The MMU responded to the filing on February 23, 2010.[33] The MMU response noted that the agreement included discriminatory treatment for the identified transactions with respect to access to ATC, that a regional approach is preferable to entering into agreements with individual neighbors,

32 See *PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc.* Docket No. ER10-713-000 (February 2, 2010)
33 See "Motion to Intervene and Comments of the Independent Market Monitor for PJM."Docket No. ER10-713-000 (February 25, 2010)

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and that a sunset should be required in order to ensure that the next step towards such regional coordination is taken without delay. PJM and PEC filed an answer on March 10, 2010, to which the MMU responded on April 2, 2010. PJM and PEC filed an additional answer on April 19, 2010.[34] On May 28, 2010, the Commission conditionally approved the revised PJM/PEC JOA.[35] PJM and PEC were required to make a compliance filing within thirty days of the date of the order answering specific questions related to the impact of the scheduling arrangement on NERC standards and discriminatory access, the market pricing mechanisms with regards to eliminating the nuclear and hydro units from the calculation and the discriminatory use of export make whole payments under this agreement. On June 28, 2010, PJM and PEC filed their response.[36] The MMU responded to the compliance filing on July 19, 2010, reiterating the argument that the PJM/PEC JOA provides for preferential treatment to ATC and that the elimination of nuclear and hydro units from the interface price calculation is not consistent with the economics of locational marginal pricing.[37] The MMU moved for a technical conference to explore these issues.[38] On January 20, 2011, the commission conditionally accepted the compliance filing made by PJM and Carolina Power, stating that the proposed CMP was a just and reasonable solution to managing congestion between Regional Transmission Organizations (RTOs) and other systems. The acceptance of the JOA revisions is subject to the condition that PJM file a revised provision to its tariff that details how similarly situated parties can elect to use such a scheduled arrangement, including the after-the-fact transmission reservations provisions.[39]

PJM and VACAR South Reliability Coordination Agreement

On May 23, 2007, PJM and VACAR South (comprised of Duke Energy Carolinas, LLC (DUK), PEC, South Carolina Public Service Authority (SCPSA), Southeast Power Administration (SEPA), South Carolina Energy and Gas Company (SCE&G) and Yadkin Inc. (a part of Alcoa)) entered into a reliability coordination agreement. This agreement was developed to augment and further support reliability. It provides for system and outage coordination, emergency procedures and the exchange of data. This arrangement permits each party to coordinate its plans and operations in the interest of reliability. Provisions are also made for making regional studies and recommendations to improve the reliability of the interconnected bulk power systems. The agreement remained in effect through 2010.

Other Agreements/Protocols with Bordering Areas

Con Edison and PSE&G Wheeling Contracts

To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New York and New Jersey. A common path is through Westchester County using lines controlled by the NYISO. Another path is through northern New Jersey using lines controlled by PJM. This wheeled power creates loop flow across the PJM system. The Con Edison/PSE&G contracts governing the New Jersey path evolved during the 1970s and were the subject of a Con Edison complaint to the FERC in 2001. In May 2005, the FERC issued an order setting out a protocol developed by the two companies, PJM and the NYISO.[40] In July 2005, the protocol was implemented. Con Edison filed a protest with the FERC regarding the

34 Joint Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C. and Progress Energy Carolinas, Inc.; Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM; Joint Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C. and Progress Energy Carolinas, Inc., in Docket No. ER10-713-000.

35 See Docket No. ER10-713-000. Amended and Restated Joint Operating Agreement Among and Between PJM Interconnection, L.L.C., and Progress Energy Carolinas.

36 See "Compliance Filing," Docket No. ER10-713-002.

37 See " Comments and Motion for Technical Conference of the Independent Market Monitor for PJM," Docket No. ER10-713-002.

38 *Id.*

39 132 FERC ¶ 61,048 (2011).

40 111 FERC ¶ 61,228 (2005).

delivery performance in January 2006.[41] In August 2007, the FERC denied a rehearing request on Con Edison's complaints regarding protocol performance and refunds.[42] PJM continued to operate under the terms of the protocol through 2010.

The contracts provide for the delivery of up to 1,000 MW of power from Con Edison's Ramapo Substation in Rockland County, New York, to PSE&G at its Waldwick Switching Substation in Bergen County, New Jersey. PSE&G wheels the power across its system and delivers it to Con Edison across lines connecting directly into New York City. Two separate contracts cover these wheeling arrangements. A 1975 agreement covers delivery of up to 400 MW through Ramapo (New York) to PSE&G's Waldwick Switching Station (New Jersey) then to the New Milford Switching Station (New Jersey) via the J line and ultimately from the Linden Switching Station (New Jersey) to the Goethals Substation (New York) and from the Hudson Generating Station (New Jersey) to the Farragut Switching Station (New York), via the A and B feeders, respectively. A 1978 agreement covers delivery of up to an additional 600 MW through Ramapo to Waldwick then to Fair Lawn, via the K line, and ultimately through a second Hudson-to-Farragut line, the C feeder. In 2001, Con Edison alleged that PSE&G had under delivered on the agreements and asked the FERC to resolve the issue.

The protocol allows Con Edison to elect up to the flow specified in each contract through the PJM Day-Ahead Energy Market. These elections are transactions in the PJM Day-Ahead Energy Market. The 600 MW contract is for firm service and the 400 MW contract has a priority higher than non-firm service but less 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. The interface prices for this transaction are not defined PJM interface prices, but are defined in the protocol based on the actual facilities governed by the protocol.

Under the FERC order, PSE&G is assigned FTRs associated with the 600 MW contract. The PSE&G FTRs are treated like all other FTRs. In 2010, PSE&G's revenues were less than its congestion charges by $1,028,909 after adjustments ($5,417 in 2009.) Under the FERC order, Con Edison receives credits on an hourly basis for its elections under the 400 MW contract from a pool containing any excess congestion revenue after hourly FTRs are funded. In 2010, Con Edison's congestion credits were $3,066,001 less than its day-ahead congestion charges (Credits had been $232,745 less than charges in 2009 (Table 4-9)).

In effect, Con Edison has been given congestion credits that are the equivalent of a class of FTRs covering positive congestion with subordinated rights to revenue. However, Con Edison is not treated as having an FTR when congestion is negative. An FTR holder in that position would pay the negative congestion credits, but Con Edison does not. The protocol's provisions about congestion payments clearly cover congestion charges and offsetting congestion credits, but are not explicit on the treatment of Con Edison's negative congestion credits, which were -$178,749 in 2010. The parties should address this issue.

41 "Protest of the Consolidated Edison Company of New York, Inc.", Protest, Docket No. EL02-23-000 (January 30, 2006).

42 120 FERC ¶ 61,161

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Table 4-9 Con Edison and PSE&G wheeling settlement data: Calendar year 2010

	Con Edison			PSE&G		
	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Congestion Charge	$5,366,488	($23,991)	$5,342,497	$8,499,150	$0	$8,499,150
Congestion Credit			$2,300,487			$7,118,980
Adjustments			$18,050			$351,261
Net Charge			$3,023,960			$1,028,909

Under the terms of the protocol, Con Edison can make a real-time election of its desired flow for each hour in the Real-Time Energy Market. If this election differs from its day-ahead schedule, the company is subject to the resultant charges or credits. This occurred in five percent of the hours in 2010.

After years of litigation concerning whether or on what terms Con Edison's protocol would be renewed, PJM filed on February 23, 2009 a settlement on behalf of the parties to subsequent proceedings to resolve remaining issues with these contracts and their proposed rollover of the agreements under the PJM OATT.[43] By order issued September 16, 2010, the Commission approved this settlement,[44] which extends Con Edison's special protocol indefinitely. The Commission rejected objections raised first by NRG and FERC trial staff, and later by the MMU that this arrangement is discriminatory and inconsistent with the Commission's open access transmission policy.[45]

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 flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface. The result is loop flow, despite the fact that system actual and scheduled flow could net to a zero difference.

43 See Docket Nos. ER08-858-000, et al. The settling parties are the New York Independent System Operator, Inc. (NYISO), Con Ed, PSE&G, PSE&G Energy Resources & Trading LLC and the New Jersey Board of Public Utilities.

44 132 FERC ¶ 61,221.

45 *See*, *e.g.*, Motion to Intervene Out-of-Time and Comments of the Independent Market Monitor for PJM in Docket No. ER08-858-000, et al. (May 11, 2010). The MMU questioned whether allowing rollover is appropriate and raised concerns that continuing these agreements could interfere with the efficient management of the NYISO/PJM seam, accord preferential access to transmission service and limit security constrained least cost dispatch. The MMU questioned whether a valid offsetting reliability consideration had been identified and explained. The MMU noted, "the settling parties fail to demonstrate any circumstances that may now exist warranting a non-conforming agreement under the current approach to seams management, nor do they attempt to explain how such circumstances would continue to exist under the reforms to be implemented through the Broader Regional Markets Initiative." Additionally, that MMU argued, "the settling parties have failed to show that continuation of the grandfathered transmission service agreements will neither interfere with the efficient calculation of LMPs in both PJM and the NYISO, and at their interface, nor harm the ability of parties to efficiently transact business."

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. PJM manages loop flow using a combination of interface price signals, redispatch and TLR procedures.

Loop flows are a significant concern. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. In general, the detailed sources of the identified differences between scheduled and actual flows remain unclear.

The fact that total PJM net actual interface flows were close to net scheduled interface flows, on average for 2010 as a whole, is not a useful measure of loop flow. There were significant differences between scheduled and actual flows for specific individual interfaces (Table 4-10). From an operating perspective, PJM tries to balance overall actual and scheduled interchange, but does not have a mechanism to control the balance between actual and scheduled interchange at individual interfaces because there are free flowing ties with contiguous balancing authorities.

In 2010, for PJM as a whole, net scheduled and actual interchange differed by 5.2 percent (Table 4-10).[46] Actual system net exports were 6,425 GWh, 353 GWh more than the scheduled total net exports of 6,778 GWh. Flow balance varied at each individual interface. The PJM/MECS Interface was the most imbalanced, with net actual exports of 13,547 GWh exceeding scheduled imports of 1,559 GWh by 15,106 GWh or 969 percent, an average of 1,724 MW during each hour of the year. At the PJM/CPLE Interface, scheduled flows were exports of 421 GWh and actual flows were imports of 8,350 GWh, creating an imbalance of 8,771 GWh or 2,083 percent, an average of 1,001 MW during each hour of the year.

46 The the “Net Scheduled” values shown in Table 4-10 include dynamic schedules. Dynamic schedules are flows from generating units that are physically located in one balancing authority area but deliver power to another balancing authority area. The power from these units flows over the lines on which the actual flow at PJM’s borders is measured. As a result, the net interchange in this table does not match the interchange values shown in Figure 4-1,Figure 4-2 and Figure 4-3, and Table 4-1 through Table 4-6.

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Table 4-10 Net scheduled and actual PJM interface flows (GWh): Calendar year 2010

	Actual	Net Scheduled	Difference (GWh)	Difference (percent of net scheduled)
CPLE	8,350	(421)	8,771	(2,083%)
CPLW	(1,907)	0	(1,907)	0%
DUK	(2,975)	(48)	(2,927)	6,098%
EKPC	1,021	(176)	1,197	(680%)
LGEE	1,300	1,754	(454)	(26%)
MEC	(2,682)	(5,172)	2,490	(48%)
MISO	(7,920)	(268)	(7,652)	2,855%
ALTE	(5,974)	(591)	(5,383)	911%
ALTW	(2,279)	(646)	(1,633)	253%
AMIL	7,260	(315)	7,575	(2,405%)
CIN	1,923	3,503	(1,580)	(45%)
CWLP	(314)	(22)	(292)	1,327%
FE	(272)	(2,297)	2,025	(88%)
IPL	2,490	(438)	2,928	(668%)
MECS	(13,547)	1,559	(15,106)	(969%)
NIPS	(2,716)	(498)	(2,218)	445%
WEC	5,509	(523)	6,032	(1,153%)
NYISO	(12,305)	(13,590)	1,285	(9%)
LIND	(1,218)	(1,218)	0	0%
NEPT	(4,767)	(4,767)	0	0%
NYIS	(6,320)	(7,605)	1,285	(17%)
OVEC	7,381	11,846	(4,465)	(38%)
TVA	3,312	(703)	4,015	(571%)
Total	(6,425)	(6,778)	353	(5.2%)

Loop Flows at the PJM/MECS and PJM/TVA Interfaces

As it had in 2009, the PJM/Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows (-15,106 GWh in 2010 and -14,441 GWh in 2009), particularly during the overnight hours. The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows (4,015 GWh in 2010 and 3,840 GWh in 2009). The net difference between scheduled flows and actual flows at the PJM/TVA Interface was imports while the net difference at the PJM/MECS Interface was exports.

Loop Flows at PJM's Southern Interfaces

Figure 4-14 and Figure 4-15 illustrate the reduction in the previously persistent difference between scheduled and actual power flows at PJM's southern interfaces (PJM/TVA and PJM/EKPC to the west and PJM/CPLE, PJM/CPLW and PJM/DUK to the east) that grew to its largest volumes through the summer of 2006. A portion of the historic loop flows were the result of the fact that the interface pricing points (Southeast and Southwest) allowed the opportunity for market participants to falsely arbitrage pricing differentials, creating a mismatch between actual and scheduled flows. On October 1, 2006, PJM modified the southern interface pricing points by creating a single import

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pricing point (SouthIMP) and a single export interface pricing point (SouthEXP). At the time of the consolidation of the Southeast and Southwest Interface pricing points, some market participants requested grandfathered treatment for specific transactions from PJM under which they would be allowed to keep the Southeast and Southwest Interface pricing. (The average difference between the real-time LMP at the Southeast pricing points and the SouthEXP pricing point was $4.32 in 2010 and the average difference between the real-time LMP at the Southwest pricing points and the SouthEXP pricing point was -$2.87 in 2010. In other words, it was more expensive to buy from PJM for export to the south under the old pricing for Southeast pricing point and less expensive to buy from PJM for export to the south under the old pricing for the Southwest pricing point.) These agreements remain in place. The MMU recommends that these grandfathered agreements be terminated, as the interface prices received for these agreements do not represent the economic fundamentals of locational marginal pricing. As an alternative, the agreements should be made public and the same terms should be made available to all qualifying entities.

Despite some improvements, significant loop flows persist. While the SouthIMP and SouthEXP pricing points have replaced the Southeast and Southwest pricing points Figure 4-14 and Figure 4-15 are included for comparison.

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 prices with physical flows and their impacts on the transmission system. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SPP, through the Midwest ISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (the Midwest ISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south would require the market participant to acquire transmission through non-market balancing authorities, and thus incur additional transmission costs. PJM's interface pricing method recognizes that transactions sourcing in SPP and sinking in PJM will create flows across the southern border and prices those transactions at the SouthIMP Interface price. As a result, the transaction is priced appropriately, but a difference between scheduled and actual flows is created at both the Midwest ISO border (higher scheduled than actual flows) as well as the southern border (higher actual than scheduled flows).

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Figure 4-14 Southwest actual and scheduled flows: January 2006 through December 2010

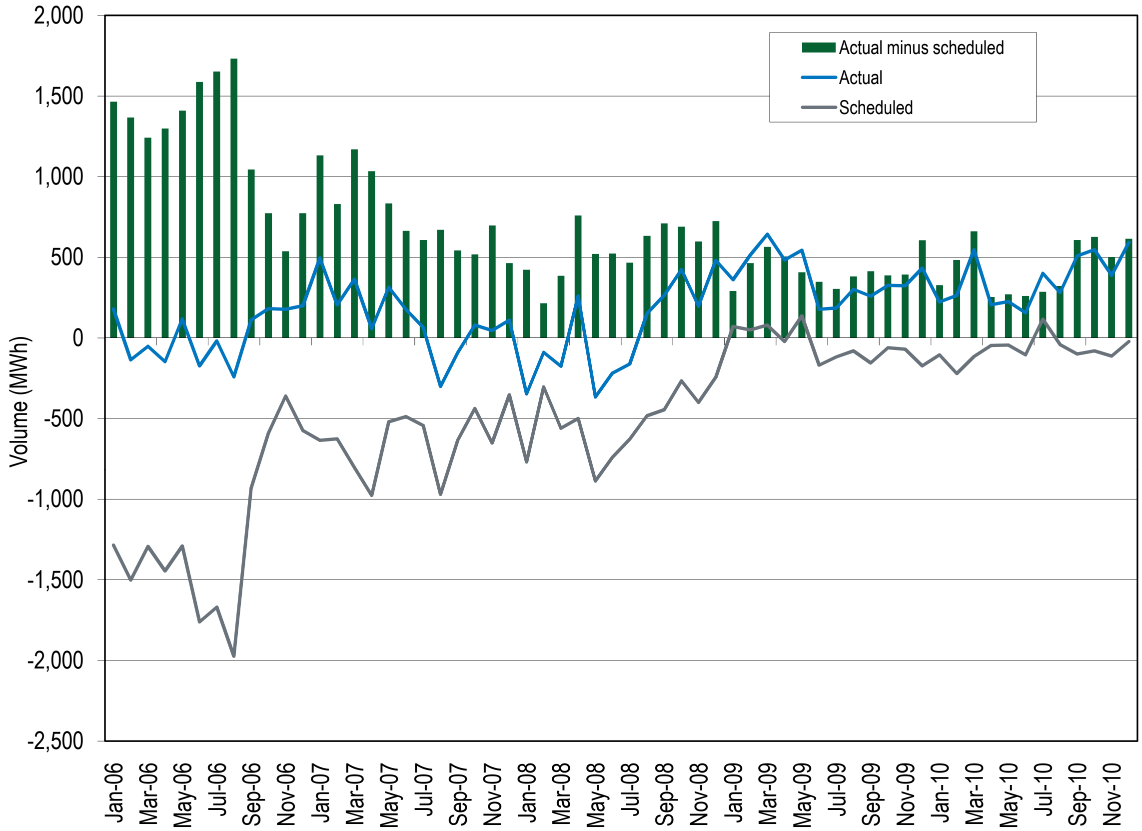
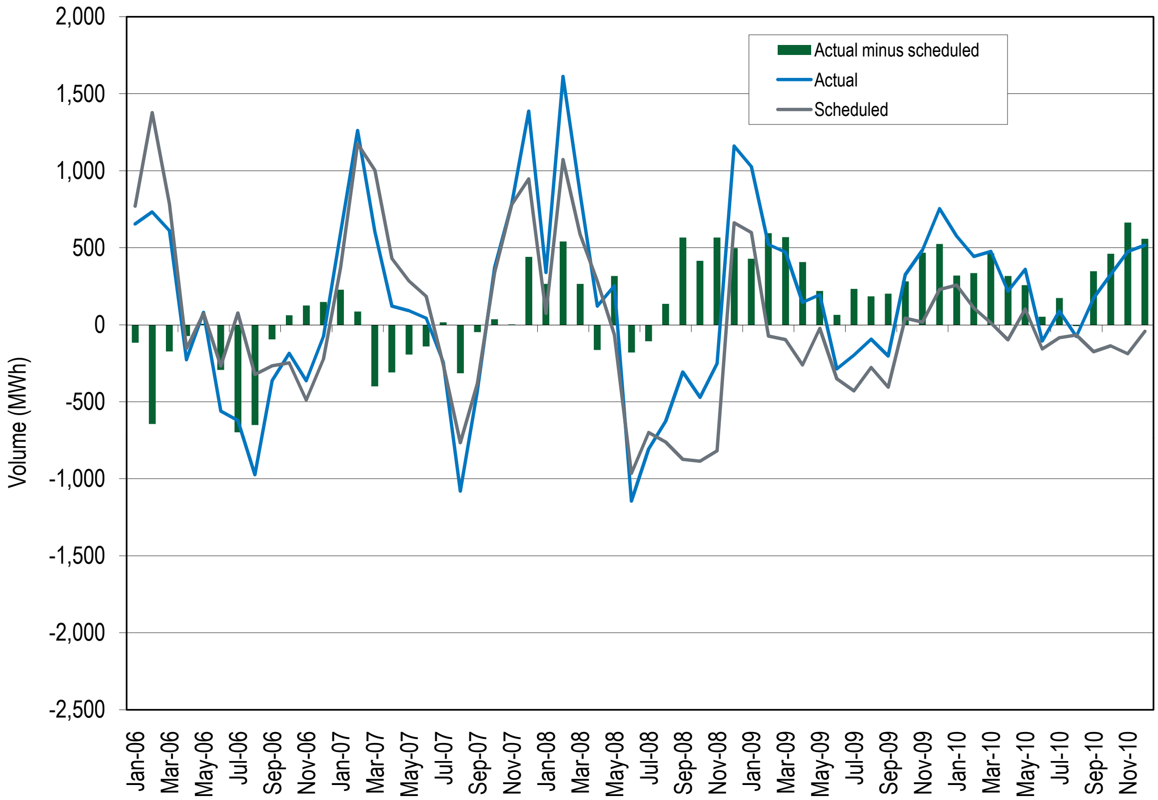


Figure 4-15 Southeast actual and scheduled flows: January 2006 through December 2010



Loop Flows at PJM's Northern Interfaces

In 2008, new loop flows were created when NYISO pricing rules gave participants an incentive to schedule power flows in a manner inconsistent with the associated actual power flows.[47] PJM's interface pricing calculations correctly reflected the actual power flows, but the NYISO's interface pricing did not. One result was increased congestion charges in the NYISO system. PJM's interface pricing rules eliminated the incentive to schedule power flows on paths inconsistent with actual power flows in order to take advantage of price differences. In this case, PJM interface pricing rules resulted in PJM paying for the import based on its source in the NYISO and disregarded the scheduled path.

By order issued July 16, 2009, the Commission directed the NYISO to "develop and file a report on long-term comprehensive solutions to the loop flow problem, including addressing interface pricing and congestion management, and any associated tariff revisions, within 180 days of the date of this order."[48]

47 See the *2008 State of the Market Report for PJM*, Volume II, "Interchange Transactions."
48 128 FERC ¶61,049 (Ordering Para. B), *order on clarification*, 128 FERC ¶61,239.

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Consistent with the Commission's direction, during the third quarter of 2009, the NYISO convened the Broader Regional Markets group, which included representatives from PJM, the NYISO, the Midwest ISO and the IESO, to develop a solution to the northeastern loop flow issues. The group solicited comments from stakeholders and the market monitors. The MMU filed comments on November 13, 2009.[49]

The group developed several recommendations, including the use of PARs to control energy flows, a buy-through congestion methodology, the development of a new tool, using existing functionality within NERCs Interchange Distribution Calculator (IDC), to visualize the loop flows and an interregional transaction coordination approach to align business rules across the northeast ISOs/RTOs. After working in collaboration with PJM, the Midwest ISO and the Ontario Independent Electricity System Operator (IESO), including an opportunity to comment by stakeholders and market monitors, the NYISO filed on January 12, 2010, a Report on Broader Regional Markets; Long-Term Solutions to Lake Erie Loop Flow.[50]

Engineering approaches to address loop flows, such as phase angle regulators and variable frequency transformers, are a means to help ameliorate loop flow issues, but they do not address the root cause of loop flows. So long as these physical solutions are used in conjunction with more comprehensive market solutions, the MMU supports cost effective investment in additional PARs for system control. With the exception of cost allocation issues, the use of PARs does not appear to be controversial. Engineering approaches should not serve as a basis to defer or deflect attention to the development of market solutions.

Implementing a buy-through congestion methodology is also unlikely to resolve the underlying pricing issue. PJM offers a similar product, where market participants will be allowed to continue to flow their transactions when they would otherwise be curtailed by a TLR, if they were willing to pay the congestion costs of their parallel flows affecting the PJM system. This product, called "TLR Buy-Through", was implemented in PJM in 2001. In the nearly nine years that PJM has offered this product, it has never been used by market participants. Instead, the transactions were curtailed in the TLR process to alleviate the loop flows.

The report also included a recommendation that the NYISO move to a less than hourly dispatch timeframe through interregional coordination. While this recommendation did not include details, redispatch on the quarter hour would allow NYISO market participants to respond more quickly to the NYISO pricing signals.

Parallel flow visualization will provide additional information to the reliability coordinators, and will also assign a non-firm generation to load component to congestion within non-market areas. The MMU supports this project, as it will provide additional details and archived data to better analyze loop flows. However, the work of the Broader Regional Market group and the continued development of this tool within the NERC/NAESB arena do not require linkage. It would be more productive to focus on direct solutions to loop flow issues rather than the already ongoing development of loosely related industry tools.

On July 15, 2010, the Commission conditionally accepted the NYISO Report subject to the parties filing answers to the questions set forth in the order within 30 days of the date of the order.[51]

49 See "IMM Comments on Draft Loop Flow Recommendations of the Broader Regional Markets" (November 13, 2009) <http://www.monitoringanalytics.com/reports/Reports/2009/IMM_Comments_on_Draft_Loop_Flow_Recommendations_20091113.pdf> (86 KB).

50 See "Report on Broader Regional Markets: Long-Term Solutions to Lake Erie Loop Flow" Docket No. ER08-1281-004 (January 12, 2010).

51 132 FERC ¶ 61,031.

The Commission requested that the parties provide additional evidence regarding the proposed solutions. On August 16, 2010, the NYISO provided their response to the July 15th Order.[52] On September 15, 2010, the PJM Market Monitoring Unit (MMU) responded to the NYISO filing.[53] The MMU commented that the NYISO response lacked detail and focus in implementing solutions that could be implemented quickly, and continued to lack detailed and firm timelines for implementation. Additionally, the MMU questioned the curtailment priority granted to transactions scheduled on non-firm transmission when electing to purchase "buy-through of congestion" as well as the inability to implement a market to market congestion management agreement with PJM. Finally, the MMU provided comments and recommendations on implementing an interface pricing solution and a market to market Congestion Management Protocol (CMP) in the NYISO to mitigate the incentives to scheduling circuitous paths into and out of the NYISO. The MMU also actively participated in the meeting of the Broader Regional Markets Group in Philadelphia on September 27, 2010, and continues to advocate in that process a joint operating agreement between NYISO and PJM that is equivalent to or better than the JOA between the Midwest ISO and PJM. On December 30, 2010, the Commission issued an Order on Rehearing and Compliance which indicated that they agreed with the MMU comments and directed the NYISO to make interface pricing revisions by the second quarter of 2011. Additionally, the Commission required that congestion management/market-to-market coordination for the Commission-jurisdictional RTO/ISOs be completed concurrently by the second quarter of 2011.[54]

Data Required for Full Loop Flow Analysis

Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces. The differences between actual and scheduled power flows can be the result of a number of underlying causes. To adequately investigate the causes of loop flows, complete data are required.

Actual power flows are the metered flows at an interface for a defined period. Scheduled power flows are the flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for a balancing authority (net actual interchange) and the total scheduled flows for the balancing authority (net scheduled interchange) for a defined period. Loop flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface. The result is loop flow, despite the fact that system actual and scheduled flow could net to a zero difference. As an illustration, although PJM's total scheduled and actual flows differed by only 5.2 percent in 2010, much greater differences existed at individual interfaces.

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 can arise from transactions scheduled into, out of or around a balancing authority 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 result from actions within balancing authorities.

52 See "Response to Questions and Supplemental Report on Broader Regional Markets; Long-Term Solutions to Lake Erie Loop Flow" Docket No. ER08-1281-004 (August 16, 2010).
53 See "Comments of the Independent Market Monitor for PJM."Docket No. ER08-1281-004 (September 15, 2010).
54 133 FERC ¶ 61,276.

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Loop flows are a significant concern. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. In general, the detailed sources of the identified differences between scheduled and actual flows remain unclear as a result of incomplete or inadequate access to the required data.

A complete analysis of loop flow could provide additional insight that could lead to enhanced overall market efficiency and clarify the interactions among market and non market areas. A complete analysis of loop flow would improve the overall transparency of electricity transactions. There are areas with transparent markets, and there are areas with less transparent markets (non market areas), but these areas together comprise a market, and overall market efficiency would benefit from the increased transparency that would derive from a better understanding of loop flows.

For a complete loop flow analysis, several types of data are required from all balancing authorities in the Eastern Interconnection. NERC Tag data, dynamic schedule and pseudo-tie data and actual tie line data are required in order to analyze the differences between actual and scheduled transactions. The ACE data, market flow impact data and generation and load data are required in order to understand the sources, within each balancing authority, of loop flows that do not result from differences between actual and scheduled transactions. All data should be made available in downloadable format in order to make analysis possible. A data viewing tool alone is not adequate.

- **NERC Tag Data**

  An analysis of loop flow requires knowledge of the scheduled path of energy transactions. NERC Tag Data includes the scheduled path and energy profile of the transactions, including the Generation Control Area (GCA), the intermediate Control Areas, the Load Control Area (LCA) and the energy profile of all transactions. Additionally, complete tag data include the identity of the specific market participants.

  Currently, the MMU has obtained some NERC Tag data via a set of "Tag Dump" files. The existing Tag Dump files include many data items from the overall NERC Tag data. Included in each file are the following data items: Tag Name, Tag Start Date/Time, Tag End Date/Time, Source Security Coordinator, Sink Security Coordinator, Source Control Area, Sink Control Area, Source, sink, Transmission Start Date/Time, Transmission End Date/Time, Transmission Provider Name, Priority, Transmission Product, OASIS Reservation, MW, Point of Receipt, Point of Delivery, Energy Start Date/Time, Energy End Data/Time, Schedule MW and Active MW. Each tag dump file is created hourly, and is in csv format. The files include active tags from the hour in which the data is created and for the next 24 hours.

  The Tag Dump files do not include the following data items: tag type, complete market path, miscellaneous information (token and value fields), tag creation timing, approval timing, denial reasons, denied tags, curtailment reasons, loss provision information, individual request information, and other data items including contact information.

  Of the data items not included in the Tag Dump files, the most important elements required for loop flow analysis are the complete market path and the loss provision information. These data items would complete the picture of the scheduled interchange among all balancing authorities.

- **Dynamic Schedule and Pseudo-Tie Data**

  Dynamic schedule and pseudo ties represent another type of interchange transaction between balancing authorities. While dynamic schedules are required to be tagged, the tagged profile is only an estimate of what energy is expected to flow. Dynamic schedules are implemented within each balancing authority's Energy Management System (EMS), with the current values shared over Inter-Control Center Protocol (ICCP) links. By definition, the dynamic schedule scheduled and actual values will always be identical from a balancing authority standpoint, and the tagged profile should be removed from the calculation of loop flows to eliminate double counting of the energy profile. Dynamic schedule data from all balancing authorities are required in order to account for all scheduled and actual flows.

  Pseudo-ties are similar to dynamic schedules in that they represent a transaction between balancing authorities and are handled within the EMS systems and data are shared over the ICCP. Pseudo-ties only differ from dynamic schedules in how the generating resource is modeled within the balancing authorities' ACE equations. Dynamic schedules are modeled as resources located in one area serving load in another, while pseudo-ties are modeled as resources in one area moved to another area. Unlike dynamic schedules, pseudo-tie transactions are not required to be tagged. Pseudo-tie data from all balancing authorities are required in order to account for all scheduled and actual flows.

- **Actual Tie Line Flow Data**

  An analysis of loop flow requires knowledge of the actual path of energy transactions. Currently, a very limited set of tie line data is made available via the NERC IDC and the Central Repository for Curtailments (CRC) website. Additionally, the available tie line data, and the data within the IDC, are presented as information on a screen, which does not permit analysis of the underlying data.

- **Area Control Error (ACE) Data**

  Area Control Error (ACE) data provides information about how well each balancing authority is matching their generation with their load. This information, combined with the scheduled and actual interchange values will show whether an individual balancing authority is pushing on or leaning on the interconnection, contributing to loop flows.

  NERC makes real-time ACE graphs available on their Reliability Coordinator Information System (RCIS) website. This information is presented only in graphical form, and the underlying data is not available for analysis.

- **Market Flow Impact Data**

  In addition to interchange transactions, internal dispatch can also affect flows on balancing authorities' tie lines. The impact of internal dispatch on tie lines is called market flow. Market flow data are imported in the IDC, but there is only limited historical data, as only market flow data related to TLR levels 3 or higher are required to be made available via a Congestion Management Report (CMR). The remaining data are deleted.

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There is currently a project in development through the NERC Operating Reliability Subcommittee (ORS) called the Market Flow Impact Tool. The purpose of this tool is to make visible the impacts of dispatch on loop flows. The MMU supports the development of this tool, and requests that FERC and NERC ensure that the underlying data are provided in a downloadable format to market monitors and other approved entities.

- **Generation and Load Data**

  Generation data (both real-time scheduled generation and actual output) and load data would permit analysis of the extent to which balancing authorities (or individual generation owners) are meeting their commitments to serve load. If a balancing authority is not meeting its load commitment with adequate generation, the result is unscheduled flows across the interconnections to establish power balance.

  Market areas are transparent in providing real-time load while non market areas are not. For example, PJM posts real-time load via its eDATA application. Most non market balancing authorities provide only the expected peak load on their individual web sites. Data on generation are not made publicly available, as this is considered market sensitive information.

The MMU requests that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. The MMU has been attempting to obtain access to this data for several years without success. Attempts to obtain the data from NERC or tagging vendors have led to denials or to the option of very expensive subscriptions that would still require obtaining approval from every entity registered in the NERC Transmission System Information Network (TSIN) due to data confidentiality agreements, including Transmission Providers and Market Participants.

Dynamic Interface Pricing

According to the *PJM Interface Price Definition Methodology*, dynamic interface pricing calculations use actual system conditions to determine a set of weighting factors for each external pricing point in an interface price definition. The weighting factors are determined in such a manner that the interface reflects actual system conditions. The topology of the transmission system is constantly changing, as generation comes on and off line, and transmission lines come in and out of service. The interface pricing methodology implies that the weighting factors reflect the actual system flows in a dynamic manner. In fact, the weightings are generally static, and are modified only occasionally. The MMU recommends that PJM monitor, and adjust as necessary, the buses and weightings applied to the interfaces to ensure that the interface prices reflect ongoing changes in system conditions and that loop flows are accounted for on a dynamic basis.

TLRs

TLRs are called to control flows on electrical facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows related to external balancing authorities, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

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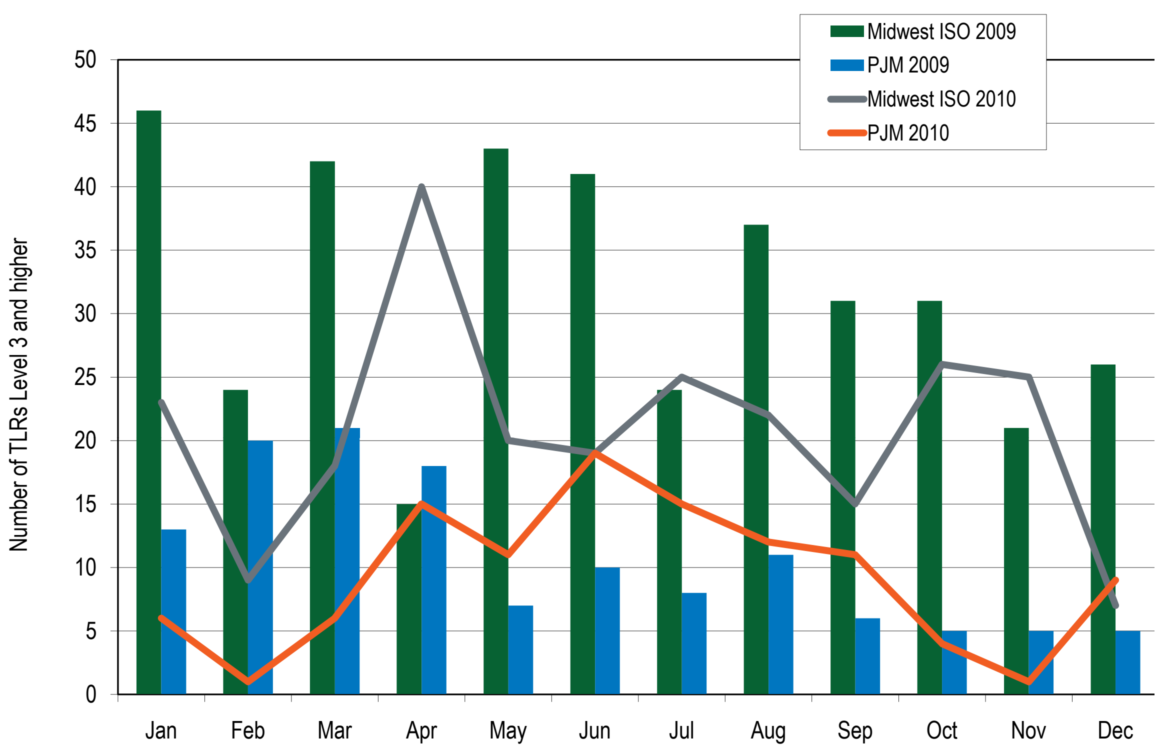
PJM called fewer TLRs in 2010 than in 2009. The fact that PJM has issued only 110 TLRs in 2010, compared to 129 in 2009, reflects the ability to successfully control congestion through redispatch of generation including redispatch under the JOA with the Midwest ISO. PJM TLRs decreased by 15 percent, from 129 during 2009 to 110 in 2010 (Figure 4-16). In addition, the number of different flowgates for which PJM declared TLRs decreased from 28 in 2009 to 25 in 2010 (Figure 4-17). The total MWh of transaction curtailments decreased by 67 percent, from 912,528 MWh in 2009 to 298,488 MWh in 2010 (Figure 4-18). Of the 110 TLRs called by PJM in 2010, two facilities comprised 35 percent of the total. The two facilities were:

- **2419 Danville – E Danville 138 kV line for the loss of Jacksons Ferry – Antioch 500 kV line.** This line is located in southern Virginia.[55] TLRs were used to control the constraints (22 TLRs in 2010; 3 TLRs in 2009);

- **East Frankfort – Crete 345 kV Line for Loss of Dumont – Wilton Center 765 kV Line.** These lines are located in northern Illinois, close to the border of Indiana. TLRs on this flowgate were generally utilized to control flows across the Illinois-Indiana border through the Northern Indiana Public Service system. While PJM and the Midwest ISO work together to control these flows using the mechanisms prescribed in the JOA, the actions were not always sufficient. This flowgate resulted in the largest amount of market to market settlements in 2010. TLRs on this flowgate were used to control the constraints (16 TLRs in 2010; 28 TLRs in 2009).

The Midwest ISO called significantly fewer TLRs in 2010 than in 2009. The Midwest ISO TLRs decreased by 35 percent, from 381 in 2009 to 249 in 2010 (Figure 4-16).

Figure 4-16 PJM and Midwest ISO TLR procedures: Calendar years 2009 and 2010



55 The reasons for the high levels of TLRs on this flowgate are considered confidential.

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Figure 4-17 Number of different PJM flowgates that experienced TLRs: Calendar years 2009 and 2010

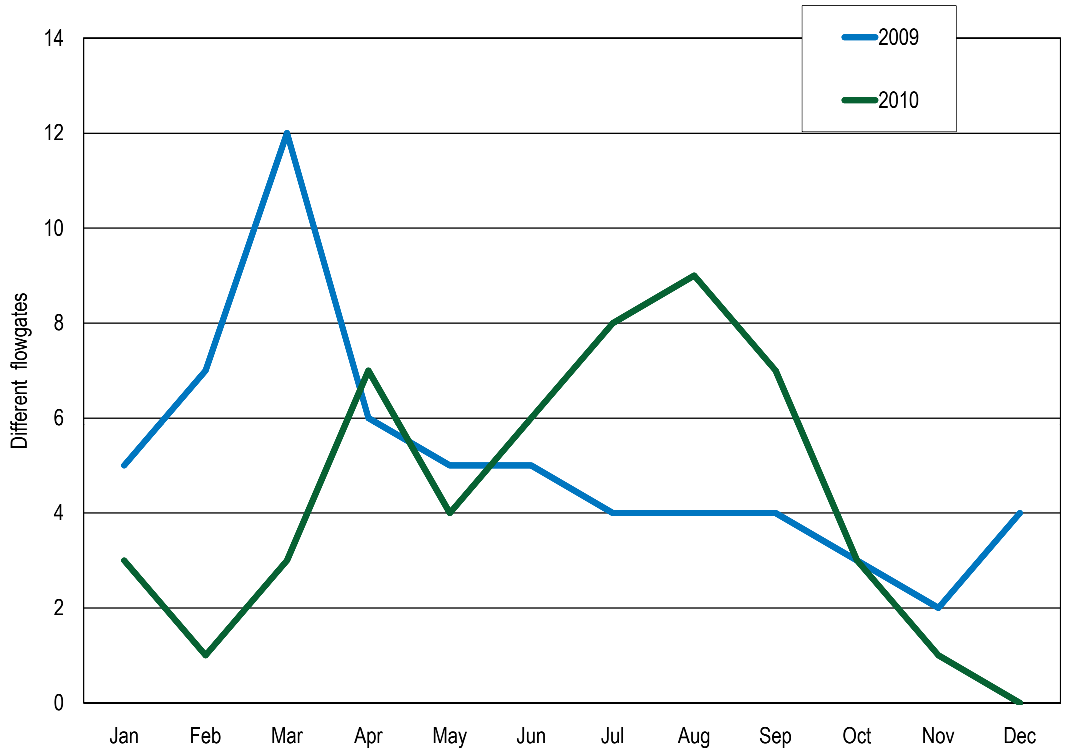

Figure 4-18 Number of PJM TLRs and curtailed volume: Calendar year 2010

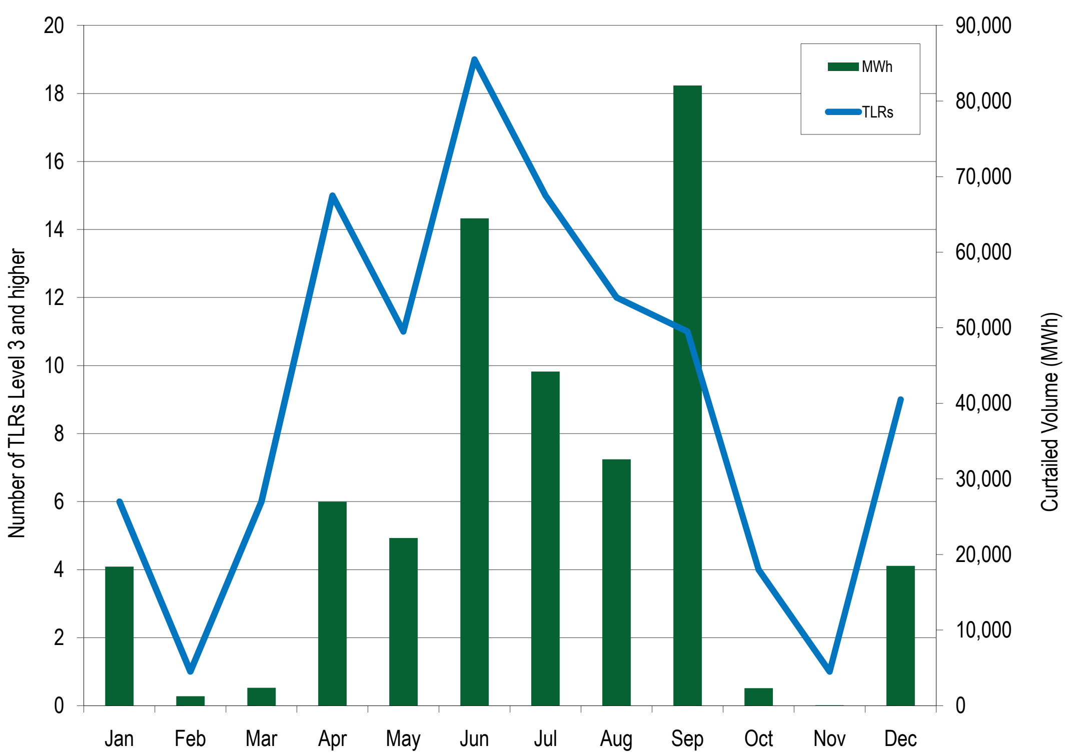

Table 4-11 shows the number of TLRs by TLR level for each reliability coordinator in the Eastern Interconnection. The TLR levels are defined in Appendix E “Interchange Transactions” of this document. In 2010, PJM issued 110 transmission loading relief procedures (TLRs). Of the 110 TLRs issued, the highest levels reached were TLR 3a in 65 instances and TLR 3b in the remaining 45 events (2009 totals were 61 TLR 3a, 68 TLR 3b, 0 TLR 4 and 0 TLR 5b).

Table 4-11 Number of TLRs by TLR level by reliability coordinator: Calendar Year 2010

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2010	ICTE	72	25	149	50	30	0	326
	MISO	123	93	0	15	18	0	249
	NYIS	104	0	0	0	0	0	104
	ONT	94	5	0	1	0	0	100
	PJM	65	45	0	0	0	0	110
	SWPP	244	1,049	19	63	32	0	1,407
	TVA	37	64	8	1	6	0	116
	VACS	1	1	0	0	0	0	2
Total		740	1,282	176	130	86	0	2,414

Up-To Congestion

The original purpose of up-to congestion transactions was to allow market participants to submit a maximum congestion charge, up to $25 per MWh, they were willing to pay on an import, export or wheel through transaction in the Day-Ahead Energy Market. This product was offered as a tool for market participants to use to limit or hedge their congestion exposure on scheduled transactions in the Real-Time Energy Market.

In submitting an up-to congestion transaction, the market participant is submitting a transaction equivalent to a matched set of incremental offers (INC) and decrement bids (DEC) that will be evaluated together and approved or denied as a single transaction, subject to a limit on the cleared price difference.

For import up-to congestion transactions, the import pricing point specified looks like a DEC bid and the sink specified on the OASIS reservation looks like an INC offer. For export transactions, the specified source on the OASIS reservation looks like a DEC bid, and the export pricing point looks like an INC offer. Similarly, for wheel through up-to congestion transactions, the import pricing point chosen looks like a DEC bid, and the export pricing point specified looks like an INC offer.

While submitting an up-to congestion bid is similar to entering a matched pair of INC offers and DEC bids, there are a number of advantages to using the up-to congestion product rather than using sets of INC and DEC bids. For example, an up-to congestion transaction is approved or denied as a single transaction, will only clear the Day-Ahead Energy Market if the maximum congestion bid criteria is met, and is not subject to day-ahead or balancing operating reserve chargIn the Day-Ahead Energy Market, an up-to congestion import transaction is submitted and modeled as an injection at the interface and a withdrawal at a specific PJM node. In real time, the power does not flow to the PJM node specified in the day-ahead transaction. This mismatch results in inaccurate pricing and can provide a gaming opportunity.

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In 2008, market participants requested that PJM increase the maximum value for up-to congestion offers, and to also allow negative offers for these transactions. PJM expressed concerns regarding the mismatch between up-to congestion transactions in the Day-Ahead Energy Market and real-time transactions.[56] On February 21, 2008, the PJM Markets and Reliability Committee (MRC) approved PJM's proposed resolution to the request for implementation on March 1, 2008.[57] The proposal allowed for a modification to the offer cap from $25 to ± $50, including an explicit allowance for negative offers. PJM also eliminated a relatively small number of available sources and sinks in an effort to partially address the mismatch between the Day-Ahead and Real-Time Energy Market scheduling.

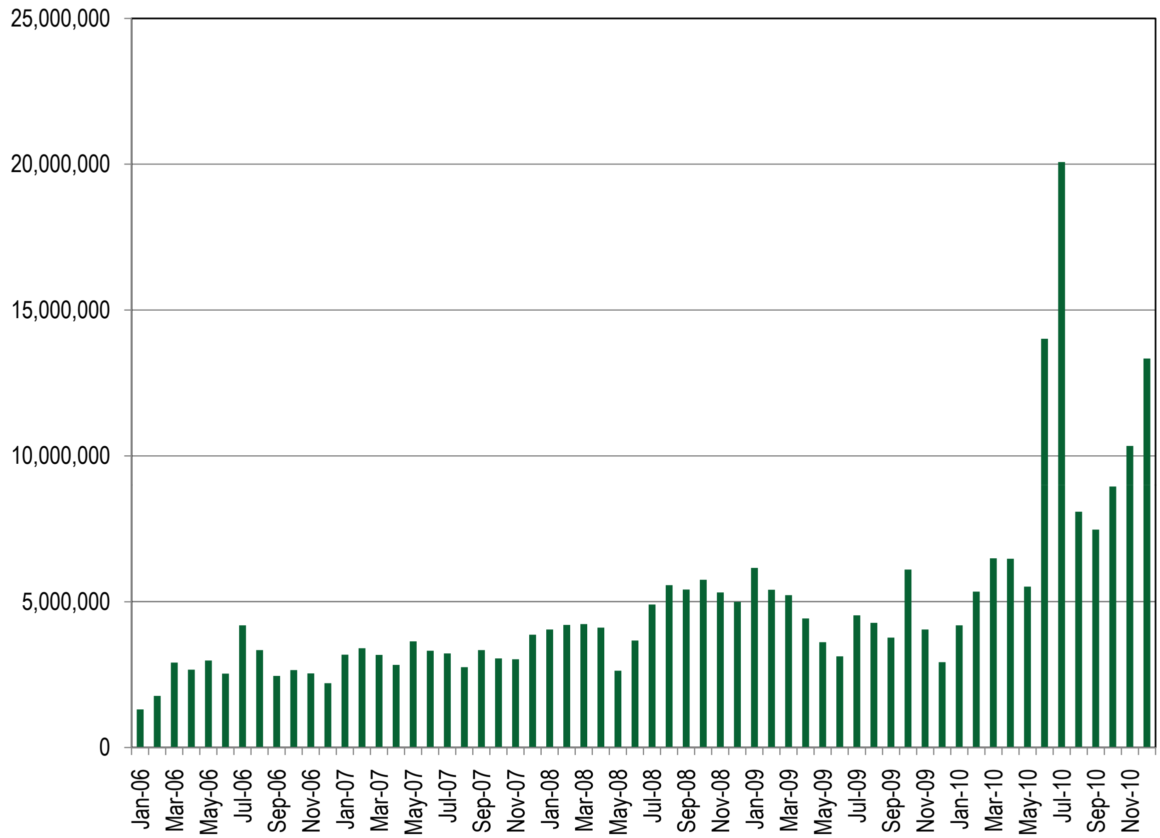
In the period following the March 1, 2008 modifications to the up-to congestion bids, through December 31, 2010, the monthly average of up-to congestion bidding increased from 3,027.1 GWh to 6,192.9 GWh. In June and July of 2010, there was a significant increase in the total up-to congestion bids as shown in Figure 4-19. This increase in activity for up-to congestion transactions was caused by the allocation methodology for the marginal loss surplus.

As a result of modifications to the marginal loss surplus allocation, the up-to congestion product was modified such that the requirement for up-to congestion transactions to obtain transmission service was eliminated. 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.

56 See PJM. "Up-to Congestion Transactions. Proposed Interim Changes Pending Development of a Spread Product" (February 21, 2008) (Accessed January 15, 2010) <http://www.pjm.com/~/media/committees-groups/committees/mrc/20080221/20080221-item-03-up-to-congestion-transactions.ashx> (39 KB).

57 See "Minutes of the Twenty-First Meeting" Minutes from PJM's MRC Meeting (February 21, 2008) <http://www.pjm.com/~/media/committees-groups/committees/mrc/20080221/20080221-minutes.ashx> (61KB).

Figure 4-19 Monthly up-to congestion bids in MWh: January 2006 through December 2010



The up-to congestion transactions in 2010 were comprised of 49.9 percent imports, 44.5 percent exports and 5.6 percent wheeling transactions (Table 4-12). Only 0.1 percent of the up-to congestion transactions had matching Real-Time Energy Market transactions. Of the up-to congestion transactions with matching Real-Time Energy Market transactions, 4.0 percent were imports, 84.9 percent were exports and 11.1 percent were wheel through transactions.

Table 4-12 Up-to congestion MW by Import, Export and Wheels: Calendar years 2006 through 2010

	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	55,052,156	49,064,283	6,192,876	110,309,315	49.9%	44.5%	5.6%
TOTAL	125,078,659	153,618,620	10,565,187	289,262,466	43.2%	53.1%	3.7%

Market participants have the opportunity to match the source and sink between the Day-Ahead and Real-Time Energy Markets, but they have not done so. An analysis of the up-to congestion

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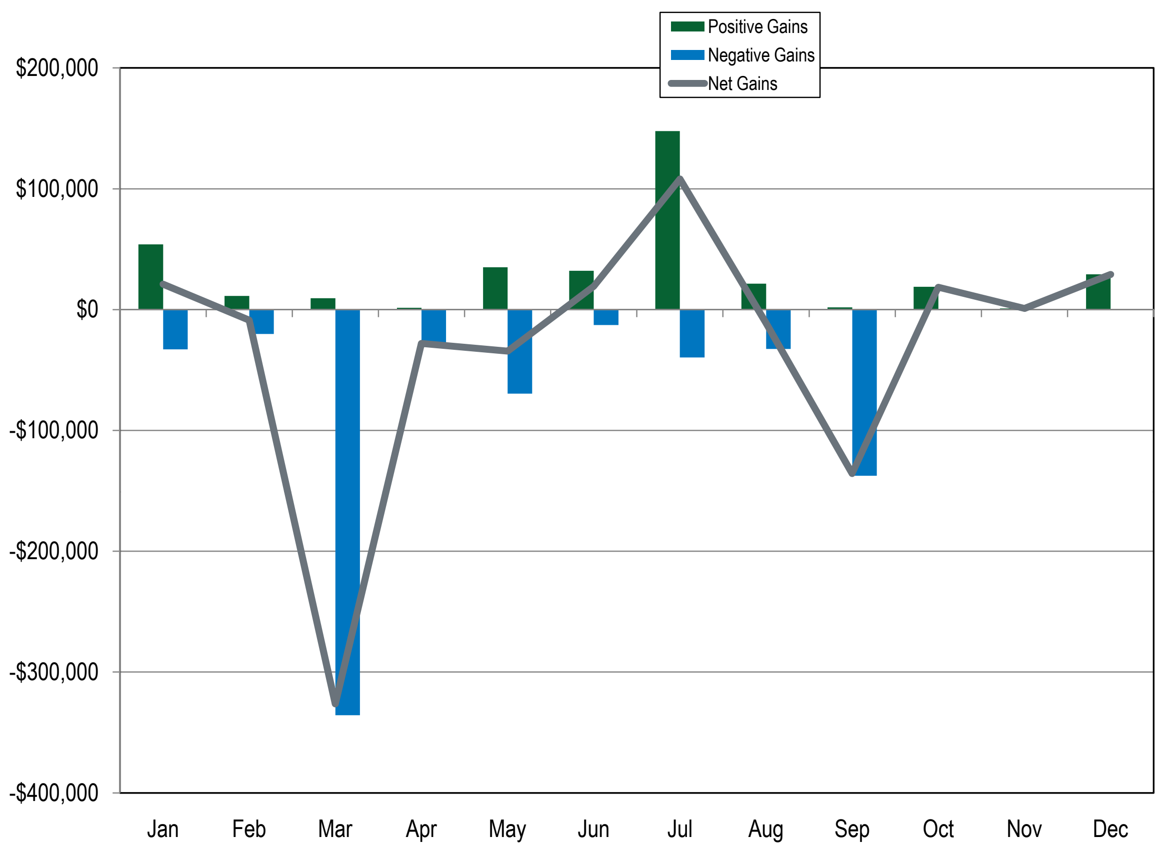
data shows that submitted Real-Time Energy Market transactions match the submitted Day-Ahead Energy Market up-to congestion bid only 0.1 percent of the time. For 99.9 percent of the time, submitted Real-Time Energy Market transactions do not match the submitted Day-Ahead Energy Market up-to congestion bids being made by participants.

When the up-to congestion product was used as intended, with matching Real-Time Energy Market transactions, 29.5 percent of such cleared transaction MW were profitable in 2010. The net loss on all these transactions was approximately $347,000. When up-to congestion transactions did not have a matching Real-Time Energy Market transaction, 43.7 percent of such cleared transaction MW were profitable. The net profit on all these transactions was approximately $64.6 million.[58]

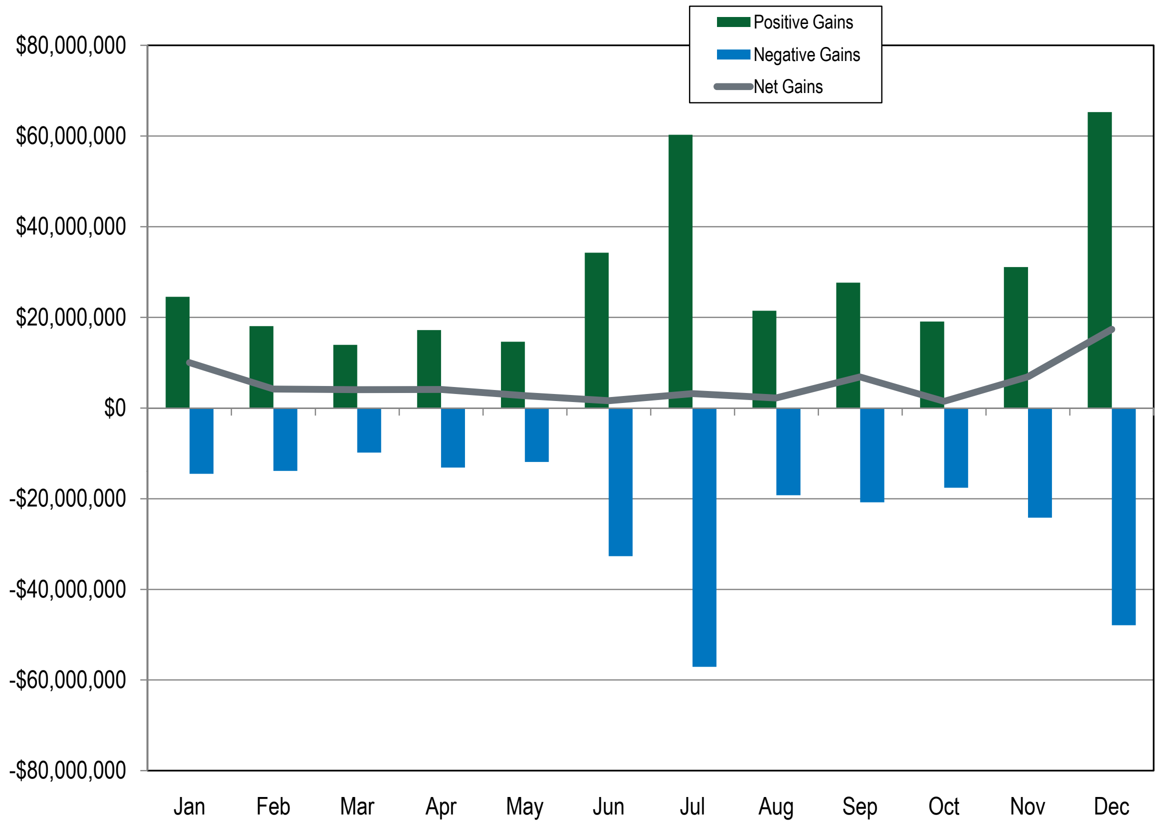
Figure 4-20 and Figure 4-21 show the monthly positive, negative and net gains for matching and non-matching up-to congestion transactions. Figure 4-20 shows the matching transactions on a different scale than Figure 4-21. There is such a small number of matching transactions that the results would not be visible on the scale of Figure 4-21.

Figure 4-20 Total settlements showing positive, negative and net gains for up-to congestion bids with a matching Real-Time Energy Market transaction: Calendar year 2010



58 The total profitability results for up-to congestion transactions reported in the 2009 State of the Market Report for PJM and the first three quarterly 2010 State of the Market Reports for PJM were incorrect.

Figure 4-21 Total settlements showing positive, negative and net gains for up-to congestion bids without a matching Real-Time Energy Market transaction: Calendar year 2010



Of all the market participants that utilize up-to congestion transactions, the top five participants accounted for 41 percent of all transactions and the top ten participants accounted for 58 percent of all transactions. The top five participants that experienced losses accounted for 91 percent of all the losses, and the top ten participants accounted for 99 percent of all the losses on those bids.

The MMU recommends that the up-to congestion transaction product be eliminated. Alternatively, the MMU recommends that PJM require all import and export up-to congestion transactions to pay day-ahead and balancing operating reserve charges. This would continue to exclude wheel through transactions from operating reserve charges. Up-to congestion transactions are being used as matching INC and DEC bids and have corresponding impacts on the need for operating reserves charges.

The MMU also recommends that PJM eliminate all internal PJM buses for use in up-to congestion bidding and for all import and export transactions in the Day-Ahead and the Real-Time Energy Markets. The use of specific buses is equivalent to creating a scheduled transaction to a specific point which will not be matched by the actual corresponding power flow.

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Interface Pricing Agreements with Individual Balancing Authorities

PJM consolidated the southeast and southwest interface pricing points to a single interface with separate import and export prices (SouthIMP and SouthEXP) on October 31, 2006.[59] Table 4-13 shows the historical differences in Real-Time Energy Market LMPs between the southeast, southwest, SouthIMP and SouthEXP Interface prices since the consolidation. The consolidation was based on an analysis which showed that scheduled flows were not consistent with actual power flows. The issue, which has arisen at other interface pricing points, is that the multiple pricing points may create the ability to engage in false arbitrage. False arbitrage occurs when participants schedule transactions in response to interface price differences, but the actual power flows associated with the transaction serve to drive prices further apart rather than relieving the underlying congestion. Some market participants complained that their interests were harmed by PJM's consolidation of the southeast and southwest interface pricing points.

Table 4-13 Real-time average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: November 1, 2006 through December 2010

	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)

PJM subsequently entered into confidential bilateral locational interface pricing agreements with three companies affected by the revised interface pricing point that provided more advantageous pricing to these companies than the applicable interface pricing rules. The three companies involved and the effective date of their agreements are: Duke Energy Carolinas, January 5, 2007;[60] Progress Energy Carolinas, February 13, 2007;[61] and North Carolina Municipal Power Agency (NCMPA), March 19, 2007.[62] Each of these agreements established a locational price for power purchases and sales between PJM and the individual company that applies under specified conditions. For example, when the company desires to sell into PJM (a PJM import), the rules required that the company cannot have simultaneous scheduled imports from other areas. Similarly, when a company wants to purchase from PJM (a PJM export), the rules require that the company cannot simultaneously have scheduled exports to other areas.

There were a number of issues with these agreements including that they were not made public until specifically requested by the MMU, that the pricing was not available to other participants in similar circumstances, that the pricing was not designed to reflect actual power flows, that the pricing did not reflect full security constrained economic dispatch in the external areas and that

59 PJM posted a copy of its notice, dated August 31, 2006, on its website at: <http://www.pjm.com/~/media/etools/oasis/pricing-information/interface-pricing-point-consolidation.ashx> (66 KB).
60 See "Duke Energy Carolinas Interface Pricing Arrangements" (January 5, 2007) (Accessed January 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/duke-pricing-agreement.ashx> (171 KB).
61 See "Progress Energy Carolinas, Inc. Interface Pricing Arrangements" (February 13, 2007) (Accessed January 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/pec-pricing-agreement.ashx> (210 KB).
62 See "North Carolina Municipal Power Agency Number 1 Interface Pricing Arrangement" (March 19, 2007) (Accessed January 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/electricities-pricing-agreement.ashx> (279 KB).

the pricing did not reflect appropriate price signals. PJM recognized that the price signals in the agreements were inappropriate, and in 2008 provided the required notification to terminate the agreements. The agreements were terminated on February 1, 2009.

In addition to terminating the agreements, PJM worked through the stakeholder process to develop a revision to the tariff that would enhance the method for calculating interface pricing with all neighboring balancing authorities that wish to take advantage of the more granular interface pricing. The new interface pricing methodology includes three options available for interface pricing between PJM and neighboring balancing authorities (BA).[63] These pricing point options include the existing SouthIMP/SouthEXP prices, the "Hi/Low" method and the "Marginal Cost Proxy Method."

The default pricing point for transactions between PJM and balancing authorities to the south are the SouthIMP and SouthEXP pricing points. While the SouthIMP and SouthEXP pricing points reflect the physical flows into and out of PJM from the ultimate source or sink, the interface encompasses a large geographic area, and individual neighboring BAs may benefit from providing additional data to take advantage of a more granular pricing mechanism.

Under the "Hi/Low" option, PJM uses the highest generator bus LMP for exports from PJM and the lowest generator bus LMP for imports into PJM to set the interface price. In addition, unit level telemetry can be provided that shows real-time unit status. When a generator is not running, the "high/low" method eliminates the LMP at that bus from the determination of the import or export price. To utilize the "high/low" option, PJM must be able to verify the source for import transactions and the sink for export transactions.

The "marginal cost proxy method" requires the submittal of generator cost data to PJM. This pricing method is based on the incremental production cost of the external supplier's marginal generator. The marginal generator is determined on the basis of the incremental production cost to supply load in the external area, supported by real-time metered output data. For imports to PJM, if the LMP at the unit, calculated by PJM with reference to PJM generation and load, is greater than or equal to the production cost for each unit on line then the interface price is equal to the PJM calculated bus LMP of the marginal unit. If the LMP is less than the production cost for any unit on line, then the interface price is equal to the lowest PJM calculated LMP of any such units. For exports from PJM, if the LMP is greater than or equal to the production cost for each unit on line then the interface price is equal to the PJM calculated LMP of the marginal production unit. If the LMP is greater than the production cost for any unit on line, then the interface price is equal to the highest PJM calculated LMP of any such units.

The proposed tariff revisions were filed with FERC on December 2, 2008[64], and approved on May 1, 2009.[65] As a condition of the approval, the Commission required that PJM establish procedures to negotiate, in good faith, a congestion management agreement (which is necessary for eligibility to continue the "marginal cost proxy" pricing beyond January 31, 2010), and to file such agreements unexecuted, if requested, after 90 days.[66] As of December 31, 2009, Duke Energy Carolinas and Progress Energy Carolinas were in the process of negotiating a congestion management agreement with PJM.

63 The NERC functional model classifies the balancing authority as a reliability service function, with, among other things, the responsibility for balancing generation, demand and interchange balance. See "Reliability Functional Model" (August 2008) (Accessed January 20, 2010) <http://www.nerc.com/files/Functional_Model_V4_CLEAN_2008Dec01.pdf> (381 KB).
64 See Transmittal Letter, Docket No. ER09-369-000 (December 2, 2008).
65 See, Letter Order, Docket No. ER09-369-000 (May 1, 2009).
66 127 FERC ¶ 61,101.

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In July 2009, Duke Energy Carolinas submitted the required data, and PJM had completed the required software modifications to support the “marginal cost proxy method.” As of December 31, 2009 neither Progress Energy Carolinas nor the North Carolina Municipal Power Agency has elected to supply the additional data necessary to take advantage of the “high/low” or the “marginal cost proxy method” for interface pricing. Table 4-14 through Table 4-16 show the real-time and a day-ahead prices for imports and exports applicable for the interface pricing under the various agreements.

In September 2009, Progress Energy Carolinas provided an update to the PJM Market Implementation Committee (MIC) on the proposed congestion management agreement.[67] The proposal included three parts: enhanced available transmission capability (ATC) coordination; monitoring of real-time parallel flow impacts; and managing real-time congestion.

On February 2, 2010, PJM and PEC filed a revision to the JOA to include a CMP.[68] The MMU responded to the filing on February 23, 2010.[69] The MMU response noted that the agreement included discriminatory treatment for the identified transactions with respect to access to ATC, that a regional approach is preferable to entering into agreements with individual neighbors, and that a sunset should be required in order to ensure that the next step towards such regional coordination is taken without delay. PJM and PEC filed an answer on March 10, 2010, to which the MMU responded on April 2, 2010. PJM and PEC filed an additional answer on April 19, 2010.[70] On May 28, 2010, the Commission conditionally approved the revised PJM/PEC JOA.[71] PJM and PEC were required to make a compliance filing within thirty days of the date of the order answering specific questions related to the impact of the scheduling arrangement on NERC standards and discriminatory access, the market pricing mechanisms with regards to eliminating the nuclear and hydro units from the calculation and the discriminatory use of export make whole payments under this agreement. On June 28, 2010, PJM and PEC filed their response.[72] The MMU responded to the compliance filing on July 19, 2010, reiterating the argument that the PJM/PEC JOA provides for preferential treatment to ATC and that the elimination of nuclear and hydro units from the interface price calculation is not consistent with the economics of locational marginal pricing.[73] The MMU moved for a technical conference to explore these issues.[74] As of December 31, 2010, the Commission had not made any additional issuances related to the Compliance Filing or the comments submitted by the MMU.

Table 4-14 shows the real-time LMP calculated per the revised agreements made effective on May 3, 2009 for the calendar year 2010. The difference between the LMP under this agreement and PJM’s SouthIMP LMP ranged from $1.83 with Duke to $2.71 with PEC.[75] The difference between the LMP under this agreement and PJM’s SouthEXP LMP ranged from $2.73 with NCMPA to $5.89 with PEC.

67 See “PJM-Progress Draft Congestion Management Agreement“ (September 10, 2009) (Accessed January 15, 2010) <http://www.pjm.com/~/media/committees-groups/committees/mic/20090910/20090910-item-08-pjm-progress-draft-congestion-management-agreement.ashx> (69 KB)
68 See Docket No. ER10-713-000 (February 2, 2010).
69 See “Motion to Intervene and Comments of the Independent Market Monitor for PJM.”Docket No. ER10-713-000 (February 25, 2010).
70 See Joint Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C. and Progress Energy Carolinas, Inc.; Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM; Joint Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C. and Progress Energy Carolinas, Inc., in Docket No. ER10-713-000.
71 See Amended and Restated Joint Operating Agreement Among and Between PJM Interconnection, L.L.C., and Progress Energy Carolinas. Docket No. ER10-713-000.
72 See “Compliance filing “, Docket No. ER10-713-002.
73 See “Comment and Motion for Technical Conference of the Independent Market Monitor for PJM,” Docket No. ER10-713-002.
74 *Id.*
75 The Progress Energy Carolinas (PEC) LMP is defined as the Carolina Power and Light (East) (CPLE) pricing point.

Table 4-14 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: Calendar year 2010

	IMPORT LMP	EXPORT LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$41.12	$42.29	$39.29	$39.14	$1.83	$3.14
PEC	$42.01	$45.04	$39.29	$39.14	$2.71	$5.89
NCMPA	$41.71	$41.87	$39.29	$39.14	$2.42	$2.73

Figure 4-22 Real-time interchange volume vs. average hourly LMP available for Duke and PEC imports: Calendar year 2010

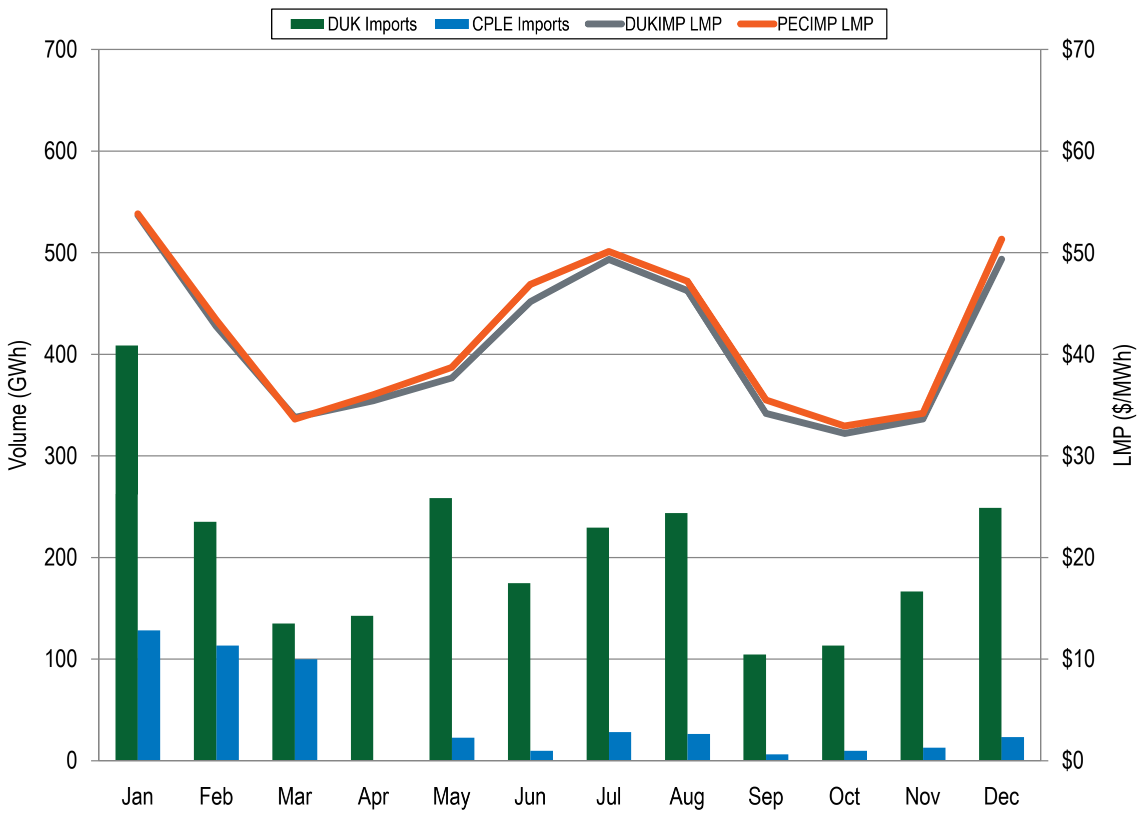

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Figure 4-23 Real-time interchange volume vs. average hourly LMP available for Duke and PEC exports: Calendar year 2010

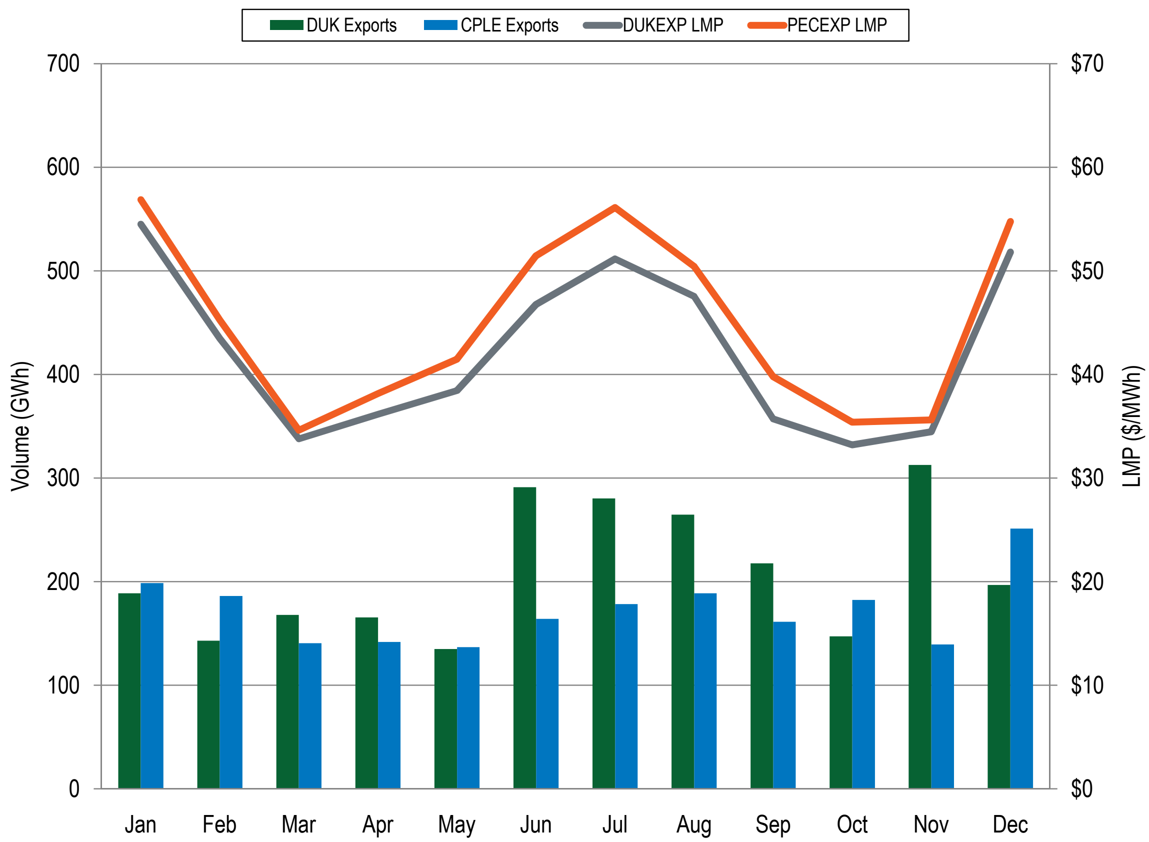

Table 4-15 shows the historical differences in Day-Ahead Energy Market LMPs between the southeast, southwest, SouthIMP and SouthEXP Interface prices since the consolidation. The consolidation was based on an analysis which showed that scheduled flows were not consistent with actual power flows. The issue, which has arisen at other interface pricing points, is that the multiple pricing points may create the ability to engage in false arbitrage. False arbitrage occurs when participants schedule transactions in response to interface price differences but the actual power flows associated with the transaction serve to drive prices further apart rather than relieving the underlying congestion. Some market participants complained that their interests were harmed by PJM's consolidation of the southeast and southwest interface pricing points.

Table 4-15 Day-ahead average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: November 1, 2006 through December 2010

	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)

Table 4-16 shows the day-ahead LMP calculated per the revised agreements made effective on May 3, 2009 for the calendar year 2010. The prices available to Duke, CPLE and NCMPA under the revised agreement remained higher than the SouthIMP and SouthEXP Interface prices but the differences were not as large. The difference between the LMP under this agreement and PJM's SouthIMP LMP ranged from $2.05 with Duke to $3.36 with PEC. The difference between the LMP under this agreement and PJM's SouthEXP LMP ranged from $3.05 with NCMPA to $6.21 with PEC.

Table 4-16 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: Calendar year 2010

	IMPORT LMP	EXPORT LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$41.45	$43.04	$39.40	$39.40	$2.05	$3.65
PEC	$42.75	$45.60	$39.40	$39.40	$3.36	$6.21
NCMPA	$42.30	$42.45	$39.40	$39.40	$2.91	$3.05

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Figure 4-24 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC imports: Calendar year 2010

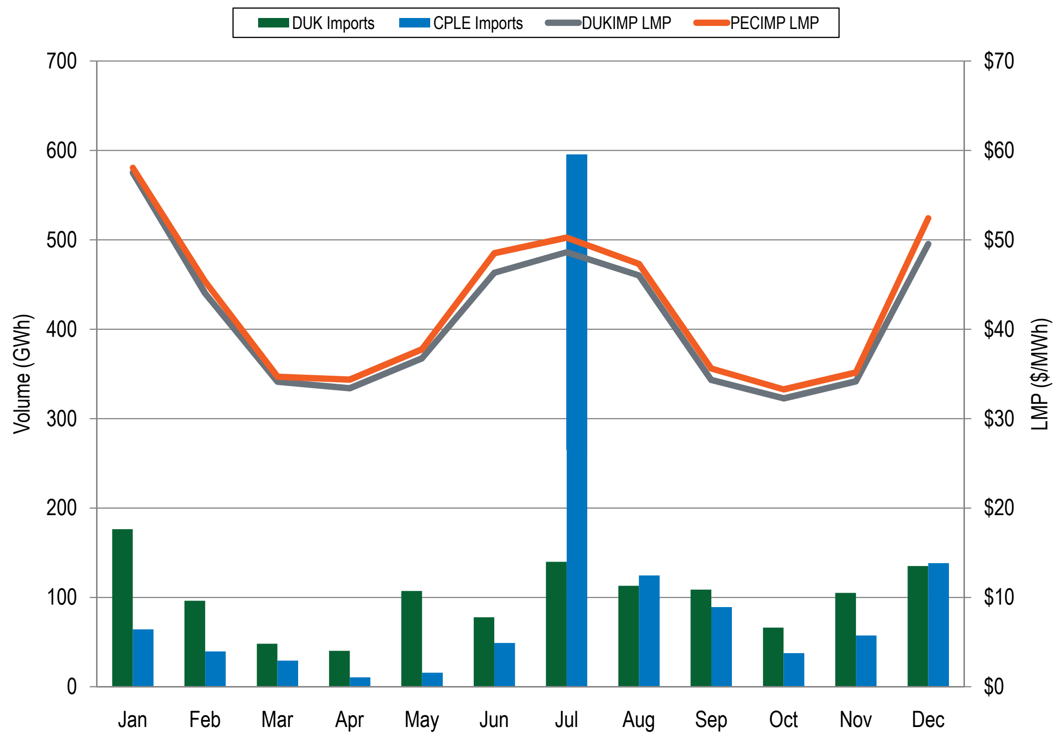
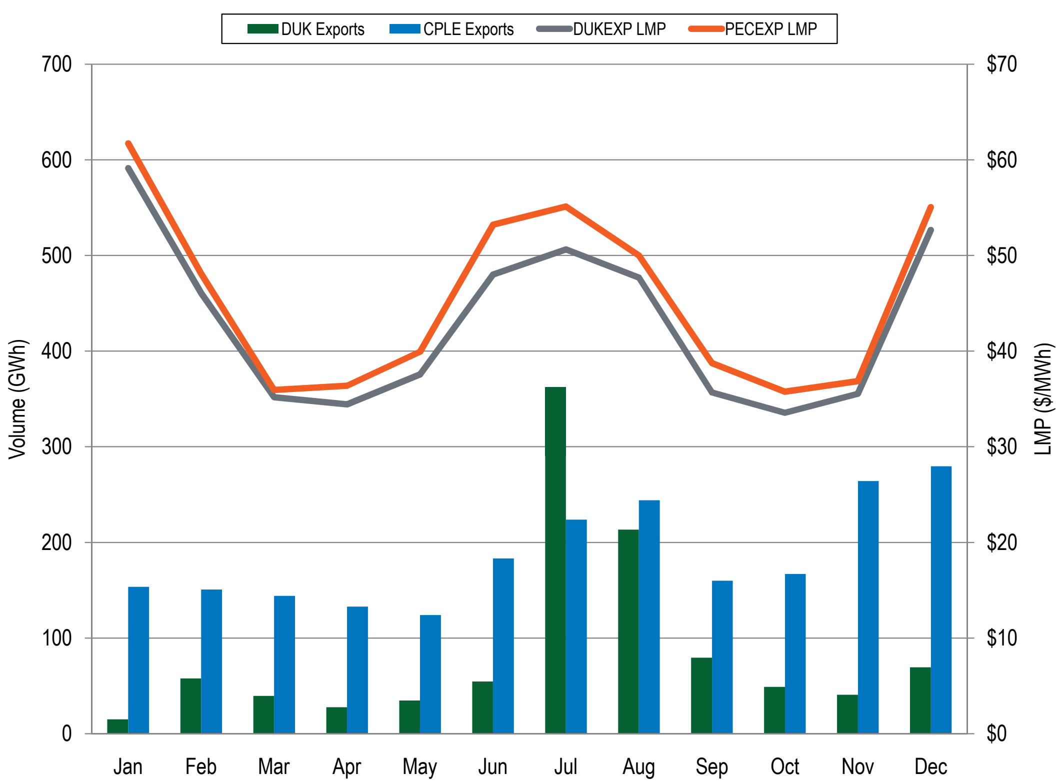


Figure 4-25 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC exports: Calendar year 2010



Marginal Loss Surplus Allocation

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.[76] On May 15, 2010, PJM implemented the modified method of allocating the marginal loss surplus. As modified, Section 5.5 of the PJM OATT provided that a cleared up-to congestion transaction in the Day-Ahead Energy Market qualified for an allocation of the marginal loss surplus for an hour if that transaction required the purchase of transmission service. Prior to the modification, up-to congestion transactions had not been eligible for an allocation of the marginal loss surplus. However, 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. These transactions included the submission of up-to congestion wheeling transactions at the same interface, submission of equal and opposite up-to congestion transactions to and from the same internal PJM bus and equal and opposite up-to congestion transactions at buses within the PJM Energy Market that are physically close to one another where the LMP between those buses would be negligible. Market participants engaging in these activities received $18.1 million in marginal loss surplus allocations (with a net profit of $9.6 million after the cost of transmission) during the period of May 15, 2010, through August 31, 2010.

As a result of this activity, PJM and the MMU presented and discussed proposed short term revisions to the market rules at the August 5, 2010, meeting of the Markets and Reliability Committee and the August 12, 2010, meeting of the Members Committee.[77] PJM proposed to eliminate the requirement for up-to congestion transactions to obtain transmission service and to discount the marginal loss allocation to non-firm transmission service customers. The MMU short term proposal was to cap the marginal loss distribution to any non-firm transmission customer so that the allocations do not exceed the total charges for transmission service. PJM stakeholders voted in favor of the PJM proposal at the August 12, 2010 PJM Members Committee, subject to an agreement to initiate additional stakeholder discussions on a long term solution to the issues.[78]

The underlying problem, the inconsistency between the approved principle and the actual implementation of the method of allocating the marginal loss surplus has not yet been addressed.[79] In addition, PJM's proposal created a spread bidding product without explicit consideration by market participants. The MMU opposed spread bidding because it risked creating opportunities for gaming with no offsetting market benefit. While limited to either source or sink at an interface, the newly created spread bidding product raises the same issues previously identified with the spread bid product proposals that had been rejected by the PJM membership. On September 17, 2010, the Commission approved the PJM revisions as filed on August 18, 2010.[80] The Order deferred consideration of the issues raised by the MMU.

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

77 A copy of the presentations can be viewed at http://www.pjm.com/~/media/committees-groups/committees/mrc/20100805/20100805-item-11-marginal-loss-allocation-issue-monitoring-analytics-presentation.ashx and http://www.pjm.com/~/media/committees-groups/committees/mrc/20100805/20100805-item-11-marginal-loss-allocation-issue-pjm-presentation.ashx.

78 See "Amended and Restated Operating Agreement", Docket No. ER10-2280-000.

79 See "Motion to Intervene and Comments of the Independent Market Monitor for PJM." Docket No. ER10-2280-000 (September 2, 2010).

80 See 132 FERC ¶ 61,244.

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Willing to Pay Congestion and Not Willing to Pay Congestion

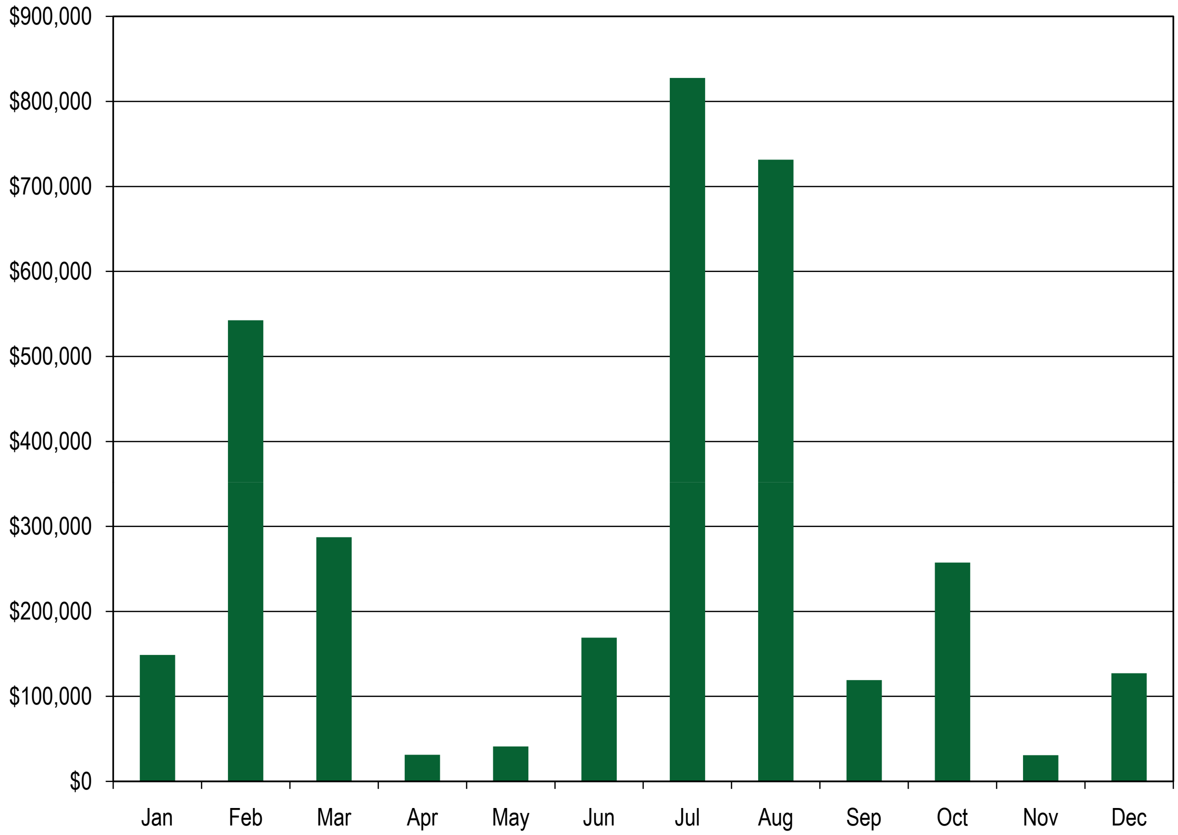
When reserving non-firm transmission, the market participant has the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system if necessary, to allow the energy transaction to continue to flow. The system redispatch often creates price separation across buses on the PJM system.

If a market participant is not willing to pay congestion, it is the responsibility of the PJM operators to curtail their transaction as soon as there is a difference in LMPs between the source and sink associated with their transaction. Uncollected congestion charges occur when PJM operators do not curtail a not willing to pay congestion transaction when there is congestion. The total uncollected congestion charges for 2010 were approximately $3.3 million, which was an increase of 379 percent from the 2009 total of $688,547 (Figure 4-26). The increase in uncollected congestion charges was the result of an increase in market participant use of not willing to pay congestion transmission on their energy transactions in 2010.

The MMU recommended modifying the evaluation criteria via a change to PJM's market software, to ensure that a not willing to pay congestion transaction is not permitted to flow in the presence of congestion. On August 16, 2010, PJM modified the EES application to automatically detect and modify not willing to pay congestion transactions, prior to their start, when system LMPs at the transactions' identified source and sink differ. This functionality prevents not willing to pay congestion transactions from starting in those instances by automatically issuing curtailment requests. The same evaluation is performed on not willing to pay congestion transactions that have already been loaded, and will curtail those transactions at the next applicable 15 minute interval. These changes reduce the amount of uncollected congestion charges by eliminating the previously utilized manual intervention for curtailments and reducing the potential for not willing to pay congestion transactions to continue to flow, undetected. While the recent EES modifications automate the process for identifying those instances, the timing requirements for curtailing transactions requires that the evaluation be done with 20 minutes notice prior to the start of the transaction. There is still the potential for not willing to pay congestion transactions to begin in cases when congestion exists prior to the transaction start time but after the evaluation. When this occurs, the transaction will be curtailed at the next applicable 15 minute interval.

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 be submitted at an interface, eliminating internal source and sink designations, thus allowing not willing to pay congestion transactions to be only submitted as wheeling transactions across the PJM footprint. At the January 11, 2011 meeting of the Market Implementation Committee (MIC) meeting, PJM stakeholders approved the changes recommended by the MMU. These modifications are currently being evaluated to determine if tariff or operating agreement changes are necessary prior to implementation.

Figure 4-26 Monthly uncollected congestion charges: Calendar year 2010



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.

Until the internal source and sink designations are eliminated from the external energy transactions in the Day-Ahead Energy Market, the MMU continues to recommend that PJM require that all import and export up-to congestion transactions pay day-ahead and balancing operating reserve charges. This would continue to exclude wheel through transactions from operating reserve charges. Up-to congestion transactions are being used as matching INC and DEC bids and have corresponding impacts on the need for operating reserve charges.

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Spot Import

Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. Spot market imports, non-firm point-to-point and network services that are willing to pay congestion, collectively Willing to Pay Congestion (WPC), were part of the PJM LMP energy market design implemented on April 1, 1998. WPC provided market participants the ability to offer energy into or bid to buy from the PJM spot market at the border/interface as price takers without restrictions based on estimated available transmission capability (ATC). Price and PJM system conditions, rather than ATC, were the only limits on interchange.

However, PJM interpreted its JOA with the Midwest ISO to require a limitation on cross-border transmission service and energy schedules in order to limit the impact of such transactions on selected external flowgates.[81] The rule caused the availability of spot import service to be limited by ATC on the transmission path. As a result, requests for service sometimes exceeded the amount of service available to customers. Spot import service (a network service) is provided at no charge to the market participant offering into the PJM spot market.

In response to market participant complaints regarding the inability to acquire spot import service after this rule change on April 1, 2007, changes were made to the spot import service effective May 1, 2008.[82] These changes limited spot imports to only hourly reservations and caused spot import service to expire if not associated with a valid NERC Tag within 2 hours when reserved the day prior to the scheduled flow or within 30 minutes when reserved on the day of the scheduled flow.

The new spot import rules provided incentives to hoard spot import capability. In the *2008 State of the Market Report for PJM*, the MMU recommended that PJM reconsider whether a new approach to limiting spot import service is required or whether a return to the prior policy with an explicit system of managing related congestion is preferable. PJM and the MMU jointly addressed this issue through the stakeholder process, recommending that all unused spot import service be retracted if not tagged within 30 minutes from the reservations queued time intraday, and two hours when queued the day prior. On June 23, 2009 PJM implemented the new business rules. Since the implementation of the rule changes, the spot import service usage (defined as scheduling) has been over 99 percent, compared to 70 percent prior to the modification (Figure 4-27).

Although the rule change resulted in an increase in scheduling, some participants were still able to schedule but not use spot import service. In 2010, market participants were still unable to acquire spot import service on the NYIS-PJM path when it was not being used to flow energy. The MMU found that the bidding process in the NYISO resulted in market participants reserving and scheduling but not using transmission to flow energy.

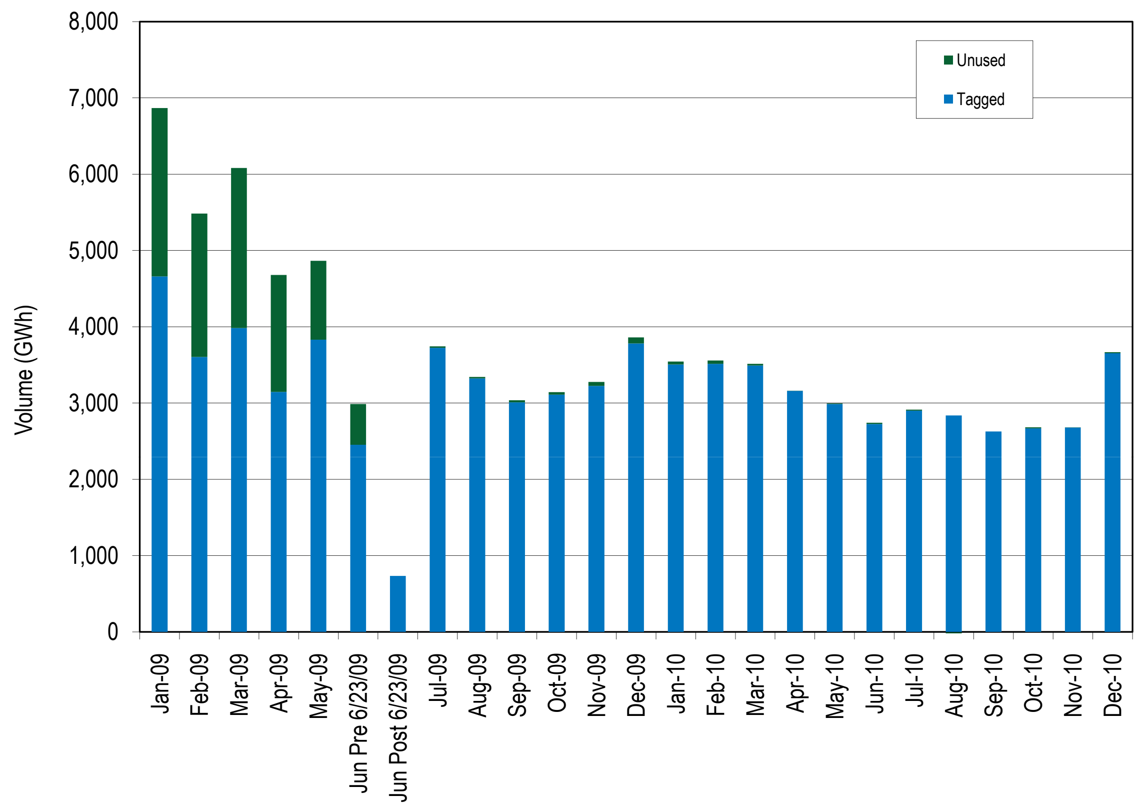
At the December 7, 2010, meeting of the Market Implementation Committee (MIC), PJM and the MMU made a joint recommendation to return to unlimited ATC for non-firm willing to pay congestion service on all paths for all non-firm willing to pay congestion transmission service. The PJM

81 See "Modifications to the Practices of Non-Firm and Spot market Import Service" (April 20, 2007) (Accessed January 15, 2010) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx> (97 KB).

82 See "Regional Transmission and Energy Scheduling Practices" (May 1, 2008) (Accessed January 15, 2010) <http://www.pjm.com/markets-and-operations/etools/~/media/etools/oasis/regional-practices-redline-doc.ashx> (450 KB).

Stakeholders agreed with recommendation, and requested PJM to determine what modifications, if any, to the PJM/MISO Joint Operating Agreement (JOA) would be needed to implement the change, as well as what system modifications would be required. The MMU believes that there are no JOA issues resulting from this change, and that the system modifications required would be minimal enough to allow for an implementation in the first half of 2011.

Figure 4-27 Spot import service utilization: Calendar years 2009 and 2010



Real-Time Dispatchable Transactions

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. 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. Import dispatchable transactions receive the hourly integrated import pricing point LMP for the hours when energy flows. If the hourly integrated import pricing point LMP is less than the

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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. Currently, real-time LMPs are readily available to market participants, and the timing requirement for submitting transactions has been reduced to 20 minutes notification. The value that dispatchable transactions once provided market participants no longer exists but the risk to other market participants is substantial.

In 2010, balancing operating reserve credits of $24 million for the calendar year 2010 were paid to three market participants. This was an increase from the 2009 total of $91,000.

The MMU recommends that dispatchable transactions be eliminated as an option for market participants. Alternatively, the MMU recommends that the evaluation of dispatchable transactions be modified from the manual process implemented today, and be included in the Generation Control Application (GCA) tool and modeled similar to a unit being bid with a one hour minimum run time. This will eliminate the potential for a dispatchable transaction to be loaded, and inadvertently continue to flow in subsequent hours where the transaction would not be economic, thus accruing a large amount of balancing operating reserve credits. Including dispatchable transactions in the GCA software would provide the most economic dispatch of PJM system resources.

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SECTION 5 – CAPACITY MARKET

Each organization serving PJM load must meet its capacity obligations by acquiring capacity resources through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can affect the financial consequences of purchasing capacity 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 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 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 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.

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Highlights and New Analysis

- The RTO resource clearing price in the 2010/2011 RPM Base Residual Auction increased $72.25 per MW-day (70.8 percent) from the 2009/2010 RPM Base Residual Auction, and the RTO resource clearing price for the 2010/2011 RPM Third Incremental Auction increased $10.00 per MW-day (25.0 percent) from the 2009/2010 RPM Third Incremental Auction.

- RPM has resulted in new resources. New generation capacity resources (5,986.1 MW), reactivated generation capacity resources (849.7 MW), uprates to existing generation capacity resources (4,905.3 MW), and the net increase in capacity imports (4,126.1 MW) totaled 15,867.2 MW since the implementation of RPM.

- The results of the 2011/2012 and 2012/2013 ATSI Integration Auctions are reported. The integration of the ATSI zone resources added 13,175.2 MW to total internal capacity. The net effect from June 1, 2010, to June 1, 2013, was an increase in total internal capacity of 25,647.3 MW (16.1 percent) from 159,030.9 MW to 184,678.2 MW.

- Capacity in the RPM load management programs increased by 1,783.3 MW from 6,899.7 MW on June 1, 2009 to 8,683.0 MW on June 1, 2010.

- Annual weighted average capacity prices increased from a 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.

- Average PJM equivalent demand forced outage rate (EFORd) decreased from 7.6 percent in 2009 to 7.2 percent in 2010.

- The PJM aggregate equivalent availability factor (EAF) decreased from 85.7 percent in 2009 to 84.8 percent in 2010. The equivalent maintenance outage factor (EMOF) increased from 2.8 percent in 2009 to 2.9 percent in 2010, the equivalent planned outage factor (EPOF) increased from 6.7 percent in 2009 to 7.4 percent in 2010, and the equivalent forced outage factor (EFOF) increased from 4.8 percent in 2009 to 4.9 percent in 2010.

Summary Recommendations

- The MMU recommends that the RPM market structure, definitions and rules be modified to improve the efficiency of market prices and to ensure that market prices reflect the forward locational marginal value of capacity.

- The MMU recommends that the obligations of capacity resources be more clearly defined in the market rules.

- The MMU recommends that the performance incentives in the RPM Capacity Market design be strengthened.

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- The MMU recommends that the terms of Reliability Must Run (RMR) service be reviewed, refined and standardized.

Overview

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market design was implemented in the PJM region on June 1, 2007.[1] The RPM 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.

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.

1 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2010 State of the Market Report for PJM*, 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.

Market Structure

- **Supply.** Total internal capacity increased 1,712.7 MW from 157,318.2 MW on June 1, 2009, to 159,030.9 MW on June 1, 2010.[6] This increase was the result of 406.9 MW of new generation, 165.0 MW that came out of retirement, 1,085.8 MW of net generation capacity modifications (cap mods), 43.7 MW of demand resource (DR) modifications (mods), and an increase of 11.3 MW due to lower equivalent demand forced outage rates (EFORds).

  In the 2011/2012, 2012/2013, and 2013/2014 auctions, new generation increased 3,969.4 MW; 486.9 MW came out of retirement and net generation cap mods were -2043.5 MW, for a total of 2,412.8 MW. DR and Energy Efficiency (EE) modifications totaled 11,360.5 MW through June 1, 2013. A decrease of 1,481.8 MW was due to higher EFORds. The classification of the Duquesne resources as external reduced total internal capacity by 3,006.6 MW, and the reclassification of the Duquesne resources as internal added 3,187.2 MW to total internal capacity. The integration of the ATSI zone resources added 13,175.2 MW to total internal capacity. The net effect from June 1, 2010, to June 1, 2013, was an increase in total internal capacity of 25,647.3 MW (16.1 percent) from 159,030.9 MW to 184,678.2 MW.

  In the 2010/2011 auction, 11 more generation resources made offers than in the 2009/2010 RPM auction. The increase consisted of 15 new resources (406.9 MW), four reactivated resources (161.7 MW), three that were previously entirely FRR committed (10.9 MW), one less resource excused from offering (3.9 MW), and one less resource entirely exported (39.9 MW), offset by four deactivated resources (59.6 MW), four resources exported from PJM (554.0 MW), three retired resources (348.4 MW), and two resources excused from offering (108.8 MW). The new generation capacity resources consisted of seven new combustion turbine (CT) resources (270.5 MW), five new wind resources (120.0 MW), three new diesel resources (16.4 MW), and four reactivated resources (165.0 MW).

  In the 2011/2012 auction, 21 more generation resources made offers than in the 2010/2011 RPM auction. The increase consisted of 20 new resources (2,203.7 MW), four reactivated resources (486.9 MW), three fewer excused resources (126.3 MW), and one additional resource imported (663.2 MW), offset by five additional resources committed fully to FRR (1.0 MW) and two retired resources (87.3 MW). The new generation capacity resources consisted of 11 new CT resources (728.7 MW), four new wind resources (75.2 MW), two new steam resources (838.0 MW), one new combined cycle resource (556.5 MW), one new diesel resource (4.2 MW) and one new solar resource (1.1 MW).

  In the 2012/2013 auction, eight more generation resources made offers than in the 2011/2012 RPM auction. The net increase of eight resources consisted of 16 new resources (772.5 MW), four resources that were previously entirely FRR committed (13.4 MW), three additional resources imported (276.8 MW), two additional resources resulting from disaggregation of RPM resources, and one resource formerly unoffered (1.9 MW), offset by nine retired resources (1,044.5 MW), four additional resources committed fully to FRR (39.5 MW), four less resources resulting from aggregation of RPM resources, and one less external resource that did not offer (663.2 MW).[7] In addition, there were the following retirements of resources

6 Unless otherwise specified, all volumes are in terms of unforced capacity (UCAP).

7 Disaggregation and aggregation of RPM resources reflect changes in how units are offered in RPM. For example, multiple units at a plant may be offered as a single unit or multiple units.

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that were either exported or excused in the 2011/2012 BRA: two CT resources (5.3 MW) and three combined cycle resources (297.6 MW). Also, resources that are no longer PJM capacity resources consisted of three CT resources (521.5 MW) in the RTO. The new generation capacity resources consisted of six new diesel resources (13.9 MW), four new wind resources (57.9 MW), three new steam units (560.4 MW), and three new CT units (140.3 MW).

In the 2013/2014 auction, 37 more generation resources made offers than in the 2012/2013 auction. The increase in generation resources consisted of 63 ATSI resources that were not offered in the 2012/2013 BRA (11,325.4 MW), 31 new resources (1,038.2 MW), four resources that were previously entirely FRR committed (234.3 MW), and four additional resources imported (460.1 MW). The reduction in generation resources consisted of seven retired resources (824.0 MW), two deactivated resources (66.6 MW), 49 additional resources committed fully to FRR (307.7 MW), four less planned generation resources that were not offered (249.3 MW), two additional resources excused from offering (4.2 MW), and one less external resource that was not offered (45.7 MW). In addition, there were the following retirements of resources that were either exported or excused in the 2012/2013 BRA: three steam units (125.9 MW). The new generation capacity resources consisted of 11 solar resources (9.5 MW), 11 wind resources (245.7 MW), four combined cycle units (671.5 MW), three diesel resources (5.4 MW), one steam unit (23.8 MW), and one CT unit (82.3 MW). In addition, there were the following new generation resources that were not offered in to the auction because they were either exported or entirely committed to FRR for the 2013/2014 delivery year: four wind resources (66.2 MW).

- **Demand.** There was a 3,156.7 MW increase in the RPM reliability requirement from 153,480.1 MW on June 1, 2009 to 156,636.8 MW on June 1, 2010. On June 1, 2010, PJM Electric Distribution Companies (EDCs) and their affiliates maintained a 77.7 percent market share of load obligations under RPM, down from 79.6 percent on June 1, 2009.

- **Market Concentration.** For the 2010/2011, 2011/2012, 2012/2013, and 2013/2014 RPM Auctions, all defined markets failed the preliminary market structure screen (PMSS). In the 2010/2011 BRA, 2010/2011 Third Incremental Auction, 2011/2012 BRA, 2011/2012 First Incremental Auction, 2011/2012 ATSI Integration Auction, 2012/2013 First Incremental Auction, 2012/2013 ATSI Integration Auction, and 2013/2014 BRA all participants in the total PJM market as well as the locational deliverability area (LDA) markets failed the three pivotal supplier (TPS) market structure test. In the 2012/2013 BRA, all participants in the RTO as well as MAAC, PSEG North, and DPL South RPM markets failed the TPS test. Six participants included in the incremental supply of EMAAC passed the TPS test. 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.[8,9,10]

- **Imports and Exports.** Net exchange decreased 707.2 MW from June 1, 2009 to June 1, 2010. Net exchange, which is imports less exports, decreased due to an increase in exports of 952.5 MW offset by an increase in imports of 245.3 MW.

8 OATT Attachment DD (Reliability Pricing Model) § 6.5.
9 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.
10 The definition of planned generation capacity resource and the rules regarding mitigation were redefined effective January 31, 2011. See 134 FERC ¶ 61,065 (2011).

- **Demand-Side and Energy Efficiency Resources.** Under RPM, demand-side resources in the Capacity Market increased by 1,783.3 MW from 6,899.7 MW on June 1, 2009 to 8,683.0 MW on June 1, 2010. Demand-side resources include demand resources and energy efficiency 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.[11]

- **RPM Net Excess.**[12] RPM net excess decreased 537.5 MW from 8,265.5 MW on June 1, 2009 to 7,728.0 MW on June 1, 2010.

Market Conduct

- **2010/2011 RPM Base Residual Auction.**[13] Of the 1,104 generation resources which submitted offers, unit-specific offer caps were calculated for 154 resources (13.9 percent). Offer caps of all kinds were calculated for 532 resources (48.1 percent), of which 370 were based on the technology specific default (proxy) ACR values.

- **2010/2011 Third Incremental Auction.**[14] Of the 303 generation resources which submitted offers, 193 resources elected the offer cap option of 1.1 times the BRA clearing price (63.7 percent). Unit-specific offer caps were calculated for one resource (0.3 percent). Offer caps of all kinds were calculated for nine resources (2.9 percent), of which seven were based on the technology specific default (proxy) ACR values.

- **2011/2012 RPM Base Residual Auction.**[15] Of the 1,125 generation resources which submitted offers, unit-specific offer caps were calculated for 145 resources (12.9 percent). Offer caps of all kinds were calculated for 470 resources (41.8 percent), of which 301 were based on the technology specific default (proxy) ACR values.

- **2011/2012 RPM First Incremental Auction.**[16] Of the 129 generation resources which submitted offers, unit-specific offer caps were calculated for 19 resources (14.7 percent). Offer caps of all kinds were calculated for 68 resources (52.8 percent), of which 47 were based on the technology specific default (proxy) ACR values.

- **2011/2012 ATSI Integration Auction.**[17] Of the 141 generation resources which submitted offers, 52 resources elected the offer cap option of 1.1 times the BRA clearing price (36.9

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

12 Prior to the 2012/2013 delivery year, net excess under RPM was calculated as cleared capacity less the reliability requirement plus ILR. For 2007/2008 through 2010/2011, certified ILR was used in the calculation. Forecast ILR less FRR DR is used in the calculation when ILR was not certified and prior to 2011/2012 because PJM forecast ILR including FRR DR for the first four Base Residual Auctions. PJM forecast ILR excluding FRR DR for 2011/2012, so FRR DR is not subtracted in the calculation for 2011/2012. Net excess calculations for auctions prior to 2010/2011 were originally calculated as cleared capacity less the reliability requirement. For delivery years 2012/2013 and beyond, net excess under RPM is calculated as cleared capacity less the reliability requirement plus the Short-Term Resource Procurement Target.

13 For a more detailed analysis of the 2010/2011 RPM Base Residual Auction, 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>.

14 For a more detailed analysis of the 2010/2011 RPM Third Incremental Auction, 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>.

15 For a more detailed analysis of the 2011/2012 RPM Base Residual Auction, 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>.

16 For a more detailed analysis of the 2011/2012 RPM First Incremental Auction, 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>.

17 For a more detailed analysis of the 2011/2012 ATSI Integration Auction, see "Analysis of the 2011/2012 and 2012/2013 ATSI Integration Auctions" (January 14, 2011) <http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_and_2012_2013_ATSI_Integration_Auctions_20110114.pdf>.

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percent). Unit-specific offer caps were calculated for four resources (2.8 percent). Offer caps of all kinds were calculated for 64 resources (45.3 percent), of which 57 were based on the technology specific default (proxy) ACR values.

- **2012/2013 RPM Base Residual Auction.**[18] Of the 1,133 generation resources which submitted offers, unit-specific offer caps were calculated for 120 resources (10.6 percent). Offer caps of all kinds were calculated for 607 resources (53.6 percent), of which 479 were based on the technology specific default (proxy) ACR values.

- **2012/2013 ATSI Integration Auction.**[19] Of the 173 generation resources which submitted offers, 26 resources elected the offer cap option of 1.1 times the BRA clearing price (15.0 percent). Unit-specific offer caps were calculated for 12 resources (6.9 percent). Offer caps of all kinds were calculated for 131 resources (75.7 percent), of which 117 were based on the technology specific default (proxy) ACR values.

- **2012/2013 RPM First Incremental Auction.** Of the 162 generation resources which submitted offers, unit-specific offer caps were calculated for 14 resources (8.6 percent). Offer caps of all kinds were calculated for 108 resources (66.6 percent), of which 92 were based on the technology specific default (proxy) ACR values.

- **2013/2014 RPM Base Residual Auction.**[20] Of the 1,170 generation resources which submitted offers, unit-specific offer caps were calculated for 107 resources (9.1 percent). Offer caps of all kinds were calculated for 700 resources (59.9 percent), of which 587 were based on the technology specific default (proxy) ACR values.

Market Performance

2010/2011 RPM Base Residual Auction

- **RTO.** Total internal RTO unforced capacity of 159,030.9 MW includes all generation resources and DR that qualified as a PJM capacity resource for the 2010/2011 RPM Base Residual Auction, excludes external units and reflects owners' modifications to installed capacity (ICAP) ratings. After accounting for FRR committed resources and imports, RPM capacity was 137,360.7 MW. The 132,190.4 MW of cleared resources for the entire RTO represented a reserve margin of 16.5 percent, resulted in net excess of 7,728.0 MW over the reliability requirement of 132,698.8 MW (Installed Reserve Margin (IRM) of 15.5 percent), and resulted in a clearing price of $174.29 per MW-day.

  Total cleared resources in the RTO were 132,190.4 MW which resulted in a net excess of 7,728.0 MW, a decrease of 537.5 MW from the net excess of 8,265.5 MW in the 2009/2010 RPM BRA. Certified interruptible load for reliability (ILR) was 8,236.4 MW.

18 For a more detailed analysis of the 2012/2013 RPM Base Residual Auction, 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>.

19 For a more detailed analysis of the 2012/2013 ATSI Integration Auction, see "Analysis of the 2011/2012 and 2012/2013 ATSI Integration Auctions" (January 14, 2011) <http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_and_2012_2013_ATSI_Integration_Auctions_20110114.pdf>.

20 For a more detailed analysis of the 2013/2014 RPM Base Residual Auction, 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>.

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Cleared capacity resources across the entire RTO will receive a total of $8.4 billion based on the unforced MW cleared and the prices in the 2010/2011 RPM BRA, an increase of approximately $960.4 million from the 2009/2010 BRA.

- **DPL South.** Total internal DPL South unforced capacity of 1,546.1 MW includes all generation resources and DR that qualified as a PJM capacity resource, excludes external units and reflects owners' modifications to ICAP ratings. All imports offered into the auction are modeled in the RTO, so total DPL South RPM unforced capacity was 1,546.1 MW.[21] All of the 1,519.7 MW cleared in DPL South were cleared in the RTO before DPL South became constrained. Of the 26.4 MW of incremental supply, none cleared, because all 26.4 MW were priced above the demand curve. The DPL South resource clearing price of $186.12 per MW-day was determined by the intersection of the demand curve and a vertical section of the supply curve.

  Total resources in DPL South were 2,966.7 MW, which when combined with certified ILR of 97.2 MW resulted in a net excess of 14.5 MW (0.5 percent) greater than the reliability requirement of 3,049.4 MW.

2010/2011 RPM Third Incremental Auction

- **RTO.** There were 4,553.9 MW offered into the 2010/2011 Third Incremental Auction while buy bids totaled 5,221.0 MW. Cleared volumes in the RTO were 1,845.8 MW, resulting in an RTO clearing price of $50.00 per MW-day. The 2,708.1 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 $33.7 million based on the unforced MW cleared and the prices in the 2010/2011 RPM Third Incremental Auction.

- **DPL South.** Although DPL South was a constrained LDA in the 2010/2011 BRA, supply and demand curves resulted in a price less than the RTO clearing price. The result was that all of DPL South supply which cleared received the RTO clearing price. Supply offers in the incremental auction in DPL South (56.8 MW) exceeded DPL South demand bids (25.9 MW).

Generator Performance

- **Forced Outage Rates.** Average PJM EFORd decreased from 7.6 percent in 2009 to 7.2 percent in 2010. PJM Peak-Period Equivalent Forced Outage Rate Peak (EFORp) increased from 4.0 percent in 2009 to 5.2 percent in 2010.[22]

- **Generator Performance Factors.** The PJM aggregate equivalent availability factor decreased from 85.7 percent in 2009 to 84.8 percent in 2010.

21 Rules for RPM auctions state that imports are modeled in the unconstrained region of the RTO. See PJM. "Manual 18: PJM Capacity Market," Revision 10 (June 1, 2010), p. 24.

22 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM GADS database. This set of capacity resources may include generators in addition to those in the set of generators committed as resources in the RPM. Data is for the calendar year ending December 31, as downloaded from the PJM GADS database on January 21, 2011. Annual 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.

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- **Outages Deemed Outside Management Control (OMC).** According to 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 procedures of the owning company. 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

Capacity Market Design and Scarcity Revenues

The wholesale power markets, in order to be viable, must be competitive and they must provide adequate revenues to ensure an incentive to invest in new capacity. A wholesale energy market will not consistently produce competitive results in the absence of local market power mitigation rules. This is the result, not of a fundamental flaw in the market design, but of the fact that transmission constraints in a network create local markets where there is structural market power. A wholesale energy market will not consistently result in adequate revenues in the absence of a carefully designed and comprehensive approach to scarcity pricing. This is a result, not of offer capping, but of the fundamentals of wholesale power markets which must carry excess capacity in order to meet externally imposed reliability rules.

Scarcity revenues to generation owners can come entirely from energy markets or they can come from a combination of energy and capacity markets. The RPM design reflects the recognition that the energy markets, by themselves and in the absence of a carefully designed expansion of scarcity pricing, will not result in adequate revenues. The RPM design provides an alternate method for collecting scarcity revenues. The revenues in the capacity market are scarcity revenues.

The Definition of Capacity

In order for capacity markets to work, it is essential that the product definition be correct.

The definition of the capacity product is central to refining the market rules governing the sale and purchase of capacity. The current definition of capacity includes several components: the obligation to offer the energy of the unit into the Day-Ahead Energy Market; the obligation to permit PJM to recall the energy from the unit under emergency procedures; the obligation to provide outage data to PJM; the obligation to provide energy during the defined high demand hours each year; the obligation that the energy output from the resource be deliverable to load in PJM; and the obligation to test generation net capability.

The most critical of these components of the definition of capacity is the obligation to offer the energy of the unit into the Day-Ahead Energy Market. If buyers are to pay the high prices associated with RPM, it must be clear what they are buying and what the obligations of the sellers are. The fundamental energy market design should assure all market participants that the outcomes are competitive. This works to the ultimate advantage of all market participants including existing and prospective load and existing and prospective generation. The market rules should explicitly require that offers into the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate.

An offer that exceeds short run marginal cost is not a competitive offer in the Day-Ahead Energy Market. Such an offer assumes the need to exercise market power to ensure revenue adequacy. An offer to provide energy only in an emergency is not a competitive offer in the Day-Ahead Energy Market. A unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy on an emergency basis.

The obligation to offer energy in the Day-Ahead Energy Market should be applied without exception to all capacity resources, including both generation and demand resources. This means that capacity resources must be available every hour of the year at a competitive price. Demand resources that agree to interrupt only 10 times per year for a maximum of six hours per interruption should not be considered capacity resources. Generation resources that agree to provide an energy offer only under PJM emergency conditions should not be considered capacity resources. Generation resources that agree to provide energy only when the price is extremely high (and greater than the short run marginal cost of such units) should not be considered capacity resources. The only exception, and it is not really an exception, is that units which have a legitimate short term emergency condition, may appropriately offer the relevant portion of the unit as an emergency resource.

Capacity resources are required to ensure the reliability of the system. Reliability is not defined as the operation of the system only during an emergency but the reliable operation of the system in every hour of the year. If the system reserve margin were comprised of demand resources that would only interrupt 10 times for a maximum of six hours or generation resources that would only perform during an emergency or generation that will only perform when the price is $999 per MWh, the probability of needing those resources would increase significantly and the number of hours during which those resources are needed would increase significantly. As a general matter, the probability of needing such resources increases with the level of such resources that are defined to be capacity and thus needed for reliability.

The actual dispatch of resources in the energy market should be a function of the marginal cost to produce energy for each resource and not based on the refusal of a resource to make a competitive offer. Net revenues from the energy market, the ancillary services markets and the capacity market are the market based compensation. Investment decisions result from this total compensation.

The sale of capacity is also the sale of recall rights to the energy from capacity resources during an emergency. Regardless of where the energy from a unit is sold, it must be recallable by PJM when PJM is in an emergency condition or a scarcity condition. PJM does not have clear protocols for recalling the energy output of capacity resources and has not recalled such energy since 1999, despite the fact that PJM has experienced emergency conditions since that time.

Capacity Prices and the Structure of Capacity Auctions

If capacity markets are to work to provide incentives for maintaining existing generation and building new generation, capacity market prices must reflect actual, local supply and demand conditions. For example, getting the price a little too low at the margin could result in undermining the incentives exactly where they need to be clear. If the prices are too low as a result of the market

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design, this would mean that the capacity market is a mechanism for transferring wealth rather than a functioning market providing market based incentives.

Capacity auctions must be mandatory for both load and generation, if they are to work. In PJM, load has a must bid requirement, which is enforced through the use of a system demand curve and the allocation of total capacity costs to all load. In PJM, generation capacity resources have a must offer requirement, which means that all existing generation capacity resources must offer into the capacity auctions unless they have a contract with an entity outside PJM or are physically unable to perform or are committed to an FRR entity.

The must bid and must offer requirements must extend to all resources. Thus, there should be no reduction of demand on the bid side. The current 2.5 percent reduction in the demand curve, to provide for short term resources, distorts the market price. The reduction in demand results in a price lower than the competitive level thus reducing the incentives to both new and existing generation. There should be no reductions in the demand for capacity, which should reflect all capacity needed to provide reliability. In addition, the limited definition of the DR product means that an inferior product is offered in the same auction as capacity and significantly affects the clearing prices. The DR product should be defined to require unlimited interruptions.

The three year forward auction was implemented in order to provide the potential for new resources to compete with existing resources and to provide an incentive for such new entry. The prior capacity credit structure did not provide for either. The three year forward structure creates both opportunity and risks. A new generation unit that offers into an auction for a delivery year three years in the future is taking the risk that the unit will not be completed, that its costs will exceed its estimates or that the clearing price will be lower than anticipated in the first or subsequent years. Demand resources also face both opportunities and risks in a three year forward auction. A demand resource that is offered into an auction for a delivery year three years in the future is taking the risk that the customer with the demand side resource will no longer exist, that its costs will exceed its estimates or that the clearing price will be lower than anticipated in the first or subsequent years. There is nothing unique about demand resources that requires a shorter lead time or that requires distorting the market design. The fact that some generation resources or demand resources can be developed in less than three years is not a reason to distort the market design. It would be possible to shorten the time frame of the auctions for all participants but at the cost of reducing competition from new generation projects.

The market design goal is to ensure that out of market payments do not permit offers at less than competitive prices, including zero, which suppress the market clearing prices. All generation should be offered in to the auctions at no less than and no more than competitive prices and receive capacity credit if cleared and not receive capacity credit if not cleared.

Locational Prices

Capacity prices must reflect local supply and demand conditions. If capacity cannot be delivered into an area as a result of transmission constraints, a local market exists and capacity market prices should reflect the local market conditions. The CETL/CETO analysis currently used by PJM to define local markets in combination with consideration of local supply and demand is not adequate to define local markets in RPM. For example, if a unit does not clear in an RPM auction and makes an economic decision to retire but is then informed by PJM that it is needed for reliability,

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this is evidence that the market is not working because the local market is not properly defined. PJM determinations that a unit is needed for reliability are based on a more detailed analysis than the CETL/CETO analysis. PJM should perform such a more detailed reliability analysis of all at risk units, including all units that do not clear in RPM auctions and units that face significant investment requirements due, for example, to environmental requirements. If such units are needed for reliability, this could result in the definition of additional LDAs to reflect the actual reliability requirements of the system. Accurate locational pricing also requires that generation owners make offers that reflect their legitimate investment requirements. For example, units that will be forced to retire by environmental regulators unless they make defined investments in new technology should reflect the costs of that investment in their capacity market offer. That is essential to the functioning of the forward looking capacity market.

Capacity Markets and Incentives

If the revenues collected in the RPM market are adequate, it is not essential that a scarcity pricing mechanism exist in the energy market. Nonetheless, it would be preferable to also have a scarcity pricing mechanism in the energy market because it provides direct, hourly market-based incentives to load and generation, as long as it is designed to ensure that scarcity revenues directly offset RPM revenues. This hybrid approach would include both a capacity market and scarcity pricing in the energy market.

Capacity market design should reflect the fact that the capacity market is a mechanism for the collection of scarcity revenues and thus reflect the incentive structure of energy markets to the maximum extent possible. For example, if a generation unit does not produce power during a high price hour, it receives no revenues from the energy market. It does not receive some revenues simply for existing; it receives zero revenues. The reason that the unit does not produce energy is not relevant. It does not receive revenues if it does not produce energy even if the reason for non performance is outside management's control. That is the basic performance incentive structure of energy markets. The same performance incentive structure should be replicated in capacity market design. If a unit that is a capacity resource does not produce energy during the 500 hours defined as critical in RPM, it will receive no energy revenues for those hours. If a unit defined as a capacity resource does not produce energy when called upon during any of the hours defined as critical, it should receive no capacity revenues. This approach to performance is also consistent with the reduction or elimination of administrative penalties associated with failure to meet capacity tests, for example.

A hybrid market design can provide scarcity revenues both via scarcity pricing in the energy market and via the capacity market. However, if there is scarcity pricing in the energy market, the market design must ensure that units receiving scarcity revenues in the capacity market do not also receive scarcity revenues in the energy market. This would be double payment of scarcity revenues. This offset must reflect the actual scarcity revenues and not those reflected in forward curves or forecasts, or those reflected in results from prior years. Scarcity revenues are episodic and unlikely to be fully reflected in historical data or in forward curves, even if such curves were based on a liquid market three years forward, which they are not, and reflected locational results, which they do not. The most straightforward way to ensure that such double payment does not occur would be to ensure that capacity resources do not receive scarcity revenues in the energy market in the first place. The settlements process can remove any scarcity revenues from payments to capacity

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resources and eliminate the need for a complex, uncertain, after the fact procedure for offsetting scarcity revenues in the capacity market.

Market Power

The RPM Capacity Market design explicitly addresses the underlying issues of ensuring that competitive prices can reflect local scarcity while not relying on the exercise of market power to achieve the design objective, and of explicitly limiting the exercise of market power.

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.

RPM has explicit market power mitigation rules designed to permit competitive, locational capacity prices while limiting the exercise of market power. The RPM construct is consistent with the appropriate market design objectives of permitting competitive prices to reflect local scarcity conditions while explicitly limiting market power. The RPM Capacity Market design provides that competitive prices can reflect locational scarcity while not relying on the exercise of market power to achieve that design objective by limiting the exercise of market power via the application of the three pivotal supplier test.

Competitive prices are the lowest possible prices, consistent with the resource costs. But, competitive prices are not necessarily low prices. In the Capacity Market, it is essential that the cost of new entry (CONE) be based on the actual resource costs of bringing a new capacity resource into service, including realistic interconnection costs. If RPM is to provide appropriate incentives for new entry, the marginal price signal must reflect the actual cost of new entry.

The existence of a capacity market that links payments for capacity to the level of unforced capacity and therefore to the forced outage rate creates an incentive to improve forced outage rates. The performance incentives in the RPM Capacity Market design need to be strengthened. The energy

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market also provides incentives for improved performance with somewhat different characteristics. Generators want to maximize their sales of energy when prices are high and if they are successful, this will also result in lower forced outage rates. Well designed scarcity pricing could also provide strong, complementary incentives for reduced outages during high load periods. It would be preferable to rely on strong market-based incentives for capacity resource performance rather than the current structure of penalties, which has its own incentive effects.

Barriers to Entry

Competitive outcomes in the capacity market can be prevented by barriers to entry. There are a variety of possible barriers to entry into the capacity market that may affect the frequency and level of entry and thus market outcomes. Such potential barriers include control of sites based on historical utility and regulatory practices; environmental rules; the costs and uncertainty associated with the transmission interconnection process and control over the timing and details of the required studies; and the uncertainty created by the PJM transmission planning process.

These and other barriers to entry should be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants. The uncertainty and resultant risks should be reflected in the cost of new entry used to establish the capacity market demand curve in RPM.

Detailed Recommendations

- The MMU recommends that the RPM market structure, definitions and rules be modified to improve the efficiency of market prices and to ensure that market prices reflect the forward locational marginal value of capacity.
    - The MMU recommends that the Short-Term Resource Procurement Target (2.5 percent demand offset) be eliminated.
    - The MMU recommends that the definition of demand side capacity (Demand Response (DR)) resources be made comparable to generation capacity resources to ensure that all resources provide the same value in the capacity market. The DR product should be defined to require unlimited interruptions. FERC recently accepted PJM’s proposal on this issue.
    - The MMU recommends that there be an explicit market power test for the RPM Incremental Auctions related to market power on the buyer side. PJM has made a filing with FERC to address this issue.
    - The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants and reflect the uncertainty and resultant risks in the cost of new entry used to establish the capacity market demand curve in RPM. PJM is addressing some of these barriers to entry.

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  - The MMU recommends that the test for determining modeled Locational Deliverability Areas in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model.

  - The MMU recommends that PJM use the most current Handy-Whitman Index value to recalculate the ACR for the applicable year and update the ten year annual average Handy-Whitman Index value to recalculate the subsequent default ACR values.

  - The MMU recommends that the cap on the amount of FRR sales into the RPM market be eliminated as a non-competitive barrier to entry.

- The MMU recommends that the obligations of capacity resources be more clearly defined in the market rules.

  - The MMU recommends that there be an explicit requirement that capacity unit offers into the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units.

  - The MMU recommends that protocols be defined for recalling the energy output of capacity resources when PJM is in an emergency condition. PJM is developing these protocols.

  - The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy on an emergency basis.

  - The MMU recommends that PJM review all requests for Out of Management Control (OMC) carefully, develop a transparent set of rules governing the designation of outages as OMC and post those guidelines. The MMU also recommends that PJM consider eliminating lack of fuel as an acceptable basis for an OMC outage.

- The MMU recommends that the performance incentives in the RPM Capacity Market design be strengthened. The MMU recommends that capacity resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical.

- The MMU recommends that the terms of Reliability Must Run (RMR) service be reviewed, refined and standardized. The MMU recommends that RMR agreements should limit ratepayers' obligations to the costs that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed.

Results

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.

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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 calendar year 2010. 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 calendar year 2010.

The MMU has also identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[23,24,25,26,27,28,29]

RPM Capacity Market

Market Design

The RPM Capacity Market, implemented June 1, 2007 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.

Annual base auctions are held in May for delivery years that are three years in the future. Prior to January 31, 2010, First, Second and Third Incremental RPM Auctions were conducted 23, 13 and four months prior to the delivery year. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[30] In calendar year 2010, the 2013/2014 BRA was held in May, a Third Incremental Auction was held in January for the delivery year 2010/2011, ATSI FRR Integration Auctions were held in March for the delivery years 2011/2012 and 2012/2013, and a First Incremental Auction was held in September for the delivery year 2012/2013.[31]

Market Structure

Supply

As shown in Table 5-2, total internal capacity increased 1,712.7 MW from 157,318.2 MW on June 1, 2009, to 159,030.9 MW on June 1, 2010. This increase was the result of 406.9 MW of new generation, 165.0 MW that came out of retirement, 1,085.8 MW of net generation capacity

23 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>.
24 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>.
25 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>.
26 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>.
27 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>.
28 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>.
29 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>.
30 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
31 Delivery years are from June 1 through May 31. The 2010/2011 delivery year runs from June 1, 2010, through May 31, 2011.

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modifications (cap mods), and 43.7 MW of demand resource (DR) modifications (mods). The net EFORd effect was 11.3 MW. The EFORd effect is the measure of the net internal capacity change attributable to EFORd changes and not capacity modifications.

In the 2011/2012, 2012/2013, and 2013/2014 auctions, new generation increased 3,969.4 MW; 486.9 MW came out of retirement and net generation cap mods were -2,043.5 MW, for a total of 2,412.8 MW. DR and Energy Efficiency (EE) modifications totaled 11,360.5 MW through June 1, 2013. A decrease of 1,481.8 MW was due to higher EFORds. The classification of the Duquesne resources as external reduced total internal capacity by 3,006.6 MW, and the reclassification of the Duquesne resources as internal added 3,187.2 MW to total internal capacity. The integration of the ATSI zone resources added 13,175.2 MW to total internal capacity. The net effect from June 1, 2010, through June 1, 2013, was an increase in total internal capacity of 25,647.3 MW (16.1 percent) from 159,030.9 MW to 184,678.2 MW.

As shown in Table 5-2 and Table 5-11, in the 2010/2011 auction, the increase of 11 RPM generation resources consisted of 15 new resources (406.9 MW), four reactivated resources (161.7 MW), three that were previously entirely FRR committed (10.9 MW), one less resource excused from offering (3.9 MW), and one less resource entirely exported (39.9 MW), offset by four deactivated resources (59.6 MW), four resources exported from PJM (554.0 MW), three retired resources (348.4 MW), and two resources excused from offering (108.8 MW). The new resources consisted of seven CT resources (270.5 MW), five new wind resources (120.0 MW), three new diesel resources (16.4 MW), and four reactivated resources (165.0 MW). There were 23 demand resources (DR) offered compared to 38 DR resources offered in the 2009/2010 RPM auction.

As also shown in Table 5-2 and Table 5-11, in the 2011/2012 auction, the increase of 21 generation resources consisted of 20 new resources (2,203.7 MW), four reactivated resources (486.9 MW), three fewer excused resources (126.3 MW), and one additional resource imported (663.2 MW), offset by five additional resources committed fully to FRR (1.0 MW) and two retired resources (87.3 MW). The new resources consisted of 11 new CT resources (728.7 MW), four new wind resources (75.2 MW), two new steam resources (838.0 MW), one new combined cycle resource (556.5 MW), one new diesel resource (4.2 MW) and one new solar resource (1.1 MW). There were 37 demand resources (DR) offered compared to 23 DR resources offered in the 2010/2011 RPM auction.

As shown in Table 5-2 and Table 5-12, in the 2012/2013 auction, the increase of eight generation resources consisted of 16 new resources (772.5 MW), four resources that were previously entirely FRR committed (13.4 MW), three additional resources imported (276.8 MW), two additional resources resulting from disaggregation of RPM resources, and one resource formerly unoffered (1.9 MW), offset by nine retired resources (1,044.5 MW), four additional resources committed fully to FRR (39.5 MW), four less resources resulting from aggregation of RPM resources, and one less external resource that did not offer (663.2 MW).[32] In addition, there were the following retirements of resources that were either exported or excused in the 2011/2012 BRA: two combustion turbine resources (5.3 MW) and three combined cycle resources (297.6 MW). Also, resources that are no longer PJM capacity resources consisted of three CT units (521.5 MW) in the RTO. The new resources consisted of six new diesel resources (13.9 MW), four new wind resources (57.9 MW), three new steam units (560.4 MW), and three new CT units (140.3 MW). There were 233 demand resources (DR) offered compared to 37 DR resources offered in the 2011/2012 RPM Base Residual

32 Disaggregation and aggregation of RPM resources reflect changes in how units are offered in RPM. For example, multiple units at a plant may be offered as a single unit or multiple units.

Auction. There were 53 Energy Efficiency (EE) resources offered as a new resource type for the 2012/2013 planning year.

As shown in Table 5-2 and Table 5-12, in the 2013/2014 auction, the increase of 37 generation resources consisted of 63 ATSI resources that were not offered in the 2012/2013 BRA (11,325.4 MW), 31 new resources (1,038.2 MW), four resources that were previously entirely Fixed Resource Requirement (FRR) committed (234.3 MW), and four additional resources imported (460.1 MW). The reduction in generation resources consisted of seven retired resources (824.0 MW), two deactivated resources (66.6 MW), 49 additional resources committed fully to FRR (307.7 MW), four less planned generation resources that were not offered (249.3 MW), two additional resources excused from offering (4.2 MW), and one less external resource that was not offered (45.7 MW). In addition, there were the following retirements of resources that were either exported or excused in the 2012/2013 BRA: three steam units (125.9 MW). The new generation capacity resources consisted of 11 solar resources (9.5 MW), 11 wind resources (245.7 MW), four combined cycle units (671.5 MW), three diesel resources (5.4 MW), one steam unit (23.8 MW), and one CT unit (82.3 MW). In addition, there were the following new generation resources that were not offered in to the auction because they were either exported or entirely committed to FRR for the 2013/2014 delivery year: four wind resources (66.2 MW). There were 426 demand resources (DR) offered compared to 233 DR resources offered in the 2012/2013 RPM Base Residual Auction. There were 128 EE resources offered compared to 53 EE resources in the 2012/2013 RPM Base Residual Auction.

Table 5-3 shows generation capacity additions since the implementation of the Reliability Pricing Model. New generation capacity resources (5,986.1 MW), reactivated generation capacity resources (849.7 MW), uprates to existing generation capacity resources (4,905.3 MW), and the net increase in capacity imports (4,126.1 MW) totaled 15,867.2 MW since the implementation of the Reliability Pricing Model.

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Table 5-2 Internal capacity: June 1, 2009 to June 1, 2013[33]

	UCAP (MW)					
	RTO	MAAC	EMAAC	DPL South	PSEG North	Pepco
Total internal capacity @ 01-Jun-09	157,318.2			1,587.0		
New generation	406.9			0.0		
Units out of retirement	165.0			0.0		
Generation cap mods	1,085.8			(85.5)		
DR mods	43.7			15.7		
Net EFORd effect	11.3			28.9		
Total internal capacity @ 01-Jun-10	159,030.9			1,546.1		
Classification of Duquesne resources to external	(3,006.6)					
New generation	2,203.7					
Units out of retirement	486.9					
Generation cap mods	439.0					
DR mods	684.4					
Net EFORd effect	44.4					
Total internal capacity @ 01-Jun-11	159,882.7	66,329.7	32,733.0	1,460.3	4,167.5	
Reclassification of Duquesne resources to internal	3,187.2	0.0	0.0	0.0	0.0	
New generation	661.3	61.9	59.7	0.0	0.0	
Units out of retirement	0.0	0.0	0.0	0.0	0.0	
Generation cap mods	(1,513.1)	(901.3)	(444.9)	(31.8)	(509.0)	
DR mods	8,028.7	3,829.7	1,480.9	64.6	67.6	
EE mods	652.5	186.9	24.4	0.0	0.9	
Net EFORd effect	(946.0)	(503.0)	(185.6)	5.8	18.3	
Total internal capacity @ 01-Jun-12	169,953.3	69,003.9	33,667.5	1,498.9	3,745.3	5,416.0
Correction in resource modeling	0.0	13.0	0.0			0.0
Adjusted internal capacity @ 01-Jun-12	169,953.3	69,016.9	33,667.5			5,416.0
Integration of existing ATSI resources	13,175.2	0.0	0.0			0.0
New generation	1,104.4	172.5	110.3			1.8
Units out of retirement	0.0	0.0	0.0			0.0
Generation cap mods	(969.4)	(1,007.7)	(884.9)			(11.0)
DR mods	1,894.1	900.2	689.5			61.8
EE mods	100.8	(34.9)	(0.3)			(20.7)
Net EFORd effect	(580.2)	31.9	118.5			(159.0)
Total internal capacity @ 01-Jun-13	184,678.2	69,078.9	33,700.6			5,288.9

33 The RTO includes MAAC, EMAAC and SWMAAC. MAAC includes EMAAC and SWMAAC. EMAAC includes DPL South and PSEG North. Results for only constrained LDAs are shown. Maps of the LDAs can be found in the *2010 State of the Market Report for PJM*, Appendix A, "PJM Geography."

Table 5-3 RPM generation capacity additions: 2007/2008 through 2013/2014

	ICAP (MW)				
Delivery Year	New Generation Capacity Resources	Reactivated Generation Capacity Resources	Uprates to Existing Generation Capacity Resources	Net Increase in Capacity Imports	Total
2007/2008	19.0	47.0	536.0	1,576.6	2,178.6
2008/2009	145.1	131.0	438.1	107.7	821.9
2009/2010	476.3	0.0	793.3	105.0	1,374.6
2010/2011	1,031.5	170.7	876.3	24.1	2,102.6
2011/2012	2,332.5	501.0	896.8	672.6	4,402.9
2012/2013	901.5	0.0	946.6	676.8	2,524.9
2013/2014	1,080.2	0.0	418.2	963.3	2,461.7
Total	5,986.1	849.7	4,905.3	4,126.1	15,867.2

Demand

There was a 3,156.7 MW increase in the RPM reliability requirement from 153,480.1 MW on June 1, 2009, to 156,636.8 MW on June 1, 2010. This increase resulted from a higher peak-load forecast.

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The Capacity Market was divided into the following sectors:

- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing Affiliate.** Affiliate companies of PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-PJM EDC.** EDCs with franchise service territories outside the PJM footprint.
- **Non-PJM EDC Generating Affiliate.** Affiliate companies of non-PJM EDCs that own generating resources.
- **Non-PJM EDC Marketing Affiliate.** Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-EDC Generating Affiliate.** Affiliate companies of non-EDCs that own generating resources.
- **Non-EDC Marketing Affiliate.** Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

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On June 1, 2010, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 77.7 percent (Table 5-4), down from 79.6 percent on June 1, 2009. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 22.3 percent, up from 20.4 percent on June 1, 2009. Prior to the 2009/2010 delivery year, obligation was defined as cleared and make-whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2009/2010 through the 2011/2012 delivery year, obligation is defined as cleared and make-whole MW in the all RPM auctions for the delivery year plus ILR forecast obligations. Effective the 2012/2013 delivery year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM auctions for the delivery year.

Table 5-4 PJM Capacity Market load obligation served: June 1, 2010

	Obligation (MW)							
	PJM EDCs	PJM EDC Generating Affiliates	PJM EDC Marketing Affiliates	Non-PJM EDC Generating Affiliates	Non-PJM EDC Marketing Affiliates	Non-EDC Generating Affiliates	Non-EDC Marketing Affiliates	Total
Obligation	66,223.4	12,774.7	24,974.3	1,144.4	12,755.6	567.1	15,408.6	133,848.1
Percent of total obligation	49.5%	9.5%	18.7%	0.9%	9.5%	0.4%	11.5%	100.0%

Market Concentration

Preliminary Market Structure Screen

Under the terms of the PJM Open Access Transmission Tariff (OATT), the MMU is required to apply the preliminary market structure screen (PMSS) prior to RPM Base Residual Auctions.[34] The results of the PMSS are applicable for the First, Second, Third, and Conditional Incremental Auctions for the given delivery year.[35] The purpose of the PMSS is to determine whether additional data are needed from owners of capacity resources in the defined areas in order to permit the MMU to apply the market structure tests defined in the Tariff.

An LDA or the RTO Region fails the PMSS if any one of the following three screens is failed: the market share of any capacity resource owner exceeds 20 percent; the HHI for all capacity resource owners is 1800 or higher; or there are not more than three jointly pivotal suppliers.[36]

As shown in Table 5-5, all defined markets failed the PMSS. As a result, capacity resource owners were required to submit avoidable cost rate (ACR) data or opportunity cost data to the MMU for resources for which they intended to submit non-zero sell offers unless certain other conditions were met.[37]

34 OATT Attachment M (PJM Market Monitoring Plan)-Appendix § II.D.1.
35 OATT Attachment DD § 5.11 (b).
36 OATT Attachment M-Appendix § II.D.2.
37 OATT Attachment DD § 6.7 (c).

Table 5-5 Preliminary market structure screen results: 2010/2011 through 2013/2014 RPM Auctions

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

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Auction Market Structure

As shown in Table 5-6, all participants in the total PJM market as well as the LDA RPM markets failed the TPS test in the 2010/2011 BRA, 2010/2011 Third Incremental Auction, the 2011/2012 BRA, the 2011/2012 First Incremental Auction, the 2011/2012 ATSI FRR Integration Auction, the 2012/2013 First Incremental Auction, the 2012/2013 ATSI FRR Integration Auction, and the 2013/2014 BRA.[38] The result was that 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.[39,40,41] In the 2012/2013 BRA, all participants included in the incremental supply of EMAAC passed the test. In applying the market structure test, the relevant supply for the RTO market includes all supply offered at less than or equal to 150 percent of the RTO cost-based clearing price.[42] The relevant supply for the constrained LDA markets includes the incremental supply inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the cost-based clearing price for the constrained LDA. The relevant demand consists of the MW needed inside the LDA to relieve the constraint.

Table 5-6 presents the results of the TPS test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the Residual Supply Index (RSI_3). The RSI_x is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSI_x is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSI_x is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.

38 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. See *Technical Reference for PJM Markets,* Section 8, "Three Pivotal Supplier Test" for additional discussion.

39 See OATT Attachment DD § 6.5.

40 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.

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

42 Effective November 1, 2009, DR and EE resources are not included in the TPS test. See 129 FERC ¶ 61,081 (2009) at P 31.

Table 5-6 RSI results: 2010/2011 through 2013/2014 RPM Auctions[43]

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
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
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

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

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Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads as a result of RPM auctions, FRR capacity plans, locational UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity outside PJM.[44]

Importing Capacity

Existing External Generation Capacity Resource

Generation external to the PJM region is eligible to be offered into an RPM auction if it meets specific requirements.[45,46] Firm transmission service from the unit to the border of PJM and generation deliverability into PJM must be demonstrated prior to the start of the delivery year. In order to demonstrate generation deliverability into PJM, external generators must obtain firm point-to-point transmission service on the PJM OASIS from the PJM border into the PJM transmission system or by obtaining network external designated transmission service. In the event that transmission upgrades are required to establish deliverability, those upgrades must be completed by the start of the delivery year. The following are also required: the external generating unit must be in the resource portfolio of a PJM member; twelve months of NERC/GADs unit performance data to establish an EFORd; the net capability of each unit must be verified through winter and summer testing; a letter of non-recallability assuring PJM that the energy and capacity from the unit is not recallable to any other balancing authority.

All external generation resources that have an RPM commitment or FRR capacity plan commitment or that are designated as replacement capacity must be offered in the PJM Day-Ahead Market.[47]

To avoid balancing market deviations, any offer accepted in the Day-Ahead Market must be scheduled to physically flow in the Real-Time Market. When submitting the Real-Time Market transaction, a valid NERC Tag is required, with the appropriate transmission reservations associated. Additionally, external capacity transactions must designate the transaction as such when submitting the NERC Tag. This designation allows the PJM dispatch operators to identify capacity backed transactions in order to avoid curtailing them out of merit order. External capacity backed transactions are evaluated the same way as all other energy transactions, and are subject to all scheduling timing requirements and PJM interchange ramp limits. If the offer is not accepted in the Day-Ahead Market, but the unit is requested during the operating day, the PJM dispatch operator will notify the participant. The market participant will then submit a tag to match the request. This tag will also be subject to all scheduling timing requirements and PJM interchange ramp limits.

44 See PJM Manual 18: PJM Capacity Market. See PJM. “Manual 18: PJM Capacity Market”, Revision 10 (June 1, 2010).
45 See PJM. “Reliability Assurance Agreement Among Load Serving Entities in the PJM Region”, Schedule 9 & 10.
46 See PJM. “Manual 18: PJM Capacity Market”, Revision 10 (June 1, 2010), pp. 22-23 & p.42.
47 See PJM. OATT, Schedule 1, Section 1.10.1A.

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Planned External Generation Capacity Resource

Planned external generation capacity resources are eligible to be offered into an RPM auction if they meet specific requirements.[48,49] Planned external generation capacity resources are proposed generation capacity resources, or a proposed increase in the capability of an existing generation capacity resource, that is located outside the PJM region; participates in the generation interconnection process of a balancing authority external to PJM; is scheduled to be physically and electrically interconnected to the transmission facilities of such balancing authority on or before the first day of the delivery year for which the resource is to be committed to satisfy the reliability requirements of the PJM Region; and is in full commercial operation prior to the first day of the delivery year.[50] An external generation capacity resource becomes an existing external generation capacity resource as of the earlier of the date that interconnection service commences or the resource has cleared an RPM auction.[51]

Exporting Capacity

Non-firm transmission can be used to export capacity from the PJM region. A generation capacity resource located in the PJM region not committed to service of PJM loads may be removed from PJM capacity resource status if the market seller shows that the resource has a financially and physically firm commitment to an external sale of its capacity.[52] The capacity market seller must also identify the megawatt amount, export zone, and time period (in days) of the export.[53]

The MMU evaluates requests submitted by capacity market sellers to delist generation capacity resources, makes a determination as to whether the resource meets the applicable criteria to delist, and must inform both the capacity market seller and PJM of such determination.[54]

When submitting a Real-Time Market export capacity transaction, a valid NERC Tag is required, with the appropriate transmission reservations associated. Capacity transactions must designate the transaction as capacity when submitting the NERC Tag. This designation allows the PJM dispatch operators to identify capacity backed transactions in order to avoid curtailing them out of merit order. External capacity backed transactions are evaluated the same way as all other energy transactions, and are subject to all scheduling timing requirements and PJM interchange ramp limits.

As shown in Table 5-7, net exchange decreased 707.2 MW from June 1, 2009 to June 1, 2010. Net exchange, which is imports less exports, decreased due to an increase in exports of 952.5 MW offset by an increase in imports of 245.3 MW.

48 See PJM. "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Section 1.69A.
49 See PJM. "Manual 18: PJM Capacity Market", Revision 10 (June 1, 2010), pp. 25-26.
50 Prior to January 31, 2011, capacity modifications to existing generation capacity resources were not considered planned generation capacity resources. See 134 FERC ¶ 61,065 (2011).
51 The definition of planned generation capacity resource and the rules regarding mitigation were redefined effective January 31, 2011. See 134 FERC ¶ 61,065 (2011).
52 See OATT Attachment DD § 6.6.
53 *Id.*
54 OATT Attachment M-Appendix § II.C.2.

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Table 5-7 PJM capacity summary (MW): June 1, 2007 to June 1, 2013[55]

	01-Jun-07	01-Jun-08	01-Jun-09	01-Jun-10	01-Jun-11	01-Jun-12	01-Jun-13
Installed capacity (ICAP)	163,721.1	164,444.1	166,916.0	168,061.5	172,666.6	181,159.7	197,775.0
Unforced capacity	154,076.7	155,590.2	157,628.7	158,634.2	163,144.3	171,147.8	186,588.0
Cleared capacity	129,409.2	129,597.6	132,231.8	132,190.4	132,221.5	136,143.5	152,743.3
Make-whole	0.0	0.0	0.0	0.0	43.0	222.1	14.0
RPM reliability requirement (pre-FRR)	148,277.3	150,934.6	153,480.1	156,636.8	154,251.1	157,488.5	173,549.0
RPM reliability requirement (less FRR)	125,805.0	128,194.6	130,447.8	132,698.8	130,658.7	133,732.4	149,988.7
RPM net excess	5,240.5	5,011.1	8,265.5	7,728.0	3,199.6	5,976.5	6,518.3
Imports	2,809.2	2,460.3	2,505.4	2,750.7	6,420.0	3,831.6	4,348.2
Exports	(3,938.5)	(3,838.1)	(2,194.9)	(3,147.4)	(3,158.4)	(2,637.1)	(2,438.4)
Net exchange	(1,129.3)	(1,377.8)	310.5	(396.7)	3,261.6	1,194.5	1,909.8
DR cleared	127.6	536.2	892.9	939.0	1,364.9	7,047.2	9,281.9
EE cleared						568.9	679.4
ILR	1,636.3	3,608.1	6,481.5	8,236.4	1,593.8		
FRR DR	445.6	452.8	423.6	452.9	452.9	488.1	488.6
Short-Term Resource Procurement Target						3,343.3	3,749.7

Demand-Side Resources

Under the PJM load management (LM) program, qualifying load management resources can be offered into RPM Auctions as capacity resources and receive the clearing price, or, prior to the 2012/2013 delivery year, they can be offered outside of the auction and receive the final, zonal ILR price.

There are three basic demand side products incorporated in the RPM market design:

- **Demand resources.** Capacity load resources that are offered into an RPM Auction as capacity and receive the relevant LDA or RTO resource clearing price.
- **Interruptible load for reliability (ILR).** Capacity load resources that are not offered into the RPM Auction, but are certified outside the auction process and receive the final, zonal ILR price determined after the close of the second incremental auction. ILR was effectively a free option to offer a resource at the BRA clearing price up until three months prior to the start of the delivery year.
- **Energy efficiency resources.** Capacity load resources that are offered into an RPM Auction as capacity and receive the relevant LDA or RTO resource clearing price. An EE Resource is a project designed to achieve a continuous (during peak periods) reduction in electric energy

55 Prior to the 2012/2013 delivery year, net excess under RPM was calculated as cleared capacity less the reliability requirement plus ILR. For 2007/2008 through 2010/2011, certified ILR was used in the calculation. Forecast ILR less FRR DR is used in the calculation when ILR was not certified and prior to 2011/2012 because PJM forecast ILR including FRR DR for the first four Base Residual Auctions. PJM forecast ILR excluding FRR DR for 2011/2012, so FRR DR is not subtracted in the calculation for 2011/2012. Net excess calculations for auctions prior to 2010/2011 were originally calculated as cleared capacity less the reliability requirement. For delivery years 2012/2013 and beyond, net excess under RPM is calculated as cleared capacity less the reliability requirement plus the Short-Term Resource Procurement Target.

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consumption that is not reflected in the peak load forecast prepared for the delivery year, and that is fully implemented at all times during such delivery year, without any requirement of notice, dispatch, or operator intervention.[56] The Energy Efficiency (EE) resource type is eligible to be offered in RPM auctions starting with the 2012/2013 delivery year and also for incremental auctions in the 2011/2012 delivery year.[57]

Under RPM, DR and EE resources must be offered into the auction for the delivery year during which they will participate while ILR resources must be certified by a published deadline which is after the Base Residual Auction for the delivery year but no later than three months prior to the delivery year during which they will participate. Beginning with the 2012/2013 delivery year, the load management product ILR was eliminated. ILR was replaced by the Short-Term Resource Procurement Target, which reduces the RTO reliability requirement by 2.5 percent with the intent of permitting short lead time resource procurement in later auctions for the delivery year, was implemented with the 2012/2013 delivery year.

As shown in Table 5-8 and Table 5-10, capacity in the RPM load management programs increased by 1,783.3 MW from 6,899.7 MW on June 1, 2009 to 8,683.0 MW on June 1, 2010. Final ILR is certified three months before the delivery year and it may differ from the ILR forecast. Table 5-9 shows RPM commitments for DR and EE resources as the result of RPM auctions prior to adjustments for replacement transactions along with certified/forecast ILR.

56 See "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Section M.
57 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).

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Table 5-8 RPM load management statistics by LDA: June 1, 2009 to June 1, 2013[58,59]

	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	1,364.9							
DR net replacements	(150.1)							
ILR forecast	1,593.8							
RPM load management @ 01-June-2011	2,808.6							
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

58 For delivery years through 2010/2011, certified ILR data were used in the calculation, because the certified ILR data are now available. Effective the 2012/2013 delivery year, ILR was eliminated. Starting with the 2012/2013 delivery year and also for incremental auctions in the 2011/2012 delivery year, the Energy Efficiency (EE) resource type is eligible to be offered in RPM auctions.

59 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 5-9 RPM load management cleared capacity and ILR: 2007/2008 through 2013/2014[60,61]

	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	1,319.5	1,364.9	0.0	0.0	1,540.6	1,593.8
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 5-10 RPM load management statistics: June 1, 2007 to June 1, 2013[62,63]

	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	2,860.1	2,958.7	(145.1)	(150.1)	0.0	0.0	2,715.0	2,808.6
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

Market Conduct

Offer Caps

If a capacity resource owner failed the market power test for the auction and the submitted sell offer exceeded the defined offer cap, market power mitigation measures were applied such that the sell offer was set equal to the defined offer cap.

The opportunity cost option allows resource owners to input a documented export opportunity cost as the offer for the unit, subject to export limits. If the relevant RPM market clears above the opportunity cost, the unit's capacity is sold in the RPM market. If the opportunity cost is greater than the clearing price, the unit's capacity does not clear in the RPM market and it is available for export.

60 For delivery years through 2010/2011, certified ILR data is shown, because the certified ILR data are now available. Effective the 2012/2013 delivery year, ILR was eliminated. Starting with the 2012/2013 delivery year and also for incremental auctions in the 2011/2012 delivery year, the Energy Efficiency (EE) resource type is eligible to be offered in RPM auctions.

61 FRR committed load management resources are not included in this table.

62 For delivery years through 2010/2011, certified ILR data were used in the calculation, because the certified ILR data are now available. Effective the 2012/2013 delivery year, ILR was eliminated. Starting with the 2012/2013 delivery year and also for incremental auctions in the 2011/2012 delivery year, the Energy Efficiency (EE) resource type is eligible to be offered in RPM auctions.

63 FRR committed load management resources are not included in this table.

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Avoidable costs are the costs that a generation owner would not incur if the generating unit did not operate for the delivery year.[64] In effect, avoidable costs are the costs that a generation owner would not incur if the generating unit were mothballed for the year. In the calculation of avoidable costs, there is no presumption that the unit would retire as the alternative to operating, although that possibility could be reflected if the owner documented that retirement was the alternative. Avoidable costs also include annual capital recovery associated with investments required to maintain a unit as a capacity resource. This component of avoidable costs is termed the avoidable project investment recovery rate (APIR). Avoidable cost based offer caps are defined to be the avoidable cost rate (ACR) less net revenues from all other PJM markets and from unit-specific bilateral contracts. Capacity resource owners could provide ACR data by providing their own unit-specific data or by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM Tariff.

Table 5-11 ACR statistics: 2010/2011 through 2011/2012 RPM Auctions

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

64 See OATT Attachment DD § 6.8 (b).

Table 5-12 ACR statistics: 2012/2013 through 2013/2014 RPM Auctions

	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 offer caps	607	53.5%	131	75.7%	108	66.6%	700	59.9%
Uncapped planned generation resources	11	1.0%	0	0.0%	17	10.5%	20	1.7%
Generators with 1.1 times BRA clearing price offer cap	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	

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Table 5-13 APIR statistics: 2010/2011 through 2013/2014 RPM Auctions[65,66,67,68]

		Weighted-Average ($ per MW-day UCAP)					
		Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
2010/2011 BRA							
Non-APIR units	ACR	$34.39	$27.10	$67.57	$167.08	$82.55	$80.86
	Net revenues	$96.75	$18.81	$15.19	$302.79	$391.00	$151.31
	Offer caps	$10.13	$14.12	$52.38	$9.67	$4.53	$11.94
APIR units	ACR	$61.61	$49.26	$152.09	$654.18	$34.62	$360.27
	Net revenues	$26.84	$10.32	$20.94	$525.48	$2.07	$263.27
	Offer caps	$37.30	$39.41	$131.15	$155.39	$32.55	$110.25
	APIR	$9.87	$30.93	$60.54	$521.16	$22.42	$272.18
	Maximum APIR effect						$577.03
2011/2012 BRA							
Non-APIR units	ACR	$39.52	$30.17	$72.20	$181.52	$62.54	$75.61
	Net revenues	$69.04	$20.16	$17.27	$466.41	$322.78	$169.93
	Offer caps	$11.76	$16.42	$62.13	$7.88	$11.50	$17.64
APIR units	ACR	$61.66	$56.28	$184.34	$723.65	$36.03	$424.49
	Net revenues	$78.17	$10.35	$19.81	$531.93	$2.06	$286.80
	Offer caps	$34.69	$46.18	$164.54	$203.41	$33.97	$147.77
	APIR	$11.82	$37.28	$91.30	$578.47	$24.68	$324.58
	Maximum APIR effect						$523.26
2011/2012 First IA							
Non-APIR units	ACR	$54.15	$29.43	NA	$284.63	$30.04	$169.77
	Net revenues	$220.31	$44.98	NA	$298.96	$0.07	$195.83
	Offer caps	$2.66	$2.64	NA	$150.63	$29.97	$83.01
APIR units	ACR	$220.20	$152.28	$194.25	$583.59	NA	$326.57
	Net revenues	$81.72	$6.94	$23.64	$328.71	NA	$128.90
	Offer caps	$138.48	$145.34	$170.62	$254.88	NA	$197.67
	APIR	$220.19	$120.84	$82.87	$324.31	NA	$170.61
	Maximum APIR effect						$468.26
2012/2013 BRA							
Non-APIR units	ACR	$41.84	$32.61	$75.47	$207.54	$57.18	$110.84
	Net revenues	$91.67	$35.29	$7.51	$396.82	$257.96	$208.65
	Offer caps	$5.28	$14.40	$67.96	$11.31	$15.63	$13.74
APIR units	ACR	$218.10	$49.83	$177.52	$715.10	NA	$464.65
	Net revenues	$98.97	$15.62	$3.62	$508.00	NA	$302.04
	Offer caps	$119.12	$34.96	$173.89	$215.38	NA	$167.62
	APIR	$218.10	$26.59	$89.08	$559.97	NA	$351.74
	Maximum APIR effect						$1,155.57

65 The weighted-average offer cap can be positive even when the weighted-average net revenues are higher than the weighted-average ACR, because the unit-specific offer caps are never less than zero. On a unit basis, if net revenues are greater than ACR, the offer cap is zero.

66 This table has been updated since the MMU RPM Auction reports were posted. The 2010/2011 and 2011/2012 BRA values for Oil and Gas Steam and Sub Critical/Super Critical Coal for resources with an APIR component were updated due to a prior misclassification.

67 For reasons of confidentiality, the APIR statistics do not include opportunity cost based offer cap data.

68 Statistics for the 2010/2011 Third IA are not included as the majority of the resources elected the offer cap option of 1.1 times the BRA clearing price.

Table 5-13 APIR statistics: 2010/2011 through 2013/2014 RPM Auctions (continued)

		Weighted-Average ($ per MW-day UCAP)					
		Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
2012/2013 First IA							
Non-APIR units	ACR	$69.71	$30.49	$86.40	$229.86	$32.75	$67.26
	Net revenues	$136.19	$5.75	$12.73	$156.50	$33.52	$30.71
	Offer caps	$32.88	$24.75	$73.67	$75.99	$27.72	$37.81
APIR units	ACR	NA	$50.56	$289.38	$660.56	NA	$367.75
	Net revenues	NA	$9.15	$50.16	$434.48	NA	$138.16
	Offer caps	NA	$41.40	$239.21	$226.09	NA	$229.59
	APIR	NA	$7.70	$156.87	$459.80	NA	$222.35
	Maximum APIR effect						$549.57
2013/2014 BRA							
Non-APIR units	ACR	$44.51	$33.30	$79.91	$212.68	$52.57	$115.83
	Net revenues	$110.63	$30.53	$12.72	$364.90	$259.34	$199.44
	Offer caps	$6.84	$16.36	$68.15	$9.29	$14.30	$14.09
APIR units	ACR	NA	$49.42	$341.77	$509.95	$305.48	$390.05
	Net revenues	NA	$9.18	$63.80	$459.41	$187.40	$292.92
	Offer caps	NA	$40.73	$277.96	$112.30	$118.09	$134.44
	APIR	NA	$25.28	$243.47	$352.55	$1.69	$268.59
	Maximum APIR effect						$1,304.36

2010/2011 RPM Base Residual Auction

As shown in Table 5-11, 1,104 generation resources submitted offers in the 2010/2011 RPM Base Residual Auction as compared to 1,093 generation resources offered in the 2009/2010 RPM Auction. Unit-specific offer caps were calculated for 154 resources (13.9 percent of all generation resources offered) including 134 resources (12.1 percent) with an APIR component and 20 resources (1.8 percent) without an APIR component. The MMU calculated offer caps for 532 resources (48.1 percent), of which 370 (33.5 percent) were based on the technology specific default (proxy) ACR values. Of the 557 generation resources, 15 planned generation resources had uncapped offers (1.4 percent), while the remaining 557 generation resources were price takers (50.5 percent), of which the offers for 546 resources were zero and the offers for 11 resources were set to zero because no data were submitted.[69]

Of the 1,104 generation resources which submitted offers, 134 (12.1 percent) included an APIR component (Table 5-11). As shown in Table 5-13, the weighted-average gross ACR for resources with APIR ($360.27 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($110.25 per MW-day) were higher than for resources without an APIR component, including resources for which the default ACR value was selected. The APIR component added an average of $272.18 per MW-day to the ACR value of the APIR resources.[70] The default

69 Planned units are subject to mitigation under specific circumstances defined in the tariff. Some of the uncapped planned units submitted zero price offers.
70 The 134 units which had an APIR component submitted $1.5 billion for capital projects associated with 12,645.3 MW UCAP.

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ACR values included an average APIR of $0.91 per MW-day. The highest APIR for a technology ($521.16 per MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($577.03 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2010/2011 RPM Third Incremental Auction

As shown in Table 5-11, 303 generation resources submitted offers in the 2010/2011 RPM Third Incremental Auction. Unit specific offer caps were calculated for one resource (0.3 percent of all generation resources offered). The MMU calculated offer caps for nine resources (2.9 percent), of which seven were based on the technology specific default (proxy) ACR values. Of the 303 generation resources, 193 resources elected the offer cap option of 1.1 times the BRA clearing price (63.7 percent), while the remaining 101 resources were price takers (33.4 percent).

2011/2012 RPM Base Residual Auction

As shown in Table 5-11, 1,125 generation resources submitted offers in the 2011/2012 RPM Base Residual Auction as compared to 1,104 generation resources offered in the 2010/2011 RPM Base Residual Auction. Unit-specific offer caps were calculated for 145 resources (12.9 percent of all generation resources offered) including 133 resources (11.8 percent) with an APIR component and 12 resources (1.1 percent) without an APIR component. The MMU calculated offer caps for 470 resources (41.8 percent), of which 301 (26.8 percent) were based on the technology specific default (proxy) ACR values. Of the 1,125 generation resources, 20 planned generation resources had uncapped offers (1.8 percent), while the remaining 635 generation resources were price takers (56.4 percent), of which the offers for 578 resources were zero and the offers for 55 resources were set to zero because no data were submitted.[71]

Of the 1,125 generation resources which submitted offers, 133 (11.8 percent) included an APIR component (Table 5-11). As shown in Table 5-13, the weighted-average gross ACR for resources with APIR ($424.49 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($147.77 per MW-day) were higher than for resources without an APIR component, including resources for which the default ACR value was selected. The APIR component added an average of $324.58 per MW-day to the ACR value of the APIR resources.[72] The default ACR values included an average APIR of $0.91 per MW-day. The highest APIR for a technology ($578.47 per MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($523.26 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2011/2012 RPM First Incremental Auction

As shown in Table 5-11, 129 generation resources submitted offers in the 2011/2012 RPM First Incremental Auction. Unit-specific offer caps were calculated for 19 resources (14.7 percent of all generation resources offered) including 18 resources (14.0 percent) with an APIR component and one resource (0.8 percent) without an APIR component. The MMU calculated offer caps for 68 resources (52.8 percent), of which 47 (36.4 percent) were based on the technology specific default

71 Planned units are subject to mitigation under specific circumstances defined in the tariff. Some of the 20 uncapped planned units submitted zero price offers.

72 The 133 units which had an APIR component submitted $613.8 million for capital projects associated with 8,813.7 MW UCAP.

(proxy) ACR values. Of the 129 generation resources, one planned generation resource had an uncapped offer (0.8 percent) while the remaining 60 generation resources were price takers (46.4 percent), of which the offers for 36 resources were zero and the offers for 24 resources were set to zero because no data were submitted.

Of the 129 generation resources which submitted offers, 18 resources (14.0 percent) included an APIR component (Table 5-11). As shown in Table 5-13, the weighted-average gross ACR for resources with APIR ($326.57 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($197.67 per MW-day) were higher than for resources without an APIR component, including resources for which the default ACR value was selected. The APIR component added an average of $170.61per MW-day to the ACR value of the APIR resources. The default ACR values included an average APIR of $1.31 per MW-day. The highest APIR for a technology ($324.31 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($468.26 per MW-day) was the maximum amount by which an offer cap was increased by APIR.

2011/2012 ATSI Integration Auction

As shown in Table 5-11, 141 generation resources submitted offers in the 2011/2012 ATSI Integration Auction. Unit-specific offer caps were calculated for four resources (2.8 percent of all generation resources), all of which included an APIR component. The MMU calculated offer caps for 64 resources (45.3 percent), of which 57 were based on the technology specific default (proxy) ACR values. Of the 141 generation resources, 52 resources elected offer cap option of 1.1 times the BRA clearing price (36.9 percent), 5 planned generation resources had uncapped offers (3.5 percent), while the remaining 20 resources were price takers (14.3 percent), of which the offers for 18 resources were zero and the offers for two resources were set to zero because no data were submitted.

2012/2013 RPM Base Residual Auction

As shown in Table 5-12, 1,133 generation resources submitted offers in the 2012/2013 RPM Auction as compared to 1,125 generation resources offered in the 2011/2012 RPM Auction. Unit-specific offer caps were calculated for 120 resources (10.6 percent of all generation resources offered) including 118 resources (10.4 percent) with an APIR component and 2 resources (0.2 percent) without an APIR component. The MMU calculated offer caps for 607 resources (53.6 percent), of which 479 (42.3 percent) were based on the technology specific default (proxy) ACR values. Of the 1,125 generation resources, 11 planned generation resources had uncapped offers (1.0 percent), while the remaining 515 generation resources were price takers (45.5 percent), of which the offers for 512 resources were zero and the offers for three resources were set to zero because no data were submitted.[73]

Of the 1,133 generation resources which submitted offers, 118 (10.4 percent) included an APIR component (Table 5-12). As shown in Table 5-13, the weighted-average gross ACR for resources with APIR ($464.65 per MW-day) and the weighted-average offer caps, net of net revenues, for

73 Planned units are subject to mitigation under specific circumstances defined in the tariff. Some of the 11 uncapped planned units submitted zero price offers.

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resources with APIR ($167.62 per MW-day) were higher than for resources without an APIR component, including resources for which the default ACR value was selected. The APIR component added an average of $351.74 per MW-day to the ACR value of the APIR resources.[74] The default ACR values included an average APIR of $1.31 per MW-day. The highest APIR for a technology ($559.97 per MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($1,155.57 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2012/2013 ATSI Integration Auction

As shown in Table 5-12, 173 generation resources submitted offers in the 2012/2013 ATSI Integration Auction. Unit-specific offer caps were calculated for 12 resources (6.9 percent of all generation resources), all of which included an APIR component. The MMU calculated offer caps for 131 resources (75.7 percent), of which 117 were based on the technology specific default (proxy) ACR values. Of the 173 generation resources, 26 resources elected offer cap option of 1.1 times the BRA clearing price (15.0 percent), while the remaining 16 resources were price takers (9.3 percent), of which the offers for 13 resources were zero and the offers for three resources were set to zero because no data were submitted.

2012/2013 RPM First Incremental Auction

As shown in Table 5-12, 162 generation resources submitted offers in the 2012/2013 RPM First Incremental Auction. Unit-specific offer caps were calculated for 14 resources (8.6 percent of all generation resources), all of which included an APIR component. The MMU calculated offer caps for 108 resources (66.6 percent), of which 92 were based on the technology specific default (proxy) ACR values. Of the 162 generation resources, 17 planned generation resources had uncapped offers (10.5 percent), while the remaining 37 resources were price takers (22.9 percent), of which the offers for 24 resources were zero and the offers for 13 resources were set to zero because no data were submitted.

Of the 162 generation resources which submitted offers, 14 resources (8.6 percent) included an APIR component (Table 5-12). As shown in Table 5-13, the weighted-average gross ACR for resources with APIR ($367.75 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($229.59 per MW-day) were higher than for resources without an APIR component, including resources for which the default ACR value was selected. The APIR component added an average of $222.35 per MW-day to the ACR value of the APIR resources. The default ACR values included an average APIR of $1.31 per MW-day. The highest APIR for a technology ($459.80 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($549.57 per MW-day) was the maximum amount by which an offer cap was increased by APIR.

2013/2014 RPM Base Residual Auction

As shown in Table 5-12, 1,170 generation resources submitted offers compared to 1,133 generation resources offered in the 2012/2013 RPM Base Residual Auction. Unit-specific offer

74 The 118 units which had an APIR component submitted $567.2 million for capital projects associated with 11,124.8 MW of UCAP.

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caps were calculated for 107 resources (9.1 percent of all generation resources offered) including 92 resources (7.9 percent) with an Avoidable Project Investment Recovery Rate (APIR) component and 15 resources (1.3 percent) without an APIR component. The MMU calculated offer caps for 700 resources (59.9 percent), of which 587 (50.2 percent) were based on the technology specific default (proxy) ACR values. Of the 1,170 generation resources, 20 planned generation resources had uncapped offers (1.7 percent), while the remaining 450 generation resources were price takers (38.4 percent), of which the offers for 441 resources were zero and the offers for nine resources were set to zero because no data were submitted.[75]

Of the 1,170 generation resources which submitted offers, 92 (7.9 percent) included an APIR component (Table 5-12). As shown in Table 5-13, the weighted-average gross ACR for resources with APIR ($390.05 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($134.44 per MW-day) were higher than for resources without an APIR component, including resources for which the default ACR value was selected. The APIR component added an average of $268.59 per MW-day to the ACR value of the APIR resources.[76] The default ACR values included an average APIR of $1.37 per MW-day, which is the average APIR ($1.31 per MW-day) for the previously estimated default ACR values in the 2012/2013 BRA escalated using the most recent Handy-Whitman Index value. The highest APIR for a technology ($352.55 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($1,304.36 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

Market Performance

The RTO resource clearing price increased $72.25 per MW-day (70.8 percent) from $102.04 per MW-day for the 2009/2010 BRA to $174.29 per MW-day for the 2010/2011 BRA (Table 5-14).

Annual weighted average capacity prices increased from a 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. Figure 5-1 presents cleared MW weighted average capacity market prices on a calendar year basis for the entire history of the PJM capacity markets.

As Table 5-7 shows, RPM net excess decreased 537.5 MW from 8,265.5 MW on June 1, 2009, to 7,728.0 MW on June 1, 2010, because of a 2,251.0 MW increase in the reliability requirement and a 41.4 MW decrease in cleared capacity, offset by a 1,754.9 MW increase in ILR.[77] The increase in unforced capacity of 1,005.5 MW was the result of an increase in total internal capacity of 1,712.7 MW plus an increase in imports of 245.3 MW, offset by an increase in exports of 952.5 MW[78] (Table 5-2).

75 Planned units are subject to mitigation under specific conditions defined in the tariff. Some of the 20 uncapped planned units submitted zero price offers.

76 The 92 units which had an APIR component submitted $326.7 million for capital projects associated with 10,328.3 MW of UCAP.

77 Prior to the 2012/2013 delivery year, net excess under RPM was calculated as cleared capacity less the reliability requirement plus ILR. For 2007/2008 through 2010/2011, certified ILR was used in the calculation. Forecast ILR less FRR DR is used in the calculation when ILR was not certified and prior to 2011/2012 because PJM forecast ILR including FRR DR for the first four Base Residual Auctions. PJM forecast ILR excluding FRR DR for 2011/2012, so FRR DR is not subtracted in the calculation for 2011/2012. Net excess calculations for auctions prior to 2010/2011 were originally calculated as cleared capacity less the reliability requirement. For delivery years 2012/2013 and beyond, net excess under RPM is calculated as cleared capacity less the reliability requirement plus the Short-Term Resource Procurement Target.

78 Unforced capacity is defined as the UCAP value of iron in the ground plus the UCAP value of imports less the UCAP value of exports.

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Table 5-15 shows RPM revenue by resource type for all RPM auctions held to date with over $500 million for new/reactivated resources based on the unforced MW cleared and the resource clearing prices.

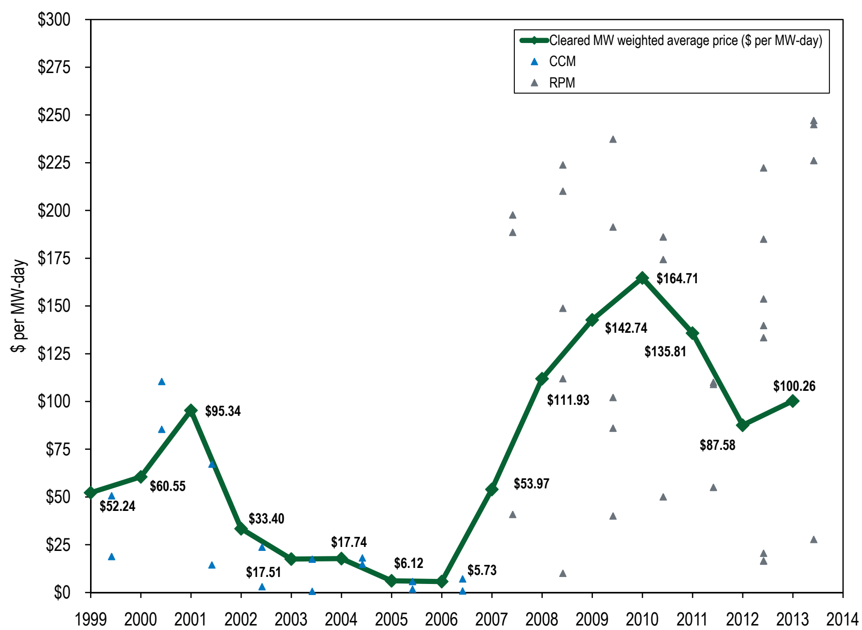
Table 5-14 Capacity prices: 2007/2008 through 2013/2014 RPM Auctions

	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 IA	$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 IA	$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 IA	$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 IA	$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
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 IA	$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 5-15 RPM revenue by type: 2007/2008 through 2013/2014[79,80]

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	$54,950,874	$262,109,171	$540,278,140	$1,024,222,184
Energy Efficiency Resources	$0	$0	$0	$0	$0	$11,155,913	$18,323,569	$29,479,482
Imports	$22,225,980	$60,918,903	$56,517,793	$106,046,871	$185,361,066	$13,115,246	$31,191,272	$475,377,131
Coal existing	$1,022,993,505	$1,845,819,870	$2,420,481,808	$2,662,434,386	$1,595,479,644	$1,015,782,743	$1,720,750,315	$12,283,742,271
Coal new/reactivated	$0	$0	$1,854,781	$3,168,069	$28,326,936	$7,413,749	$12,493,918	$53,257,453
Gas existing	$1,476,347,853	$1,970,649,854	$2,379,139,654	$2,684,798,328	$1,658,450,310	$1,148,404,128	$1,944,548,260	$13,262,338,388
Gas new/reactivated	$3,472,667	$9,751,112	$30,168,831	$58,065,964	$98,115,633	$75,945,518	$165,431,441	$440,951,166
Hydroelectric existing	$209,490,444	$287,850,403	$364,742,517	$442,429,815	$278,438,160	$178,866,339	$308,348,743	$2,070,166,420
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	$1,079,384,691	$761,838,276	$1,341,583,669	$8,818,475,460
Nuclear new/reactivated	$0	$0	$0	$0	$0	$0	$0	$0
Oil existing	$485,747,786	$511,428,579	$610,535,427	$570,678,904	$316,085,286	$353,422,286	$559,796,082	$3,407,694,349
Oil new/reactivated	$0	$4,837,523	$5,676,582	$4,339,539	$930,006	$2,772,987	$5,669,955	$24,226,592
Solid waste existing	$29,956,764	$33,843,188	$41,243,412	$40,731,606	$25,605,360	$26,835,364	$43,611,119	$241,826,814
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	$44,286	$944,720	$947,905	$1,936,911
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	$9,730,842	$3,771,957	$11,859,958	$50,348,808
Total	$4,252,287,381	$6,087,147,586	$7,503,218,157	$8,449,652,496	$5,332,237,713	$3,863,627,224	$6,708,567,045	$42,196,737,603

Figure 5-1 History of capacity prices: Calendar year 1999 through 2013[81,82]



79 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.

80 The results for the ATSI Integrations Auctions are not included in this table.

81 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.

82 The RPM weighted average prices were updated since the *2010 Quarterly State of the Market Report for PJM: January through September* to account for Make-Whole MW.

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Table 5-16 RPM cost to load: 2010/2011 through 2013/2014 RPM Auctions[83,84,85]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2010/2011 BRA			
RTO	$182.85	129,332.6	$8,631,690,057
DPL	$187.04	4,515.5	$308,271,379
2011/2012 BRA			
RTO	$110.04	133,815.3	$5,389,363,034
2012/2013 BRA			
RTO	$16.46	69,648.3	$418,440,022
MAAC	$129.63	31,338.7	$1,482,789,024
EMAAC	$135.18	21,171.5	$1,044,616,630
DPL	$162.99	4,685.6	$278,752,670
PSEG	$149.65	12,642.7	$690,572,720
2013/2014 BRA			
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

Table 5-16 shows the RPM annual charges to load. For the 2010/2011 planning year, annual charges totaled approximately $8.9 billion.

2010/2011 RPM Base Residual Auction

Cleared capacity resources across the entire RTO will receive a total of $8.4 billion based on the unforced MW cleared and the prices in the 2010/2011 BRA.

RTO

Table 5-17 shows total RTO offer data for the 2010/2011 RPM Base Residual Auction, including the DPL South LDA. Total internal RTO unforced capacity of 159,030.9 MW includes all generation resources and DR that qualified as a PJM capacity resource for the 2010/2011 RPM Base Residual Auction, excluding external units, and also includes owners' modifications to installed capacity

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

84 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.

85 Prior to the 2009/2010 delivery year, the Final UCAP Obligation is determined after the clearing of the Second IA. For the 2009/2010 through 2011/2012 delivery years, the Final UCAP Obligations are determined after the clearing of the Third IA. 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 and Obligation MW are not finalized.

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ratings which are permitted under the PJM Reliability Assurance Agreement (RAA) and associated manuals.[86,87]

After accounting for FRR committed resources and for imports, RPM capacity was 137,360.7 MW.[88] This amount was reduced by exports of 3,147.4 MW and 490.1 MW which were excused from the RPM must-offer requirement as a result of planned capacity retirements (275.9 MW), non-utility generator (NUG) ownership questions (166.2 MW), planned reductions due to environmental regulations (33.0 MW), and other factors (15.0 MW). Subtracting 630.5 MW of FRR optional volumes not offered, resulted in 133,092.7 MW that were available to be offered into the auction.[89] After accounting for the above, all capacity resources were offered into the RPM Auction. There were seven new CT units (270.5 MW), three new diesel resources (16.4 MW), and five new wind resources (120.0 MW) offered into the auction. Offered volumes included 1,034.9 MW of EFORd offer segments.[90]

The downward sloping demand curve resulted in more capacity cleared in the market than would have cleared with a vertical demand curve equal to the reliability requirement. The 132,190.4 MW of cleared resources for the entire RTO represented a reserve margin of 16.5 percent, resulted in net excess of 1,149.2 MW greater than the reliability requirement of 132,698.8 MW (IRM of 15.5 percent).[91,92,93] As shown in Figure 5-2, the downward sloping demand curve resulted in a resource clearing price of $174.29 per MW-day. Net excess decreased 537.5 MW from the net excess of 8,265.5 MW in the 2009/2010 RPM Base Residual Auction, because of a 2,251.0 MW increase in the reliability requirement and a 41.4 MW decrease in cleared capacity, offset by a 1,754.9 MW increase in ILR (Table 5-7). Certified ILR was 8,236.4 MW.

As shown in Table 5-17, the net load price that LSEs will pay is $182.85 per MW-day in the RTO area not included in the constrained LDAs. This value is the final zonal capacity price. Prior to the 2012/2013 delivery year, the final zonal capacity price is the resource-clearing price adjusted for differences between the certified ILR for the delivery year and the forecasted RTO ILR obligation.

86 See "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region" (June 1, 2007), Schedule 9.

87 See PJM. "Manual 21: Rules and Procedures for Determination of Generating Capability," Revision 09 (May 1, 2010).

88 The FRR alternative allows an LSE, subject to certain conditions, to avoid direct participation in the RPM Auctions. The LSE is required to submit an FRR capacity plan to satisfy the unforced capacity obligation for all load in its service area.

89 FRR entities are allowed to offer into the RPM Auction excess volumes above their FRR quantities, subject to a sales cap amount. The 630.5 MW are a combination of excess volumes included in the sales cap amount which were not offered into the auction and volumes above the sales cap amount which were not permitted to be offered into the auction.

90 The EFORd offer segment was eliminated on March 27, 2009. See 126 FERC ¶ 61,275 (2009) at P 170.

91 Prior to the 2012/2013 delivery year, net excess under RPM was calculated as cleared capacity less the reliability requirement plus ILR. For delivery years 2012/2013 and beyond, net excess under RPM is calculated as cleared capacity less the reliability requirement plus the Short-Term Resource Procurement Target.

92 The IRM increased from 15.0 percent to 15.5 percent for the 2010/2011 delivery year.

93 The demand curve UCAP quantities are based on three points, which are ratios of the installed reserve margin (IRM = 15.5 percent) times the reliability requirement, less the forecast RTO ILR obligation. For the three points, the ratios are 1.12/1.15, 1.16/1.15 and 1.20/1.15. For these three points the UCAP prices are based on factors multiplied by net Cost of New Entry (CONE) divided by one minus the pool-wide EFORd. Net CONE is defined as CONE minus the energy and ancillary service revenue offset (E&AS). For the three points, the factors are 1.5, 1.0 and 0.2. For 2010/2011, CONE was $197.83 per MW-day and E&AS was $34.36 MW-day.

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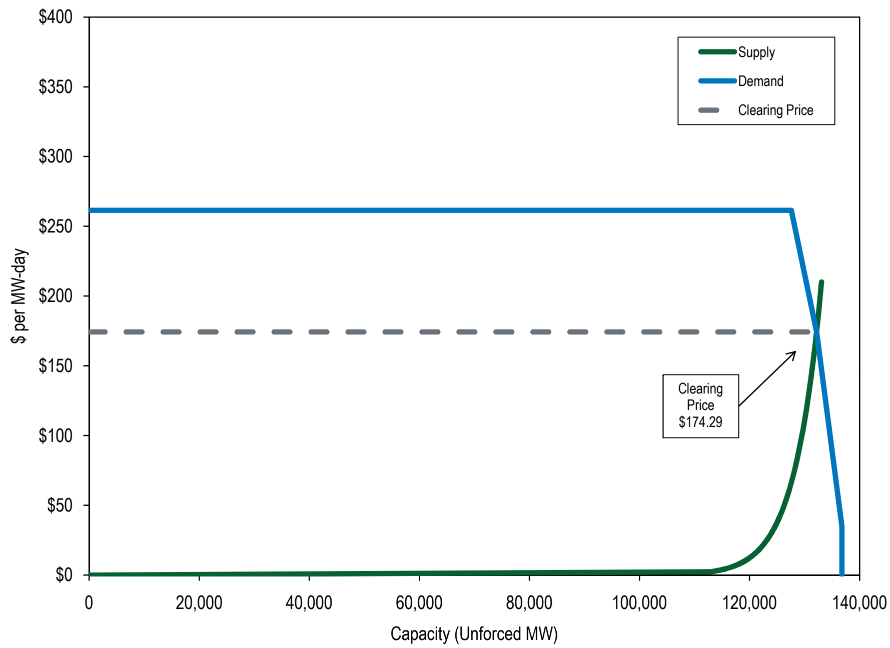
Table 5-17 RTO offer statistics: 2010/2011 RPM Base Residual Auction[94]

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total internal RTO capacity (gen and DR)	168,457.3	159,030.9		
FRR	(26,305.7)	(24,420.9)		
Imports	2,982.4	2,750.7		
RPM capacity	145,134.0	137,360.7		
Exports	(3,378.2)	(3,147.4)		
FRR optional	(744.5)	(630.5)		
Excused	(546.2)	(490.1)		
Available	140,465.1	133,092.7	100.0%	100.0%
Generation offered	139,529.5	132,124.8	99.3%	99.3%
DR offered	935.6	967.9	0.7%	0.7%
Total offered	140,465.1	133,092.7	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	139,253.9	132,190.4	99.1%	99.3%
Cleared in LDAs	0.0	0.0	0.0%	0.0%
Total cleared	139,253.9	132,190.4	99.1%	99.3%
Make-whole	0.0	0.0	0.0%	0.0%
Uncleared in RTO	1,184.5	875.9	0.9%	0.7%
Uncleared in LDAs	26.7	26.4	0.0%	0.0%
Total uncleared	1,211.2	902.3	0.9%	0.7%
Reliability requirement		132,698.8		
Total cleared plus make-whole		132,190.4		
ILR certified		8,236.4		
Net excess/(deficit)		7,728.0		
Resource clearing price ($ per MW-day)		$174.29	A	
Final zonal capacity price ($ per MW-day)		$182.85	B	
Final zonal CTR credit rate ($ per MW-day)		$0.00	C	
Final zonal ILR price ($ per MW-day)		$174.29	A-C	
Net load price ($ per MW-day)		$182.85	B-C	

94 Prices are only for those capacity resources outside of DPL South.

Figure 5-2 RTO market supply/demand curves: 2010/2011 RPM Base Residual Auction[95]



DPL South

Table 5-18 shows total DPL South offer data for the 2010/2011 RPM Base Residual Auction. Total internal DPL South unforced capacity of 1,546.1 MW includes all generation resources and DR that qualified as a PJM capacity resource, excluding external units, and also includes owners' modifications to ICAP ratings. All imports offered into the auction are modeled in the RTO, so total DPL South RPM unforced capacity was 1,546.1 MW.[96] All DPL South capacity resources were offered into the RPM Auction.

All of the 1,519.7 MW cleared in DPL South were cleared in the RTO before DPL South became constrained. Of the 26.4 MW of incremental supply, none cleared, because all 26.4 MW were priced above the demand curve. The DPL South resource clearing price was $186.12 per MW-day, as shown in Figure 5-3. The price was determined by the intersection of the demand curve and a vertical section of the supply curve.

Total resources in DPL South were 2,966.7 MW, which when combined with certified ILR of 97.2 MW resulted in a net excess of 14.5 MW (0.5 percent) greater than the reliability requirement of 3,049.4 MW.

95 The supply curve has been smoothed using a statistical technique that fits a smooth curve to the underlying supply curve 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 while the prices on the supply curve reflect the smoothing method. The demand curve excludes incremental demand which cleared in DPL South.

96 Rules for RPM auctions state that imports are modeled in the unconstrained region of the RTO. See PJM. "Manual 18: PJM Capacity Market," Revision 09 (June 1, 2010), p. 24.

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As shown in Table 5-18, the DPL zone net load price that LSEs will pay is $187.04 per MW-day. This value is the final zonal capacity price ($187.34 per MW-day) less the final CTR credit rate ($0.30 per MW-day). Prior to the 2012/2013 delivery year, the CTR MW value allocated to load in an LDA with a binding locational constraint is the Base Unforced Capacity imported into an LDA in the BRA for the delivery year less the import capability increase into the LDA attributable to Quality Transmission Upgrades (QTU) for the delivery year less the Incremental Capacity Transfer Rights that are allocated into the LDA for the delivery year, where the Base Unforced Capacity imported into an LDA is equal to the Base LDA UCAP obligation less the cleared unforced capacity in the BRA internal to the LDA less the ILR forecast for the LDA. This MW value is multiplied by the locational price adder for the LDA to arrive at the economic value of the CTRs allocated to the load in the LDA. This value is then divided by the LDA UCAP obligation to arrive at the final CTR credit rate for the LDA. The final CTR credit rate is an allocation of the economic value of transmission import capability that exists in constrained LDAs and serves to offset a portion of the locational price adder charged to load in constrained LDAs.

Table 5-18 DPL South offer statistics: 2010/2011 RPM Base Residual Auction[97]

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total internal DPL South capacity (gen and DR)	1,652.3	1,546.1		
Imports	0.0	0.0		
RPM capacity	1,652.3	1,546.1		
Exports	0.0	0.0		
Excused	0.0	0.0		
Available	1,652.3	1,546.1	100.0%	100.0%
Generation offered	1,637.1	1,530.4	99.1%	99.0%
DR offered	15.2	15.7	0.9%	1.0%
Total offered	1,652.3	1,546.1	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	1,625.6	1,519.7	98.4%	98.3%
Cleared in LDA	0.0	0.0	0.0%	0.0%
Total cleared	1,625.6	1,519.7	98.4%	98.3%
Make-whole	0.0	0.0	0.0%	0.0%
Uncleared	26.7	26.4	1.6%	1.7%
Reliability requirement		3,049.4		
Total cleared plus make-whole		1,519.7		
CETL		1,447.0		
Total resources		2,966.7		
ILR certified		97.2		
Net excess/(deficit)		14.5		
Resource clearing price ($ per MW-day)		$186.12		
DPL zone weighted average resource clearing price ($ per MW-day)		$178.57	A	
Final zonal capacity price ($ per MW-day)		$187.34	B	
Final zonal CTR credit rate ($ per MW-day)		$0.30	C	
Final zonal ILR price ($ per MW-day)		$178.27	A-C	
Net load price ($ per MW-day)		$187.04	B-C	

97 There is no separate zonal capacity price or CTR credit rate for DPL South as the DPL South LDA is completely contained within the DPL Zone.

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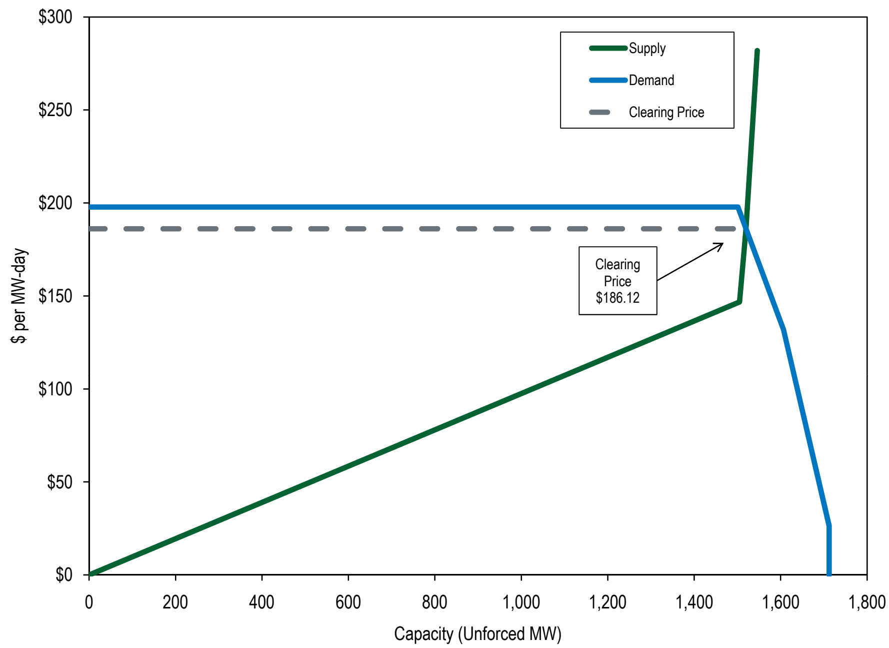
Figure 5-3 DPL South supply/demand curves: 2010/2011 RPM Base Residual Auction[98]



2010/2011 RPM Third Incremental Auction

Under RPM, prior to January 31, 2010, the Third Incremental Auction was held in January prior to the start of the delivery year, and effective January 31, 2010, the Third Incremental Auction is held in February prior to the start of the delivery year.

RTO

Table 5-19 shows total RTO offer and bid data for the 2010/2011 RPM Third Incremental Auction. There were 4,553.9 MW offered into the incremental auction while buy bids totaled 5,221.0 MW. The offered volumes came from uncleared internal generation offers from the 2010/2011 BRA (598.2 MW), new generation (176.2 MW), reactivated generation (127.7 MW), capacity modifications (cap mods) to existing generation resources (534.5 MW), additional UCAP due to improved EFORds since the BRA (1,425.5 MW), replacements (-264.0 MW), locational UCAP transactions (-135.6 MW), imports (395.2 MW), DR offers (1,451.6 MW) less a net change in FRR commitments (-401.4 MW), a net change in exports (-114.4 MW), a net change in unoffered MW in the 2010/2011 BRA (270.2 MW), and excused generation (1.0 MW). Buy bids were submitted to cover short positions due to deratings and EFORd increases or because participants wished to purchase additional capacity. Cleared volumes in the RTO were 1,845.8 MW, resulting in an RTO clearing price of $50.00 per MW-day. The RTO clearing price in the 2010/2011 BRA was $174.29 per MW-day. The 2,708.1 MW of uncleared volumes can be used as replacement volumes or traded bilaterally.

98 The supply curve has been smoothed using a statistical technique that fits a smooth curve to the underlying supply curve 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 while the prices on the supply curve reflect the smoothing method. The demand curve is reduced by the CETL.

Although DPL South was constrained in the 2010/2011 BRA, supply offers in the incremental auction in DPL South (56.8 MW) exceeded DPL South demand bids (25.9 MW). The offered volumes came from uncleared internal generation offers from the 2010/2011 BRA (25.6 MW), capacity modifications (cap mods) to existing generation resources (-2.2 MW), additional UCAP due to improved EFORds since the BRA (34.0 MW), and replacements (-0.6 MW). Supply and demand curves resulted in a price less than the RTO clearing price. The result was that all of DPL South supply which cleared received the RTO clearing price.

Cleared capacity resources across the entire RTO will receive a total of $33.7 million based on the unforced MW cleared and the prices in the 2010/2011 RPM Third Incremental Auction.

Table 5-19 RTO offer statistics: 2010/2011 RPM Third Incremental Auction

	Offered (Supply)		Bid (Demand)
	ICAP (MW)	UCAP (MW)	UCAP (MW)
Generation	3,274.3	3,102.3	
DR	1,402.9	1,451.6	
Total	4,677.2	4,553.9	5,221.0
Cleared in RTO	1,947.6	1,845.8	1,845.8
Cleared in LDAs	0.0	0.0	0.0
Total cleared	1,947.6	1,845.8	1,845.8
Uncleared in RTO	2,729.6	2,708.1	3,375.2
Uncleared in LDAs	0.0	0.0	0.0
Total uncleared	2,729.6	2,708.1	3,375.2
Resource clearing price ($ per MW-day)		$50.00	

Incremental Auction Design

Prior to the 2012/2013 delivery year, the First and Third Incremental Auctions are conducted to allow capacity resource providers to buy and sell capacity to accommodate adjustments to resource positions as a result of capacity and DR modifications to existing capacity resources, new capacity resources, resource retirements, resource cancellations or delays, changes in a generation resource's equivalent demand forced outage rate (EFORd), or cancellations or delays of a Qualifying Transmission Upgrade. For the 2012/2013 delivery year and beyond, Incremental Auctions are conducted to allow for replacement resource procurement, procurement or release of capacity due to reliability requirement adjustments, and deferred Short-Term Resource Procurement. Prior to the 2012/2013 delivery year, the demand curve in the Third Incremental Auction is entirely a function of resource provider demand bids, and there is no administrative market demand curve. Effective with the 2012/2013 delivery year, the demand curves in the First, Second, and Third Incremental Auctions may be comprised of

- buy bids submitted by participants;

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- a portion of the Updated VRR Curve Increment to procure capacity equal to the Short-Term Resource Procurement Applicable Share (STRPTAS) plus the increase in the reliability requirement, if the PJM or LDA reliability requirement increases from the most recent prior auction conducted for the delivery year by more than the lesser of 500 MW or one percent of the applicable prior reliability requirement for First and Second Incremental Auctions and by a threshold of zero for Third Incremental Auctions;

- a portion of the Updated VRR Curve Increment to procure capacity equal to the STRPTAS plus the decrease in the reliability requirement if the PJM or LDA reliability requirement decreases by more than the lesser of 500 MW or one percent of the applicable prior reliability requirement for First and Second Incremental Auctions and by a threshold of zero for Third Incremental Auctions and the decrease in the reliability requirement exceeds the STRPTAS; or

- the entire Updated VRR Curve Increment if the updated PJM or LDA reliability requirement less the Short-Term Resource Procurement Target used in the most recent auction conducted for the delivery year exceeds the total capacity committed in all prior auctions for the delivery year by an amount greater than or equal to the lesser of 500 MW or one percent of the applicable prior reliability requirement.[99,100]

The STRPTAS is equal to 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for First and Second Incremental Auctions and 0.6 times the Short-Term Resource Procurement Target used in the Base Residual Auction for Third Incremental Auctions. The Updated VRR Curve Increment is the portion of the Updated VRR Curve, updated to reflect the Short-term Resource Procurement Target applicable to the relevant Incremental Auction and any change in the Reliability Requirement, to the right of the vertical line at the level of unforced capacity (UCAP) commitments for the delivery year. Prior to the 2012/2013 delivery year, supply curves in RPM Incremental Auctions are entirely a function of participant sell offers. Effective with the 2012/2013 delivery year, the supply curves in the First, Second, and Third Incremental Auction may be comprised of

- sell offers submitted by participants;

- or a portion of the Updated VRR Curve Decrement to procure capacity equal to the STRPTAS plus the decrease in the reliability requirement if the PJM or LDA reliability requirement decreases from the most recent prior auction conducted for the delivery year by more than the lesser of 500 MW or one percent of the applicable prior reliability requirement or First and Second Incremental Auctions and a threshold of zero for Third Incremental Auctions and the decrease in the reliability requirement exceeds the STRPTAS.

The Updated VRR Curve Decrement is the portion of the Updated VRR Curve, updated to reflect the Short-term Resource Procurement Target applicable to the relevant Incremental Auction and any change in the Reliability Requirement, to the left of the vertical line at the level of unforced capacity commitments for the delivery year.

99 For the rules relating to the tests used to determine if PJM must procure or release capacity, see OATT Attachment DD: Reliability Pricing Model, § 5.4 (c).

100 For the rules used to determine the MW quantities and prices of PJM buy bids and sell offers, see OATT Attachment DD: Reliability Pricing Model, § 5.12 (b).

Reliability Must Run Units

Part V of the PJM Tariff provides for reliability and market power analyses of power plants proposed for deactivation.[101] An owner may deactivate, meaning either a retirement or mothball, with 90 days notice.[102] PJM performs a reliability analysis to determine whether deactivation would "adversely affect the reliability of the Transmission System absent upgrades," and, if it identified an adverse effect, "an estimate of the … time it will take to complete the … upgrades ..."[103] The MMU analyzes the "effect of the proposed deactivation with regard to market power issues."[104] If PJM determines that a unit is needed for reliability, it would request that the unit provide reliability must run (RMR) service.[105]

The tariff does not require owners to provide RMR service. An owner that agrees to provide RMR service may collect its costs under a formula rate provided in Part V.[106] This rate accounts for "deactivation avoidable costs."[107] An owner may, in the alternative, file with FERC to "recover the entire cost of operating the generating unit."[108]

RMR Service represents a period of post market operations for a unit. During the prior period of market operations, the owner has invested in, maintained and marketed the unit and has obtained the best return it could through a market design that is regulated through competition. Under regulation through competition, the owner does not have to show that its profits are justified by the costs incurred, but it also bears the risks to recover its costs. RMR service is a consequence of the owner's decision to exit the market when it makes a determination that the unit is no longer economic but the system operator, PJM, has determined that continued service is needed for reliability. Ratepayers and not the owner appropriately bear all of the additional costs that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. The entire cost of any additional investment necessary to continue operating during the period of RMR service is appropriately borne by ratepayers. Those costs include a return on and of any additional capital investment required to fulfill the RMR agreement and approved by PJM. Ratepayers should not bear any of the costs incurred that preceded the decision to retire. Those costs were incurred by the owner based on the owner's full responsibility for the consequences. The owner was entitled to any level of profits that investment generated and it also bore the risk of a disappointing return or even a loss. RMR service is not a reason to undo the prior terms of service.

In 2010, PJM and the MMU evaluated 12 proposed deactivations. These included: AEP – Sporn 5; AMP – Gorsuch; Dominion – Altavista (Hall Branch); Dominion – Chesapeake GT 7; Dominion – North Branch; Exelon – Cromby Diesel 98; Exelon – Cromby Unit No. 2; Exelon – Eddystone Unit No. 2; First Energy – RE Berger 4&5; Ingenco – Petersburg; MM Hackensack – Baleville and Kingsland; NRG – Indian River 3; and VMEU – Vineland 9.[109]

101 OATT § 113.2.
102 OATT § 113.1.
103 OATT § 113.2.
104 OATT § Attachment M–Appendix § IV.1.
105 OATT § 113.2.
106 OATT §§ 114, 115.
107 *Id.*
108 OATT § 113.2, 119.
109 In addition, PJM evaluated the deactivation request for Ingenco – Richmond.

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On December 9, 2009, Exelon Generation Company notified PJM of its intent to retire its Cromby Unit No. 2 (Cromby) and Eddystone Unit No. 2 (Eddystone), effective May 31, 2011. The MMU determined that the proposal did not raise market power issues. PJM determined that the units would be needed until December 31, 2011, (Cromby) and December 31, 2012, (Eddystone), in order to provide time for the system to add upgrades necessary to accommodate the retirements.

Exelon agreed to provide RMR service and determined to file for the recovery of its RMR costs directly with the FERC under section 119 of the PJM tariff.[110] In pleadings filed on July 15, August 13 and September 13, 2010, the MMU argued to the FERC that the filing was deficient, particularly with respect to the support offered for the proposed treatment of depreciated capital investment costs, and requested that the FERC institute a process to consider the issue.[111] The MMU explained that it appeared that Exelon Generation proposed to fully recover during the period of RMR service investment costs made prior to the decision to retire. By order issued September 16, 2010, the Commission set the matter for hearing, but held the hearing in abeyance pending settlement discussions.[112] The MMU, Exelon Generation Company, FERC trial staff, public advocates and consumer representatives have actively participated in settlement discussion, and the Settlement Judge reported on December 15, 2010, that the parties "have reached a settlement in principle."[113]

The Exelon proceeding raises questions about whether PJM has a consistent and fair approach to RMR service. An initial question is whether it is appropriate for RMR service to be voluntary, even if, as a practical matter, owners have been cooperative with PJM about extending service to accommodate reliability needs. All stakeholders have a shared interest in reliability, and it should not impose any hardship on generator owners if their costs are fully covered during the RMR period of service. An obligation to provide RMR service could be reasonably conceived as a term and condition of receiving interconnection service in an organized wholesale market.

Another issue is the appropriate treatment of costs in RMR filings. Sections 114 and 115 of the PJM tariff unambiguously limit recovery to "avoidable costs." Perhaps as a consequence, owners have to date sought recovery directly from the FERC under section 119 of the OATT.[114] This section refers to collecting the "entire cost of operating the generating unit." Avoidable costs means costs that would not have been incurred but for continued operation of the unit. Some have read the phrase "entire cost of operating the generating unit" as a justification for recovery of pre-notification sunk fixed costs in addition to avoidable costs.

Ambiguity about what costs are eligible for recovery has encouraged owners to file to recover all of their depreciated costs during what is typically a relatively short period of RMR service. The Market Monitor is concerned about the implications of this approach. Owners should not be permitted to transfer risks assumed while participating in competitive markets simply because the system is not ready to accommodate a retirement proposed with as little as 90 days notice. If this were permitted, RMR service could become a stratagem for depriving customers of one the key benefits of restructuring, the shifting of investment risks to suppliers and away from ratepayers. To date, the

110 See Exelon Generation Company, LLC filing in FERC Docket No. ER10-1418 (June 10, 2010).

111 "Comments and Motion for Technical Conference of the Independent Market Monitor for PJM," "Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM," "Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM [2nd]," filed in Docket No. ER10-1418.

112 132 FERC ¶ 61,219.

113 Settlement Status Report, Judge Birchman, Docket No. ER10-1418.

114 See Hudson Unit No. 1 and Sewaren Units Nos. 1–4 (Docket No. ER05-644), Brunot Island Units Nos. CT2A, CT2B, CT3 and CC4 (ER07-859).

number of retirements has been manageable, but there is the potential for a significant increase in retirements.

The MMU recommends that the two approaches to RMR cost recovery included in the current rules be clarified and made consistent. The theory of recovery should be same under either approach, and it should be based on avoidable costs. Units needed for RMR service have market power because only the identified unit(s) can provide the required reliability.

Generator Performance

Generator performance results from the interaction between the physical characteristics of the units and the level of expenditures made to maintain the capability of the units, which in turn is a function of incentives from energy, ancillary services and capacity markets. Generator performance can be measured using indices calculated from historical data. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on hours when units are needed to operate by the system operator (generator forced outage rates).[115]

Generator Performance Factors

Generator performance factors are based on a defined period, usually a year, and are directly comparable.[116] Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

The PJM aggregate EAF decreased from 85.7 percent in 2009 to 84.8 percent in 2010. The EMOF increased from 2.8 percent in 2009 to 2.9 percent in 2010, the EPOF increased from 6.7 percent in 2009 to 7.4 percent in 2010, and the EFOF increased from 4.8 percent in 2009 to 4.9 percent in 2010 (Figure 5-4).[117]

115 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM GADS database. This set of capacity resources may include generators in addition to those in the set of generators committed as resources in the RPM.

116 Data from all PJM capacity resources for the years 2007 through 2010 were analyzed.

117 Data are for the calendar year ending December 31, 2010, as downloaded from the PJM GADS database on January 21, 2011. Annual 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.

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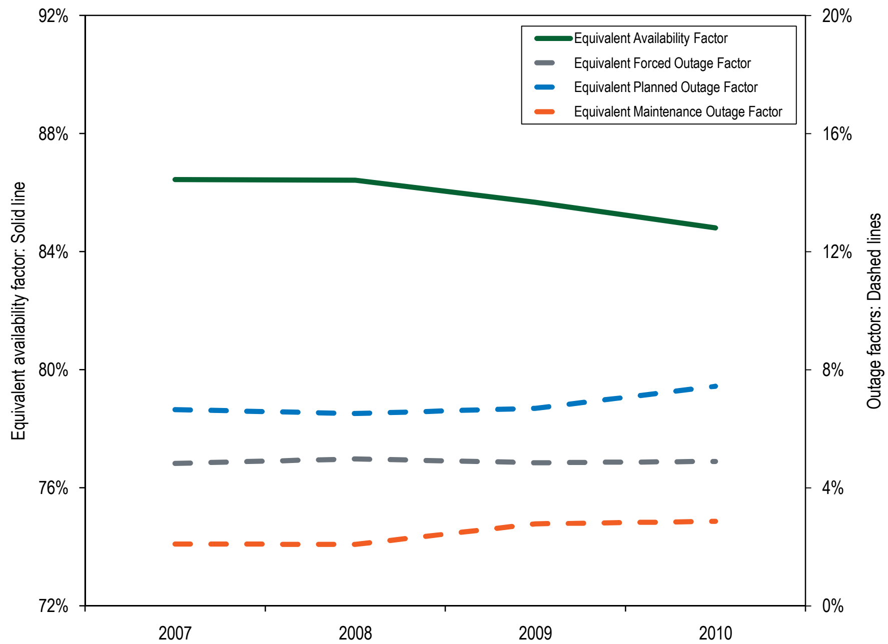
Figure 5-4 PJM equivalent outage and availability factors: Calendar years 2007 to 2010



Generator Forced Outage Rates

The equivalent demand forced outage rate (EFORd) (generally referred to as the forced outage rate) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd is calculated using historical performance data. PJM systemwide EFORd is a capacity-weighted average of individual unit EFORd. Unforced capacity in the PJM Capacity Market for any individual generating unit is equal to one minus the EFORd adjusted to exclude Outside Management Control (OMC) events multiplied by the unit's net dependable summer capability.[118] The PJM Capacity Market creates an incentive to minimize the forced outage rate because the amount of capacity resources available to sell from a unit (unforced capacity) is inversely related to the forced outage rate.

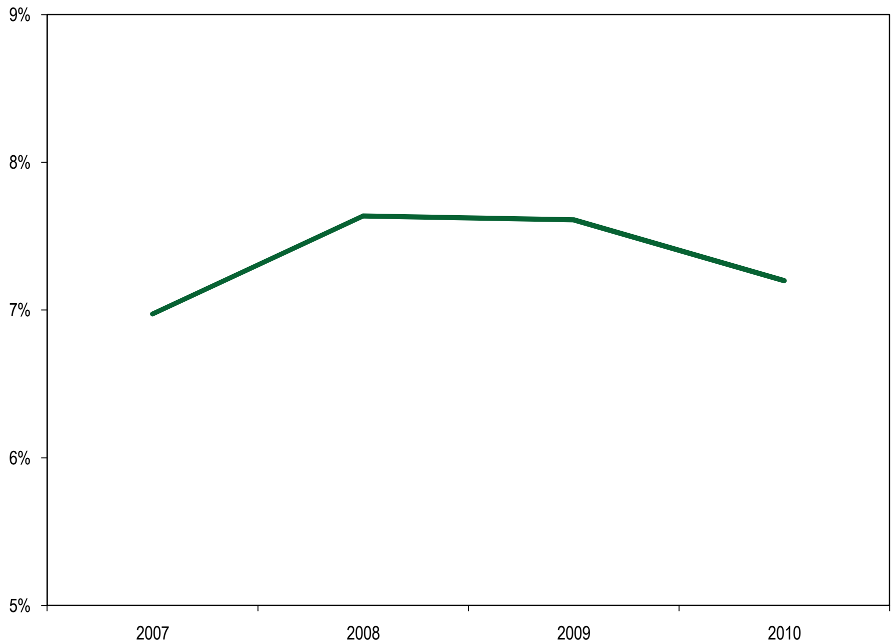
EFORd calculations use historical data, including equivalent forced outage hours,[119] service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[120] The average PJM EFORd changed from 7.0 percent in 2007 to 7.6 percent in 2008 and 2009 to 7.2 percent in 2010. Figure 5-4 shows the average EFORd since 2007 for all units in PJM. The decreases in both EFORd and EAF in 2010 are consistent. EAF decreased as a result of the increase in EPOF, the EMOF and the EFOF. EFORd, on the other hand, describes the forced outage rate during periods of demand, which is a subset of the hours included in EFOF and does not include planned or maintenance outages.

118 EFORd adjusted to exclude Outside Management Control (OMC) events is defined as XEFORd.

119 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable prorated to represent full hours.

120 See "Manual 22: Generator Resource Performance Indices," Revision 15 (June 1, 2007), Equations 2 through 5.

Figure 5-5 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2007 to 2010



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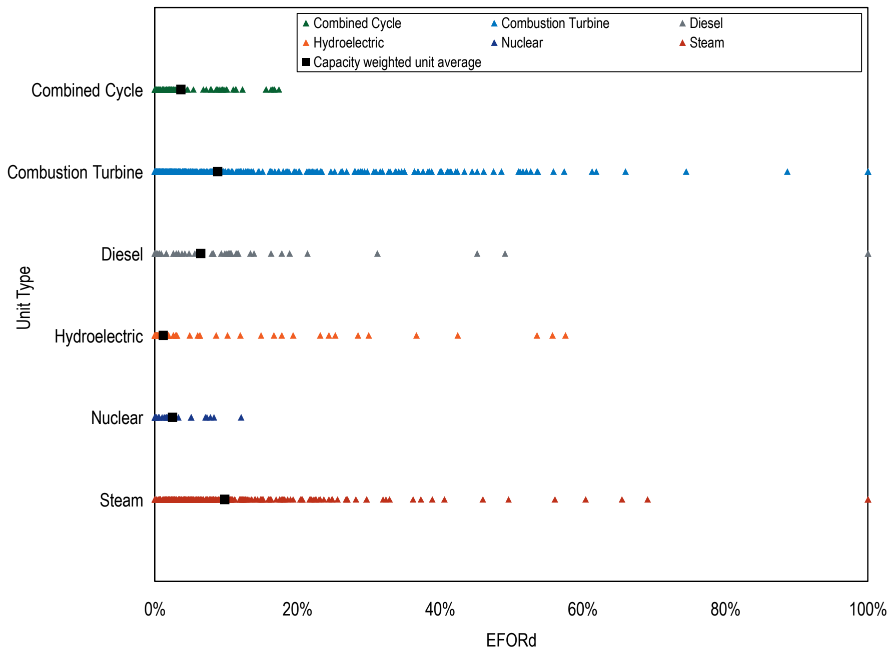
Distribution of EFORd

The average EFORd results do not show the underlying pattern of EFORd rates by unit type. The distribution of EFORd by unit type is shown in Figure 5-6. Each generating unit is represented by a single point, and the capacity weighted unit average is represented by a solid square. Diesel and combustion turbine units have the greatest variance of EFORd, while nuclear and combined cycle units have the lowest variance in EFORd values.

Figure 5-6 PJM 2010 Distribution of EFORd data by unit type



Components of EFORd

Table 5-20 compares PJM EFORd data by unit type to the five-year North American Electric Reliability Council (NERC) average EFORd data for corresponding unit types. The 2010 PJM forced outage rates for combined cycle, combustion turbine, diesel, hydroelectric and nuclear units were below the NERC five-year averages. The 2010 PJM EFORd for fossil steam units exceeded the NERC average.[121]

Table 5-20 PJM EFORd data comparison to NERC five-year average for different unit types: Calendar years 2007 to 2010

	2007	2008	2009	2010	NERC EFORd 2005 to 2009 Average
Combined Cycle	3.7%	3.8%	4.2%	3.7%	5.9%
Combustion Turbine	11.0%	11.1%	9.9%	8.8%	9.1%/8.9%
Diesel	11.9%	10.4%	9.3%	6.5%	13.0%
Hydroelectric	2.1%	2.0%	3.1%	1.2%	5.0%
Nuclear	1.4%	1.9%	4.1%	2.5%	3.1%
Steam	9.1%	10.1%	9.4%	9.8%	7.2%
Total	7.0%	7.6%	7.6%	7.2%	NA

Table 5-21 shows the contribution of each unit type to the system EFORd, calculated as the total forced MW for the unit type divided by the total capacity of the system.[122] Forced MW for a unit type is the EFORd multiplied by the generator's net dependable summer capability.

Table 5-21 Contribution to EFORd for specific unit types (Percentage points): Calendar years 2007 to 2010[123]

	2007	2008	2009	2010	Change in 2010 from 2009
Combined Cycle	0.4	0.5	0.5	0.4	(0.0)
Combustion Turbine	1.7	1.7	1.6	1.4	(0.2)
Diesel	0.0	0.0	0.0	0.0	(0.0)
Hydroelectric	0.1	0.1	0.1	0.0	(0.1)
Nuclear	0.3	0.4	0.8	0.5	(0.3)
Steam	4.4	5.0	4.7	4.8	0.2
Total	7.0	7.6	7.6	7.2	(0.4)

Steam units continue to be the largest contributor to overall PJM EFORd.

121 NERC defines combustion turbines in two categories: jet engines and gas turbines. The EFORd for the 2005 to 2009 period are 9.1 percent for jet engines and 8.9 percent for gas turbines per NERC's GADS "2005-2009 Generating Availability Report" <http://www.nerc.com/files/gar2009.zip> (2.58 MB). Also, the NERC average for fossil steam units is a unit-year-weighted value for all units reporting. The PJM values are weighted by capability for each calendar year.

122 The generating unit types are: combined cycle, combustion turbine, diesel, hydroelectric, nuclear and steam. For all tables, run of river and pumped storage hydroelectric are combined into a single hydroelectric category.

123 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.

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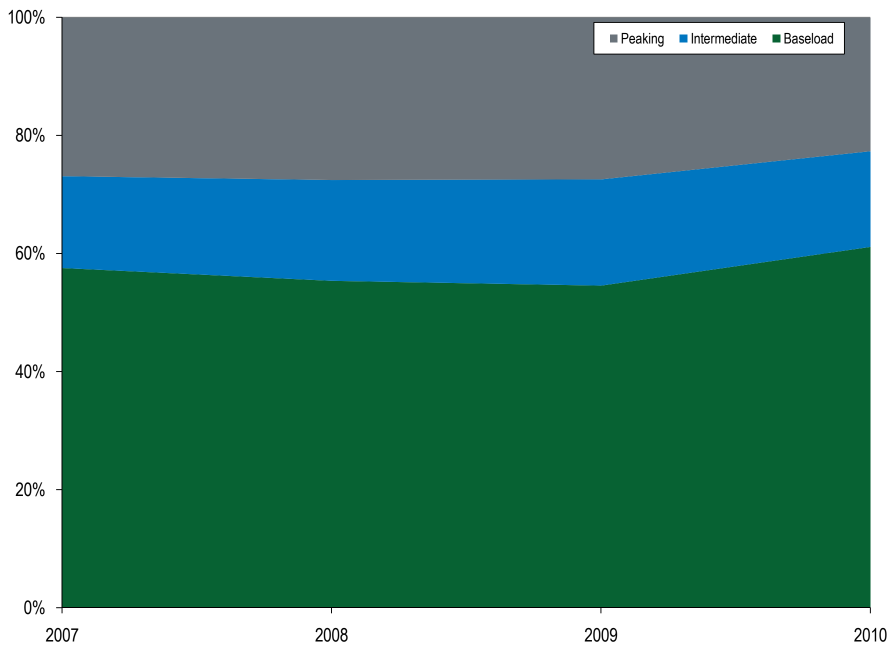
Duty Cycle and EFORd

In addition to disaggregating system EFORd by unit type, units were categorized by actual duty cycles as baseload, intermediate or peaking to determine the relationship between type of operation and forced outage rates.[124] Figure 5-7 shows the contribution of unit types to system average EFORd. Total capacity in 2010 consists of 68.4 percent baseload capacity, 14.2 percent intermediate capacity, and 17.4 percent peak capacity.

Figure 5-7 Contribution to EFORd by duty cycle: Calendar years 2007 to 2010



Forced Outage Analysis

The MMU analyzed the causes of forced outages for the entire PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[125] On a systemwide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor.

2010 PJM EFOF was 4.9 percent. This means there was 4.9 percent lost availability because of forced outages. Table 5-22 shows that forced outages for boiler tube leaks, at 22.9 percent of the systemwide EFOF, were the largest single contributor to EFOF. Forced outages for economic

124 Duty cycle is the time the unit is generating divided by the time the unit is available to generate. A baseload unit is defined here as a unit that generates during 50 percent or more of its available hours. An intermediate unit is defined here as a unit that generates during from 10 percent to 50 percent of its available hours. A peaking unit is defined here as a unit that generates during less than 10 percent of its available hours.

125 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a systemwide basis.

reasons, at 8.9 percent, were the second largest contributor to EFOF. Forced outages for electrical problems, at 6.6 percent, were the third largest contributor to EFOF.

Table 5-22 Contribution to EFOF by unit type by cause: Calendar year 2010

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	0.4%	0.0%	0.0%	0.0%	0.0%	29.2%	22.9%
Economic	1.7%	16.8%	9.6%	13.5%	0.0%	9.8%	8.9%
Electrical	8.7%	37.9%	3.3%	12.0%	10.6%	3.5%	6.6%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	7.2%	5.6%
Boiler Internals and Structures	0.5%	0.0%	0.0%	0.0%	0.0%	4.8%	3.8%
Boiler Fuel Supply from Bunkers to Boiler	0.0%	0.0%	0.0%	0.0%	0.0%	4.4%	3.4%
Feedwater System	2.8%	0.0%	0.0%	0.0%	6.6%	3.1%	3.2%
Circulating Water Systems	1.4%	0.0%	0.0%	0.0%	12.8%	2.0%	2.8%
Miscellaneous (Steam Turbine)	3.4%	0.0%	0.0%	0.0%	0.4%	3.0%	2.6%
Catastrophe	0.3%	0.5%	2.1%	7.6%	0.0%	2.7%	2.2%
Condensing System	1.1%	0.0%	0.0%	0.0%	7.4%	1.8%	2.1%
Fuel Quality	0.1%	0.0%	0.7%	0.0%	0.0%	2.4%	1.9%
Boiler Piping System	3.4%	0.0%	0.0%	0.0%	0.0%	2.1%	1.8%
Controls	2.5%	0.8%	0.9%	3.5%	5.7%	1.4%	1.8%
Stack Emission	0.0%	0.1%	0.2%	0.0%	0.0%	2.3%	1.8%
Boiler Tube Fireside Slagging or Fouling	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%	1.5%
Auxiliary Systems	2.3%	4.2%	0.0%	0.9%	7.6%	0.4%	1.4%
Miscellaneous (Balance of Plant)	3.6%	1.6%	0.0%	6.7%	2.0%	1.1%	1.4%
Inlet Air System and Compressors	13.8%	5.9%	0.0%	0.0%	0.0%	0.0%	1.2%
All Other Causes	54.1%	32.3%	83.1%	55.7%	46.9%	16.9%	23.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-23 shows the categories which are included in the economic category.[126] Lack of fuel that is considered Outside Management Control accounted for 78.0 percent of all economic reasons while lack of fuel that was not Outside Management Control accounted for only 4.7 percent.

OMC Lack of fuel is described as "Lack of fuel where the operator is not in control of contracts, supply lines, or delivery of fuels"[127] and was used by 28 combined cycle, combustion turbine and steam units in 2010. Only a handful of units use other economic problems to describe outages. Other economic problems are not defined by NERC GADS and are best described as economic problems that cannot be classified by the other NERC GADS economic problem cause codes. Lack of water events occur when a hydroelectric plant does not have sufficient fuel (water) to operate.

126 The classification and definitions of these outages are defined by NERC GADS.
127 The classification and definitions of these outages are defined by NERC GADS.

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Table 5-23 Contributions to Economic Outages: 2010

	Contribution to Economic Reasons
Lack of fuel (OMC)	78.0%
Other economic problems	16.1%
Lack of fuel (Non-OMC)	4.7%
Lack of water (Hydro)	0.9%
Fuel conservation	0.3%
Ground water or other water supply problems	0.0%
Total	100.0%

Table 5-24 Contribution to EFOF by unit type: Calendar year 2010

	EFOF	Contribution to EFOF
Combined Cycle	2.6%	6.4%
Combustion Turbine	1.9%	6.0%
Diesel	4.5%	0.2%
Hydroelectric	0.7%	0.6%
Nuclear	2.3%	8.5%
Steam	7.7%	78.4%
Total	4.9%	100.0%

The contribution to systemwide EFOF by a generator or group of generators is a function of duty cycle, EFORd and share of the systemwide capacity mix. For example, fossil steam units had the largest share (49.4 percent) of PJM capacity, had a high duty cycle and in 2010 had an EFORd of 9.8 percent which yields a 78.4 percent contribution to PJM systemwide EFOF. Nuclear units had an 18.4 percent share of PJM capacity, had a high duty cycle, and in 2010 had an EFORd of 2.5 percent which yields an 8.5 percent contribution to PJM systemwide EFOF. Using the values in Table 5-24 the contribution of individual unit type causes to PJM systemwide EFOF can be determined. For example, the value for boiler tube leaks in Table 5-22 multiplied by the contribution value in Table 5-24 for the same unit type will yield the percent contribution to the EFOF for that outage cause. Boiler tube leaks contributed 29.2 percent of the EFOF for steam units, total EFOF for steam units was 7.7 percent, which means that boiler tube leaks account for 1.4 percentage points of the 7.7 percent steam unit EFOF.

Outages Deemed Outside Management Control

In 2006, NERC created specifications for certain types of outages to be deemed Outside Management Control (OMC).[128] An outage can be classified as an OMC outage only if the outage meets the requirements outlined in Appendix K of the "Generator Availability Data System Data Reporting Instructions." Appendix K of the "Generator Availability Data Systems Data Reporting Instructions" also lists specific cause codes (i.e., codes that are standardized for specific outage causes) that would be considered OMC outages.[129] Not all outages caused by the factors in these specific OMC cause codes are OMC outages. For example, fuel quality issues (i.e., codes 9200 to 9299) may be within the control of the owner or outside management control. Each outage must be considered per the NERC directive.

All outages, including OMC outages, are included in the EFORd that is used for planning studies that determine the reserve requirement. However, OMC outages are excluded from the calculations used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market. This modified EFORd is termed the XEFORd.

Table 5-25 shows OMC forced outages by cause code. OMC forced outages account for approximately 10.6 percent of all forced outages. The largest contributor to OMC outages, lack of fuel, is the cause of 65.6 percent of OMC outages and 6.9 percent of all forced outages. The NERC GADS guidelines in Appendix K describe OMC lack of fuel as "lack of fuel where the operator is not in control of contracts, supply lines, or delivery of fuels." Of the OMC lack of fuel outages in 2010, 98.8 percent of the outages were submitted by units operated by a single owner.

It is questionable whether the OMC outages defined as lack of fuel should be identified as OMC and excluded from the calculation of XEFORd and EFORp. All submitted OMC outages are reviewed by PJM's Resource Adequacy Department. The MMU recommends that PJM review all requests for OMC carefully, develop a transparent set of rules governing the designation of outages as OMC and post those guidelines. The MMU also recommends that PJM consider eliminating lack of fuel as an acceptable basis for an OMC outage.

128 Generator Availability Data System Data Reporting Instructions states"The electric industry in Europe and other parts of the world has made a change to examine losses of generation caused by problems with and outside plant management control… There are a number of outage causes that may prevent the energy coming from a power generating plant from reaching the customer. Some causes are due to the plant operation and equipment while others are outside plant management control. The standard sets a boundary on the generator side of the power station for the determination of equipment outside management control." The Generator Availability Data System Data Reporting Instructions can be found on the NERC website: <http://www.nerc.com/files/2009_GADS_DRI_Complete_SetVersion_010111.pdf> (4.9 MB).

129 For a list of these cause codes, see the *Technical Reference for PJM Markets,* Section 2, "Capacity Market."

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Table 5-25 OMC Outages: Calendar year 2010

OMC Cause Code	% of OMC Forced Outages	% of all Forced Outages
Lack of fuel	65.6%	6.9%
Flood	11.9%	1.3%
Other catastrophe	8.2%	0.9%
Switchyard circuit breakers external	3.9%	0.4%
Transmission equipment beyond the 1st substation	3.2%	0.3%
Other switchyard equipment external	1.6%	0.2%
Switchyard system protection devices external	1.5%	0.2%
Transmission system problems other than catastrophes	1.3%	0.1%
Lack of water (hydro)	0.7%	0.1%
Other miscellaneous external problems	0.6%	0.1%
Lightning	0.6%	0.1%
Storms (ice, snow, etc)	0.3%	0.0%
Transmission line (connected to powerhouse switchyard to 1st Substation)	0.1%	0.0%
Fire, not related to a specific component	0.1%	0.0%
Low BTU coal	0.1%	0.0%
Switchyard transformers and associated cooling systems external	0.0%	0.0%
Transmission equipment at the 1st substation	0.0%	0.0%
Miscellaneous regulatory	0.0%	0.0%
Total	100.0%	10.6%

Table 5-26 shows the impact of OMC outages on EFORd for 2010. The difference is especially noticeable for steam units and combustion turbine units. For steam units, the OMC outage reason that resulted in the highest total MW loss in 2010 was lack of fuel. Combustion turbine units have natural gas fuel curtailment outages that were also classified as OMC. If companies' natural gas fuel supply is curtailed because of pipeline issues, the event can be deemed OMC. However, natural gas curtailments caused by lack of firm transportation contracts or arbitraging transportation reservations should not be classified as OMC. In 2010, steam XEFORd was 1.3 percentage points less than EFORd, which translates into a 1,085 MW difference in unforced capacity.

Table 5-26 PJM EFORd vs. XEFORd: Calendar year 2010

	2010 EFORd	2010 XEFORd	Difference
Combined Cycle	3.7%	3.5%	0.1%
Combustion Turbine	8.8%	6.9%	1.9%
Diesel	6.5%	4.5%	2.0%
Hydroelectric	1.2%	0.9%	0.3%
Nuclear	2.5%	2.5%	0.0%
Steam	9.8%	8.5%	1.3%
Total	7.2%	6.2%	1.0%

Components of EFORp

The equivalent forced outage rate during peak hours (EFORp) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate during the peak hours of the day in the peak months of January, February, June, July and August. EFORp is calculated using historical performance data and is designed to measure if a unit would have run had the unit not been forced out. Like XEFORd, EFORp excludes OMC outages. PJM systemwide EFORp is a capacity-weighted average of individual unit EFORp.

Table 5-27 shows the contribution of each unit type to the system EFORp, calculated as the total forced MW for the unit type divided by the total capacity of the system. Forced MW for a unit type is the EFORp multiplied by the generator's net dependable summer capability.

Table 5-27 Contribution to EFORp by unit type (Percentage points): Calendar years 2009 to 2010

	2009	2010
Combined Cycle	0.4	0.4
Combustion Turbine	0.4	0.4
Diesel	0.0	0.0
Hydroelectric	0.1	0.0
Nuclear	0.8	0.5
Steam	2.3	3.8
Total	4.0	5.2

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Table 5-28 PJM EFORp data by unit type: Calendar years 2009 to 2010

	2009	2010
Combined Cycle	3.4%	3.0%
Combustion Turbine	2.5%	2.7%
Diesel	4.4%	3.3%
Hydroelectric	2.9%	1.1%
Nuclear	4.2%	2.9%
Steam	4.7%	7.7%
Total	4.0%	5.2%

EFORd, XEFORd and EFORp

EFORd, XEFORd and EFORp are designed to measure the rate of forced outages, which are defined as outages that cannot be postponed beyond the end of the next weekend.[130] It is reasonable to expect that units have some degree of control over when to take a forced outage, depending on the underlying cause of the forced outage. If units had no control over the timing of forced outages, outages during peak hours of the peak months would be expected to occur at roughly the same rate as outages during periods of demand throughout the rest of the year. With the exception of nuclear units, EFORp is lower than EFORd, suggesting that units elect to take forced outages during off-peak hours, as much as it is within their control to do so. That is consistent with the incentives created by the PJM Capacity Market. EFORp of nuclear units is slightly higher than EFORd and XEFORd, suggesting that nuclear units have a slightly higher rate of forced outages during the peak months of January, February, June, July and August.

Table 5-29 shows the contribution of each unit type to the system EFORd, XEFORd and EFORp, calculated as the total forced MW for the unit type divided by the total capacity of the system. Table 5-30 shows the capacity-weighted class average of EFORd, XEFORd and EFORp.

Table 5-29 Contribution to PJM EFORd, XEFORd and EFORp by unit type: Calendar year 2010

	EFORd	XEFORd	EFORp
Combined Cycle	0.4	0.4	0.4
Combustion Turbine	1.4	1.1	0.4
Diesel	0.0	0.0	0.0
Hydroelectric	0.0	0.0	0.0
Nuclear	0.5	0.5	0.5
Steam	4.8	4.2	3.8
Total	7.2	6.2	5.2

130 See "Manual 22: Generator Resource Performance Indices," Revision 15 (June 1, 2007), Definitions.

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Table 5-30 PJM EFORd, XEFORd and EFORp data by unit type: Calendar year 2010[131]

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	3.7%	3.5%	3.0%	0.1%	0.7%
Combustion Turbine	8.8%	6.9%	2.7%	1.9%	6.1%
Diesel	6.5%	4.5%	3.3%	2.0%	3.2%
Hydroelectric	1.2%	0.9%	1.1%	0.3%	0.1%
Nuclear	2.5%	2.5%	2.9%	0.0%	(0.4%)
Steam	9.8%	8.5%	7.7%	1.3%	2.1%
Total	7.2%	6.2%	5.2%	1.0%	2.0%

Comparison of Expected and Actual Performance

If the unit EFORd were normally distributed and if EFORd based planning assumptions were consistent with actual unit performance, the distribution of actual performance would be identical to a hypothetical normal distribution based on average EFORd performance. There are a limited number of units within each unit type and the distribution of EFORd may not be a normal distribution.

This analysis was performed based on resource-specific EFORd and Summer Net Capability capacity values for the year ending December 31, 2010. [132] These values were used to estimate a normal distribution for each unit type,[133] which was superimposed on a distribution of actual historical availability for the same resources for the year ending December 31, 2010.[134] The top thirty load days were selected for each year and the performance of the resources was evaluated for the peak hour of those days, a sample of 30 peak load hours.

Figure 5-8 compares the normal distribution to the actual distribution based on the defined sample.

Overall, generating units performed better during the selected peak hours than would have been expected based on the EFORd statistic. In particular, CT and ST units tend to have more capacity available during the sampled hours than implied by the EFORd statistic.

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

132 See "Manual 21: Rules and Procedures for Determination of Generating Capability," Revision 08 (January 1, 2010), Summer Net Capability.

133 The formulas used to approximate the parameters of the normal distribution are defined as:

$$\text{Mean} = \sum_i \left[\text{MW}_i * \left(1 - \text{EFORd}_i\right) \right]$$

$$\text{Variance} = \sum_i \left[\text{MW}_i * \text{MW}_i * \left(1 - \text{EFORd}_i\right) * \text{EFORd}_i \right]$$

$$\text{Standard Deviation} = \sqrt{\text{Variance}}$$

134 Availability calculated as net dependable capacity affected only by forced outage and forced derating events. Planned and maintenance events were excluded from this analysis.

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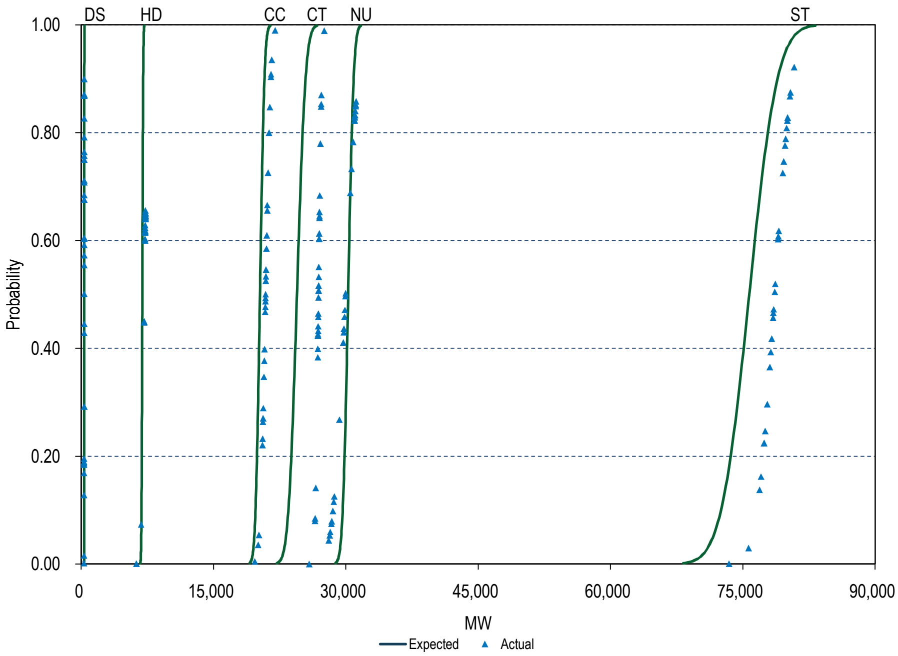
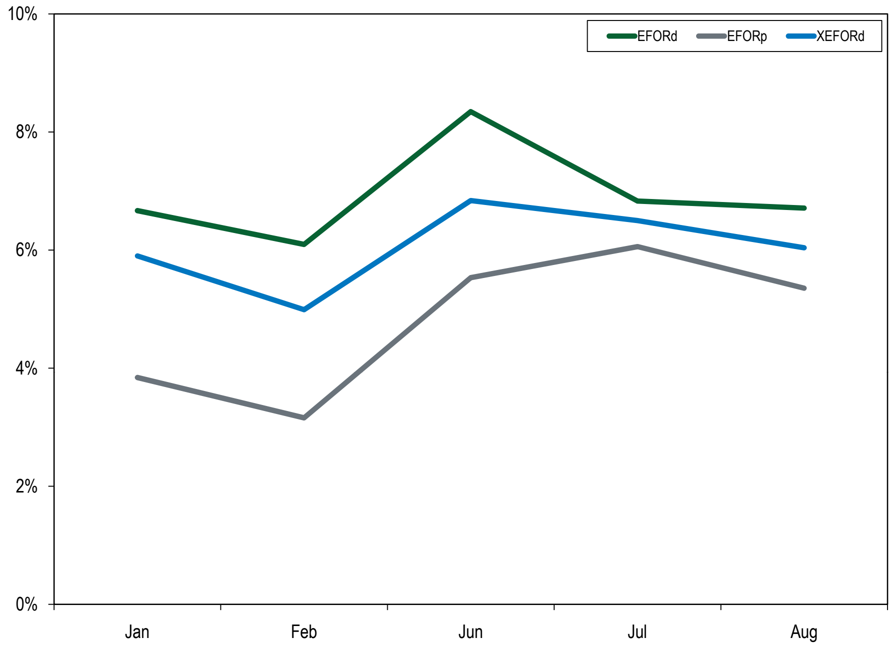
Figure 5-8 PJM 2010 distribution of EFORd data by unit type



Performance During Peak Months

For the peak months of January, February, June, July and August, EFORp values were significantly less than EFORd and XEFORd values as shown in Figure 5-9. EFORd during the peak months ranged from 6.1 percent to 8.3 percent, which is around the average for the year of 7.2 percent.

Figure 5-9 PJM EFORd, XEFORd and EFORp for the peak months of January, February, June, July and August: 2010



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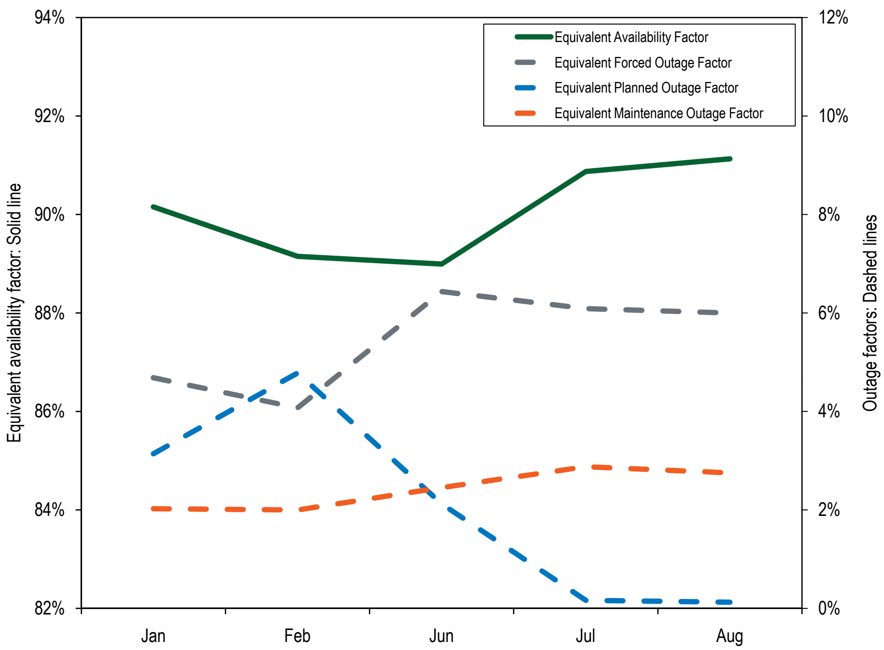
During the peak months of January, February, June, July and August, unit availability as measured by the equivalent availability factor increased, primarily due to decreasing planned outages, as illustrated in Figure 5-10. EAF during the peak months ranged from 89.0 percent to 91.1 percent, which is significantly higher than the average for the year of 84.8 percent.

Figure 5-10 PJM peak month generator performance factors



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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.

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the settlement in the RPM case.[3] 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 the market clearing price.

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.

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

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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 2010.

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 73 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 because, 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.

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.

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- 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 and New Analysis

- Regulation prices were 23.3 percent lower in 2010 than in 2009 and lower than in any year since the current Regulation Market structure was introduced in 2005. Regulation total costs per MW were 7.4 percent higher in 2010 than in 2009. The total cost of regulation per MW was 77.4 percent higher than the market clearing price in 2010. The result was a decrease in the ratio of price to cost. With the exception of 2009, the ratio of price to cost has declined in every year since 2005, and the ratio of price to cost is at its lowest level since 2005.

- Total self-scheduled regulation MW in 2010 was 15.5 percent of all regulation, an increase from 10.9 percent in 2009. The supply of eligible regulation increased by two percent in 2010 relative to 2009 levels.

- Synchronized reserve prices were 36.1 percent higher in 2010 than in 2009, but lower than in any other year since 2005. Synchronized reserves total costs per MW were 47.5 percent higher

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in 2010 than in 2009. The total cost of synchronized reserves per MW was 36.6 percent higher than the market clearing price in 2010. The result was a decrease in the ratio of price to cost.

- Since 2001, the cost of ancillary services per MW of load has been relatively low and stable.
- Of the LSEs' obligation to provide regulation, 82.2 percent was purchased in the spot market, 15.4 percent was self scheduled, and 2.3 percent was purchased bilaterally.
- DASR prices are closely related to energy prices, peaking in the summer months. In 2010, the load weighted price of DASR was $0.16 per MW. In 2009, the load weighted price of DASR was $0.05 per MW. The maximum clearing price was $39.99 per MW in July.
- Black start zonal charges ranged from $0.03 per MW in DLCO zone to $0.55 per MW in PSEG zone.

Summary Recommendations

- The Regulation Market design and implementation continue to be flawed and require a detailed review to ensure that the market will produce competitive outcomes. Some of the flaws identified by the MMU were addressed by PJM in 2010, but some remain. The MMU recommends a number of market design changes designed to improve the performance of the Regulation Market, including use of a single clearing price based on actual LMP, modifications to the LOC calculation methodology, a software change to save some data elements necessary for verifying market outcomes, and further documentation of the implementation of the market design through SPREGO.
- The MMU recommends that the single clearing price for synchronized reserves be determined based on the actual LMP. This consistent with PJM's recommendation on this topic in the scarcity pricing matter. The MMU also recommends that documentation of the Tier 1 synchronized reserve deselection process be published.
- The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test in order to address potential market power issues.
- The MMU recommends that PJM, FERC, reliability authorities and state regulators reevaluate the way in which black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market.

Overview

Regulation Market

The PJM Regulation Market in 2010 continues to be operated as a single market. There have been no structural changes since December 1, 2008. On December 1, 2008, PJM implemented

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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. At the FERC's direction, the MMU prepared and submitted a report on November 30, 2009, on the impact of these changes.[5] The MMU also reported on the impact of these changes in the *2009 State of the Market Report*.[6] In September 2010, PJM fixed an error that had been identified by the MMU, which resulted in too small a number of switches to a different offer schedule for the opportunity cost calculation.[7] Despite this fix, several implementation issues remain in addition to the market design issues.

The MMU has continued to analyze the functioning of the Regulation Market. The MMU recognized flaws in its quantification of the impact of the Regulation Market changes in prior reports.[8] [9] The MMU determined that the MMU's prior quantification of the impact on the clearing price of the changed calculation of opportunity cost was not correct. A complete quantification of the impact is not required as a precondition to modifying the flawed market design. Differences from PJM estimates of the impact were the result of incorrect calculations by the MMU, which accounted for much of the difference, but were also the result of incorrect implementation of the rules by PJM, the failure by PJM to save some data required to check clearing prices, and a lack of transparency of the market clearing process. A continuing issue in carrying out analysis of the Regulation Market is that some data that are critical to the market clearing process are not saved, which makes it impossible to validate or check the final clearing price and its determinants. The MMU has requested that these data items be saved for future analysis. Absent these data items, it is not possible to determine the full dollar impact of the rules changes of December 2008 or confirm that the current market implementation is consistent with the current market rules. Equally important, absent these data items it is not possible to verify the Regulation Market prices to ensure consistency with economic fundamentals.

Market Structure

- **Supply.** In 2010, 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 2010. The ratio of eligible regulation offered to regulation required averaged 2.95 for 2010, essentially unchanged from the 2009 ratio of 2.98.

- **Demand.** Beginning August 7, 2008, PJM began to define separate on-peak and off-peak regulation requirements, resulting in a decrease in total demand for regulation. The on-peak 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. Previously the requirement had been fixed at 1.0 percent of the daily forecast operating load. The average hourly regulation demand for 2010 increased to 893 MW, from 849 MW for 2009, as a result of increased forecast loads.

5 The MMU report filed in Docket No. ER09-13-000 is posted at: <http://www.monitoringanalytics.com/reports/Reports/2009/IMM_PJM_Regulation_Market_Impact_20081201_Changes_20091130.pdf>(465 KB).

6 See the *2009 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Service Markets."

7 See "Minutes" of the Market Implementation Committee. Agenda Item #9, pg. 5 <http://www.pjm.com/~/media/committees-groups/committees/mic/20101109/20101109-minutes.ashx, 11/09/2010> November 9, 2010.

8 See the 2010 Quarterly State of the Market Report for PJM, January through June, pg. 155, fn 15.

9 See the 2010 Quarterly State of the Market Report for PJM, January through September, pg. 166, fn 18.

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- **Market Concentration.** During 2010, the PJM Regulation Market had a load weighted, average Herfindahl-Hirschman Index (HHI) of 1464 which is classified as "moderately concentrated."[10] The minimum hourly HHI was 763 and the maximum hourly HHI was 3675. The largest hourly market share in any single hour was 53 percent, and 79 percent of all hours had a maximum market share greater than 20 percent.[11] In 2010, 73 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 2010 was characterized by structural market power in 73 percent of the hours.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. As of December 1, 2008, 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.[12] 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.[13] 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.

  As part of the changes to the Regulation Market implemented on December 1, 2008, PJM was to calculate unit specific opportunity costs using the lesser of the available price based energy offer or the most expensive available cost based energy offer as the reference, rather than the offer on which the unit was operating in the energy market.[14] Depending on whether the units affected by the rule change are backed down or raised to regulate, the application of the rule change increased or decreased the unit's applicable opportunity costs relative to the correct definition of opportunity cost used prior to December 1, 2008. The impact of these changes to

10 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.

11 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.

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

13 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."

14 See PJM. "Manual 11: Scheduling Operations," Revision 45 (June 23, 2010), p. 59: "SPREGO utilizes the lesser of the available price-based energy schedule or most expensive available cost-based energy schedule (the "lost opportunity cost energy schedule"), and forecasted LMPs to determine the estimated opportunity cost each resource would incur if it adjusted its output as necessary to provide its full amount of regulation."

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the calculation is that the hourly Regulation Market clearing price was either higher or lower than the outcome that would have occurred under the correct opportunity cost calculation used prior to December 1, 2008. However, PJM did not correctly implement this rule change until the third quarter of 2010.[15] The actual impact of the changed definition of opportunity cost was reduced as a result of the incorrect implementation of the rule.

Market Performance

- **Price.** For the PJM Regulation Market in 2010, the load weighted, average price per MW (the Regulation Market clearing price, including opportunity cost) associated with meeting PJM's demand for regulation was $18.08 per MW. This was a decrease of $5.48, or 23 percent, from the average price for regulation during 2009. The total cost of regulation increased by $2.13 from $29.63 per MW, for all of 2009, to $32.07, or 7 percent. The difference between total regulation cost per MW and regulation price remains high. The Regulation Market clearing price was only 57 percent of the total regulation cost per MW.

- **Price and Opportunity Cost.** Prices in the PJM Regulation Market in 2010 were higher than they would have been in some hours and lower than they would have been in some hours as a result of the change to the definition of opportunity cost in the December 2008 Regulation Market changes. The modified definition of opportunity cost resulted in a switch of the offer schedule used for the calculation of opportunity cost and therefore resulted in an impact on the Regulation Market clearing price.

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 2010. 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 where it remained throughout 2010.[16] Synchronized reserves added out of market were five percent of all synchronized reserves during 2010, while they were 15 percent for the same time period in 2009. Opportunity cost payments accounted for 27 percent of total costs during 2010 compared to 32 percent for 2009.

15 PJM staff reported the error at the November 9, 2010 meeting of the Market Implementation Committee and stated that the implementation was corrected on September 17, 2010.

16 See the *2009 State of the Market Report for PJM*, Volume II, Section 6, p. 40.

Market Structure

- **Supply.** In 2010, synchronized reserve offers were somewhat higher than in 2009. The offered and eligible excess supply ratio was 1.16 for the PJM Mid-Atlantic Synchronized Reserve Region.[17] For the RFC zone, the excess supply ratio was 2.68. 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 May 5, 2010, the synchronized reserve demand in the Mid-Atlantic Subzone was increased from 1,150 MW to 1,200 MW. This change was made to accommodate a dynamically changing largest contingency for the AP South constraint. In addition, double spinning was declared for May 24 and 25 of 1,800 MW because of a planned outage. On July 17, 2010, the synchronized reserve requirement for the Mid-Atlantic Subzone was increased from 1,200 MW to 1,300 MW. On September 21 and 22 the synchronized reserve requirement for the Mid-Atlantic Subzone was temporarily increased to 1,600 MW. Between November 15 and November 20 the synchronized reserve requirement for the Mid-Atlantic Subzone was increased to 1,630 MW. On October 12 and 13 the synchronized reserve requirement for the Mid-Atlantic Subzone was increased to 2,500 MW. For 2010, average synchronized reserve requirements were 1,246 MW for the Mid-Atlantic Subzone.

  For 2010, in the Mid-Atlantic Subzone, no Tier 2 synchronized reserve was needed in 33 percent of hours. The average required Tier 2 (including self scheduled) was 358 MW. The average required Tier 2 fell to 198 MW for the June through September period. For January through May and October through December the average was 438 MW. The decrease in the demand for Tier 2 was the result of an increase in Tier 1 during the summer months.

  In the PJM Mid-Atlantic Synchronized Reserve Subzone, 67 percent of hours cleared a Tier 2 Synchronized Reserve Market. The average demand for Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone was 358 MW. The demand was met by self scheduled synchronized reserves, which averaged 129 MW, and cleared Tier 2 synchronized reserves, which averaged 220 MW in 2010.

  Synchronized reserves added out of market were five percent of all PJM Mid-Atlantic subzone synchronized reserves in 2010.

  For the first six months of 2010, the synchronized reserve requirement was 1,320 MW for the RFC Synchronized Reserve Zone. On July 1, 2010, the requirement for the RFC Synchronized Reserve Zone was increased from 1,320 MW to 1,350 MW, to accommodate the largest single unit contingency. Additionally, there were 85 hours between September 20 and September 29 when the synchronized reserve requirement for the RFC Synchronized Reserve Zone was increased to 1,700 MW as a result of outages.

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

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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, less than one percent of hours cleared a Tier 2 Synchronized Reserve Market in the RFC. A Tier 2 Synchronized Reserve Market was cleared for the Southern Synchronized Reserve Zone for only 11 hours in 2010.

- **Market Concentration.** The average load weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone for 2010 was 3222, which is classified as "highly concentrated."[18] For purchased synchronized reserve (cleared plus added) the HHI was 3268. In 2010, 68 percent of hours had a maximum market share greater than 40 percent, compared to 36 percent of hours in 2009.

  In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, in 2010, 62 percent of hours that cleared a synchronized reserve market had three or fewer pivotal suppliers. In the full RFC Synchronized Reserve Market (which cleared only 27 hours in 2010) 100 percent of hours that cleared a synchronized reserve market had three or fewer pivotal suppliers. In the Southern Synchronized Reserve Zone (which cleared only 11 hours in 2010) none of those hours had three or fewer pivotal suppliers. The MMU concludes from these TPS results that the RTO zone and Mid-Atlantic subzone Synchronized Reserve Markets in 2010 were 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.

  Demand side resources remained significant participants in the Synchronized Reserve Market in 2010. In eight percent of hours in which a Tier 2 Synchronized Reserve Market was cleared for the Mid-Atlantic Subzone, all synchronized reserves were provided by demand side resources.

Market Performance

- **Price.** The load weighted, average PJM price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market was $10.55 per MW in 2010, a $2.80 per MW increase from 2009. The market clearing price was only 63 percent of the total synchronized reserve cost per MW in 2010, lower than in 2009.

- **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 2010.

18 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).

DASR

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[19] 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.[20] The RFC and Dominion DASR requirements are added together to form a single RTO DASR requirement which is obtained via the DASR Market. The requirement is applicable for all hours of the operating day. If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

Market Structure

- **Concentration.** In 2010, the three pivotal supplier test was failed in the DASR Market in 1.3 percent of hours, all of which were in the months of June, July, August, and September.

- **Demand.** In 2010, the required DASR was 6.88 percent of peak load forecast, up from 6.75 percent in 2009.[21] As a result of increased demand for energy, reflected in higher forecast peak loads and increased DASR requirements, the DASR MW purchased increased by 9 percent in 2010 over 2009.

Market Conduct

- **Withholding.** Economic withholding remains a problem in the DASR Market. Continuing a pattern seen since the inception of the DASR Market, five percent of units offered at $50 or more and 45 units offered at more than $900, in a market with an average clearing price of $0.16 and a maximum clearing price of $39.99. PJM rules require all units with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[22] Units that do not offer will have their offers set to $0/MW. Every unit type had significant offers at $10/MW or lower.

- **DSR.** Demand side resources do participate in the DASR Market, but remain insignificant.

Market Performance

- **Price.** DASR prices are closely related to energy prices, peaking in the summer months. In 2010, the load weighted price of DASR was $0.16 per MW. In 2009, the load weighted price of DASR was $0.05 per MW. The maximum clearing price was $39.99 per MW in July.

19 See 117 FERC ¶ 61,331 (2006).
20 See PJM. "Manual 13: Emergency Operations," Revision 42, (January 21, 2011); pp 11-12.
21 See the *2010 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Services" at Day Ahead Scheduling Reserve *(DASR)*.
22 PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 45 (June 23, 2010), p. 122.

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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.[23]

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 2009, charges were about $12.3 million. In 2010, total black start service charges were $10.0 million. There was substantial zonal variation.

As a consequence of new NERC standards related to Critical Infrastructure Protection and PJM's filing to revise its formula rate for black start service to allow for the recovery of the costs necessary for compliance with the new NERC standards, black start costs likely will increase substantially.

The MMU recommends that PJM, FERC, reliability authorities and state regulators reevaluate the way in which black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market rather than a separate zone by zone basis. Elements of such reform should include, at a minimum, the clear assignment of responsibility to PJM for determining a single system restoration plan that identifies locations where black start units are needed. PJM should assume an explicit obligation to secure black start service on a least cost basis and implement a method to evaluate competitive alternatives to providing black start service at identified locations on a rolling basis as service obligations of existing providers terminate.

Ancillary Services costs per MW of load: 2001 - 2010

Table 6-4 shows PJM ancillary services costs from 2001 through 2010 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; Blackstart Services; Direct Assignment Facilities; and Reliability First Corporation charges. Supplementary Operating Reserve includes Day-Ahead Operating Reserve; Balancing Operating Reserve; and Synchronous Condensing.

23 OATT Schedule 1 § 1.3BB.

Table 6-4 History of ancillary services costs per MW of Load: 2001 through 2010

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

Conclusion

While the MMU has identified a number of issues with the design and implementation of the Regulation Market, these issues can be resolved as a single package in a timely manner. The MMU recommends that such a resolution be pursued in 2011 with the goal of implementing the appropriate changes in 2011.

The design of the Regulation Market can be improved. The MMU recommends that, as part of a package of modifications to improve the Regulation Market design, the clearing price for regulation be determined based on the actual LMP. The regulation clearing price is generally too low because it is based on forecast LMP, which appears to systematically understate actual LMP. The proposed modifications to the pricing of regulation by both PJM and the MMU in their scarcity pricing recommendations will result in revenue increases that are expected to exceed any revenue loss from correcting the opportunity cost calculation.[24] The MMU recommends that when this modification is implemented, the margin be reduced to no higher than its current level. The result would be to make Regulation Market prices more transparent and more reflective of the actual cost of providing regulation and is expected to increase revenues to the providers of regulation, after accounting for all the recommended changes.

The MMU continues to conclude that the results of the Regulation Market are not competitive.[25] The MMU's conclusion is not the result of the behavior of market participants, which was competitive, in part as a result of the application of the three pivotal supplier test, but is the result of the market design changes. The results of the Regulation Market are not competitive because the changes in market rules, in particular the changes to the calculation of the opportunity cost, are inconsistent with basic economic logic, and because of incorrect implementation of the market rules. For

24 See, *e.g.*, PJM compliance filing in Docket No. ER09-1063-004 (June 18, 2010); Protest and Compliance Proposal of the Independent Market Monitor for PJM, Docket No. ER09-1063-004, (July 19, 2010).

25 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."

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example, the changes to the calculation of the opportunity cost resulted in offers greater than competitive offers in some hours and therefore in prices greater than competitive prices in some hours, and resulted in offers less than competitive offers in some hours and therefore in prices less than competitive prices in some hours. The competitive price is the price that would have resulted from a combination of competitive offers from market participants and the application of the prior, correct and consistent approach to the calculation of the opportunity cost. The offers from market participants are not at issue, as PJM directly calculates and adds opportunity costs to the offers of participants, following the revised market rules.

The MMU recommends that the December 1, 2008, modification to the definition of opportunity cost be reversed and that the elimination of the offset against operating reserve credits also be reversed based on the MMU conclusion that these features result in a non-competitive market outcome, and because they are inconsistent with the treatment of the same issues in other PJM markets and inconsistent with basic economic logic. The MMU also recommends that, to the extent that it is believed that additional revenue to generation owners is needed to maintain the outcome of the settlement in the short run, revenue neutrality be maintained by modifying the margin from its current level of $12.00 per MW at the same time that the opportunity cost definition is corrected. This change would maintain transparent incentives consistent with an effective market design.

The MMU also recommends that PJM save all data necessary to reproduce the market clearing results to ensure transparency of the price formation process and to permit checking the Regulation Market results for consistency with economic fundamentals.

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 recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test. The MMU concludes that the DASR Market results were competitive in 2010.

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 2010 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 2010. The MMU concludes that the DASR Market results were competitive in 2010.

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Detailed Recommendations

- The Regulation Market design and implementation continue to be flawed and require a detailed review to ensure that the market will produce competitive outcomes. Some of the flaws identified by the MMU were addressed by PJM in 2010, but some remain. The MMU recommends a number of market design changes designed to improve the performance of the Regulation Market, including use of a single clearing price based on actual LMP, modifications to the LOC calculation methodology, a software change to save some data elements necessary for verifying market outcomes, and further documentation of the implementation of the market design through SPREGO.

    - The MMU recommends that the single clearing price for regulation be determined based on the actual LMP. This is expected to result in a net increase in payments to providers of regulation as a result of an increase in the regulation clearing price which more than offsets unit specific reductions in unit specific, post clearing opportunity cost payments. This would improve the transparency of the Regulation Market as the resulting price of regulation would internalize some of the costs currently being collected through uplift and would thereby make the market price more reflective of the actual costs of providing the service.

    - The MMU recommends that the December 1, 2008, modification to the definition of opportunity cost be reversed and that the elimination of the offset against operating reserve credits be reversed based on the MMU conclusion that these features result in a non-competitive market outcome, and because they are inconsistent with the treatment of the same issues in other PJM markets and inconsistent with basic economic logic.

    - The MMU recommends that the December 1, 2008 modification to the net revenue offset elimination be reversed and that the net revenues earned in the Regulation Market be offset against operating reserve credits in the same manner that all net revenues from all other PJM markets are offset against operating reserve credits and in the same manner that Regulation Market credits were offset against operating reserve credits prior to December 1, 2008.

    - The MMU recommends that, to the extent that it is believed that additional revenue to generation owners is needed to maintain the outcome of the settlement in the short run, revenue neutrality be maintained by modifying the margin from its current level of $12.00 per MW at the same time that the opportunity cost definition is corrected.

    - The MMU recommends that PJM save all data necessary to reproduce the market clearing results to ensure transparency of the price formation process and to permit checking the Regulation Market results for consistency with economic fundamentals.

    - The MMU recommends that PJM improve the documentation it creates and maintains with respect to the detailed processes for clearing the Regulation Market.

- The MMU recommends that the synchronized market price signal be improved and the market rules be made more transparent.

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- The MMU recommends that the single clearing price for synchronized reserves be determined, after the fact, on the actual LMP. This is expected to result in a net increase in payments to providers of synchronized reserves as a result of an increase in the clearing price which more than offsets unit specific reductions in unit specific, post clearing opportunity cost payments. This would improve the transparency of the synchronized reserve market as the resulting price of synchronized reserve would internalize some of the costs currently being collected through uplift and would make the more reflective of the actual costs of providing the service.

- Dispatchers can deselect a unit from regulation, Tier 1 or Tier 2 synchronized reserve, or unit dispatch prior to running the market solution. This is the equivalent of imposing a constraint on the market solution. The MMU recommends that a full list of potential reasons for unit deselection be published in PJM's M-11 Scheduling Operations Manual. The MMU recommends mandatory documentation of reasons for Tier 1 deselection as a way to improve transparency.

- The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test in order to address the identified market power issues.

- The MMU recommends that PJM, FERC, reliability authorities and state regulators reevaluate the way in which black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market. Elements of such reform should include, at a minimum, the clear assignment of responsibility to PJM for determining a single system restoration plan that identifies locations where black start units are needed. Transmission owners should play an advisory role. PJM should assume an explicit obligation to secure black start service on a least cost basis and implement a method to evaluate competitive alternatives to providing black start service at identified locations on a rolling basis as service obligations of existing providers terminate.

Regulation Market

Market Structure

The market structure of the 2010 PJM Regulation Market remains unchanged since December, 2008. The rule changes of December 1, 2008, significantly affected the design of the Regulation Market. Both PJM and the MMU have done extensive analysis of these changes in 2010 resulting in several technical improvements to the market solution software.

Supply

The supply of regulation can be measured as regulation capability, regulation offered, or regulation offered and eligible. For purposes of evaluating the Regulation Market, the relevant regulation supply is the level of supply that is both offered to the market on an hourly basis and is eligible to participate in the market on an hourly basis. This is the only supply that is actually considered in the determination of market prices. The level of supply that clears in the market on an hourly basis is called cleared regulation. Assigned regulation is the total of self-scheduled and cleared regulation. Assigned regulation is selected from regulation that is eligible to participate.

Regulation capability is the sum of the maximum daily offers for each unit and is a measure of the total volume of regulation capability as reported by resource owners.

Regulation offered represents the level of regulation capability offered to the PJM Regulation Market. Resource owners may offer those units with approved regulation capability into the PJM Regulation Market. PJM does not require a resource capable of providing regulation service to offer its capability to the market. Regulation offers are submitted on a daily basis.

Regulation offered and eligible represents the level of regulation capability offered to the PJM Regulation Market and actually eligible to provide regulation in an hour. Some regulation offered to the market is not eligible to participate in the Regulation Market as a result of identifiable offer parameters specified by the supplier. As an example, the regulation capability of a unit is included in regulation offered based on the daily offer and availability status, but that regulation capability is not eligible in one or more hours because the supplier sets the availability status to unavailable for one or more hours of that same day. The availability status of a unit may be set in both a daily offer and an hourly update table in the PJM market user interface. As another example, the regulation capability of a unit is included in regulation offered if the owner of a unit offers regulation, but that regulation capability is not eligible if the owner sets the unit's economic maximum generation level equal to its economic minimum generation level. In that case, the unit cannot provide regulation and is not eligible to provide regulation. As another example, the regulation capability of a unit is included in regulation offered, but that regulation capability is not eligible if the unit is not operating, unless the unit meets specific operating parameter requirements. A unit whose owner has not submitted a cost based offer will not be eligible to regulate even if the unit is a regulation resource.

Only those offers eligible to provide regulation in an hour are part of supply for that hour, and only eligible offers are considered by PJM for purposes of clearing the market. Regulation assigned represents those regulation resources selected through the Regulation Market clearing mechanism to provide regulation service for a given hour.

During 2010, the PJM Regulation Market total capability was 8,053 MW.[26] Total capability is a theoretical measure which is never actually achieved. The level of regulation resources offered on a daily level and the level of regulation resources eligible to participate on an hourly level in the market were lower than the total regulation capability. In 2010, the average daily offer level, excluding units with offers which were made unavailable for the day, was 5,645 MW or 70 percent of total capability while the average hourly eligible offer level was 2,591 MW or 32 percent of total capability. In 2009, the average hourly eligible offer level was 33 percent of the average daily offer level. Although regulation is offered daily, eligible regulation changes hourly. Typically less regulation is eligible during off-peak hours because fewer steam units are running during those hours. Table 6-5 shows capability, daily offer and average hourly eligible MW for all hours as well as for off-peak and on-peak hours.

26 Total offer capability is defined as the sum of the maximum daily offer volume for each offering unit during the period, without regard to the actual availability of the resource or to the day on which the maximum was offered.

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Table 6-5 PJM regulation capability, daily offer and hourly eligible: Calendar year 2010[27]

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
All Hours	8,053	5,645	70%	2,591	32%
Off Peak	8,053			2,335	29%
On Peak	8,053			2,872	36%

The average eligible regulation supply-to-requirement ratio in the PJM Regulation Market during 2010 was 2.94. When this ratio equals 1.0, it indicates that offered supply exactly equals demand for the referenced time period. Even during periods of diminished supply such as off-peak hours, eligible regulation supply was adequate to meet the regulation requirement.

Demand

Demand for regulation does not change with price, i.e. demand is price inelastic. The demand for regulation is set administratively based on reliability objectives and forecast load. Regulation demand is also referred to in the *2010 State of the Market Report for PJM* as "required regulation."

The PJM regulation requirement is set by PJM Interconnection in accordance with NERC control standards. In August 2008, the requirement was adjusted to be 1.0 percent of the forecast peak load for on peak hours and 1.0 percent of the forecast valley load for off peak hours. In 2010, the PJM regulation requirement ranged from 502 MW to 1,365 MW. The average required regulation off-peak was 811 MW and the average required regulation on-peak was 981 MW (Table 6-6). In 2010, PJM scheduled a total of 9,037,733 MW of regulation compared to 8,254,358 MW in 2009.

Table 6-6 PJM Regulation Market required MW and ratio of eligible supply to requirement: Calendar year 2010

Period Type	Average Required Regulation (MW)	Ratio of Supply to Requirement
2010	893	2.95
Fall	797	3.22
Spring	775	2.80
Summer	1,046	2.88
Winter	952	2.88
Off Peak	811	2.94
On Peak	981	2.95

Market Concentration

Hourly HHI values were calculated based on cleared regulation. HHI values showed less variability in 2010 than in 2009. HHI ranged from a maximum of 3675 to a minimum of 763, with a load weighted average value of 1449, which is categorized as moderately concentrated by the FERC

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

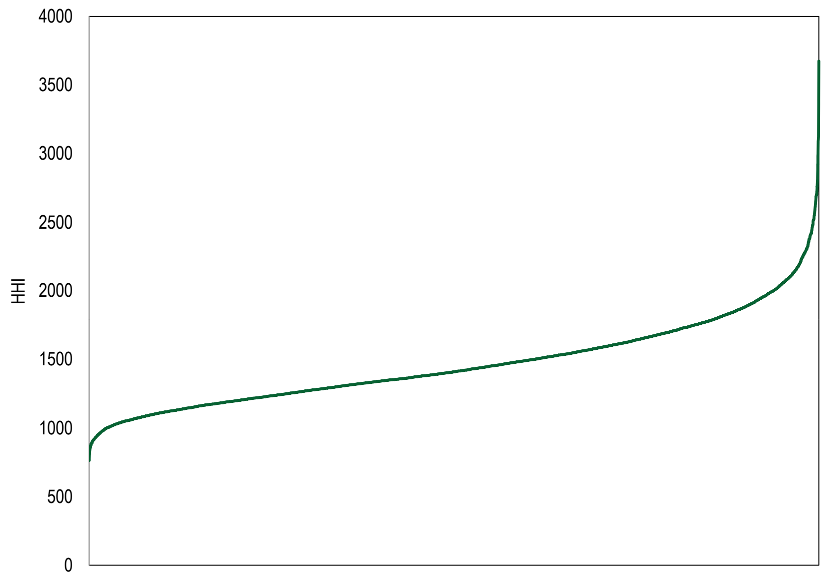
definitions. Table 6-7 summarizes the 2010 PJM Regulation Market HHIs. The maximum HHI and the average HHI were higher in 2010 than in 2009.

Table 6-7 PJM cleared regulation HHI: Calendar year 2010

Market Type	Minimum HHI	Load-weighted Average HHI	Maximum HHI
Cleared Regulation, 2010	763	1449	3675

In 2010, two percent of all periods had an HHI less than 1000 and 14 percent of all periods had an HHI greater than 1800, with a maximum HHI of 3675.[28] An HHI of 1800 is the threshold for "highly concentrated" by the FERC definitions. The maximum period HHI in 2009 was 9405. See the HHI distribution curve in Figure 6-1.

Figure 6-1 PJM Regulation Market HHI distribution: Calendar year 2010



The highest hourly market share was 53 percent (compared to the highest hourly market share in 2009 of 97 percent). Seventy nine percent of all hours had a maximum market share greater than 20 percent in 2010. The largest annual average hourly market share by a company was 18 percent. The top five annual average hourly market shares for cleared regulation in 2010 are listed in Table 6-8.

28 See the *2010 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part 1," 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.

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Table 6-8 Highest annual average hourly Regulation Market shares: Calendar year 2010

Company Market Share Rank	Cleared Regulation Top Yearly Market Shares
1	18%
2	16%
3	15%
4	15%
5	9%

In 2010, 73 percent of hours failed the three pivotal supplier test. This means that for 73 percent of hours the total regulation requirement could not be met in the absence of the three largest suppliers. One supplier of regulation was pivotal in 98 percent of pivotal hours. A second company was pivotal in 93 percent of the pivotal hours. A third company was pivotal in 86 percent of pivotal hours. Table 6-9 includes a monthly summary of three pivotal supplier results.

Table 6-9 Regulation market monthly three pivotal supplier results: Calendar year 2010

Month	Percent of Hours With Three Pivotal Suppliers
Jan	74%
Feb	70%
Mar	83%
Apr	82%
May	79%
Jun	81%
Jul	75%
Aug	69%
Sep	70%
Oct	47%
Nov	63%
Dec	89%

Thus, in addition to failing the three pivotal supplier test in a significant number of hours, the pivotal suppliers in the Regulation Market were the same suppliers in the majority of hours when the test was failed. This is a further indication that the structural market power issue in the Regulation Market remained persistent and repeated during 2010.

The MMU concludes from these results that the PJM Regulation Market in 2010 was characterized by structural market power. This conclusion is based on the results of the three pivotal supplier test.

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Market Conduct

Offers

PJM implemented the three pivotal supplier test in the Regulation Market in December 2008. As a result, generators wishing to participate in the PJM Regulation Market must submit cost based regulation offers for specific units by 1800 Eastern Prevailing Time (EPT) of the day before the operating day. Generators may also submit price based offers. The regulation cost based offer price is limited to costs plus $12.00. The costs are validated in accordance with unit specific operating parameters entered with the cost based offer. A unit is not required to provide these parameters if its offer is less than $12.00. The unit specific operating parameters are heat rate at economic maximum, heat rate at regulation minimum, variable operating and maintenance (VOM) rate and fuel cost. Regulation offers are applicable for the entire 24 hour period for which they are submitted. As in any competitive market, regulation offers at marginal cost are considered to be competitive.

The cost based and price based offers and the associated cost related parameters are the only components of the regulation offer applicable for the entire operating day. The following information must be included in each offer, but can be entered or changed up to 60 minutes prior to the operating hour: regulating status (i.e., available, unavailable or self-scheduled); regulation capability; regulation minimum (may be increased but not decreased); and regulation maximum (may be decreased but not increased). The Regulation Market is cleared on a real-time basis and regulation prices are posted hourly throughout the operating day. The amount of self-scheduled regulation is confirmed 60 minutes before each operating hour, and regulation assignments are made at least 30 minutes before each operating hour.

PJM's Regulation Market is cleared hourly, based on both offers submitted by the units and the hourly lost opportunity cost of each unit, calculated based on the forecast LMP at the location of each regulating unit.[29] The total offer price is the sum of the unit specific offer and the opportunity cost. In order to clear the market, PJM ranks the offers of all offered and eligible regulating resources in ascending total offer price order; it does the same for synchronized reserve. PJM then determines the least expensive set of resources necessary to provide regulation, synchronized reserve and energy for the operating hour, taking into account any resources self-scheduled to provide any of these services. Prior to clearing and assignment of regulation in a given hour, the Regulation Market is subject to market power screening via the TPS test.

Regulation Market participation is a function of the obligation of all LSEs to provide regulation in proportion to their load share. LSEs can purchase regulation in the Regulation Market, purchase regulation from other providers bilaterally, or self-schedule regulation to satisfy their obligation (Figure 6-2).[30] Increased self scheduled regulation lowers the requirement for cleared regulation, resulting in fewer MW cleared in the market and lower clearing prices. Total self-scheduled regulation MW in 2010 was 15.5 percent of all regulation, which is an increase from 10.9 percent in 2009. The amount of self scheduled regulation was higher during off peak hours than during on

29 PJM estimates the opportunity cost for units providing regulation based on a forecast of locational marginal price (LMP) for the upcoming hour. In May 2009, PJM also began including the lost opportunity cost impact in adjoining hours of dispatching a unit to its regulation set point. As part of the settlement that included the implementation of the three pivotal supplier test on December 1, 2008, the opportunity cost calculator now uses the lesser of the available price based energy schedule or the most expensive available cost based energy schedule.

30 See PJM "Manual 28: Operating Agreement Accounting," Revision 46, (October 1, 2010); para 4.3, pp 14-15.

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peak hours while the amount of cleared regulation is higher during on peak hours than during off peak hours (Table 6-10).

Figure 6-2 Off peak and on peak regulation levels: Calendar year 2010

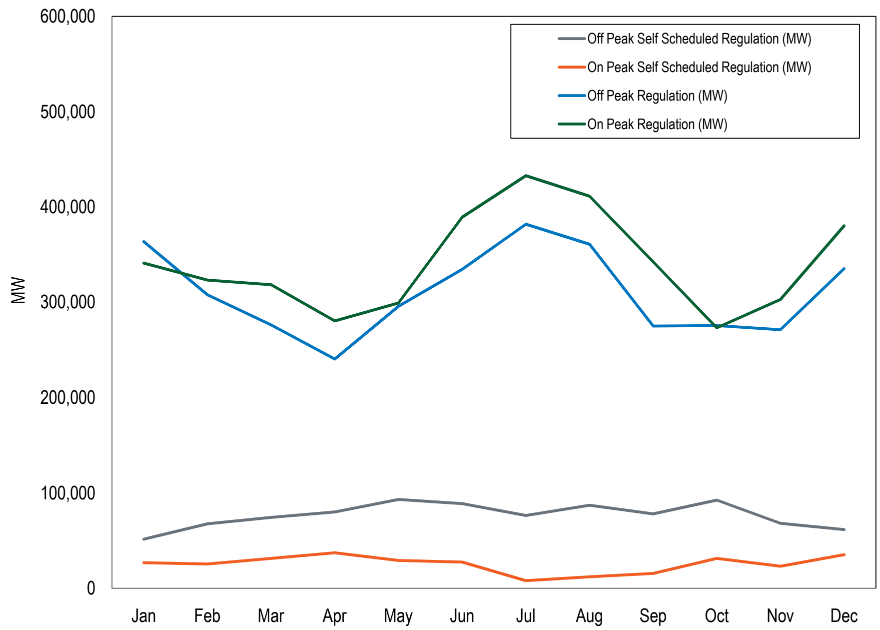

Table 6-10 Regulation sources: spot market, self-scheduled, bilateral purchases: Calendar year 2010

Month	Spot Regulation (MW)	Self Scheduled Regulation (MW)	Bilateral Regulation (MW)
Jan	617,411	75,684	11,267
Feb	524,440	92,380	15,188
Mar	475,724	103,919	14,736
Apr	394,591	113,441	10,494
May	457,088	116,602	14,761
Jun	534,164	106,595	18,079
Jul	631,078	76,177	16,067
Aug	640,608	94,115	15,801
Sep	498,707	86,209	13,515
Oct	356,136	115,314	13,046
Nov	458,101	88,133	17,995
Dec	607,322	93,502	14,540
Total	6,195,368	1,162,072	175,489

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Market Performance

Price

Figure 6-3 shows the daily average Regulation Market clearing price and the opportunity cost component for the marginal units in the PJM Regulation Market. All units chosen to provide regulation received as payment the higher of the clearing price, based on the forecast LMP, multiplied by the unit's assigned regulating capability, or the unit's regulation offer plus the individual unit's real-time opportunity cost, based on actual LMP, multiplied by its assigned regulating capability.[31]

Regulation credits are awarded to generation owners that have either self-scheduled or sold regulation into the market. Regulation credits for units self-scheduled to provide regulation are equal to the clearing price times the unit's self-scheduled regulating capability. Regulation credits for units that offer regulation into the market and are selected to provide regulation are the higher of the clearing price times the unit's assigned regulating capability, or the unit's regulation offer plus the unit's specific after the fact opportunity cost, times its assigned regulating capability. Although most units are paid the clearing price (RMCP) times their assigned regulation MWh, a substantial portion of the RMCP is the opportunity cost calculated during market clearing based on forecast LMP and cost of the marginal unit. This means that a substantial portion of the total cost of regulation is determined by opportunity cost. As shown in Figure 6-3, about half of the regulation price is the opportunity cost of the marginal unit. Opportunity cost is a greater percentage of price when prices are high since offers tend to remain constant.

The load weighted, average offer (excluding opportunity cost) of the marginal unit for the PJM Regulation Market during 2010 was $9.28 per MWh, an increase from the load weighted average offer in 2009 of $8.79. Although higher than in 2009, offers remain low compared to prior years as a result of the application of the three pivotal supplier test, which prevents non competitive offers from setting price. The load weighted, average opportunity cost of the marginal unit for the PJM Regulation Market in 2010 was $8.01. In the PJM Regulation Market the marginal unit opportunity cost averaged 47 percent of the RMCP. This is a slight reduction from the 2009 level of 49 percent.

31 See PJM. "Manual 28: Operating Agreement, Accounting," Revision 46, Section 4, "Regulation Credits" (October 1, 2010), p. 13. PJM uses estimated opportunity cost to clear the market and real-time opportunity cost to compensate generators that provide regulation and synchronized reserve. Real-time opportunity cost is calculated using real-time LMP.

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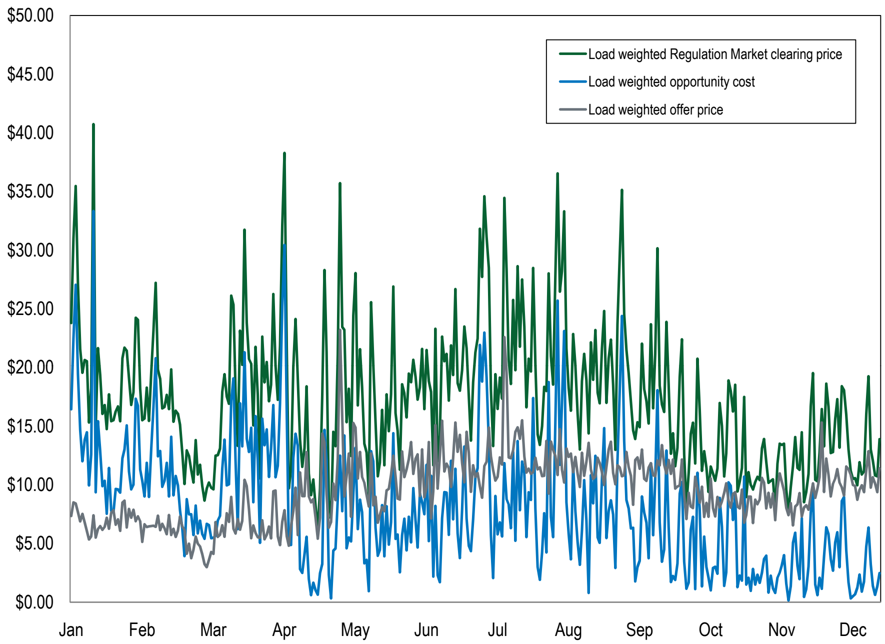
Figure 6-3 PJM Regulation Market daily average market-clearing price, opportunity cost and offer price (Dollars per MWh): Calendar year 2010



On a shorter term basis, regulation prices follow daily and weekly patterns. The supply of regulation is largest during on-peak hours, between 0600 and 2300 EPT, Monday through Friday.

During the off-peak hours fewer steam generators are running and available to regulate. At times, units must be kept running for regulation that are not economic for energy, resulting in an increase in the opportunity cost portion of the clearing price. At other times, expensive combustion turbine generators must be started to meet regulation requirements.

Figure 6-4 shows the level of demand for regulation by month in 2010 and the corresponding level of regulation price.

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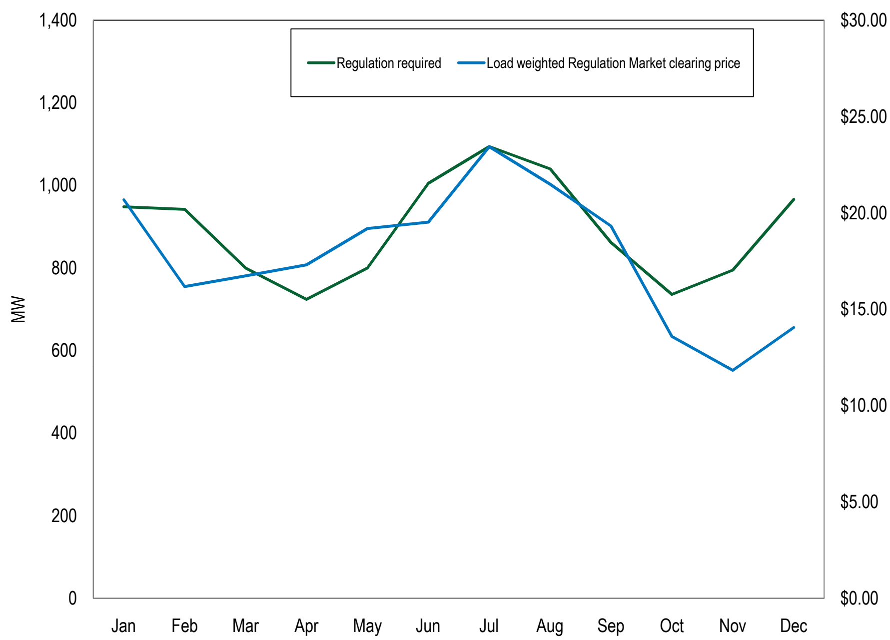
Figure 6-4 Monthly average regulation demand (required) vs. price: Calendar year 2010



The total cost of regulation per MW exceeds the price per MW because some regulation is procured out of the market, regulation MW actually delivered differs from regulation MW offered and cleared, or because there are adjustments to unit specific opportunity cost after the market clears. A well designed and efficient market will minimize this difference. Units which provide regulation are paid the higher of the RMCP, or their offer plus their unit specific opportunity cost. The offer plus the unit specific opportunity cost may be higher than the RMCP for a number of reasons. If real-time LMP is greater than the LMP forecast prior to the operating hour and included in the RMCP, unit specific opportunity costs will be higher than forecast. Such higher LMPs can be local, because of congestion, or more general, if system conditions change. Other reasons include unit redispatch because of constraints or unanticipated unit performance problems. When some units are paid more than the RMCP based on unit specific lost opportunity costs, the result is that PJM's regulation cost per MWh is higher than the RMCP. Figure 6-5 compares the regulation total cost per MWh (clearing price plus post market opportunity costs) with the regulation clearing price to show the difference between the per MWh price of regulation and the per MWh total cost of regulation. The results in Figure 6-5 show that a significant portion of the costs of regulation are not incorporated in the Regulation Market clearing price. This discrepancy results in a lack of transparency in the Regulation Market.

PJM may call on resources not otherwise scheduled to run in order to provide regulation, in accordance with PJM's obligation to minimize the total cost of energy, operating reserves, regulation, and other ancillary services. This often increases total regulation costs. If a resource is called on by PJM for the purpose of providing regulation, the resource is guaranteed recovery of regulation lost opportunity costs as well as start-up, no-load, and energy costs.

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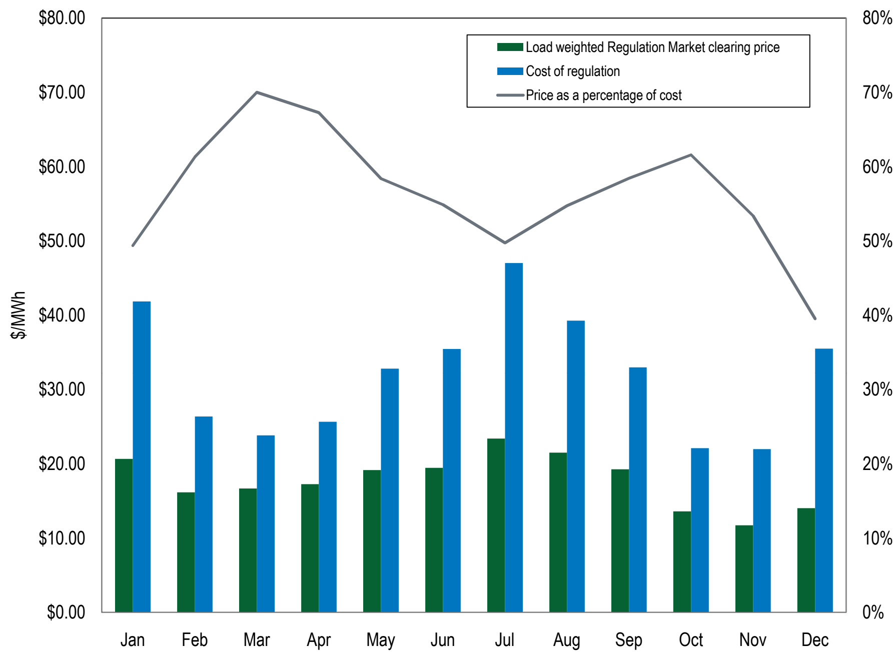
Figure 6-5 Monthly load weighted, average regulation cost and price: Calendar year 2010



Total scheduled regulation MWh, total regulation charges, regulation price and regulation cost are listed in Table 6-11.

Table 6-11 Total regulation charges: Calendar year 2010

Month	Scheduled Regulation (MW)	Total Regulation Charges	Load Weighted Regulation Market Clearing Price	Cost of Regulation
Jan	704,362	$29,479,645	$20.66	$41.85
Feb	632,007	$16,673,515	$16.17	$26.38
Mar	594,378	$14,167,033	$16.69	$23.84
Apr	518,526	$13,307,387	$17.26	$25.66
May	588,452	$19,307,043	$19.16	$32.81
Jun	658,837	$23,355,270	$19.46	$35.45
Jul	723,322	$34,017,913	$23.39	$47.03
Aug	750,524	$29,482,419	$21.50	$39.28
Sep	598,431	$19,734,114	$19.27	$32.98
Oct	484,496	$10,705,184	$13.61	$22.10
Nov	545,214	$11,983,314	$11.73	$21.98
Dec	715,364	$25,403,910	$14.04	$35.51

For 2010, the load weighted, average regulation price was $18.08 per MWh. The average regulation cost was $32.07 per MWh. The difference between the Regulation Market price and the actual cost of regulation was greater in 2010 than it was in 2009. The cost of regulation was 77 percent higher

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than the market price of regulation. The payment of a large portion of regulation charges on a unit specific basis rather than on the basis of a market clearing price remains a cause for concern as it results in a weakened market price signal to the providers of regulation and effectively pays a substantial proportion of Regulation Market revenues on an as bid basis rather than on the basis of the clearing price.

Regulation prices were 23.3 percent lower in 2010 than in 2009 and lower than in any year since the current Regulation Market structure was introduced in 2005. Regulation total costs per MW were 7.4 percent higher in 2010 than in 2009. The total cost of regulation per MW was 77.4 percent higher than the market clearing price in 2010. The result was a decrease in the ratio of price to cost. With the exception of 2009, the ratio of price to cost has declined in every year since 2005, and the ratio of price to cost is at its lowest level since 2005.

A key source of the difference between the market clearing price and the cost per MW of regulation results from differences in opportunity cost between the forecast LMP and actual LMP. To address this issue, the MMU recommends that the hourly clearing price for regulation be determined after the close of the hour. All units cleared in the Regulation Market in the hour prior would be paid the market-clearing regulation price based on the actual LMP rather than the forecast LMP. This is expected to result in a net increase in payments to providers of regulation as a result of an increase in the regulation clearing price which more than offsets unit specific reductions in unit specific, post clearing opportunity cost payments. This would improve the transparency of the Regulation Market as the resulting price of regulation would internalize some of the costs currently being collected through uplift and would make the market price more reflective of the actual costs of providing the service.

Table 6-12 Comparison of load weighted price and cost for PJM Regulation, August 2005 through December 2010[32]

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%

Issues in the Regulation Market Design

The MMU has identified several significant issues with the design and implementation of the Regulation Market. These are broad statements of the issues and do not include an exhaustive list of all concerns. The issues address economic efficiency and competitiveness, and transparency.

32 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.

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- The definition of opportunity cost for units providing regulation is not correct. The result is a clearing price not reflective of the actual opportunity cost and therefore not efficient or competitive. The correct way to calculate opportunity cost and maintain incentives across both markets is to treat the offer on which the unit is dispatched as the measure of its marginal costs for both the energy market and the Regulation Market.

- PJM does not save some data elements that are necessary in order to replicate Regulation Market clearing prices. As a result, the opportunity cost used in the clearing price cannot be calculated and the clearing price cannot be calculated. While it may be possible to recreate data that is not saved, that is not the same as saving the data and making it available.

- It is not clear at what stages in the market clearing process the opportunity cost calculation includes shoulder hour opportunity costs. The documentation should be updated to clarify when shoulder hour opportunity costs are included in the market clearing process.

- The MMU analysis of the Regulation Market following the December 1, 2008, market rule changes resulted in the discovery that a significant number of marginal units whose schedule should have been switched to the lower of the price or cost based offer under the new rule were not switched. The MMU communicated this to PJM. PJM subsequently modified the market clearing process, effective September 9, 2010. The MMU has not been provided an updated design document for these changes. It is not clear that PJM's approach is a complete fix but it is difficult to evaluate in the absence of documentation.

Analysis of Regulation Market Changes

There were significant changes made to the Regulation Market effective December 1, 2008. The rule changes are summarized in Table 6-13. The changes were the result of a filing by PJM that reflected a compromise among market participants in the PJM process.[33] The MMU filed comments supporting the filing with the caveat that if the MMU review of the actual impact of the changes "results in a conclusion that these features result in non-competitive market outcomes, the Market Monitor will request that one or more of these provisions be removed or modified."[34]

33 See Filing initiating Docket No. ER09-13-000 (October 1, 2008).
34 *Id.* at 2.

Table 6-13 Summary of changes to Regulation Market design

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.

As directed by the FERC, the MMU performed an analysis of these Regulation Market rule changes, delivering a report on November 30, 2009.[35]

Introduction of TPS Testing

The implementation of the TPS test is consistent with the longstanding MMU recommendation that real-time, hourly market structure tests be implemented in the Regulation Market, that market power mitigation be applied only for hours in which the market structure is noncompetitive and that market power mitigation be applied only to the companies failing the market structure tests.

Increase Offer Margin from $7.50 to $12.00

The tariff modifications included an increase of the margin that may be added to cost-based regulation offers from $7.50 to $12.00 per MW. The average cost based regulation offer is less than $10.00 per MW, so this margin represents a substantial adder to costs, more than 100 percent of the average cost of regulation. The MMU does not now recommend reducing the margin to the prior level of $7.50 per MW.

While there was no analytical support provided for the increased margin, it is simply a direct increase in payments. If an increase in payments for regulation is the goal, this is the best mechanism for implementing that goal as it is transparent and does not require inconsistent changes in market rules to increase revenues to the owners of regulation units.

Table 6-14 shows the additional revenues that are paid as a result of the rule change that increased the margin on cost based offers from $7.50 to $12.00 per MWh (Table 6-14). The impact of the increased margin is calculated using the offer margin of all offering units, creating a new supply

35 The MMU report filed in Docket No. ER09-13-000 is posted at: <http://www.monitoringanalytics.com/reports/Reports/2009/IMM_PJM_Regulation_Market_Impact_20081201_Changes_20091130.pdf>(465 KB).

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curve, and re-solving for the new marginal unit and new RMCP. The calculation assumes that synchronized reserve assignments and operating reserve allocations remain the same as in the existing solution. The increase in credits paid, of $6,814,605, is a result of the higher offer margin permitted under the new rules.

Table 6-14 Impact of $12 adder to cost based regulation offer: December 2008 through December 2010

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%
Total				$485,846,657	$7,407,790	1.5%

Change in the Definition of Opportunity Cost

The market clearing price of regulation is a sum of the regulation offer and the lost opportunity cost (LOC), including any applicable shoulder LOC, and in the case of off-line CTs a start-up cost. Offers in the Regulation Market consist of a cost based offer and, optionally, a price-based offer.

The December 1, 2008, tariff modifications included a significant change in the definition of LOC. In the Regulation Market the direct offer price is made by the market participant and the opportunity cost is calculated by PJM based on forecast LMP for the next hour and added by PJM to the direct offer price to get the total offer price. The opportunity cost is, on average, approximately half the total offer price (Figure 6-3). Any modification to the measurement of opportunity cost will have a significant impact on the Regulation Market. The opportunity cost is also directly affected by the levels of LMP.

Under the prior rules, opportunity cost was defined as the difference between the LMP and the offer on which the unit was dispatched in the energy market. Under the December 1, 2008, tariff modifications, opportunity cost is defined as the difference between the LMP, and the lesser of the available price-based energy schedule or the most expensive available cost-based energy schedule. Thus, for units backing down to provide regulation, the new rules result in higher calculated opportunity costs.

The change to the tariff is inconsistent with the definition of opportunity cost, is inconsistent with the way in which opportunity cost is calculated elsewhere in the PJM tariff and is inconsistent with the way in which opportunity cost has been calculated for regulation under the PJM tariff for approximately ten years. The MMU recommends that this modification be reversed and that the correct definition of opportunity cost be reinstated for regulation. In addition to getting the price right, the concept and application of opportunity cost is critical to ensuring an efficient allocation of resources between the energy market and the ancillary services markets. The goal is to hold generators neutral to the decision whether to sell MWh in the energy market or to regulate, in order to ensure that the energy markets and the ancillary markets all clear in an efficient and consistent manner. The goal is also to ensure that regulation offers are taken in merit order based on their actual marginal costs, including their correctly calculated opportunity cost.

The correct way to calculate opportunity cost and maintain incentives across both markets is to treat the offer on which the unit is dispatched as the measure of its marginal costs for both the energy market and the Regulation Market. To do otherwise is to impute a lower marginal cost to the unit than its owner does and therefore impute a higher opportunity cost than the owner does.

A quantification of the financial impact of this rule is not possible because PJM does not save all of the data used to determine the final opportunity cost and market clearing price.[36]

In addition, the implementation of the December 1, 2008, changes was not done correctly. Had the revised opportunity cost rule been implemented correctly the MMU estimates that the schedule switching of marginal units in the Regulation Market would have occurred in 3,793 hours during the 25 month period of December 2008 through December 2010 of which 2,088, 55.0 percent, would have resulted in higher opportunity costs, and 1,621, 42.7 percent, would have resulted in lower opportunity costs being added to the marginal regulation offer. In the remaining 83 hours the schedule switch would not have affected the opportunity cost calculation of the marginal unit.

As actually implemented by PJM, schedule switching of marginal units occurred in 2,074 hours, of which 1,327, 64.0 percent, had higher than correct opportunity costs and 680 hours, 32.8 percent, had lower than correct opportunity costs added to the marginal regulation offer. In the remaining 67

36 The MMU has communicated this concern to PJM and been informed that steps are underway to make additional data available to the MMU.

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hours the schedule switch would not have affected the opportunity cost calculation of the marginal unit.

PJM made a change to the market software (SPREGO) effective September 9, 2010 to address the identified issue with schedule switching.[37]

Eliminate Offset Against Balancing Operating Reserves Credits

The tariff modifications eliminated the offset of the net revenues earned in the Regulation Market against operating reserve credits. There was no specific rationale advanced for this change. This tariff modification is directly counter to the fundamentals of the PJM markets and the purpose of operating reserve credits. The MMU recommends that this modification be reversed and that the net revenues earned in the Regulation Market be offset against operating reserve credits in the same manner that all net revenues from all other PJM markets are offset against operating reserve credits and in the same manner that Regulation Market credits were offset against operating reserve credits prior to December 1, 2008.

The logic of including all market revenues in the calculation of operating reserve credits is clear. The goal is to ensure that unit owners are never required to run their units without compensation of all marginal costs, but all market compensation is included when determining whether there is a shortfall. The exclusion of the regulation revenues is arbitrary and results in an increase in operating reserve charges and a shift of revenues to the owners of regulating units from those who pay operating reserve charges. There is no reason to modify a fundamental market rule in order to provide greater incentives in the Regulation Market. This argument is reinforced by the appropriately increased scrutiny paid to operating reserves in recent years and given the overall goal to reduce these non market payments. If there is actually a need for greater incentives, it should be established directly and the incentive payment made directly in the Regulation Market, for example through the offer margin.

Table 6-15 shows the additional revenue paid as a result of the rule change that no longer nets regulation revenue against balancing operating reserves. This rule change did not change the Regulation Market clearing price. The increase in total regulation credits paid, of $3,236,381, is a result of the elimination of the offset against operating reserve credits that result from the new rules.

37 See “Minutes,” Market Implementation Committee , 11/09/2010, Agenda Item #9, pg. 5. <http://www.pjm.com/~/media/committees-groups/committees/mic/20101109/20101109-minutes.ashx>.

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Table 6-15 Additional credits paid to regulating units from no longer netting credits above RMCP against operating reserves: December 2008 through December 2010

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%
Total		$3,236,381	$485,969,594	0.7%

Summary

The changes in market design increased the payments for regulation service. The impact on the Regulation Market that resulted from the December 1, 2008 rule eliminating the netting of credits against balancing operating reserves was $3,236,381. The impact on the Regulation Market of the December 2008 change increasing the allowable price offer markup from $7.50 to $12 was $6,814,605. These two rule changes increased regulation costs by $10,050,986 over the 25 month period from December 1, 2008 through December 31, 2010.

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The dollar impact of changing the lost opportunity cost definition cannot be determined at this time primarily because the necessary data have not been saved by PJM. The rule would likely have changed the price in approximately 21 percent of hours between December 1, 2008, and December 31, 2010, (hours in which the marginal unit would have a schedule switch for the LOC calculation) and that in approximately 65 percent of those hours the marginal unit reduced output to regulate, meaning that the corresponding schedule switch would increase lost opportunity cost compared to the correct value. In the other 35 percent of the hours, the marginal unit increased output to regulate, meaning that the corresponding schedule switch would tend to reduce lost opportunity cost compared to the correct value.

The addition of the three pivotal supplier test to the Regulation Market improved the competitiveness of the Regulation Market results, compared to the prior market design, by eliminating the non-competitive behaviors that had existed in prior years. However, the other changes in the rules for the Regulation Market, in particular the change to the calculation of the opportunity cost, produced market results that were not competitive. The other changes in the rules resulted in prices in the Regulation Market that deviated from the competitive price that would have resulted without these changes.

Regulation Market prices were lower in 2010 than in 2009. Supply was up slightly and self-scheduled regulation increased significantly.

The competitive price is the price that would have resulted from the application of the prior, correct approach to the calculation of the opportunity cost and to the calculation of the offset against operating reserves. These Regulation Market results are not based on the behavior of market participants, which is competitive as a result of the application of the three pivotal supplier test. As a result, the MMU concludes that the results of the Regulation Market were not competitive in 2010.

Synchronized Reserve Market

Market Structure

PJM continued to operate the two synchronized reserve markets it implemented on February 1, 2007: the RFC Synchronized Reserve Zone Market; and the Southern Synchronized Reserve Zone (Dominion) Market. The RFC Synchronized Reserve Zone Market's reliability requirements are set by the Reliability*First* Corporation. PJM sets the synchronized reserve requirement for the RFC Synchronized Reserve Zone as the larger of Reliability*First* Corporation's imposed minimum requirement or the largest contingency on the system. Although the RFC Synchronized Reserve Market is one market, transmission constraints often limit the amount of Tier 1 synchronized reserve that can be made available to the PJM Mid-Atlantic Subzone of the RFC. This subzone is defined as the RFC Synchronized Reserve Zone exclusive of parts of AP, parts of AEP, DAY, DLCO, and ComEd zones.[38] PJM must clear enough Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market to ensure that the Mid-Atlantic locational synchronized reserve requirement of 1,300 MW is met, after accounting for available Tier 1 supply. This results in a separate Mid-Atlantic Subzone clearing price.

38 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 45 (June 23, 2010), p. 66.

The Southern Synchronized Reserve Zone (Dominion) Market's reliability requirements are set by the Southeastern Electric Reliability Council (SERC).

Supply

Synchronized reserve is an ancillary service defined as generation or curtailable load that is synchronized to the system and capable of producing output or shedding load within 10 minutes. Synchronized reserve can, at present, be provided by a number of resources, including steam units with available ramp, condensing hydroelectric units, condensing combustion turbines (CTs) and CTs running at minimum generation. Synchronized reserve can also be supplied by DSR resources subject to the limit that they provide no more than 25 percent of the total synchronized reserve requirement. Synchronized reserve DSR resources can be provided by behind the meter generation or by load reductions.

All of the resources that participate in the Synchronized Reserve Markets are categorized as Tier 2 synchronized reserve. Tier 1 resources are those resources that are online, following economic dispatch, and able to respond to a spinning event by ramping up from their present output. All resources operating on the PJM system are considered potential Tier 1 resources, except for those explicitly assigned to Tier 2 synchronized reserve. Tier 2 resources include units that are backed down to provide synchronized reserve capability, condensing units synchronized to the system and available to increase output and demand side resources.

Under Synchronized Reserve Market rules, Tier 1 resources are paid when they respond to an identified spinning event as an incentive to respond when needed.[39] Tier 1 synchronized reserve payments or credits are equal to the integrated increase in MW output above economic dispatch from each generator over the length of a spinning event, multiplied by the synchronized reserve energy premium less the hourly integrated LMP. The synchronized reserve energy premium is defined as the average of the five minute LMPs calculated during the spinning event plus $50 per MWh. All units called on to supply Tier 1 or Tier 2 synchronized reserve have their actual MW monitored. Tier 1 units are not penalized if their output fails to match their expected response as they are only compensated for their actual response.

Under Synchronized Reserve Market rules, Tier 2 synchronized reserve resources are paid to be available as synchronized reserve, regardless of whether the units are called upon to generate in response to a spinning event, and are subject to penalties if they do not provide synchronized reserve when called. The price for Tier 2 synchronized reserve is determined in the Synchronized Reserve Market. Several steps are necessary before the hourly Synchronized Reserve Market is cleared. Ninety minutes prior to the start of the hour, PJM estimates the amount of Tier 1 reserve available from every unit. Sixty minutes prior to the start of the hour, self-scheduled Tier 2 units are identified. Thirty minutes prior to the hour, Tier 1 is estimated again. If synchronized reserve requirements are not met by Tier 1 and self-scheduled Tier 2 resources, then a Tier 2 market is cleared at least 30 minutes prior to the start of the hour. The Tier 2 market clearing price is equivalent to the price of the highest-priced, Tier 2 resource needed to meet the demand for synchronized

39 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 45 (June 23, 2010), p. 75.

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reserve requirements, the marginal unit, based on the simultaneous clearing of the Regulation Market and the Synchronized Reserve Market.[40]

The Synchronized Reserve Market is characterized by structural market power. As a result, the synchronized reserve offer submitted for a unit can be no greater than the unit's incremental operating and maintenance cost plus a $7.50 per MWh margin.[41,42] The market clearing price is comprised of the marginal unit's synchronized reserve offer price, the cost of energy use, the startup cost (if the unit is not running) and the unit's lost opportunity cost. Opportunity cost is calculated by PJM based on forecast LMPs and generation schedules from the unit dispatch system. Opportunity cost for demand-side resources is always zero. All units cleared in the Synchronized Reserve Markets are paid the higher of either the market-clearing price or the unit's synchronized reserve offer plus the unit specific opportunity cost and the cost of energy use incurred.

For the RFC Synchronized Reserve Zone in 2010, the offered and eligible excess supply ratio was 2.68. Within the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone, the offered and eligible excess supply ratio was 1.16.[43] These excess supply ratios are determined using the administratively established requirement for synchronized reserve. Actual market demand for Tier 2 synchronized reserve is lower than the synchronized reserve requirement because a significant amount of Tier 1 synchronized reserve is usually available.

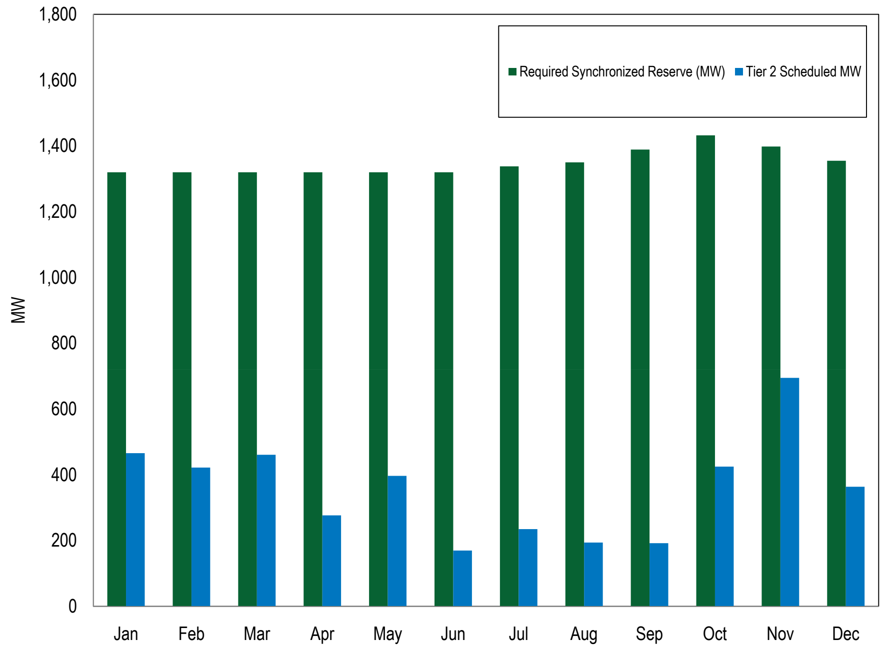
Demand

The market demand for Tier 2 synchronized reserve is determined by subtracting the amount of forecast Tier 1 synchronized reserve available from each synchronized reserve zone's synchronized reserve requirement for the period. Market demand is further reduced by subtracting the amount of self scheduled Tier 2 resources. The total synchronized reserve requirement is different for the two Synchronized Reserve Markets. The synchronized reserve requirement is determined at the discretion of PJM to ensure system reliability and to maintain compliance with applicable NERC and regional reliability organization requirements. RFC and Dominion reserve requirements are determined on at least an annual basis. Mid-Atlantic Subzone requirements are established on a seasonal basis.[44]

Currently the RFC synchronized reserve requirement is the greater of the Reliability*First* Corporation's imposed minimum requirement or the system's largest contingency. The actual synchronized reserve requirement for the RFC Zone for January 2010, through June 2010, was 1,320 MW. For the rest of 2010 it has remained at 1,350 MW. Exceptions to this requirement can occur when grid maintenance or outages change the largest contingency. Such a condition occurred between September 20 and September 29, when the synchronized reserve requirement was set to 1,700 MW. Between November 15 and November 19 it was set to 1,725 MW. Between October 11 and October 13 it was set to 2,500 MW. Figure 6-6 shows the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled during 2010 for the RFC Synchronized Reserve Market.

40 Although it is unusual, a PJM dispatcher can deselect units which have been committed after the clearing price has been established. This only happens if real-time system conditions require dispatch of a spinning unit for constraint control, or problems with a generator or monitoring equipment are reported.
41 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 45 (June 23, 2010), p. 65.
42 See PJM. "Manual 15: Cost Development Guidelines," Revision 15 (October 27, 2010), p. 37.
43 The Synchronized Reserve Market in the PJM Southern Region cleared in so few hours that related data for that market are not meaningful.
44 See PJM. "Manual 10: Pre-Scheduling Operations," Revision 25 (January 1, 2010), p. 18.

Figure 6-6 RFC Synchronized Reserve Zone monthly average synchronized reserve required vs. Tier 2 scheduled MW: Calendar year 2010



The RFC Synchronized Reserve Zone is large and some available Tier 1 must be physically located in the Mid-Atlantic Subzone as a result of transmission limits between the western and eastern portions of the zone. PJM calculates the transfer capability of these transmission facilities. The calculation of Mid-Atlantic Subzone Tier 1 includes what is available in the east plus the amount of Tier 1 synchronized reserve in the west that can be transferred into the east. The Synchronized Reserve Market solution is especially sensitive to this limit (known as transfer capacity). The higher this transfer capacity, the greater is the amount of Tier 1 synchronized reserve available in the East and so the less Tier 2 synchronized reserve that needs to be cleared to satisfy the synchronized reserve requirement. From 2007 through mid-March 2009, PJM market operations had estimated this transfer capacity at 70 percent of available RFC Tier 1 not exclusively in the Eastern subzone. However, PJM dispatch frequently observed a more restrictive limitation on transfer capacity in real-time operations on the western interface (Bedington—Black Oak) and needed to add additional synchronized reserve outside of the market solution in order to cover the requirement. This was the source of Added Synchronized Reserve resulting in lost opportunity costs being added to synchronized reserve costs.[45]

In mid March of 2009, PJM reset the transfer capacity from 70 percent to 15 percent. PJM also changed the transfer interface from Bedington – Black Oak to AP South. As a result, less Tier 1 synchronized reserve was available to the Mid-Atlantic Subzone for the market solution, increasing

45 See *2007 State of the Market Report*, Volume II, section 6 Ancillary Service Markets pp. 299, 300. Also *2008 State of the Market Report for PJM*, Volume II, section 6 Ancillary Service Markets, p. 328.

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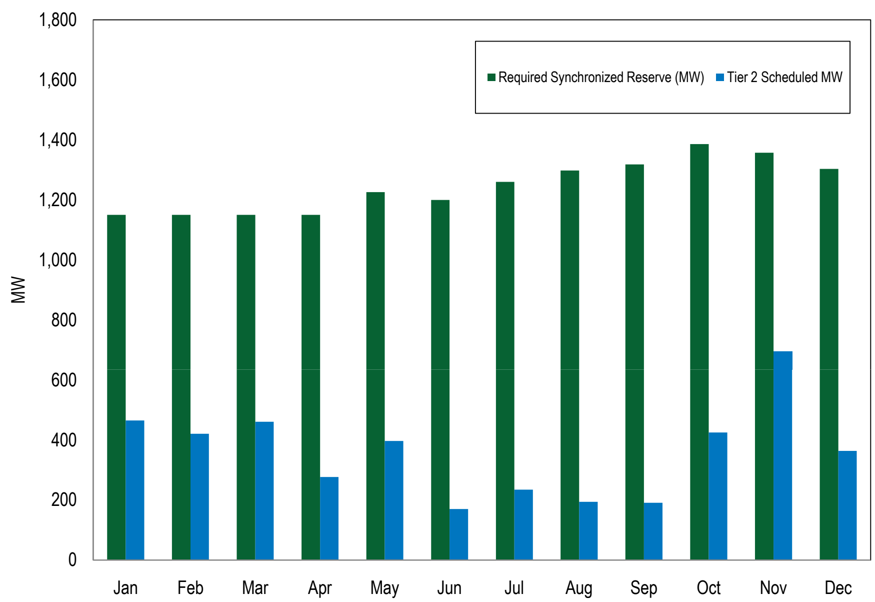
the amount of Tier 2 that had to be cleared to satisfy the requirement. This also reduced the amount of Tier 2 synchronized reserve that had to be added by PJM dispatch after market.[46]

As a whole, the RFC Synchronized Reserve Zone almost always has enough Tier 1 to cover its synchronized reserve requirement. Available Tier 1 in the western part of the RFC Synchronized Reserve Zone generally exceeds the total synchronized reserve requirement in the west. In 2010, the RFC Synchronized Reserve Zone cleared a Tier 2 Synchronized Reserve Market in less than one percent of all hours. This is not the case in the Mid-Atlantic Subzone. As a result, there is frequently a Tier 2 synchronized reserve requirement only in the Mid-Atlantic Subzone and a separate clearing price only for the Mid-Atlantic Subzone. The Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone cleared a separate Tier 2 market in 67 percent of all hours. Figure 6-7 compares the required synchronized reserve MW to the scheduled Tier 2 MW for the Mid-Atlantic Subzone only.

Figure 6-7 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone average hourly synchronized reserve required vs. Tier 2 scheduled: Calendar year 2010

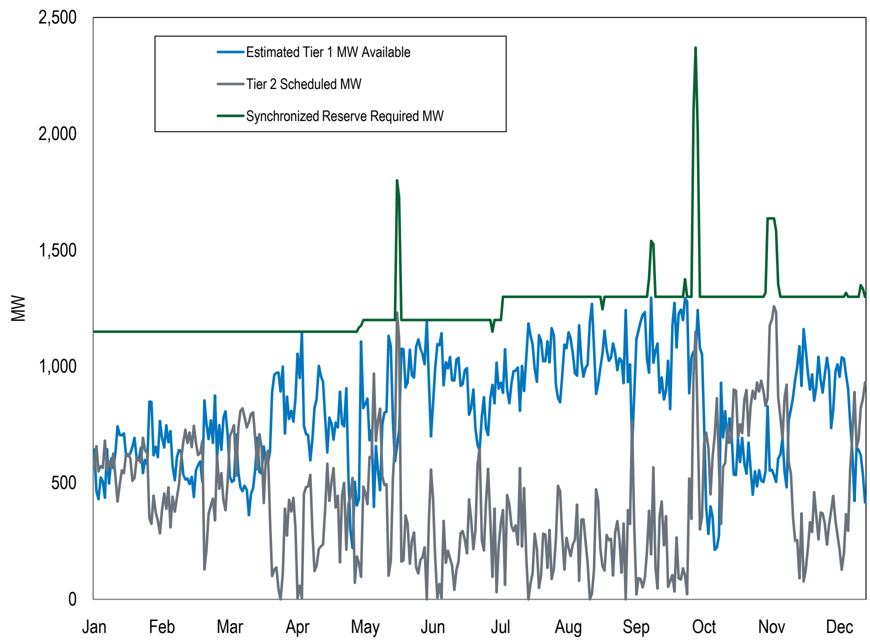


The actual synchronized reserve requirement for the Mid-Atlantic Subzone for 2010 was usually 1,300 MW but there were several days when temporary grid conditions created a double contingency which increased the requirements. Required synchronized reserve was as high as 2,500 MW on October 11-13, 2010. Throughout 2010, the average synchronized reserve required MW in the Mid-Atlantic Subzone was 1,247 MW. The difference between the level of required synchronized reserve and the level of Tier 2 synchronized reserve scheduled is the amount of Tier 1 synchronized reserve available on the system.

46 See *2009 State of the Market Report*, Volume II, section 6 Ancillary Service Markets pp. 384, Table 6-14.

Figure 6-8 shows the relationship among the PJM Mid-Atlantic synchronized reserve required, the estimated Tier 1 available and the amount of Tier 2 synchronized reserve needed to be purchased. The more Tier 1 is available the less Tier 2 is required.

Figure 6-8 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone daily average hourly synchronized reserve required, Tier 2 MW scheduled, and Tier 1 MW estimated: Calendar year 2010



The Southern Synchronized Reserve Zone is part of the Virginia and Carolinas Area (VACAR) subregion of SERC. VACAR specifies that available, 15 minute quick start reserve can be subtracted from Dominion's share of the largest contingency to determine synchronized reserve requirements.[47] The amount of 15 minute quick start reserve available in VACAR is sufficient to make Tier 2 synchronized reserve demand zero for most hours. The actual hourly Southern Synchronized Reserve Zone's synchronized reserve requirement was usually zero because Dominion's share of the largest contingency within VACAR was offset by its quick start capability. The Southern Synchronized Reserve Zone cleared a Tier 2 market for only 11 hours in 2010.

Market Concentration

The RFC Tier 2 Synchronized Reserve Market was slightly more concentrated in 2010 than it had been in 2009. The RFC Synchronized Reserve Market remains highly concentrated and dominated by a relatively small number of companies. The participation of demand resources in the market continues to have a significant impact on the market solution, resulting in lower prices and less concentration. The HHI for the Mid-Atlantic Subzone of the 2010 RFC Synchronized Reserve Market was 3222, which is defined as "highly concentrated."

47 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 45 (June 23, 2010), p. 66.

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The largest hourly market share was 98 percent and 68 percent of all hours had a maximum market share greater than or equal to 40 percent. In less than one percent of Mid-Atlantic Subzone hours during which a market was cleared in 2010, a single company had 90 percent or more of the market share. The highest annual average market share for a single company for all hours in which it had any market share, was 43 percent. In other words, a single company sold 43 percent of synchronized reserves on average for all hours in which it had market share over the entire year (Table 6-16).

Table 6-16 Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market's cleared market shares: Calendar year 2010

Company Market Share Rank	Cleared Synchronized Reserve Average Market Share
1	43%
2	25%
3	25%
4	17%
5	12%

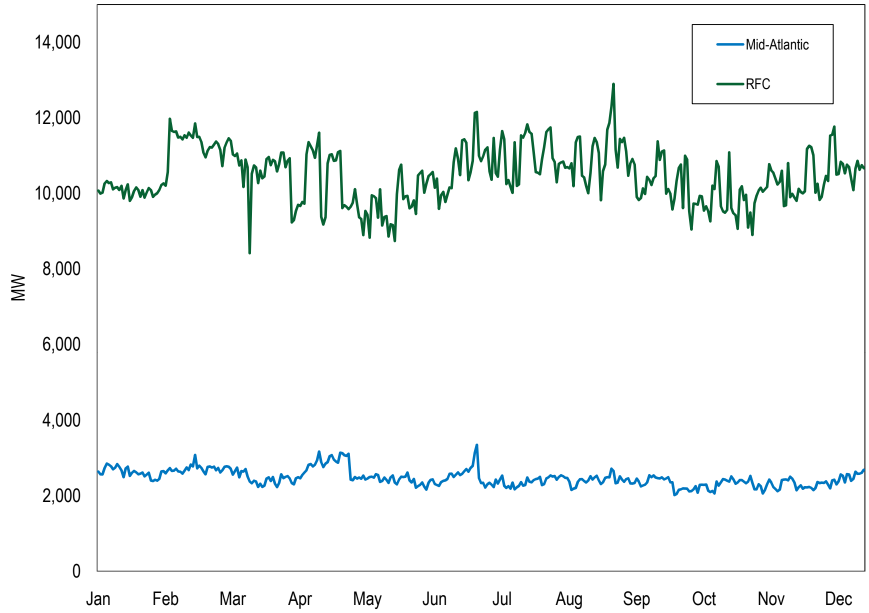
In 2010, 62 percent of hours in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market failed the three pivotal supplier test. One company was pivotal in 99 percent of all pivotal hours, a second company was pivotal in 47 percent of all pivotal hours, and a third company was pivotal in 34 percent of all pivotal hours. These results indicate that the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, the only synchronized reserve market that clears on a regular basis, is not structurally competitive.

Market Conduct

Offers

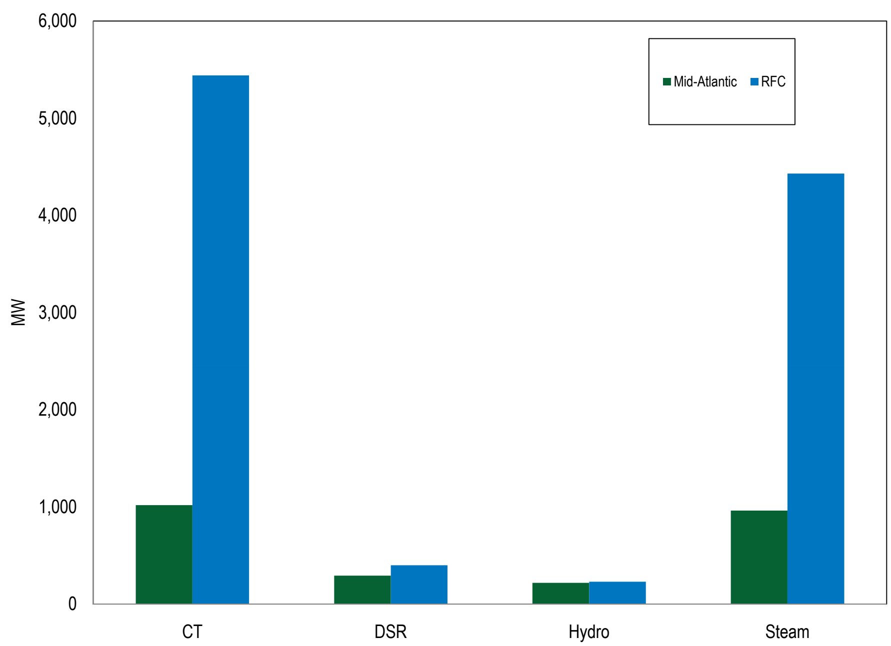
Figure 6-9 shows the daily average hourly offered Tier 2 synchronized reserve MW. For steam units, offered MW are eligible only if the offering unit is running. For that reason, the eligible offer volume shows weekly variability based on off-peak/on-peak operating cycles as well as seasonal variability.

Figure 6-9 Tier 2 synchronized reserve average hourly offer volume (MW): Calendar year 2010



Synchronized reserve is offered by steam, CT, hydroelectric and DSR resources. Figure 6-10 shows average offer MW volume by market and unit type.

Figure 6-10 Average daily Tier 2 synchronized reserve offer by unit type (MW): Calendar year 2010



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The contribution of DSR resources to the Synchronized Reserve Market remained significant in 2010. The significance of DSR in the Synchronized Reserve Markets is greater than its eligible offer MW as illustrated in Figure 6-10. In 2010, DSR accounted for 20 percent of all cleared Tier 2 synchronized reserves. In 8 percent of hours when a synchronized reserve market was cleared all cleared MW was DSR. In the hours when all supply was DSR, the unweighted average SRMCP was $1.39. The unweighted average SRMCP for all cleared hours was $8.49. As defined by PJM, demand-side resources may at times be generation that is behind the meter.

DSR

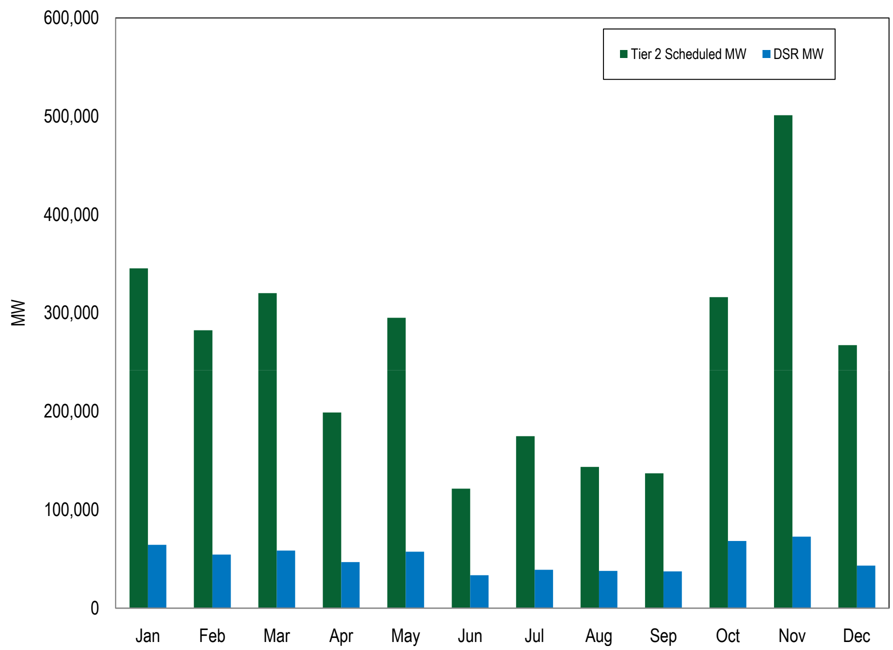
Demand-side resources were permitted to participate in the Synchronized Reserve Markets effective August 2006. DSR continues to have a significant impact on the Synchronized Reserve Market. In 8 percent of hours where a synchronized reserve market was cleared in the Mid-Atlantic Subzone of the RFC (see Table 6-17), all cleared synchronized reserve was DSR synchronized reserve. The clearing price for those hours was significantly lower than the average clearing price overall.

Table 6-17 Average RFC SRMCP when all cleared synchronized reserve is DSR, average SRMCP, and percent of all cleared hours that all cleared synchronized reserve is DSR: Calendar year 2010

Month	Average SRMCP	Average SRMCP when all cleared synchronized reserve is DSR	Percent of cleared hours all synchronized reserve is DSR
Jan	$5.84	$2.03	4%
Feb	$5.97	$0.10	1%
Mar	$8.45	$2.01	6%
Apr	$7.84	$1.86	17%
May	$9.98	$1.68	15%
Jun	$9.61	$0.74	9%
Jul	$16.30	$0.79	7%
Aug	$11.17	$0.93	12%
Sep	$10.45	$1.15	12%
Oct	$8.21	$1.06	8%
Nov	$9.59	$0.36	1%
Dec	$12.49	$0.88	4%

Figure 6-11 shows total cleared plus self-scheduled monthly synchronized reserve MW and cleared plus self-scheduled MW for DSR synchronized reserve. Participation of demand response in the Synchronized Reserve Market remained strong in 2010. Demand response remained significantly less expensive than other forms of synchronized reserve. Demand resources typically offer at a lower price, and demand resources do not have lost opportunity costs added to their offer in market clearing. Furthermore demand resources add some diversity to the supply of synchronized reserve, reducing market concentration.

Figure 6-11 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: Calendar year 2010



Market Performance

Price

Figure 6-12 shows the relationship among required Tier 2 synchronized reserve, Synchronized Reserve Market clearing price, and percent of cleared synchronized reserve satisfied by DSR in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market. This figure shows both that the synchronized reserve clearing price tends to increase with demand and that DSR satisfies a large percentage of Tier 2 synchronized reserve when the demand is low.

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Figure 6-12 Required Tier 2 synchronized reserve, Synchronized Reserve Market clearing price, and DSR percent of Tier 2

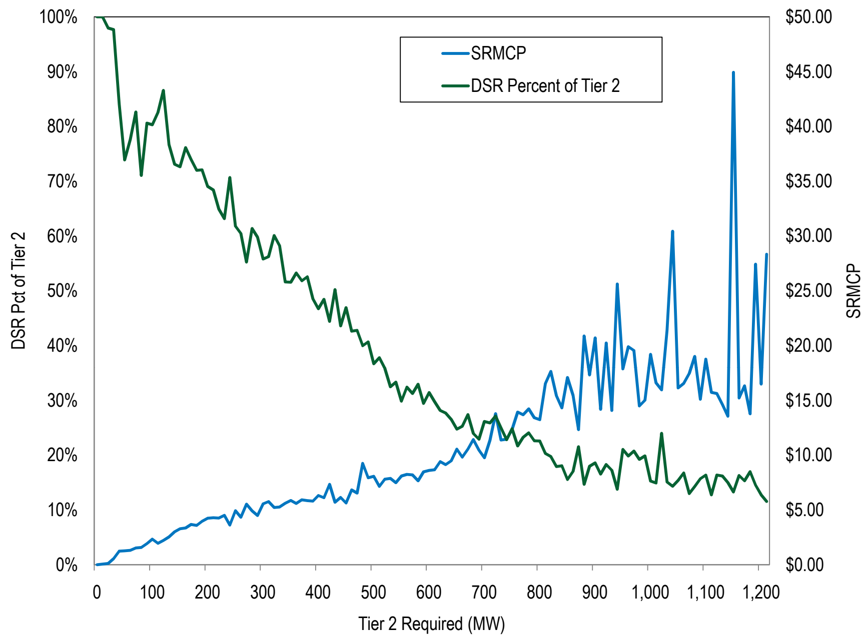


Figure 6-15 shows the load weighted, average Tier 2 price and the cost per MW associated with meeting PJM demand for synchronized reserve. The price of Tier 2 synchronized reserve is the Synchronized Reserve Market-clearing price (SRMCP). Resources which provide synchronized reserve are paid the higher of the SRMCP or their offer plus their unit specific opportunity cost. The offer plus the unit specific opportunity cost may exceed the SRMCP for a number of reasons. If real-time LMP is greater than the LMP forecast prior to the operating hour and included in the SRMCP, unit specific opportunity cost will be higher than forecast. Such higher LMPs can be local because of congestion or more general if system conditions change. The additional costs of noneconomic dispatch are added to the total cost of synchronized reserve. When some units are paid the value of their offer plus their unit specific opportunity cost, the result is that PJM's synchronized reserve cost per MW is higher than the SRMCP.

The load weighted, average price for synchronized reserve in the PJM Mid-Atlantic Subzone of the RFC Synchronized Reserve Market in 2010 was $10.55 while the corresponding cost of synchronized reserve was $14.41.

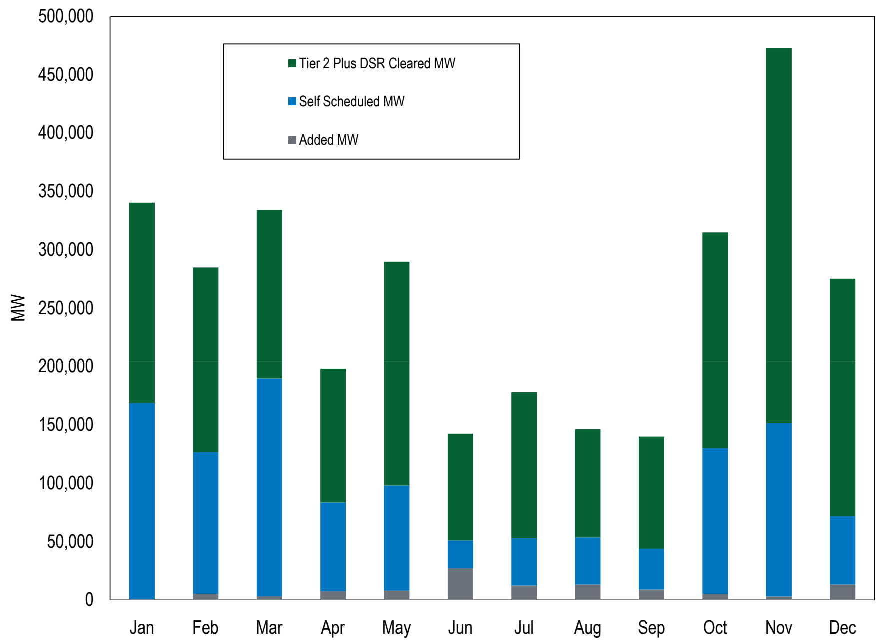
The RFC Synchronized Reserve Market cleared as a single market less than one percent of all hours in 2010 with a load weighted average $0.80 clearing price.

Price and Cost

A high price to cost ratio is an indicator of an efficient market design, where the costs are the result of the economic solution. A low price to cost ratio is in part a result of out-of-market purchases of Tier 2 synchronized reserve by PJM dispatchers who need the reserves for reliability reasons.

The primary reason for the relatively low price to cost ratio is the difference in opportunity cost calculated using the forecast LMP and the actual LMP.

Figure 6-13 Tier 2 synchronized reserve purchases by month for the Mid-Atlantic Subzone: Calendar year 2010



The problem of out-of-market purchases of Tier 2 synchronized reserve was greatly diminished by the March 13, 2009 change in the transfer capacity used in the market solution (Figure 6-13). The difference between the Tier 2 Synchronized Reserve Market price and the cost for Tier 2 synchronized reserve in 2010 was slightly higher than it had been in 2009 (Figure 6-14). In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market for 2010, the cost of Tier 2 synchronized reserves was 37 percent higher than the load-weighted price. In 2009 this difference had been 26 percent.

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Figure 6-14 Impact of Tier 2 synchronized reserve added MW to the RFC Synchronized Reserve Zone, Mid-Atlantic Subzone: Calendar year 2010

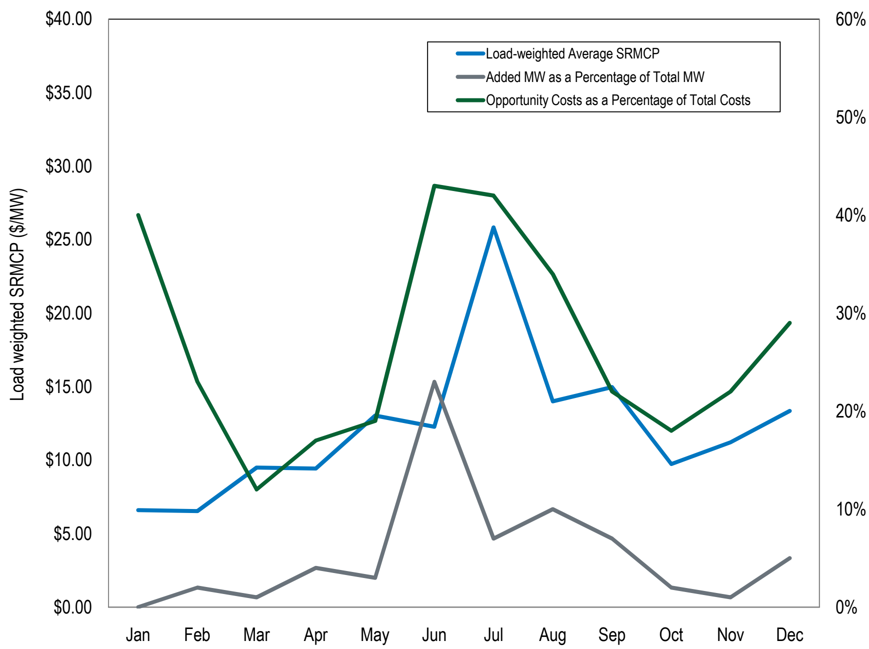
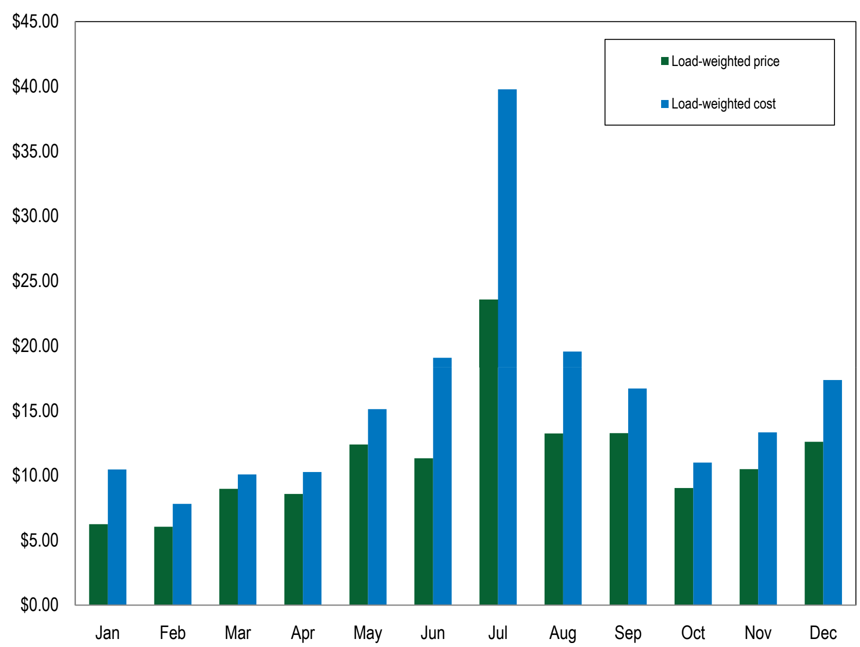


Figure 6-15 Comparison of RFC Mid-Atlantic Subzone Tier 2 synchronized reserve price and cost (Dollars per MW): Calendar year 2010



A high price to cost ratio is an indicator of an efficient market design, where the costs are the result of the economic solution. Table 6-18 shows the price and cost history of the Synchronized Reserve Market since 2005. In March of 2009, PJM took steps to reduce the amount of aftermarket added synchronized reserve being added by the dispatchers. As a result, the price to cost ratio increased in 2009.

Synchronized reserve prices were 36.1 percent higher in 2010 than in 2009, but lower than in any other year since 2005. Synchronized reserves total costs per MW were 47.5 percent higher in 2010 than in 2009. The total cost of synchronized reserves per MW was 36.6 percent higher than the market clearing price in 2010. The result was a decrease in the ratio of price to cost.

A key source of the difference between the market clearing price and the cost per MW of synchronized reserve results from differences in opportunity cost between the forecast LMP and actual LMP. To address this issue, the MMU recommends that the hourly clearing price for synchronized reserve be determined after the close of the hour. All units cleared in the synchronized reserve market in the hour prior would be paid the market-clearing price based on the actual LMP rather than the forecast LMP.

Table 6-18 Comparison of load weighted price and cost for PJM Synchronized Reserve, January 2005 through December 2010

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%

Market Solution and Actual Dispatch of Ancillary Services

The actual dispatch of ancillary services can and does differ from the market solution at times, as a result of reliability concerns. The result is usually that total costs per MW (credits/MW) are higher than the clearing price (RMCP). The MMU analyzes this cost/price differential and reports the cost and price.

The market solution software (SPREGO) optimizes regulation and spinning using a theoretical unit dispatch and estimated Tier 1 synchronized reserve based on forecast load. Dispatchers can deselect a unit from regulation, Tier 1 or Tier 2 synchronized reserve, or unit dispatch prior to running the market solution. This is the equivalent of imposing a constraint on the market solution.

The MMU recommends that a full list of potential reasons for unit deselection be published in PJM's M-11 Scheduling Operations Manual. The MMU also recommends that dispatchers document all actual unit deselections and the reasons for deselection.

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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, nor the Mid-Atlantic subzone of the RFC market experienced deficits in 2010.

Day Ahead Scheduling Reserve (DASR)

The Day-Ahead Scheduling Reserve Market is a market based mechanism for the procurement of supplemental, 30-minute reserves on the PJM System.[48] Prior to June 1, 2008, PJM obtained supplemental reserves from several sources including available unused capacity of generating units that had been dispatched for energy, available capacity of units not dispatched for energy but capable of coming online in 30 minutes and dispatch of additional units for the purpose of making supplemental reserve available.

On June 1, 2008, PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the settlement in the RPM case.[49] 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 the market clearing price. The DASR 30-minute reserve requirements are determined by the reliability region.[50] In the Reliability*First* (RFC) region, reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[51] Under-forecasted load rates are based on the 80th percentile of a rolling three-year average (November 1 – October 31). For 2010, the load forecast error component of this calculation was 1.90 percent of peak load forecast. The forced outage rate component of the calculation is based on a three-year rolling average of the forced outage rate that occurs from 1800 of the scheduling day through the operating day at 2000. For 2010, the forced outage component of the Day-Ahead Scheduling Reserve was 4.98 percent. For 2010 the Day-Ahead Scheduling Reserve for RFC areas of PJM was 6.88 percent times Peak Load Forecast for RFC. Dominion Day-Ahead Scheduling Reserve is based on its share of the VACAR Reserve Sharing agreement and is set annually. In 2010 VACAR scheduling reserve was set at 418 MW. The RFC and Dominion Day-Ahead Scheduling Reserve 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.

DASR is an offer-based market that clears for all hours of the day at 1600 EPT day-ahead. DASR Market clearing is simultaneous with the Day-Ahead Energy Market.

48 PJM uses the terms “supplemental operating reserves” and “scheduling operating reserves” interchangeably.
49 See, 117 FERC ¶ 61,331 (2006).
50 PJM. “Manual 13, Emergency Requirements,” Revision 41 (October 1, 2010), pp. 11-12.
51 PJM. “Manual 10, Pre-Scheduling Operations,” Revision 25 (January 1, 2010), p. 17.

Market Structure

All generating resources capable of increasing their output in 30 minutes are eligible to provide DASR. Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are also eligible to provide DASR. All DASR offers must be submitted by 1200 EPT day-ahead. There is a must offer requirement in the DASR Market, but any offer price will satisfy the requirement. Resources which are eligible for DASR but which have not offered into the market will have their offers set to $0.00.

In 2010, the three pivotal supplier test was failed in the DASR Market in a total of 122 hours (1.3 percent of all hours), all of which were in June, July, August, and September.

Demand side resources do participate in the DASR Market, but remain insignificant. Demand side resources began to offer and clear the DASR market in November 2008. No demand side resources cleared the DASR market in 2010.

In 2010, the required DASR was 6.88 percent of peak load forecast, up from 6.75 percent in 2009.[52] As a result of increased demand for energy, reflected in higher forecast peak loads and increased DASR requirements, the DASR MW purchased increased by 9 percent in 2010 over 2009.

Market Conduct

PJM rules require all units with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[53] Units that do not offer will have their offers set to $0/MW. In 2010, 54 percent of all generating units had no DASR offers or offers of $0. Every unit type had significant offers at $10/MW or lower. Economic withholding remains an issue in the DASR Market. Continuing a pattern seen since the inception of the DASR Market, five percent of units offered at $50 or more and 45 units offered at more than $900, in a market with an average clearing price of $0.16 and a maximum clearing price of $39.99. Such offers are high enough to ensure that the unit will never clear and thus constitute economic withholding. The level of economic withholding has been small enough that it has not affected prices. The DASR Market has been characterized by low prices.

Table 6-19 lists the unit types offering at $990/MW. Of the 24 CTs, four offered at $990/MW in January and February but changed their offer to $0 for the other 10 months of 2010. All of these units, with the exception of four CTs, had offer prices of $990 for the entire year in 2010. The Market User Interface does provide a mechanism for a unit not to offer for a particular day although none of the units offering at $990/MW chose to use this option.

52 See the *2010 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Services" at Day Ahead Scheduling Reserve *(DASR)*.

53 PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 45 (June 23, 2010), p. 122.

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Table 6-19 Count of units by unit type offering DASR at $990/MW

Unit Type	Unit Count
Diesel	2
CT	24
Nuclear	10
Steam	6
Wind	3

Market Performance

DASR prices are closely related to energy prices, peaking in the summer months. In 2010, the load weighted price of DASR was $0.16 per MW. In 2009, the load weighted price of DASR was $0.05 per MW. The maximum clearing price in 2010 was $39.99 per MW in July.

Table 6-20 2010 PJM, Day-Ahead Scheduling Reserve Market MW and clearing prices

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	6,246	$0.00	$0.75	$0.05	4,647,334	$242,018
Feb	6,191	$0.00	$0.50	$0.06	4,160,064	$228,087
Mar	5,441	$0.00	$0.50	$0.03	4,042,540	$110,074
Apr	4,871	$0.00	$0.42	$0.01	3,789,115	$45,352
May	5,487	$0.00	$2.00	$0.05	4,082,028	$164,277
Jun	6,864	$0.00	$5.00	$0.18	4,941,835	$838,178
Jul	7,464	$0.00	$39.99	$0.76	5,553,319	$3,606,940
Aug	7,131	$0.00	$12.00	$0.38	5,305,750	$1,754,295
Sep	5,889	$0.00	$5.00	$0.06	4,239,965	$241,840
Oct	5,074	$0.00	$0.04	$0.00	3,775,214	$10,421
Nov	5,412	$0.00	$0.05	$0.01	3,912,897	$33,543
Dec	6,328	$0.00	$2.00	$0.03	4,707,794	$129,790

The MMU concludes that the results of the DASR Market were competitive in 2010. The MMU concludes that the DASR Market was structurally competitive in 2010. The MMU concludes that participant behavior was mixed as a result of the economic withholding by some units. This behavior was limited to a relatively small number of units and had no impact on DASR prices in 2010 as a result of a favorable balance between supply and demand, but that balance could change quickly as a result of weather or other factors and the impacts could be significant. The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test in order to address potential market power issues.

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Black Start Service

PJM and its transmission owners must provide for sufficient and appropriately located resources that are capable of providing black start service in the PJM region. To accomplish this, transmission owners prepare system restoration plans that identify critical resources for reenergizing the grid following a possible blackout. Individual transmission owners, with PJM, identify the black start units included in each transmission owner's system restoration plan. PJM ensures the availability of black start by charging transmission customers according to their zonal load ratio share and compensating black start unit owners according to an incentive rate or their revenue requirements (Table 6-21). PJM defines a minimum critical black start for each transmission zone.[54]

Black start service is necessary to help ensure the reliable restoration of the grid following a black out. Black start service is the ability of a generating unit to start without an outside electrical supply or the demonstrated ability of a generating unit with a high operating factor to automatically remain operating at reduced levels when disconnected from the grid.[55]

Table 6-21 Black start yearly zonal charges for network transmission use: Calendar year 2010

Zone	Network Charges	Black Start Rate ($/MW)
AECO	$371,700	$0.38
AEP	$628,476	$0.07
AP	$135,825	$0.04
BGE	$499,080	$0.21
ComEd	$3,773,721	$0.49
DAY	$137,622	$0.11
DLCO	$28,835	$0.03
DPL	$359,691	$0.30
JCPL	$444,216	$0.25
Met-Ed	$414,618	$0.46
PECO	$779,523	$0.31
PENELEC	$334,265	$0.37
Pepco	$250,259	$0.13
PPL	$150,145	$0.06
PSEG	$1,676,711	$0.55

Schedule 6A of the PJM OATT makes available formula rates for units identified as "critical" in system restoration plans to collect their costs and authorizes PJM to perform billing and settlement of these costs (including costs collected pursuant to separately filed and eligible FERC tariffs). Schedule 6A was originally implemented in a manner most suited to the needs of existing older units that were equipped to provide black start service. Because the investment in the equipment needed to provide black start service by these units was made some time ago, the purpose of

54 See PJM. "Manual 36, System Restoration," Revision 12 (January 1, 2010) p. 53.
55 OATT, Sheet No. 33.01.

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Schedule 6A was primarily to provide a level of compensation sufficient to encourage the owners of identified critical resources to continue providing the service.[56] These provisions established a rolling two-year commitment, appropriate for older units with no requirement for new investment in black start related equipment.

In 2003, PJM, working with American Electric Power Service Corporation ("AEP"), determined that new black start capability was needed at a certain location on the AEP system, partly as a result of the retirement of a legacy black start service unit. PJM issued a request for proposal, and received only offers from suppliers who would need to install new equipment in order to provide the service. PJM selected from the few potentially viable projects, Constellation's offer to provide black start service from its Big Sandy Peaker Plant ("Big Sandy"). Big Sandy required approximately $667,000 to install a 750 kW diesel generator and associated controls. Constellation deemed the recovery provisions included in Schedule 6A inadequate, especially in light of the maximum two-year commitment to which AEP would agree. Constellation therefore sought and obtained FERC approval to collect its entire capital investment over that two-year period, citing as precedent a comparable arrangement between University Park Energy, LLC ("UPE") and Commonwealth Edison Company ("ComEd") that PJM grandfathered in the course of integrating ComEd's system into PJM. Constellation indicated to the Commission its expectation that Big Sandy, like UPE, expected to collect payment under Schedule 6A's formula rates after completing recovery of 100 percent of its investment. This might also have served as the pattern for the procurement of black start services from Lincoln Generating Facility, LLC, except that, partly in response to concerns raised by the MMU, Lincoln agreed to file for a longer five-year commitment period, although full investment cost recovery was accelerated to the first two years.

The MMU had concerns that Schedule 6A was not providing an appropriate framework for the procurement of black start service from new resources. The fundamental problem was that transmission customers in the PJM Region were paying over a short time the cost of substantial capital investments in black start capable resources with no assurance that those resources would continue to provide black start service after the expiration of the initial two-year term. Moreover, the rates of return for a new black start unit that recovered its full capital cost in two years and then reverted to the incentive structure under the formula rates, recovering its cost twice, were far in excess of returns typical for services procured under cost-of-service ratemaking.

In late 2007, PJM reactivated the Black Start Service Working Group ("BSSWG") in order to consider how to recover the new costs of compliance with the NERC standards for Critical Infrastructure Protection (CIP) applicable specifically to black start units and to update an outdated reference in the formula to the pre-RPM "Capacity Deficiency Rate." PJM's stakeholders agreed to also develop modifications to provide for a mechanism that conforms the commitment period to provide black start service to the period for recovery of the costs of new investment in black start equipment. The revisions to Schedule 6A developed by the BSSWG to address these and other issues were filed with the FERC on February 19, 2009.[57] By order issued May 29, 2009, the Commission approved the reforms.[58] The Commission did not approve a measure supported by the MMU that would have prevented double recovery of revenues by certain black start units that received accelerated

56 See PJM filing initiating FERC Docket No. ER02-2651-000 at 4 (September 30, 2002)("2002 Schedule 6A Filing").
57 PJM filed the revised Schedule 6A in FERC Docket No. ER09-730-000.
58 127 FERC ¶ 61,197.

recovery of investment in black start equipment prior to the reforms becoming effective on April 21, 2009.[59]

Structure

There is no organized market for black start service in PJM and there is unlikely to be a competitive market for black start service given the very local nature of the requirements. PJM in conjunction with its transmission owners identifies locations where critical black start units are needed and conducts requests for proposals to procure service at those locations. Proposals are accepted from any party willing and able to provide the service at the required location. No customers or their representatives are involved in this process. The MMU is not aware that any request for proposal process has received more than a handful of offers. This result is not unexpected, as there are a very limited number of existing facilities at particular locations indentified in PJM's system restoration plans eligible to provide the service needed. The MMU has concerns that there is a disconnect between a service that is required for system reliability and the need to secure voluntary participation in the system restoration plans from the relatively few potentially cost-effective providers at the critical locations identified. Clearly, the owners of the few facilities able to respond to the requests for proposal have local market power in the provision of black start services as a result both of inelastic demand and the small size of the local market. The significantly increasing costs and risks associated with providing this service as a result of more rigorous and enforceable security standards may aggravate this problem, despite PJM's efforts to address this issue.

Conduct

Consistent with its limited and shared authority, PJM generally has managed the request for proposals process in an orderly and transparent manner. PJM and transmission owners have ensured the provision of black start service, but there is no basis for confidence that black start service has been obtained at least cost. The MMU is concerned that the process does not ensure adequate scrutiny of the proposals or meaningful competition.

Performance

Although the procurement process is transparent and administered well, it is not a "competitive" process. The request for proposal process cannot be relied upon to ensure just and reasonable rates for black start service because the market is characterized by inelastic demand and substantial local market power. PJM has correctly described Schedule 6A and its formula rates as "designed to provide generators with an adequate incentive to supply Black Start Service but not to result in excessive payments," and its performance should be evaluated in that framework.[60]

As revised, the formula under Schedule 6A allows black start service providers to recover the costs of new investment and reasonably conforms the terms of commitment by the providers of black start service to the period over which investment costs are recovered. However, the inclusion of

59 See Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM filed in ER09-730-002 (August 28, 2009); 128 FERC ¶ 61,249 at PP 18—20 (September 17, 2009).
60 2002 Schedule 6A Filing at 4.

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CIPS costs applicable to black start service may lead to substantial increases in the cost of black start service. Certain units may incur these costs and continue to be included in system restoration plans even though the plans could be developed in a manner that would provide the same service at much lower cost. The principal obstacle is that PJM does not have the authority to develop a comprehensive system restoration plan or a clear mandate to conduct procurement in manner that results in a least cost solution for the entire system. There is no clear representation in the process afforded to those responsible to pay for the service. Accordingly, the MMU recommends that PJM, FERC, reliability authorities and state regulators reevaluate how black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market.

The current process provides for PJM and transmission owners to jointly develop and administer the black start service plan for each transmission zone. These rules should be revised to assign responsibility for administering the plan to PJM and allow transmission owners to play an advisory role. This is especially important to address situations where transmission owners have affiliates providing black start service in the PJM region. PJM should administer the plan on a regional basis.

PJM also needs to reform the procurement process. Currently, PJM stakeholders are considering an approach that would conduct an RFP for black start service before approving an incumbent provider's request to recover through black start service rates the costs of substantial investment. This is especially important when the investment relates to the ability of the host unit to remain in service, not just the equipment needed solely for the purpose of providing black start service. This discussion, however, is much too limited. There is no reason why PJM should not procure black start service on an efficient and least cost basis through an orderly and non discriminatory RFP process. At present, providers may exit service commitments as their service obligations expire, but there is no comparable process for the purchasers of black start service to evaluate alternatives as purchase obligations expire. It is not clear whether the problem is the rules or how those rules have been implemented. In any event, a clearly defined regional black start procurement process is needed, as well more explicit provisions concerning how purchasers will be represented in that process. Clarification could come in the form of a clear statement of PJM's fiduciary as well as reliability responsibilities as it procures black start service (as well as other non market ancillary services).

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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 2010.

Highlights and New Analysis

- Congestion costs in 2010 increased by 99 percent over congestion costs in 2009 (Table 7-2). Despite the increase, total congestion in 2010 was lower than total congestion in every year from 2005, when PJM grew through a series of major integrations, through 2008.

- In 2010, Dominion was the most congested zone. Dominion accounted for nearly 20 percent of the total congestion cost (Table 7-17). In 2009, ComEd was the most congested zone, accounting for nearly 30 percent of the total congestion cost.

- Summer high-demand months (May through August) accounted for 45 percent of the total congestion cost in 2010. By contrast, the same period accounted for 26 percent of the total congestion cost in 2009 (Table 7-3).

- Review of the generation and transmission interconnection process. The generation and transmission interconnection process is complex and time consuming as a result of the nature of the required analyses.

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."

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- Review of backbone facilities. 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.

Recommendations

- The MMU recommends that PJM continue its efforts to find ways to modify the generation and transmission interconnection process to minimize the uncertainty for potential market entrants.

- The MMU recommends that PJM propose modifications to the transmission planning process that would limit significant changes in the status of major transmission projects after they have been approved, and thus limit the uncertainty imposed on markets by the use of evaluation criteria that are very sensitive to changes in forecasts of economic variables. These issues are currently being considered in the PJM stakeholder process.

- The MMU recommends continued efforts to incorporate transmission investments into competitive markets. Transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities, and the lack of existing transmission, can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in an area.

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $709.1 million or 99 percent, from $719.0 million in 2009 to $1,428.1 million in 2010. Day-ahead congestion costs increased by $816.4 million or 91 percent, from $901.4 million in 2009 to $1,717.9 million in 2010. Balancing congestion costs decreased by $107.3 million or 59 percent, from -$182.4.0 million in 2009 to -$289.7 million in 2010. Despite the increase, total congestion in 2010 was lower than total congestion in every year from 2005, when PJM grew through a series of major integrations, through 2008. 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, which is higher than the three percent share in 2009, but lower than the share of total billings from 2003 through 2008. Total PJM billings in 2010 were $34.771 billion.

- **Monthly Congestion.** Fluctuations in monthly congestion costs continued to be substantial. In 2010, 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 2010 ranged from $20.4 million in March to $268.9 million in July.

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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 between eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface and other 500 kV constraints in the east. 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 2010.[3] Day-ahead congestion frequency increased from 2009 to 2010 by 21,998 congestion event hours or 28 percent. In 2010, there were 100,728 day-ahead, congestion-event hours compared to 78,530 day-ahead, congestion-event hours in 2009. Day-ahead, congestion-event hours increased on internal PJM interfaces, transformers and lines while congestion frequency decreased on the reciprocally coordinated flowgates between PJM and the Midwest Independent Transmission System Operator, Inc. (Midwest ISO). Real-time congestion frequency increased from 2009 to 2010 by 8,012 congestion event hours. In 2010, there were 23,459 real-time, congestion-event hours compared to 15,447 real-time, congestion-event hours in 2009. Real-time, congestion-event hours increased on the internal PJM interfaces transformers and lines, while congestion-event hours decreased on the reciprocally coordinated flowgates between PJM and the Midwest ISO. The AP South Interface was the largest contributor to congestion costs in 2010. With $421.6 million in total congestion costs, it accounted for 30 percent of the total PJM congestion costs in 2010. The top five constraints in terms of congestion costs together contributed $745.8 million, or 52 percent, of the total PJM congestion costs in 2010. The top five constraints were the AP South interface, the Bedington – Black Oak interface, the 5004/5005 interface, the Doubs transformer, and the AEP-DOM interface.

- **Zonal Congestion.** In 2010, the Dominion Control Zone experienced the highest congestion costs of the control zones in PJM with $285.5 million.[4] The AP South interface, the Cloverdale – Lexington line, the Doubs transformer, the Bedington – Black Oak interface, and the Clover transformer contributed $183.4 million, or 64 percent of the total Dominion Control Zone congestion costs (Table 7-53). The AP Control Zone had the second highest congestion cost in PJM in 2010. The $282.7 million in congestion costs in the AP Control Zone represented a 187 percent increase from the $95.3 million in congestion costs for the zone in 2009. The AP South interface contributed $110.3 million, or 39 percent of the total AP Control Zone congestion cost. Increases in day-ahead congestion frequency and congestion costs from the Bedington – Black Oak interface and the Doubs transformer also contributed to the increase in congestion cost in the AP Control Zone from 2009 to 2010. The Bedington – Black Oak interface contributed $32.5 million to the AP Control Zone congestion costs and the Doubs transformer contributed $27 million to the AP Control Zone congestion costs.

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.

4 See the *Report to the North Carolina Utilities Commission: Congestion in the Dominion Service Territory in North Carolina: May 1, 2008 through April 30, 2010*, <http://www.monitoringanalytics.com/reports/Reports/SR2010/State_Congestion_Report_NC_DOM_20100715.pdf >.

Generation and Transmission Interconnection Planning Process

Any entity (developer or applicant) that requests interconnection of a generating facility, including increases to the capacity of an existing generating unit, or requests interconnection of a merchant transmission facility, must follow the PJM interconnection process. The process is complex and time consuming as a result of the nature of the required analyses. Nonetheless, this process potentially creates barriers to entry by creating uncertainty for potential entrants about the cost and time associated with interconnecting to the grid. The MMU recommends that PJM continue its efforts to find ways to modify the generation and transmission interconnection process to minimize the uncertainty for potential market entrants.

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) (Figure 7-1). The total planned costs for all of these projects are $6,048.4 million.

Economic Planning Process

- **Transmission and Markets.** As a general matter, transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in an area. While the RPM construct does provide that qualifying transmission upgrades may be submitted as offers, there have been no such offers. More generally, network transmission is not built based directly on market signals because the owners of network transmission are compensated through a non market mechanism, typically under traditional regulation. PJM has taken a first step towards integrating transmission investments into the market through the use of economic evaluation metrics.[5] Economic evaluation metrics can be used to determine whether there are positive economic benefits associated with an investment in transmission that might warrant the investment even when it is not required for reliability. The goal of transmission planning should ultimately be the incorporation of transmission investment decisions into market driven processes as much as possible.

- **Restructuring Responsibility for Grid Development.** The FERC's recent decisions in the *Primary Power* and *Central Transmission* cases addressed significant issues about the ownership of transmission, the resultant incentives to build new transmission facilities and

5 *See* 126 FERC ¶ 61,152 (2009) (final approval for an approach with predefined formulas for determining whether a transmission investment passes the cost-benefit test including explicit accounting for changes in production costs, the costs of complying with environmental regulations, generation availability trends and demand-response trends), *order on reh'g*, 123 FERC ¶ 61,051 (2008).

the potential for competitive forces to reduce the cost of transmission.[6] On June 17, 2010, the FERC issued a Notice of Proposed Rulemaking (NOPR) including a proposal to "remove from Commission-approved tariffs or agreements a right of first refusal created by those documents that provides an incumbent transmission provider with an undue advantage over a nonincumbent transmission developer."[7] These cases and the proposed rule have the potential to significantly change the incentives to build transmission for both incumbents and potential entrants and therefore to have potentially significant impacts on the wholesale power markets.

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 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 2010 were $34,771 million. Total congestion costs increased by $709.1 million or 99 percent, from $719.0 million in 2009 to $1,428.1 million in 2010. Day-ahead congestion costs increased by $816.4 million or 91 percent, from $901.4 million in 2009 to $1,717.9 million in 2010. Balancing congestion costs decreased by $107.3 million or 59 percent, from -$182.4 million in 2009 to -$289.7 million in 2010. 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 2009 to 2010 by 22,198 congestion event hours or 28 percent. In 2010, there were 100,728 day-ahead, congestion-event hours compared to 78,530 day-ahead, congestion-event hours in 2009. Real-time congestion frequency increased from 2009 to 2010 by 8,012 congestion event hours. In 2010, there were 23,459 real-time, congestion-event hours compared to 15,447 real-time, congestion-event hours in 2009.

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.[8] During the first seven months of the 2010 to 2011 planning period, total ARR and FTR revenues hedged 78.7 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 85.2 percent of the target allocation level for the first seven months of the 2010 to 2011 planning period. [9] 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 4.2 percent of total real-time energy charges to load for the calendar year 2010.[10]

6 131 FERC ¶ 61,015 (April 13, 2010); 131 FERC ¶ 61,243 (June 17, 2010).

7 See *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, FERC Docket No. RM10-23-000, 131 FERC ¶ 61,253.

8 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."

9 See the *2010 State of the Market Report for PJM* Section 8, "Financial Transmission and Auction Revenue Rights," at Table 8-21, "Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2008 to 2009 and 2009 to 2010"

10 See the *2010 State of the Market Report for PJM* Section 8, "Financial Transmission and Auction Revenue Rights," at Table 8-34, "ARRs and FTRs as a hedge against energy charges by control zone: Calendar year 2010"

One constraint accounted for 30 percent of total congestion costs in 2010 and the top five constraints accounted for 52 percent of total congestion costs. The AP South Interface was the largest contributor to congestion costs in 2010.

The congestion metric requires careful review when considering the significance of congestion. The net congestion bill is calculated by subtracting generating congestion credits from load congestion payments. The logic is that increased congestion payments by load are offset by increased congestion revenues to generation, for the area analyzed. Net congestion, which includes both load congestion payments and generation congestion credits, is not a good measure of the congestion costs paid by load from the perspective of the wholesale market.[11] While total congestion costs represent the overall charge or credit to a zone, the components of congestion costs measure the extent to which load or generation bear total congestion costs. Load congestion payments, when positive, measure the total congestion cost to load in an area. Load congestion payments, when negative, measure the total congestion credit to load in an area. Negative load congestion payments result when load is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in western control zones and higher prices in eastern and southern control zones. Load in western control zones will benefit from lower prices and receive a congestion credit (negative load congestion payment). Load in the eastern and southern control zones will incur a congestion charge (positive load congestion payment). The reverse is true for generation congestion credits. Generation congestion credits, when positive, measure the total congestion credit to generation in an area. Generation congestion credits, when negative, measure the total congestion cost to generation in an area. Negative generation congestion credits are a cost in the sense that revenues to generators in the area are lower, by the amount of the congestion cost, than they would have been if they had been paid LMP without a congestion component, the total of system marginal price and the loss component. Negative generation congestion credits result when generation is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in the western control zones and higher prices in the eastern and southern control zones. Generation in the western control zones will receive lower prices and incur a congestion charge (negative generation congestion credit). Generation in the eastern and southern control zones will receive higher prices and receive a congestion credit (positive generation congestion credit).

As an example, total congestion costs in PJM in 2010 were $1,428.1 million, which was comprised of load congestion payments of $362.4 million, negative generation credits of $1,147.8 million and negative explicit congestion of $82.1 million (Table 7-2).

Congestion

Congestion Accounting

Transmission congestion can exist in PJM's Day-Ahead and Real-Time Energy Market. Transmission congestion charges in the Day-Ahead Energy Market can be directly hedged by FTRs. Balancing

11 The actual congestion payments by retail customers are a function of retail ratemaking policies and may or may not reflect an offset for congestion credits.

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market congestion charges can be hedged by FTRs to the extent that a participant's energy flows in real time are consistent with those in the Day-Ahead Energy Market.[12]

Total congestion charges are equal to the net congestion bill plus explicit congestion charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

The net congestion bill is calculated by subtracting generating congestion credits from load congestion payments. The logic is that increased congestion payments by load are offset by increased congestion revenues to generation, for the area analyzed. Whether the net congestion bill is an appropriate measure of congestion for load depends on who pays the load congestion payments and who receives the generation congestion credits. The net congestion bill is an appropriate measure of congestion for a utility that charges load congestion payments to load and credits generation congestion credits to load. The net congestion bill is not an appropriate measure of congestion in situations where load pays the load congestion payments but does not receive the generation credits as an offset.

In the 2010 analysis of total congestion costs, load congestion payments are netted against generation congestion credits on an hourly basis, by billing organization, and then summed for the given period.[13] A billing organization may offset load congestion payments with its generation portfolio or by purchasing supply from another entity via a bilateral transaction.Load Congestion Payments and Generation Congestion Credits are calculated for both the Day-Ahead and Balancing Energy Markets.

- **Day-Ahead Load Congestion Payments.** Day-ahead load congestion payments are calculated for all cleared demand, decrement bids and Day-Ahead Energy Market sale transactions. (Decrement bids and energy sales can be thought of as scheduled load.) Day-ahead load congestion payments are calculated using MW and the load bus CLMP, the decrement bid CLMP or the CLMP at the source of the sale transaction, as applicable.

- **Day-Ahead Generation Congestion Credits.** Day-ahead generation congestion credits are calculated for all cleared generation and increment offers and Day-Ahead Energy Market purchase transactions. (Increment offers and energy purchases can be thought of as scheduled generation.) Day-ahead generation congestion credits are calculated using MW and the generator bus CLMP, the increment offer's CLMP or the CLMP at the sink of the purchase transaction, as applicable.

- **Balancing Load Congestion Payments.** Balancing load congestion payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing load congestion payments are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.

- **Balancing Generation Congestion Credits.** Balancing generation congestion credits are calculated for all deviations between a PJM member's real-time generation and energy

12 The terms *congestion charges* and *congestion costs* are both used to refer to the costs associated with congestion. The term, *congestion charges*, is used in documents by PJM's Market Settlement Operations.

13 This analysis does not treat affiliated billing organizations as a single organization. Thus, the generation congestion credits from one organization will not offset the load payments of its affiliate. This may overstate or understate the actual load payments or generation credits of an organization's parent company.

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purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing generation congestion credits are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.

- **Explicit Congestion Charges.** Explicit congestion charges are the net congestion charges associated with point-to-point energy transactions. These charges equal the product of the transacted MW and CLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit congestion charges equal the product of the deviations between the real-time and day-ahead transacted MW and the differences between the real-time CLMP at the transactions' sources and sinks.

The congestion charges associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. The congestion charges in each zone are the sum of the congestion charges associated with each constraint that affects prices in the zone. The network nature of the transmission system means that congestion costs in a zone are frequently the result of constrained facilities located outside that zone.

Congestion costs can be both positive and negative and consequently load payments and generation credits can also be both positive and negative. The CLMP is calculated with respect to the system reference bus LMP, also called the system marginal price (SMP). When a transmission constraint occurs, the resulting CLMP is positive on one side of the constraint and negative on the other side of the constraint and the corresponding congestion costs are positive or negative. For each transmission constraint, the CLMP reflects the cost of a constraint at a pricing node and is equal to the product of the constraint shadow price and the distribution factor at the respective pricing node. The total CLMP at a pricing node is the sum of all constraint contributions to LMP and is equal to the difference between the actual LMP that results from transmission constraints, excluding losses, and the SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.[14]

14 For an example of the congestion accounting methods used in this section, see *Technical Reference for PJM Markets*, Section 3, "FTRs and ARRs."

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Total Calendar Year Congestion

Congestion charges have ranged from 3 percent to 9 percent of annual total PJM billings since 2003.[15] Table 7-1 shows total congestion by year from 2003 through 2010. After unusually low congestion charges of $719 million in the year 2009, the congestion charges nearly doubled to $1,428 million in the year 2010.[16] Despite the increase, the net congestion charges collected in 2010 amount to only two-thirds of that collected in 2008.

Table 7-1 Total annual PJM congestion (Dollars (Millions)): Calendar years 2003 to 2010

	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%	$34,771	4%
Total	$9,591		$185,358	5%

Total congestion charges in Table 7-1 include both congestion charges associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the Midwest ISO whose operating limits are respected by PJM.[17]

Table 7-2 shows the 2010 PJM congestion costs by category. The 2010 PJM total congestion costs were comprised of $362.4 million in load congestion payments, $1,147 million in negative generation congestion credits, and negative $82.1 million in explicit congestion costs. Load payments for congestion increased by 43 percent while generation credits for congestion in absolute terms increased by 123 percent and explicit congestion in absolute terms also increased by 66 percent.

Table 7-2 Total annual PJM congestion costs by category (Dollars (Millions)): Calendar years 2009 and 2010

	Congestion Costs (Millions)			
Year	Load Payments	Generation Credits	Explicit	Total
2009	$253.3	($515.1)	($49.4)	$719.0
2010	$362.4	($1,147.8)	($82.1)	$1,428.1

15 Calculated values shown in Section 7, "Congestion," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

16 PJM reports congestion in terms of revenue collected to fund FTR Target Allocations. This means that any hour that results in a net negative congestion cost (i.e. the sum of day-ahead and balancing congestion costs in a given hour is less than zero) is excluded from the total congestion cost calculation for a given period. Therefore, the total congestion costs reported here will be less than those reported by PJM, for the same period, because they include the net negative congestion costs.

17 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) (Accessed January 23, 2011), Section 6.1 <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx>.

Monthly Congestion

Table 7-3 shows that during calendar year 2010, monthly congestion charges ranged from a maximum of $268.9 million in July 2010 to a minimum of $20.4 million in March 2010. Nearly half of all calendar year 2010 congestion occurred in the months of June through September.

Table 7-3 Monthly PJM congestion charges (Dollars (Millions)): Calendar years 2009 to 2010

	2009	2010	Change	Percent Change
Jan	$149.3	$218.5	$69.2	46.3%
Feb	$83.0	$106.4	$23.4	28.3%
Mar	$74.6	$20.4	($54.2)	(72.7%)
Apr	$25.6	$42.6	$17.0	66.1%
May	$25.9	$68.5	$42.6	164.7%
Jun	$49.8	$188.5	$138.7	278.8%
Jul	$39.4	$268.9	$229.5	582.6%
Aug	$72.1	$105.1	$33.0	45.9%
Sep	$23.9	$119.9	$96.0	400.7%
Oct	$42.7	$50.3	$7.6	17.7%
Nov	$36.3	$52.0	$15.7	43.4%
Dec	$96.4	$187.1	$90.6	94.0%
Total	$719.0	$1,428.1	$709.1	98.6%

Congestion Component of LMP

The congestion component of LMP was calculated for each PJM control zone, to provide an indication of the geographic dispersion of congestion costs. The congestion component of LMP for control zones is presented in Table 7-4 for calendar years 2009 and 2010.

Table 7-4 shows overall congestion patterns in 2010. Price separation between eastern and western control zones in PJM was primarily a result of congestion on the AP South interface. This constraint generally had a positive congestion component of LMP in eastern and southern control zones located on the constrained side of the affected facilities while the unconstrained western zones had a negative congestion component of LMP.

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Table 7-4 Annual average congestion component of LMP: Calendar years 2009 to 2010

	2009		2010	
Control Zone	Day Ahead	Real Time	Day Ahead	Real Time
AECO	$2.03	$1.83	$2.96	$3.64
AEP	($2.12)	($2.16)	($4.05)	($4.83)
AP	$0.62	$1.32	$0.06	$0.12
BGE	$3.33	$3.04	$5.75	$6.68
ComEd	($5.09)	($5.61)	($7.38)	($8.58)
DAY	($2.77)	($2.72)	($4.74)	($5.69)
DLCO	($3.37)	($3.02)	($4.75)	($5.94)
Dominion	$2.47	$2.37	$5.10	$5.35
DPL	$2.25	$2.32	$3.17	$3.82
JCPL	$1.82	$2.01	$2.59	$2.92
Met-Ed	$2.10	$2.03	$3.13	$3.47
PECO	$1.87	$1.71	$2.69	$2.84
PENELEC	($0.10)	($0.06)	($0.68)	($1.42)
Pepco	$3.75	$3.74	$6.16	$6.72
PPL	$1.88	$1.75	$2.20	$2.34
PSEG	$2.12	$2.27	$3.04	$3.99
RECO	$1.47	$1.55	$2.19	$2.50

Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control the impact of a contingency on a monitored facility or to control an actual overload. A congestion-event hour exists when a specific facility is constrained for one or more five-minute intervals within an hour. A congestion-event hour differs from a constrained hour, which is any hour during which one or more facilities are congested. Thus, if two facilities are constrained during an hour, the result is two congestion-event hours and one constrained hour. Constraints are often simultaneous, so the number of congestion-event hours likely exceeds the number of constrained hours and the number of congestion-event hours likely exceeds the number of hours within a year. In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is also consistent with the way in which PJM reports real-time congestion. In 2010, there were 100,728 day-ahead, congestion-event hours compared to 78,530 day-ahead, congestion-event hours in 2009. In 2010, there were 23,459 real-time, congestion-event hours compared to 15,447 real-time, congestion-event hours in 2009.

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Congestion by Facility Type and Voltage

Day-ahead, congestion-event hours decreased on the reciprocally coordinated flowgates between PJM and the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) while congestion frequency on internal PJM interfaces, transmission lines and transformers increased. Real-time, congestion-event hours decreased on the reciprocally coordinated flowgates between PJM and the Midwest ISO, while congestion frequency on interfaces, transmission lines and transformers increased.

Day-ahead congestion costs decreased on the reciprocally coordinated flowgates between PJM and the Midwest ISO and increased on PJM interfaces, transmission lines and transformers in 2010. Balancing congestion costs increased on the reciprocally coordinated flowgates between PJM and the Midwest ISO and transformers and decreased on PJM interfaces and transmission lines in 2010.

Table 7-5 provides congestion-event hour subtotals and congestion cost subtotals comparing 2010 calendar year results by facility type: line, transformer, interface, flowgate and unclassified facilities.[18,19] For comparison, this information is presented in Table 7-6 for calendar year 2009.[20]

Total congestion costs associated with the reciprocally coordinated flowgates between PJM and the Midwest ISO increased by $0.5 million from $11.4 million in 2009 to $11.9 million in 2010.[21] The day-ahead congestion cost and congestion event hours decreased in 2010 compared to 2009. Balancing congestion costs increased in 2010, while balancing congestion event hours decreased in comparison to 2009. Balancing congestion cost on the reciprocally coordinated flow gates were generally negative in 2009 and 2010. A decrease in congestion event-hours from 3,418 to 3,242 event hours was consistent with an increase in the congestion cost from -$80.8 million to -$60.1 million. The Crete – St Johns line flowgate accounted for $29.7 million in congestion costs and was the largest contributor to positive congestion costs among flowgates in 2010. The largest contribution to negative congestion costs among flowgates came from the Pleasant Prairie – Zion flowgate with -$10.9 million in 2010 congestion costs.

Total congestion costs associated with interfaces increased from $322.8 million in 2009 to $712.5 million in 2010. Interfaces typically include multiple transmission facilities and reflect power flows into or through a wider geographic area. Interface congestion constituted 50 percent of total PJM congestion costs in 2010. Among interfaces, the AP South, the Bedington – Black Oak and the 5004/5005 interfaces accounted for the largest contribution to positive congestion costs in 2010. The AP South interface, with $421.6 million in congestion, had the highest congestion cost of any facility in PJM, accounting for 30 percent of the total PJM congestion costs in 2010. The AP South, the Bedington – Black Oak and the 5004/5005 interfaces together accounted for $618.8 million or

18 Unclassified constraints appear in the Day-Ahead Market only and represent congestion costs incurred on market elements which are not posted by PJM. Congestion frequency associated with these unclassified constraints is not presented in order to be consistent with the posting of constrained facilities by PJM.

19 The term *flowgate* refers to Midwest ISO flowgates in this context.

20 For 2008 and 2009, the load congestion payments and generation congestion credits represent the net load congestion payments and net generation congestion credits for an organization, as this shows the extent to which each organization's load or generation was exposed to congestion costs.

21 The congestion costs reported here for the reciprocally coordinated flowgates between PJM and the Midwest ISO flowgates are calculated in the same manner as all other internal PJM constraints and use the congestion accounting methods defined in this section. For the payments to and from the Midwest ISO based on the market-to-market settlement calculations, defined in the "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.", see the *2010 State of the Market Report for PJM*, Volume II, Section 4, "Interchange Transactions," at "PJM and Midwest ISO Joint Operating Agreement."

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87 percent of all interface congestion costs and were the largest contributors to positive congestion among interfaces in 2010.

Total congestion costs associated with transmission lines increased 74 percent from $282.9 million in 2009 to $493.1 million in 2010. Transmission line congestion accounted for 35 percent of the total PJM congestion costs for 2010. The East Frankfort – Crete and Cloverdale – Lexington lines together accounted for $68.9 million or 14 percent of all transmission line congestion costs and were the largest contributors to positive congestion among transmission lines in 2010.

Total congestion costs associated with transformers increased 29 percent from $103.6 million in 2009 to $184.4 million in 2010. Congestion on transformers accounted for 13 percent of the total PJM congestion costs in 2010. The Doubs and Belmont transformers together accounted for $91.3 million or 49 percent of all transformer congestion costs and were the largest contributors to positive congestion costs among transformers in 2010.

Table 7-5 Congestion summary (By facility type): Calendar year 2010

	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	($9.5)	($76.1)	$5.5	$72.0	($3.1)	$3.8	($53.2)	($60.1)	$11.9	6,830	3,242
Interface	$84.6	($631.0)	$2.7	$718.2	$22.4	$24.0	($4.1)	($5.7)	$712.5	9,823	2,619
Line	$178.4	($433.9)	$68.9	$681.2	($44.3)	$42.5	($101.3)	($188.1)	$493.1	72,457	14,291
Transformer	$128.3	($81.5)	$10.4	$220.1	($10.9)	$4.7	($20.2)	($35.8)	$184.4	11,618	3,307
Unclassified	$16.6	($0.3)	$9.3	$26.2	$0.0	$0.0	$0.0	$0.0	$26.2	NA	NA
Total	$398.3	($1,222.9)	$96.7	$1,717.9	($35.9)	$75.0	($178.8)	($289.7)	$1,428.1	100,728	23,459

Table 7-6 Congestion summary (By facility type): Calendar year 2009

	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	$18.0	($56.4)	$17.9	$92.3	($10.5)	$5.4	($65.0)	($80.8)	$11.4	9,434	3,418
Interface	$48.0	($263.5)	$2.1	$313.5	$4.0	($2.4)	$2.9	$9.3	$322.8	5,884	1,378
Line	$114.8	($195.7)	$41.0	$351.4	($18.7)	$11.5	($38.4)	($68.6)	$282.9	52,608	7,529
Transformer	$108.5	($14.6)	$22.9	$145.9	($13.8)	($4.4)	($32.9)	($42.3)	$103.6	10,604	3,122
Unclassified	$3.1	$4.9	$0.0	($1.7)	$0.0	$0.0	$0.0	$0.0	($1.7)	NA	NA
Total	$292.3	($525.2)	$83.9	$901.4	($39.0)	$10.1	($133.4)	($182.4)	$719.0	78,530	15,447

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Table 7-7 Congestion Event Hours (Day Ahead against Real Time): Calendar Years 2009 to 2010

	Congestion Event Hours					
	2010			2009		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	6,830	1,023	15.0%	9,434	1,181	12.5%
Interface	9,823	1,881	19.1%	5,884	723	12.3%
Line	72,457	6,132	8.5%	52,608	3,752	7.1%
Transformer	11,618	1,529	13.2%	10,604	2,280	21.5%
Total	100,728	10,565	10.5%	78,530	7,936	10.1%

Table 7-8 Congestion Event Hours (Real Time against Day Ahead): Calendar Years 2009 to 2010

	Congestion Event Hours					
	2010			2009		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	3,242	1,042	32.1%	3,418	1,181	34.6%
Interface	2,619	1,881	71.8%	1,378	720	52.2%
Line	14,291	6,002	42.0%	7,529	3,711	49.3%
Transformer	3,307	1,496	45.2%	3,122	2,035	65.2%
Total	23,459	10,421	44.4%	15,447	7,647	49.5%

Table 7-7 and Table 7-8 compare day-ahead and real-time congestion event hours. Among the hours for which a facility is constrained in the day-ahead market, the number of hours during which the facility is also constrained in the real-time market are presented in Table 7-7. In 2010, there were 100,728 congestion event hours in the day-ahead market. Among those, only 10,565 (10.5 percent) were also constrained in the real-time. In 2009, among the 78,530 day-ahead congestion event hours, only 7,936 (10.1 percent) were binding in the real-time.

Among the hours for which a facility is constrained in the real-time market, the number of hours during which the facility is also constrained in the day-ahead market are presented in Table 7-8. In 2010, there were 23,459 congestion event hours in the real-time market. Among these, 10,421 (44.4 percent) were also constrained in the day-ahead market. In 2009, among the 15,447 real-time congestion event hours, only 7,647 (49.5 percent) were binding in the day-ahead.

Table 7-9 shows congestion costs by facility voltage class for 2010. In comparison to 2009 (shown in Table 7-10), congestion costs increased across 765 kV, 500 kV, 345 kV, 230 kV, 138 kV, 115 kV, 34 kV, 12 kV and unclassified facilities in 2010.

Congestion costs associated with 765 kV facilities increased from \$0.1 million in 2009 to the \$4.5 million experienced in 2010. Congestion on 765 kV facilities comprised less than 1 percent of total 2010 PJM congestion costs.

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Congestion costs associated with 500 kV facilities increased 92 percent from $406.5 million in 2009, to $779.3 million in 2010. Congestion on 500 kV facilities comprised 55 percent of total 2010 PJM congestion costs. The AP South interface, the Bedington – Black Oak interface, the 5004/5005 interface and the AEP-DOM interface accounted for $745.8 million or 96 percent of all 500 kV congestion costs; they were the largest contributors to positive congestion among 500 kV facilities in 2010.

Congestion costs associated with 345 kV facilities increased by 25 percent from 58.1 million in 2009, to $72.3 million in 2010. Congestion on 345 kV facilities comprised five percent of total 2010 PJM congestion costs. The East Frankfurt – Crete line and the Crete – St. Johns line accounted for $69.4 million or 96 percent of all 345 kV congestion costs; they were the largest contributors to positive congestion among 345 kV facilities in 2010.

Congestion costs associated with 230 kV facilities increased 181 percent from $83.6 million in 2009 to $234.6 million in 2010. Congestion on 230 kV facilities comprised 16 percent of total 2010 PJM congestion costs. The Doubs transformer accounted for $64.7 million or 28 percent of all 230 kV congestion costs and was the largest contributor to positive congestion among 230 kV facilities in 2010.

Congestion costs associated with 138 kV facilities increased 67 percent from $158.3 million in 2009 to $264 million in 2010. Congestion on 138 kV facilities comprised 18 percent of total 2010 PJM congestion costs. The Belmont transformer and Tiltonsville – Windsor line together accounted for $46.0 million or 17 percent of all 138 kV congestion costs; they were the largest contributors to positive congestion among 138 kV facilities in 2010.

Congestion costs associated with 115 kV facilities decreased by 250 percent from $12.1 million in 2009, to $42.4 million in 2010. Congestion on 115 kV facilities comprised three percent of total 2009 PJM congestion costs. The Hunterstown and Erie West transformers together accounted for $15.6 million or 37 percent of all 115 kV congestion costs; they were the largest contributors to positive congestion among 115 kV facilities in 2010.

Congestion costs associated with 69 kV and below facilities increased by nearly 128 percent from $2.1 million in 2009, to $4.7 million in 2010. Congestion on 69 kV and below facilities comprised less than one percent of total 2010 PJM congestion costs. The Oak Hill transformer accounted for $2.5 million in congestion costs. It had the largest contribution to congestion costs among 69 kV and below facilities.

Table 7-9 Congestion summary (By facility voltage): Calendar year 2010

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	$1.1	($6.9)	$0.7	$8.7	($1.1)	($0.1)	($3.2)	($4.2)	$4.5	146	74
500	$108.3	($678.0)	$9.9	$796.1	$19.0	$15.0	($20.8)	($16.8)	$779.3	12,041	4,305
345	($9.8)	($168.7)	$28.9	$187.8	($10.3)	$10.3	($94.9)	($115.5)	$72.3	14,081	4,736
230	$74.4	($193.8)	$24.1	$292.3	($9.8)	$24.9	($23.0)	($57.7)	$234.6	20,187	4,252
138	$146.7	($172.7)	$22.5	$342.0	($24.3)	$19.3	($34.4)	($78.0)	$264.0	40,955	7,794
115	$45.5	($6.1)	$1.0	$52.6	($3.0)	$5.2	($2.0)	($10.2)	$42.4	6,387	1,593
69	$15.2	$3.5	$0.3	$12.0	($6.6)	$0.3	($0.5)	($7.4)	$4.6	6,639	686
34	($0.0)	($0.0)	$0.0	$0.0	$0.1	$0.0	$0.0	$0.1	$0.1	37	19
12	$0.3	$0.2	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	255	0
Unclassified	$16.6	($0.3)	$9.3	$26.2	$0.0	$0.0	$0.0	$0.0	$26.2	NA	NA
Total	$398.3	($1,222.9)	$96.7	$1,717.9	($35.9)	$75.0	($178.8)	($289.7)	$1,428.1	100,728	23,459

Table 7-10 Congestion summary (By facility voltage): Calendar year 2009

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	($0.0)	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	24	0
500	$114.9	($275.4)	$14.2	$404.4	($0.5)	($15.0)	($12.3)	$2.1	$406.5	11,643	3,301
345	$30.6	($61.4)	$34.8	$126.8	($5.3)	$7.1	($56.3)	($68.7)	$58.1	8,503	2,506
230	$56.4	($45.8)	$9.4	$111.7	($15.0)	$5.9	($7.2)	($28.0)	$83.6	15,103	2,095
138	$68.2	($147.7)	$24.9	$240.7	($14.8)	$10.4	($57.2)	($82.5)	$158.3	30,566	6,662
115	$11.6	($0.7)	$0.4	$12.6	$0.4	$0.6	($0.2)	($0.5)	$12.1	4,893	552
69	$7.3	$0.7	$0.2	$6.8	($3.8)	$0.9	($0.1)	($4.8)	$1.9	6,661	329
34	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	185	2
12	$0.4	$0.3	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	952	0
Unclassified	$3.1	$4.9	$0.0	($1.7)	$0.0	$0.0	$0.0	$0.0	($1.7)	NA	NA
Total	$292.3	($525.2)	$83.9	$901.4	($39.0)	$10.1	($133.4)	($182.4)	$719.0	78,530	15,447

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Constraint Duration

Table 7-11 lists calendar year 2009 and 2010 constraints that were most frequently in effect and Table 7-12 shows the constraints which experienced the largest change in congestion-event hours from 2009 to 2010.[22]

The AP South interface, the East Frankfort – Crete line and the Athenia – Saddlebrook line were the most frequently occurring constraints in 2010. The Kammer transformer saw the largest decrease in congestion-event hours from 2009. The Athenia – Saddlebrook line saw the largest increase in congestion-event hours from 2009 to 2010, but still remained in the top 25 of the most frequently occurring transmission constraints. The Kammer transformer and the AP South interface were also among the top contributors to 2010 congestion costs (Table 7-13).

Table 7-11 Top 25 constraints with frequent occurrence: Calendar years 2009 to 2010

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2009	2010	Change	2009	2010	Change	2009	2010	Change	2009	2010	Change
1	AP South	Interface	3,549	4,645	1,096	604	1,528	924	41%	53%	13%	7%	17%	11%
2	East Frankfort - Crete	Line	2,163	3,084	921	605	850	245	25%	35%	11%	7%	10%	3%
3	Athenia - Saddlebrook	Line	1,108	3,318	2,210	139	364	225	13%	38%	25%	2%	4%	3%
4	Waterman - West Dekalb	Line	1,499	3,002	1,503	57	343	286	17%	34%	17%	1%	4%	3%
5	Tiltonsville - Windsor	Line	2,070	2,723	653	311	506	195	24%	31%	7%	4%	6%	2%
6	Pleasant Valley - Belvidere	Line	3,648	2,553	(1,095)	405	467	62	42%	29%	(13%)	5%	5%	1%
7	Crete - St Johns Tap	Flowgate	1,571	2,066	495	306	823	517	18%	24%	6%	3%	9%	6%
8	Bedington - Black Oak	Interface	669	2,291	1,622	73	212	139	8%	26%	19%	1%	2%	2%
9	5004/5005 Interface	Interface	776	1,644	868	294	605	311	9%	19%	10%	3%	7%	4%
10	Belmont	Transformer	764	1,887	1,123	76	203	127	9%	22%	13%	1%	2%	1%
11	Cloverdale - Lexington	Line	1,019	1,127	108	434	684	250	12%	13%	1%	5%	8%	3%
12	Electric Jct - Nelson	Line	823	1,495	672	202	258	56	9%	17%	8%	2%	3%	1%
13	Pleasant Prairie - Zion	Flowgate	151	1,321	1,170	135	404	269	2%	15%	13%	2%	5%	3%
14	Nelson - Cordova	Line	0	1,546	1,546	22	95	73	0%	18%	18%	0%	1%	1%
15	Burlington - Croydon	Line	2,805	1,500	(1,305)	3	33	30	32%	17%	(15%)	0%	0%	0%
16	Pinehill - Stratford	Line	1,221	1,520	299	0	0	0	14%	17%	3%	0%	0%	0%
17	Carnegie - Tidd	Line	0	1,234	1,234	7	259	252	0%	14%	14%	0%	3%	3%
18	Danville - East Danville	Line	286	1,307	1,021	38	142	104	3%	15%	12%	0%	2%	1%
19	Branchburg - Readington	Line	37	1,235	1,198	13	185	172	0%	14%	14%	0%	2%	2%
20	Wylie Ridge	Transformer	354	728	374	335	683	348	4%	8%	4%	4%	8%	4%
21	Doubs	Transformer	429	909	480	246	500	254	5%	10%	5%	3%	6%	3%
22	Leonia - New Milford	Line	3,847	1,241	(2,606)	39	50	11	44%	14%	(30%)	0%	1%	0%
23	Lindenwold - Stratford	Line	681	1,272	591	0	0	0	8%	15%	7%	0%	0%	0%
24	Mount Storm - Pruntytown	Line	525	571	46	132	574	442	6%	7%	1%	2%	7%	5%
25	Glidden - West Dekalb	Line	1,166	1,090	(76)	21	21	0	13%	12%	(1%)	0%	0%	0%

22 Presented in descending order of absolute change between 2009 and 2010 day-ahead and real-time, congestion-event hours.

Table 7-12 Top 25 constraints with largest year-to-year change in occurrence: Calendar years 2009 to 2010

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2009	2010	Change	2009	2010	Change	2009	2010	Change	2009	2010	Change
1	Kammer	Transformer	3,674	0	(3,674)	1,328	0	(1,328)	42%	0%	(42%)	15%	0%	(15%)
2	Dunes Acres - Michigan City	Flowgate	2,949	264	(2,685)	910	42	(868)	34%	3%	(31%)	10%	0%	(10%)
3	Leonia - New Milford	Line	3,847	1,241	(2,606)	39	50	11	44%	14%	(30%)	0%	1%	0%
4	Athenia - Saddlebrook	Line	1,108	3,318	2,210	139	364	225	13%	38%	25%	2%	4%	3%
5	AP South	Interface	3,549	4,645	1,096	604	1,528	924	41%	53%	13%	7%	17%	11%
6	Waterman - West Dekalb	Line	1,499	3,002	1,503	57	343	286	17%	34%	17%	1%	4%	3%
7	Bedington - Black Oak	Interface	669	2,291	1,622	73	212	139	8%	26%	19%	1%	2%	2%
8	Nelson - Cordova	Line	0	1,546	1,546	22	95	73	0%	18%	18%	0%	1%	1%
9	Carnegie - Tidd	Line	0	1,234	1,234	7	259	252	0%	14%	14%	0%	3%	3%
10	Pleasant Prairie - Zion	Flowgate	151	1,321	1,170	135	404	269	2%	15%	13%	2%	5%	3%
11	Branchburg - Readington	Line	37	1,235	1,198	13	185	172	0%	14%	14%	0%	2%	2%
12	Pana North	Flowgate	986	0	(986)	318	0	(318)	11%	0%	(11%)	4%	0%	(4%)
13	Burlington - Croydon	Line	2,805	1,500	(1,305)	3	33	30	32%	17%	(15%)	0%	0%	0%
14	Belmont	Transformer	764	1,887	1,123	76	203	127	9%	22%	13%	1%	2%	1%
15	5004/5005 Interface	Interface	776	1,644	868	294	605	311	9%	19%	10%	3%	7%	4%
16	East Frankfort - Crete	Line	2,163	3,084	921	605	850	245	25%	35%	11%	7%	10%	3%
17	Danville - East Danville	Line	286	1,307	1,021	38	142	104	3%	15%	12%	0%	2%	1%
18	State Line - Wolf Lake	Flowgate	1,284	376	(908)	183	7	(176)	15%	4%	(10%)	2%	0%	(2%)
19	Oak Grove - Galesburg	Flowgate	790	117	(673)	638	242	(396)	9%	1%	(8%)	7%	3%	(5%)
20	Kammer - Ormet	Line	552	0	(552)	509	3	(506)	6%	0%	(6%)	6%	0%	(6%)
21	Hillsdale - New Milford	Line	0	1,022	1,022	0	23	23	0%	12%	12%	0%	0%	0%
22	Pleasant Valley - Belvidere	Line	3,648	2,553	(1,095)	405	467	62	42%	29%	(13%)	5%	5%	1%
23	Cedar Grove - Clifton	Line	1,194	205	(989)	38	8	(30)	14%	2%	(11%)	0%	0%	(0%)
24	Crete - St Johns Tap	Flowgate	1,571	2,066	495	306	823	517	18%	24%	6%	3%	9%	6%
25	Pumphrey - Westport	Line	1,181	244	(937)	0	0	0	13%	3%	(11%)	0%	0%	0%

Constraint Costs

Table 7-13 and Table 7-14 present the top constraints affecting congestion costs by facility for calendar years 2010 and 2009.[23] The AP South interface was the largest contributor to congestion costs in 2010. With $421.6 million in total congestion costs, it accounted for 30 percent of the total PJM congestion costs in 2010. The top five constraints in terms of congestion costs together comprised 52 percent of the total PJM congestion costs in 2010.

23 Presented in descending order of annual total congestion costs.

Table 7-13 Top 25 constraints affecting annual PJM congestion costs (By facility): Calendar year 2010

				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
1	AP South	Interface	500	($10.8)	($433.4)	($2.4)	$420.2	$11.2	$11.4	$1.6	$1.4	$421.6	30%
2	Bedington - Black Oak	Interface	500	$9.4	($96.0)	$2.7	$108.1	($0.1)	$1.1	($1.5)	($2.8)	$105.3	7%
3	5004/5005 Interface	Interface	500	$50.1	($42.0)	($0.1)	$92.1	$10.2	$9.0	($1.3)	($0.2)	$91.9	6%
4	Doubs	Transformer	AP	$39.7	($28.2)	$0.5	$68.4	$0.2	$1.1	($2.8)	($3.7)	$64.7	5%
5	AEP-DOM	Interface	500	$10.5	($52.8)	$2.5	$65.8	$0.3	$1.0	($2.8)	($3.5)	$62.3	4%
6	East Frankfort - Crete	Line	ComEd	$2.6	($43.0)	$6.1	$51.7	($4.5)	($0.4)	($7.6)	($11.8)	$39.9	3%
7	Crete - St Johns Tap	Flowgate	Midwest ISO	($9.0)	($51.4)	($5.1)	$37.3	$0.0	($1.1)	($8.9)	($7.8)	$29.5	2%
8	Cloverdale - Lexington	Line	AEP	$16.5	($14.4)	$3.0	$33.9	($3.0)	($3.6)	($5.5)	($4.9)	$28.9	2%
9	Belmont	Transformer	AP	$15.8	($15.0)	($0.6)	$30.2	($4.4)	($1.0)	($0.3)	($3.7)	$26.6	2%
10	Unclassified	Unclassified	Unclassified	$16.6	($0.3)	$9.3	$26.2	$0.0	$0.0	$0.0	$0.0	$26.2	2%
11	Brandon Shores - Riverside	Line	BGE	$16.7	($10.5)	($0.4)	$26.8	$0.8	$2.3	$0.4	($1.2)	$25.7	2%
12	Mount Storm - Pruntytown	Line	AP	$2.1	($20.5)	$2.1	$24.7	($0.1)	($5.1)	($4.8)	$0.2	$24.9	2%
13	West	Interface	500	$21.5	($1.6)	($0.2)	$22.9	$0.6	$1.3	$0.0	($0.7)	$22.2	2%
14	Tiltonsville - Windsor	Line	AP	$21.4	($2.2)	$1.4	$25.0	($4.5)	$0.2	($0.9)	($5.6)	$19.4	1%
15	Pleasant Valley - Belvidere	Line	ComEd	($9.0)	($29.2)	$3.5	$23.7	$0.1	$3.0	($4.9)	($7.8)	$15.9	1%
16	Graceton - Raphael Road	Line	BGE	($3.1)	($16.0)	$0.6	$13.6	$0.1	($1.6)	($0.2)	$1.5	$15.1	1%
17	Brunner Island - Yorkana	Line	Met-Ed	($2.5)	($15.2)	$0.4	$13.1	$0.8	($1.1)	($0.9)	$1.0	$14.1	1%
18	Crescent	Transformer	DLCO	$7.9	($5.2)	$0.8	$13.9	($0.0)	($0.6)	($1.0)	($0.4)	$13.5	1%
19	Clover	Transformer	Dominion	$3.2	($10.6)	$2.1	$15.9	($1.3)	($1.0)	($3.2)	($3.4)	$12.5	1%
20	Millville - Sleepy Hollow	Line	Dominion	$9.2	($2.8)	$0.3	$12.3	$0.0	$0.0	$0.0	$0.0	$12.3	1%
21	Millville - Old Chapel	Line	Dominion	$8.6	($2.6)	$1.0	$12.2	$0.0	$0.0	$0.0	$0.0	$12.2	1%
22	Branchburg - Readington	Line	PSEG	$5.7	($7.3)	$0.7	$13.7	($0.5)	$1.5	$0.1	($1.9)	$11.8	1%
23	Kanawha - Kincaid	Line	AEP	$8.9	($1.2)	$1.5	$11.6	$0.0	$0.0	$0.0	$0.0	$11.6	1%
24	Pleasant Prairie - Zion	Flowgate	Midwest ISO	($3.3)	($7.8)	$3.0	$7.5	($0.5)	$1.2	($16.7)	($18.4)	($10.9)	(1%)
25	Eddystone - Island Road	Line	PECO	$0.7	($7.7)	$1.1	$9.6	($0.0)	$0.0	$0.0	($0.0)	$9.5	1%

Table 7-14 Top 25 constraints affecting annual PJM congestion costs (By facility): Calendar year 2009

				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	2009
1	AP South	Interface	500	$12.0	($186.0)	($0.2)	$197.8	$2.9	($2.9)	$2.9	$8.7	$206.5	29%
2	West	Interface	500	$19.4	($22.9)	$0.7	$42.9	$0.4	($0.3)	$0.1	$0.8	$43.7	6%
3	5004/5005 Interface	Interface	500	$11.1	($31.0)	$0.3	$42.4	$1.3	$0.3	$0.2	$1.1	$43.6	6%
4	Pleasant Valley - Belvidere	Line	ComEd	($6.3)	($45.2)	$4.0	$42.9	($0.6)	$2.9	($5.3)	($8.8)	$34.2	5%
5	Kammer	Transformer	500	$50.8	$16.1	$9.0	$43.8	($4.9)	($6.7)	($11.6)	($9.8)	$34.0	5%
6	East Frankfort - Crete	Line	ComEd	$5.9	($19.1)	$8.6	$33.6	($1.0)	$1.3	($5.7)	($8.0)	$25.6	4%
7	Doubs	Transformer	AP	$17.6	($10.8)	$0.9	$29.3	($2.1)	$0.2	($1.8)	($4.2)	$25.1	3%
8	Mount Storm - Pruntytown	Line	AP	$1.8	($16.8)	$0.5	$19.1	$0.9	($1.7)	($1.1)	$1.5	$20.5	3%
9	Bedington - Black Oak	Interface	500	$3.8	($15.5)	$0.8	$20.1	($0.4)	($0.1)	$0.1	($0.2)	$19.8	3%
10	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$13.5	($23.2)	$8.6	$45.4	($7.2)	($2.0)	($23.4)	($28.6)	$16.7	2%
11	Cloverdale - Lexington	Line	AEP	$8.1	($5.3)	$2.0	$15.3	($0.0)	($3.1)	($2.8)	$0.3	$15.6	2%
12	Crete - St Johns Tap	Flowgate	Midwest ISO	$3.2	($15.1)	$3.8	$22.0	($1.1)	$0.4	($6.1)	($7.7)	$14.4	2%
13	Tiltonsville - Windsor	Line	AP	$10.6	($0.9)	$0.3	$11.8	($0.4)	($0.6)	($0.7)	($0.6)	$11.2	2%
14	AEP-DOM	Interface	500	$1.4	($7.6)	$0.5	$9.5	($0.5)	($0.2)	($0.0)	($0.3)	$9.2	1%
15	Pana North	Flowgate	Midwest ISO	$0.1	($2.2)	$1.8	$4.2	($0.5)	$1.1	($11.5)	($13.0)	($8.9)	(1%)
16	Graceton - Raphael Road	Line	BGE	$1.5	($6.0)	$0.6	$8.1	$1.5	$0.1	($0.7)	$0.7	$8.8	1%
17	Ruth - Turner	Line	AEP	$2.5	($6.5)	$0.5	$9.5	($1.5)	($0.6)	($0.6)	($1.5)	$8.0	1%
18	Sammis - Wylie Ridge	Line	AP	$4.5	($3.5)	$3.5	$11.5	($1.1)	($0.2)	($2.8)	($3.7)	$7.8	1%
19	Kanawha River	Transformer	AEP	$2.0	($3.7)	$0.3	$6.0	$0.1	($0.5)	($0.1)	$0.5	$6.5	1%
20	Kammer - Ormet	Line	AEP	$4.3	($4.1)	($0.1)	$8.3	($1.6)	$0.5	($0.0)	($2.2)	$6.2	1%
21	Glidden - West Dekalb	Line	ComEd	($0.6)	($6.0)	$0.4	$5.9	$0.1	($0.0)	($0.0)	$0.1	$6.0	1%
22	Breed - Wheatland	Line	AEP	($0.2)	($5.2)	$0.6	$5.6	$0.0	($0.0)	($0.0)	($0.0)	$5.6	1%
23	Kanawha - Kincaid	Line	AEP	$1.9	($3.5)	$0.2	$5.6	$0.0	$0.0	$0.0	$0.0	$5.6	1%
24	Schahfer - Burr Oak	Flowgate	Midwest ISO	$0.4	($1.3)	$0.6	$2.3	($2.0)	$0.4	($5.4)	($7.8)	($5.6)	(1%)
25	Mount Storm	Transformer	AP	$0.9	($4.7)	($0.1)	$5.5	($0.2)	$0.1	$0.1	($0.2)	$5.3	1%

Congestion-Event Summary for Midwest ISO Flowgates

PJM and the Midwest ISO have a joint operating agreement (JOA) which defines a coordinated methodology for congestion management. This agreement establishes reciprocal, coordinated flowgates in the combined footprint whose operating limits are respected by the operators of both organizations.[24] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.[25] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch. Table 7-15 and Table 7-16 show the Midwest ISO flowgates which PJM took dispatch action to control during 2010 and 2009, respectively, and which had the greatest congestion cost impact on PJM. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The top congestion cost impacts for Midwest ISO flowgates affecting PJM dispatch are presented by constraint, in descending order of the absolute value of

24 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2009) (Accessed February 19, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx>.

25 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2009) (Accessed February 19, 2010), Section 2.2.24 <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx>.

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total congestion costs. Among Midwest ISO flowgates in 2010, the Crete – St Johns flowgate made the most significant contribution to positive congestion while the Pleasant Prairie – Zion flowgate made the most significant contribution to negative congestion. Among Midwest ISO flowgates in 2009, the Dunes Acres – Michigan City flowgate made the most significant contribution to positive congestion, while the Pana North flowgate made the most significant negative contribution.

Table 7-15 Top congestion cost impacts from Midwest ISO flowgates affecting PJM dispatch (By facility): Calendar year 2010

		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	($9.0)	($51.4)	($5.1)	$37.3	$0.0	($1.1)	($8.9)	($7.8)	$29.5	2,066	823
2	Pleasant Prairie - Zion	($3.3)	($7.8)	$3.0	$7.5	($0.5)	$1.2	($16.7)	($18.4)	($10.9)	1,321	404
3	Benton Harbor - Palisades	$0.0	($0.0)	$0.0	$0.1	($0.0)	$0.7	($4.5)	($5.2)	($5.1)	11	114
4	Rising	$0.0	($5.1)	$0.9	$6.0	($0.2)	$0.4	($0.9)	($1.6)	$4.5	875	80
5	Oak Grove - Galesburg	($0.1)	($0.4)	$0.2	$0.4	($0.2)	$0.7	($3.0)	($3.9)	($3.4)	117	242
6	Dunes Acres - Michigan City	$0.5	($0.7)	$0.9	$2.1	($0.1)	($0.3)	$0.4	$0.6	$2.7	264	42
7	Palisades - Vergennes	$2.8	($0.6)	$0.5	$3.9	($0.1)	$0.4	($1.0)	($1.5)	$2.3	235	91
8	Breed - Wheatland	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($2.0)	($2.1)	($2.1)	0	76
9	Burnham - Sheffield	($0.3)	($1.9)	$0.4	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	252	0
10	DC Cook - Palisades	$0.0	$0.0	$0.0	$0.0	($0.3)	$0.1	($1.5)	($1.9)	($1.9)	0	36
11	Paxton - Sidney	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($1.4)	($1.5)	($1.5)	0	29
12	Burr Oak	$0.2	($0.2)	$0.0	$0.4	$0.3	$0.3	($1.9)	($1.8)	($1.4)	140	210
13	State Line - Wolf Lake	$0.3	($0.7)	$0.6	$1.5	($0.1)	$0.0	($0.0)	($0.1)	$1.4	376	7
14	Eugene - Bunsonville	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.0	($0.8)	($0.9)	($0.9)	0	51
15	Marktown - Inland Steel	$0.6	($1.0)	$0.7	$2.2	($0.9)	$0.7	($1.4)	($3.1)	($0.9)	424	344
16	Michigan City - Laporte	$0.1	($0.1)	$0.1	$0.3	($0.2)	($0.0)	($0.7)	($0.9)	($0.7)	50	67
17	Lanesville	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($0.4)	($0.5)	($0.5)	0	48
18	Beaver Valley - Sammis	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($0.2)	($0.4)	($0.4)	0	8
19	Nucor - Whitestown	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.4)	($0.4)	($0.4)	0	23
20	Stillwell - Dumont	$0.0	($0.2)	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	42	0

Table 7-16 Top congestion cost impacts from Midwest ISO flowgates affecting PJM dispatch (By facility): Calendar year 2009

		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	Dunes Acres - Michigan City	$13.5	($23.2)	$8.6	$45.4	($7.2)	($2.0)	($23.4)	($28.6)	$16.7	2,949	910
2	Crete - St Johns Tap	$3.2	($15.1)	$3.8	$22.0	($1.1)	$0.4	($6.1)	($7.7)	$14.4	1,571	306
3	Pana North	$0.1	($2.2)	$1.8	$4.2	($0.5)	$1.1	($11.5)	($13.0)	($8.9)	986	318
4	Schahfer - Burr Oak	$0.4	($1.3)	$0.6	$2.3	($2.0)	$0.4	($5.4)	($7.8)	($5.6)	62	81
5	Paddock - Townline	$0.5	($3.6)	$0.4	$4.6	$0.6	$0.3	($0.3)	($0.0)	$4.5	404	215
6	Breed - Wheatland	$0.0	$0.0	$0.0	$0.0	$0.1	$0.7	($3.2)	($3.8)	($3.8)	0	161
7	Pleasant Prairie - Zion	($0.0)	($0.4)	$0.2	$0.6	$0.2	$0.8	($3.6)	($4.2)	($3.6)	151	135
8	Rising	($0.1)	($2.7)	$0.5	$3.1	$0.0	$0.2	($0.8)	($1.0)	$2.1	572	150
9	Palisades - Argenta	$0.1	($0.1)	$0.1	$0.3	($0.3)	$0.6	($1.1)	($2.1)	($1.8)	49	58
10	State Line - Wolf Lake	$0.5	($2.6)	$1.1	$4.3	($0.5)	$0.6	($1.6)	($2.7)	$1.6	1,284	183
11	Eugene - Bunsonville	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($1.1)	($1.3)	($1.3)	0	44
12	Oak Grove - Galesburg	($0.6)	($4.3)	$0.1	$3.8	$0.8	$1.4	($4.2)	($4.8)	($1.0)	790	638
13	State Line - Roxana	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.0	($0.4)	($0.6)	($0.6)	0	30
14	Pawnee	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.4)	($0.4)	($0.4)	0	35
15	Lanesville	$0.3	($0.1)	$0.1	$0.5	$0.0	$0.1	($0.8)	($0.9)	($0.4)	104	32
16	Pierce - Foster	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.3	($0.0)	($0.4)	($0.4)	0	5
17	Burr Oak	$0.1	($0.4)	$0.5	$0.9	($0.2)	$0.2	($0.8)	($1.3)	($0.3)	94	66
18	Krendale - Seneca	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	($0.1)	($0.2)	($0.2)	0	30
19	Bunsonville - Eugene	$0.0	($0.1)	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	24	0
20	State Line	$0.0	($0.0)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	385	0

Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 7-17 and Table 7-18 show the 500 kV constraints impacting congestion costs in PJM. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The 500 kV constraints impacting congestion costs in PJM are presented by constraint, in descending order of the absolute value of total congestion costs. In 2010, the AP South interface constraint contributed to positive congestion. There were no significant contributions to negative congestion from 500 kV constraints in 2010. In 2009, the AP South contributed to positive congestion. Also in 2009, there were no significant contributions to negative congestion.

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Table 7-17 Regional constraints summary (By facility): Calendar year 2010

				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	($10.8)	($433.4)	($2.4)	$420.2	$11.2	$11.4	$1.6	$1.4	$421.6	4,645	1,528
2	Bedington - Black Oak	Interface	500	$9.4	($96.0)	$2.7	$108.1	($0.1)	$1.1	($1.5)	($2.8)	$105.3	2,291	212
3	5004/5005 Interface	Interface	500	$50.1	($42.0)	($0.1)	$92.1	$10.2	$9.0	($1.3)	($0.2)	$91.9	1,644	605
4	AEP-DOM	Interface	500	$10.5	($52.8)	$2.5	$65.8	$0.3	$1.0	($2.8)	($3.5)	$62.3	691	187
5	West	Interface	500	$21.5	($1.6)	($0.2)	$22.9	$0.6	$1.3	$0.0	($0.7)	$22.2	179	65
6	East	Interface	500	$2.7	($5.0)	$0.1	$7.8	$0.0	($0.0)	$0.0	$0.0	$7.8	256	8
7	Harrison - Pruntytown	Line	500	$1.9	($4.1)	$0.8	$6.9	($0.6)	($0.3)	($2.7)	($2.9)	$4.0	231	224
8	Central	Interface	500	$1.2	($0.2)	$0.1	$1.4	$0.1	$0.1	($0.1)	($0.0)	$1.3	117	13
9	Doubs - Mount Storm	Line	500	$0.0	$0.0	$0.0	$0.0	$0.5	$0.7	($0.1)	($0.3)	($0.3)	0	45
10	Conemaugh - Hunterstown	Line	500	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($0.1)	($0.3)	($0.3)	0	5
11	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
12	Juniata - Keystone	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	1

Table 7-18 Regional constraints summary (By facility): Calendar year 2009

				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	$12.0	($186.0)	($0.2)	$197.8	$2.9	($2.9)	$2.9	$8.7	$206.5	3,549	604
2	West	Interface	500	$19.4	($22.9)	$0.7	$42.9	$0.4	($0.3)	$0.1	$0.8	$43.7	504	87
3	5004/5005 Interface	Interface	500	$11.1	($31.0)	$0.3	$42.4	$1.3	$0.3	$0.2	$1.1	$43.6	776	294
4	Kammer	Transformer	500	$50.8	$16.1	$9.0	$43.8	($4.9)	($6.7)	($11.6)	($9.8)	$34.0	3,674	1,328
5	Bedington - Black Oak	Interface	500	$3.8	($15.5)	$0.8	$20.1	($0.4)	($0.1)	$0.1	($0.2)	$19.8	669	73
6	AEP-DOM	Interface	500	$1.4	($7.6)	$0.5	$9.5	($0.5)	($0.2)	($0.0)	($0.3)	$9.2	335	136
7	East	Interface	500	$0.3	($0.3)	($0.0)	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	32	0
8	Doubs - Mount Storm	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	$0.0	$0.1	$0.1	0	18
9	Harrison Tap - Kammer	Line	500	$0.0	($0.0)	$0.0	$0.0	$0.1	$0.0	$0.0	$0.1	$0.1	1	11
10	Central	Interface	500	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.1	($0.0)	($0.1)	$0.1	19	8
11	Belmont - Harrison	Line	500	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	5	2
12	Harrison - Pruntytown	Line	500	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.1)	($0.0)	($0.0)	$0.0	2	43
13	Conemaugh - Hunterstown	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	0	1
14	Harrison Tap - North Longview	Line	500	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	0

Zonal Congestion

Summary

Day-ahead and balancing congestion costs within specific zones for calendar years 2010 and 2009 are presented in Table 7-19 and Table 7-20. While total congestion costs represent the overall charge or credit to a zone, the components of congestion costs measure the extent to which load or generation bear total congestion costs. Load congestion payments, when positive, measure the total congestion cost to load in an area. Load congestion payments, when negative, measure the total congestion credit to load in an area. Negative load congestion payments result when load is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in western control zones and higher prices in eastern and southern control zones. Load in western control zones will benefit from lower prices and receive a congestion credit (negative load congestion payment). Load in the eastern and southern control zones will incur a congestion charge (positive load congestion payment). The reverse is true for generation congestion credits. Generation congestion credits, when positive, measure the total congestion credit to generation in an area. Generation congestion credits, when negative, measure the total congestion cost to generation in an area. Negative generation congestion credits result when generation is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in the western control zones and higher prices in the eastern and southern control zones. Generation in the western control zones will receive lower prices and incur a congestion charge (negative generation congestion credit). Generation in the eastern and southern control zones will receive higher prices and receive a congestion credit (positive generation congestion credit).

PJM congestion accounting nets load congestion payments against generation congestion credits by billing organization. The net congestion bill for a zone or constraint may be either positive or negative, depending on the relative size and sign of load congestion payments and generation congestion credits. When summed across a zone, the net congestion bill shows the overall congestion charge or credit for an area, not including explicit congestion, but the net congestion bill is not a good measure of whether load is paying higher prices in the form of congestion.

The Dominion Control Zone, the AP Control Zone and the ComEd Control Zone are examples of how a positive net congestion bill can result from very different combinations of load payments and generation credits. The Dominion Control Zone had the highest congestion charges, $285.5 million, of any control zone in 2010. The large positive congestion costs in the Dominion Control Zone were the result of large positive load congestion payments plus negative generation congestion credits. This is an unusual combination because when load and generation are in the same area, higher load congestion payments will be at least partially offset by higher generation credits. In Dominion, negative generation credits were received by generators on the low side of the AP South constraint while most of the load was on the high side of the constraint and paid higher congestion costs. The AP Control Zone had the second highest congestion charges, $282.7 million, of any control zone in 2010. The positive congestion costs in the AP Control Zone were the result of relatively low positive load congestion payments and larger negative generation congestion credits, which added to the total congestion costs for AP rather than offsetting the positive load congestion payments. The ComEd Control Zone had the third highest congestion charges, $263.2 million, of any control zone

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in 2010. The positive congestion costs in the ComEd Control Zone were the result of large negative load congestion payments offset by even larger negative generation congestion credits. Thus, the lower prices in ComEd, which resulted from a lower congestion component of LMP, meant that load paid lower prices and lower congestion, and that generators received lower prices and a lower congestion component. The result was positive measured congestion costs. This somewhat counter intuitive result is the result of congestion accounting conventions.

Table 7-19 Congestion cost summary (By control zone): Calendar year 2010

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$40.9	$15.1	$0.3	$26.1	$0.5	($1.3)	($0.1)	$1.7	$27.7
AEP	($137.6)	($353.1)	$11.2	$226.7	($21.6)	$31.2	($18.9)	($71.7)	$155.0
AP	$14.8	($293.7)	$0.8	$309.3	$7.5	$28.8	($5.3)	($26.6)	$282.7
BGE	$198.2	$124.6	$9.3	$82.9	$15.2	($4.9)	($11.4)	$8.7	$91.6
ComEd	($483.2)	($795.1)	($5.5)	$306.4	($21.8)	$9.5	($11.9)	($43.2)	$263.2
DAY	($18.7)	($30.0)	$5.6	$16.9	$1.4	$1.8	($6.9)	($7.3)	$9.6
DLCO	($95.1)	($139.6)	($0.7)	$43.8	($11.9)	$1.1	$0.2	($12.9)	$30.9
DPL	$72.7	$23.5	$1.3	$50.5	$0.0	$1.7	($1.6)	($3.3)	$47.2
Dominion	$260.1	($33.3)	$15.9	$309.3	($5.6)	($0.6)	($18.8)	($23.9)	$285.5
External	($184.1)	($198.7)	$17.4	$32.0	$2.2	($20.0)	($69.1)	($46.9)	($14.9)
JCPL	$76.1	$26.5	$0.5	$50.2	$1.0	($0.5)	($0.7)	$0.8	$51.0
Met-Ed	$61.2	$52.0	$1.3	$10.5	($0.8)	$0.2	($1.5)	($2.6)	$8.0
PECO	$62.5	$72.1	$0.3	($9.3)	($2.9)	$2.3	($0.9)	($6.0)	($15.3)
PENELEC	($56.5)	($154.8)	$1.0	$99.2	$17.0	$8.4	($0.7)	$7.8	$107.0
PPL	$96.4	$110.4	$3.6	($10.4)	$12.4	$9.1	($0.5)	$2.7	($7.7)
PSEG	$129.5	$100.2	$28.3	$57.6	($9.6)	$20.2	($23.5)	($53.3)	$4.3
Pepco	$357.5	$250.9	$6.1	$112.8	($20.0)	($12.1)	($6.8)	($14.8)	$98.0
RECO	$3.5	$0.2	$0.1	$3.4	$1.0	($0.0)	($0.2)	$0.9	$4.3
Total	$398.3	($1,222.9)	$96.7	$1,717.9	($35.9)	$75.0	($178.8)	($289.7)	$1,428.1

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Table 7-20 Congestion cost summary (By control zone): Calendar year 2009

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$24.5	$9.2	$0.2	$15.6	($0.5)	$0.9	$0.4	($1.0)	$14.6
AEP	($60.2)	($160.5)	$9.0	$109.3	($7.2)	$8.4	($10.7)	($26.3)	$83.0
AP	$33.2	($80.7)	$12.9	$126.9	($4.5)	$5.0	($22.1)	($31.6)	$95.3
BGE	$97.6	$75.9	$2.4	$24.0	$6.9	($5.0)	($2.3)	$9.5	$33.5
ComEd	($255.3)	($493.1)	($4.1)	$233.7	($7.6)	$6.1	($0.4)	($14.0)	$219.7
DAY	($9.7)	($18.7)	($0.5)	$8.5	$0.9	$1.7	$0.1	($0.7)	$7.8
DLCO	($50.7)	($75.8)	($0.0)	$25.1	($4.0)	$5.3	($0.2)	($9.5)	$15.6
DPL	$49.7	$15.0	$0.4	$35.1	($1.9)	$1.6	($0.4)	($4.0)	$31.1
Dominion	$94.0	($15.4)	$7.5	$117.0	$1.1	($3.0)	($8.2)	($4.1)	$112.9
External	($22.2)	($56.7)	$37.3	$71.9	($1.3)	($7.6)	($79.1)	($72.8)	($1.0)
JCPL	$46.7	$18.9	$0.1	$27.9	$0.4	($2.7)	($0.2)	$2.9	$30.8
Met-Ed	$36.9	$36.8	$0.2	$0.4	$0.1	($1.0)	($0.3)	$0.8	$1.1
PECO	$19.0	$39.9	$0.1	($20.8)	($0.4)	$2.8	($0.1)	($3.3)	($24.1)
PENELEC	($6.8)	($38.9)	$0.3	$32.4	$1.3	$0.8	($0.1)	$0.4	$32.8
PPL	$14.6	$23.4	$2.7	($6.1)	($0.3)	($0.5)	$0.2	$0.4	($5.7)
PSEG	$74.8	$61.7	$11.7	$24.8	($0.7)	$6.9	($6.2)	($13.8)	$11.0
Pepco	$203.9	$133.9	$3.5	$73.5	($21.2)	($9.7)	($3.6)	($15.1)	$58.4
RECO	$2.2	$0.0	$0.1	$2.3	$0.0	($0.0)	($0.1)	($0.1)	$2.2
Total	$292.3	($525.2)	$83.9	$901.4	($39.0)	$10.1	($133.4)	($182.4)	$719.0

Details of Regional and Zonal Congestion

Constraints were examined by zone and categorized by their effect on regions. Zones correspond to regulated utility franchise areas. Regions generally comprise two or more zones. PJM is comprised of three regions: the PJM Mid-Atlantic Region with 11 control zones (the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO control zones); the PJM Western Region with five control zones (the AP, ComEd, AEP, DLCO and DAY control zones); and the PJM Southern Region with one control zone (the Dominion Control Zone).

Table 7-21 through Table 7-54 present the top 15 constraints affecting each control zone's congestion costs, including the facility type and the location of the constrained facility for both 2010 and 2009. In addition, day-ahead and real-time congestion-event hours are presented for each of the highlighted constraints. Constraints can have wide-ranging effects, influencing prices and congestion across multiple zones. Many constraints that are physically located outside of a control zone can impact the congestion costs of that control zone. The following tables present the constraints in descending order of the absolute value of total congestion costs for each zone. In

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addition to the top 15 constraints, these tables show the top five local constraints for the control zone, which were not in the top 15 constraints, but are located inside the respective control zone. These constraints are shown to illustrate the effect local constraints have on the control zone in which they are located. In 2010, the RECO control zone did not have any constraints within their boundaries, thus the table shows only the top 15 constraints.

For each of the constraints presented in the following tables, the zonal cost impacts are decomposed into their Day-Ahead Energy Market and balancing market components. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value.

Mid-Atlantic Region Congestion-Event Summaries

AECO Control Zone

Table 7-21 AECO Control Zone top congestion cost impacts (By facility): Calendar year 2010

				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	$9.7	$4.4	$0.0	$5.4	$0.7	($0.7)	($0.0)	$1.3	$6.7	1,644	605
2	England - Middletap	Line	AECO	$4.0	$0.7	$0.0	$3.3	($0.4)	($0.4)	($0.0)	($0.0)	$3.2	336	69
3	West	Interface	500	$3.8	$1.9	$0.0	$1.9	$0.1	$0.0	($0.0)	$0.1	$2.0	179	65
4	Monroe	Transformer	AECO	$1.7	$0.2	$0.0	$1.5	$0.1	($0.2)	($0.0)	$0.2	$1.8	232	48
5	Graceton - Raphael Road	Line	BGE	($2.1)	($0.7)	($0.0)	($1.4)	($0.2)	$0.1	$0.0	($0.3)	($1.7)	565	308
6	Brandon Shores - Riverside	Line	BGE	$2.4	$1.1	$0.0	$1.3	$0.0	($0.2)	($0.0)	$0.2	$1.5	344	162
7	Absecon - Lewis	Line	AECO	$0.2	$0.0	$0.0	$0.2	($1.5)	$0.1	($0.1)	($1.6)	($1.4)	81	18
8	Wylie Ridge	Transformer	AP	$1.1	$0.4	$0.0	$0.7	$0.5	($0.1)	($0.0)	$0.6	$1.3	728	683
9	Crete - St Johns Tap	Flowgate	Midwest ISO	$1.4	$0.4	($0.0)	$1.0	$0.2	($0.0)	($0.0)	$0.3	$1.3	2,066	823
10	AP South	Interface	500	$2.1	$1.0	$0.0	$1.1	$0.1	($0.1)	($0.0)	$0.1	$1.2	4,645	1,528
11	Shieldalloy - Vineland	Line	AECO	$3.3	$0.9	$0.1	$2.4	($1.2)	$0.1	($0.0)	($1.3)	$1.1	245	172
12	East Frankfort - Crete	Line	ComEd	$1.2	$0.3	$0.0	$0.9	$0.2	($0.0)	($0.0)	$0.2	$1.1	3,084	850
13	Tiltonsville - Windsor	Line	AP	$1.2	$0.5	$0.0	$0.7	$0.1	($0.1)	($0.0)	$0.2	$0.9	2,723	506
14	Bedington - Black Oak	Interface	500	$1.5	$0.6	$0.0	$0.9	$0.0	$0.0	($0.0)	$0.0	$0.9	2,291	212
15	Branchburg - Readington	Line	PSEG	($1.3)	($0.5)	($0.0)	($0.8)	($0.1)	$0.0	$0.0	($0.1)	($0.8)	1,235	185
26	Corson - Court	Line	AECO	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.1	($0.0)	($0.3)	($0.3)	7	15
29	Sherman Avenue	Transformer	AECO	$0.4	$0.0	$0.0	$0.4	($0.1)	$0.0	($0.0)	($0.1)	$0.3	70	25
42	Corson - Union	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.2	($0.0)	$0.0	$0.2	$0.2	0	16
91	Corson	Transformer	AECO	$0.0	$0.0	$0.0	$0.0	$0.1	$0.0	$0.0	$0.1	$0.1	0	17
102	Lewis - Motts - Cedar	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	25	0

Table 7-22 AECO Control Zone top congestion cost impacts (By facility): Calendar year 2009

				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	Kammer	Transformer	500	$4.2	$1.3	$0.0	$2.9	$0.2	($0.0)	$0.0	$0.3	$3.1	3,674	1,328
2	West	Interface	500	$4.9	$2.3	$0.1	$2.6	$0.0	($0.0)	($0.0)	$0.0	$2.7	504	87
3	5004/5005 Interface	Interface	500	$4.4	$1.9	$0.0	$2.5	$0.1	$0.0	$0.0	$0.1	$2.7	776	294
4	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$1.4	$0.3	$0.0	$1.1	$0.1	($0.0)	$0.0	$0.2	$1.3	2,949	910
5	Graceton - Raphael Road	Line	BGE	($1.5)	($0.5)	($0.0)	($1.1)	$0.2	$0.1	$0.0	$0.0	($1.1)	527	152
6	Wylie Ridge	Transformer	AP	$1.8	$0.9	$0.0	$0.9	($0.0)	$0.1	$0.1	($0.0)	$0.9	354	335
7	Absecon - Lewis	Line	AECO	$1.0	$0.1	$0.0	$1.0	($1.2)	$0.5	($0.0)	($1.7)	($0.8)	170	149
8	Atlantic - Larrabee	Line	JCPL	($0.5)	($0.1)	($0.0)	($0.4)	($0.2)	$0.1	$0.0	($0.3)	($0.7)	284	73
9	Doubs	Transformer	AP	$1.0	$0.4	$0.0	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.6	429	246
10	AP South	Interface	500	$1.0	$0.5	$0.0	$0.6	$0.0	$0.0	$0.1	$0.1	$0.6	3,549	604
11	Tiltonsville - Windsor	Line	AP	$0.7	$0.2	$0.0	$0.5	$0.0	($0.0)	($0.0)	$0.1	$0.5	2,070	311
12	East Frankfort - Crete	Line	ComEd	$0.7	$0.2	$0.0	$0.5	$0.0	($0.0)	$0.0	$0.0	$0.5	2,163	605
13	Monroe	Transformer	AECO	$0.5	$0.0	$0.0	$0.4	$0.1	($0.0)	$0.0	$0.1	$0.5	263	13
14	Shieldalloy - Vineland	Line	AECO	$1.1	$0.3	$0.0	$0.9	($0.3)	$0.1	($0.0)	($0.4)	$0.5	148	61
15	Sammis - Wylie Ridge	Line	AP	$0.7	$0.3	$0.0	$0.4	$0.0	($0.0)	($0.0)	$0.0	$0.5	806	157
16	Monroe - New Freedom	Line	AECO	$0.8	$0.4	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	584	0
23	Lewis - Motts - Cedar	Line	AECO	$0.2	$0.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	108	0
34	Corson - Union	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.1	$0.1	0	3
84	Clayton - Williams	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	3	0
118	Corson	Transformer	AECO	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0

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BGE Control Zone

Table 7-23 BGE Control Zone top congestion cost impacts (By facility): Calendar year 2010

				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	Brandon Shores - Riverside	Line	BGE	$17.3	($8.9)	$0.2	$26.4	($2.1)	$0.2	($0.3)	($2.5)	$23.9	344	162
2	AP South	Interface	500	$55.3	$43.9	$2.3	$13.6	$4.4	($1.6)	($1.8)	$4.2	$17.8	4,645	1,528
3	Doubs	Transformer	AP	$13.3	$8.0	$0.4	$5.6	$1.1	($1.4)	($0.7)	$1.8	$7.5	920	525
4	Bedington - Black Oak	Interface	500	$22.3	$17.2	$0.9	$6.0	$0.6	($0.4)	($0.7)	$0.4	$6.3	2,291	212
5	5004/5005 Interface	Interface	500	$9.0	$4.6	$0.4	$4.8	$0.6	($0.2)	($0.3)	$0.4	$5.3	1,644	605
6	Graceton - Raphael Road	Line	BGE	$10.0	$6.7	$0.7	$4.0	$0.2	($0.7)	($0.7)	$0.2	$4.2	565	308
7	West	Interface	500	$6.5	$3.3	$0.1	$3.3	$0.2	($0.0)	($0.1)	$0.2	$3.5	179	65
8	Mount Storm - Pruntytown	Line	AP	$4.3	$3.6	$0.2	$0.8	$1.3	($0.6)	($0.6)	$1.4	$2.2	571	574
9	Brunner Island - Yorkana	Line	Met-Ed	$3.6	$2.1	$0.2	$1.7	$0.2	($0.0)	($0.2)	($0.1)	$1.6	237	180
10	Millville - Sleepy Hollow	Line	Dominion	$4.4	$3.4	$0.4	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	401	0
11	Cloverdale - Lexington	Line	AEP	$4.8	$4.5	$0.2	$0.5	$0.9	($0.3)	($0.3)	$0.9	$1.4	1,127	684
12	Wylie Ridge	Transformer	AP	$2.7	$2.0	$0.1	$0.9	$1.0	$0.1	($0.4)	$0.6	$1.4	728	683
13	Crete - St Johns Tap	Flowgate	Midwest ISO	$4.0	$3.0	$0.3	$1.3	$0.3	($0.0)	($0.2)	$0.1	$1.4	2,066	823
14	Millville - Old Chapel	Line	AP	$3.5	$2.9	$0.3	$0.9	$1.6	$0.1	($1.0)	$0.4	$1.3	210	303
15	Tiltonsville - Windsor	Line	AP	$3.1	$2.1	$0.1	$1.1	$0.2	($0.1)	($0.2)	$0.2	$1.3	2,723	506
32	Fullerton - Windyedge	Line	BGE	$0.4	($0.1)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	23	0
33	Graceton - Safe Harbor	Line	BGE	$0.9	$0.6	$0.1	$0.5	$0.2	$0.1	($0.2)	($0.0)	$0.4	104	70
34	Glenarm - Windy Edge	Line	BGE	$0.5	$0.2	$0.0	$0.3	$0.0	($0.1)	($0.0)	$0.1	$0.4	74	39
39	Green Street - Westport	Line	BGE	$0.3	($0.1)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	146	0
55	Five Forks - Rock Ridge	Line	BGE	$0.3	$0.1	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	39	0

Table 7-24 BGE Control Zone top congestion cost impacts (By facility): Calendar year 2009

				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	$25.2	$23.7	$0.5	$2.0	$1.7	($1.2)	($0.5)	$2.5	$4.5	3,549	604
2	Kammer	Transformer	500	$11.9	$9.0	$0.2	$3.2	$1.0	($0.6)	($0.2)	$1.3	$4.5	3,674	1,328
3	Brandon Shores - Riverside	Line	BGE	$1.9	($1.0)	$0.0	$3.0	($0.1)	($0.0)	($0.0)	($0.1)	$2.9	134	13
4	Doubs	Transformer	AP	$6.4	$5.0	$0.4	$1.8	$0.5	($0.6)	($0.4)	$0.7	$2.5	429	246
5	Graceton - Raphael Road	Line	BGE	$6.6	$4.2	$0.1	$2.4	$0.0	$0.0	($0.1)	($0.1)	$2.3	527	152
6	5004/5005 Interface	Interface	500	$3.1	$1.7	$0.1	$1.5	$0.3	($0.2)	($0.1)	$0.4	$1.9	776	294
7	West	Interface	500	$8.9	$7.4	$0.2	$1.6	$0.1	($0.2)	($0.1)	$0.2	$1.9	504	87
8	Wylie Ridge	Transformer	AP	$3.6	$3.4	$0.1	$0.3	$0.6	($0.7)	($0.2)	$1.2	$1.5	354	335
9	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$3.4	$2.8	$0.0	$0.6	$0.3	($0.0)	($0.0)	$0.4	$1.0	2,949	910
10	Bedington - Black Oak	Interface	500	$3.9	$3.3	$0.1	$0.8	$0.1	($0.0)	($0.0)	$0.1	$0.9	669	73
11	Mount Storm - Pruntytown	Line	AP	$3.2	$2.9	$0.0	$0.2	$0.5	($0.3)	($0.1)	$0.6	$0.9	525	132
12	Pumphrey - Westport	Line	Pepco	$0.5	($0.1)	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	1,181	0
13	Fullerton - Windyedge	Line	BGE	$0.5	($0.1)	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	31	0
14	Tiltonsville - Windsor	Line	AP	$1.5	$1.0	$0.0	$0.5	$0.1	($0.0)	($0.0)	$0.1	$0.6	2,070	311
15	Cloverdale - Lexington	Line	AEP	$2.6	$2.5	$0.0	$0.2	$0.4	($0.1)	($0.1)	$0.4	$0.6	1,019	434
16	Five Forks - Rock Ridge	Line	BGE	$0.7	$0.2	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	136	0
21	Conastone	Transformer	BGE	$1.0	$0.6	($0.0)	$0.3	$0.0	($0.0)	($0.0)	$0.1	$0.4	75	12
24	Green Street - Westport	Line	BGE	$0.3	($0.0)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	365	0
27	Conastone - Otter	Line	BGE	$0.4	$0.2	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	92	32
30	Waugh Chapel	Transformer	BGE	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.2)	$0.0	$0.2	$0.2	0	8

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DPL Control Zone

Table 7-25 DPL Control Zone top congestion cost impacts (By facility): Calendar year 2010

				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	$16.2	$6.2	$0.1	$10.1	$0.6	($0.0)	($0.2)	$0.5	$10.6	1,644	605
2	AP South	Interface	500	$5.6	$2.3	$0.1	$3.4	$0.3	$0.1	($0.1)	$0.0	$3.5	4,645	1,528
3	Oak Hall	Transformer	DPL	$3.0	$0.6	$0.0	$2.5	$0.0	$0.0	$0.0	$0.0	$2.5	668	0
4	Graceton - Raphael Road	Line	BGE	($3.9)	($1.2)	($0.0)	($2.7)	($0.1)	($0.2)	$0.1	$0.2	($2.5)	565	308
5	Crete - St Johns Tap	Flowgate	Midwest ISO	$2.6	$0.3	$0.0	$2.3	$0.2	$0.1	($0.1)	$0.0	$2.3	2,066	823
6	Wylie Ridge	Transformer	AP	$2.0	$0.3	$0.0	$1.7	$0.6	$0.2	($0.1)	$0.4	$2.0	728	683
7	West	Interface	500	$5.4	$3.4	$0.0	$2.0	$0.1	$0.1	($0.0)	$0.0	$2.0	179	65
8	East Frankfort - Crete	Line	ComEd	$2.3	$0.3	$0.0	$2.0	$0.0	$0.0	($0.0)	$0.0	$2.0	3,084	850
9	Bedington - Black Oak	Interface	500	$3.3	$1.3	$0.1	$2.0	$0.1	$0.1	($0.1)	($0.1)	$2.0	2,291	212
10	New Church - Piney Grove	Line	DPL	$2.1	$0.4	$0.0	$1.7	$0.0	$0.0	$0.0	$0.0	$1.7	334	0
11	East	Interface	500	$2.2	$0.6	$0.0	$1.6	($0.0)	$0.0	($0.0)	($0.0)	$1.5	256	8
12	Brandon Shores - Riverside	Line	BGE	$3.4	$2.0	$0.0	$1.5	$0.1	($0.0)	($0.0)	$0.1	$1.5	344	162
13	Longwood - Wye Mills	Line	DPL	$1.8	$0.3	$0.0	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	357	0
14	Middletown - Mt Pleasant	Line	DPL	$1.7	$0.4	$0.0	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	163	0
15	Cloverdale - Lexington	Line	AEP	$1.5	$0.3	$0.0	$1.2	$0.2	$0.0	($0.1)	$0.1	$1.2	1,127	684
17	Kenney - Stockton	Line	DPL	$1.0	$0.3	$0.0	$0.7	($1.6)	($0.0)	($0.1)	($1.7)	($1.0)	96	122
22	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
24	Easton - Trappe	Line	DPL	$0.9	$0.2	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	117	0
26	Dupont Seaford - Laurel	Line	DPL	$0.0	$0.0	$0.0	$0.0	($0.4)	$0.4	($0.0)	($0.7)	($0.7)	0	15
27	Keeney At5n	Transformer	DPL	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.6	($0.0)	($0.7)	($0.7)	0	13

Table 7-26 DPL Control Zone top congestion cost impacts (By facility): Calendar year 2009

				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	Kammer	Transformer	500	$7.5	$1.7	$0.0	$5.9	($0.1)	$0.3	($0.1)	($0.4)	$5.4	3,674	1,328
2	West	Interface	500	$9.2	$3.8	$0.0	$5.5	($0.0)	$0.1	($0.0)	($0.1)	$5.3	504	87
3	5004/5005 Interface	Interface	500	$7.3	$2.8	$0.1	$4.5	$0.1	$0.3	($0.1)	($0.3)	$4.2	776	294
4	Short - Laurel	Line	DPL	$0.0	$0.0	$0.0	$0.0	($2.1)	$0.2	($0.1)	($2.4)	($2.4)	0	27
5	Wylie Ridge	Transformer	AP	$3.4	$1.3	$0.0	$2.1	$0.2	$0.2	($0.0)	($0.0)	$2.1	354	335
6	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$2.4	$0.3	($0.0)	$2.1	($0.1)	$0.0	$0.0	($0.1)	$2.0	2,949	910
7	AP South	Interface	500	$3.0	$0.9	$0.0	$2.1	$0.0	$0.1	($0.0)	($0.1)	$1.9	3,549	604
8	Graceton - Raphael Road	Line	BGE	($2.7)	($0.7)	($0.0)	($2.0)	$0.4	($0.2)	$0.0	$0.6	($1.4)	527	152
9	Middletown - Mt Pleasant	Line	DPL	$1.8	$0.3	$0.0	$1.5	($0.2)	$0.0	$0.0	($0.2)	$1.3	312	17
10	Sammis - Wylie Ridge	Line	AP	$1.5	$0.3	$0.0	$1.2	($0.0)	$0.0	($0.0)	($0.1)	$1.1	806	157
11	East Frankfort - Crete	Line	ComEd	$1.3	$0.3	$0.0	$1.0	$0.0	($0.0)	($0.0)	$0.1	$1.1	2,163	605
12	Tiltonsville - Windsor	Line	AP	$1.2	$0.3	$0.0	$0.9	($0.0)	$0.0	($0.0)	($0.1)	$0.8	2,070	311
13	North Seaford - Pine Street	Line	DPL	$1.0	$0.2	$0.0	$0.8	($0.0)	($0.0)	($0.0)	$0.0	$0.8	331	1
14	Cloverdale - Lexington	Line	AEP	$1.0	$0.2	$0.0	$0.8	$0.0	($0.0)	($0.0)	$0.0	$0.8	1,019	434
15	Doubs	Transformer	AP	$1.8	$1.1	$0.0	$0.8	$0.0	$0.1	($0.0)	($0.1)	$0.7	429	246
17	Easton - Trappe	Line	DPL	$0.7	$0.1	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	212	0
18	Church - I.B. Corners	Line	DPL	$0.7	$0.1	$0.0	$0.6	($0.0)	$0.0	($0.0)	($0.0)	$0.6	66	5
20	Longwood - Wye Mills	Line	DPL	$0.6	$0.1	$0.0	$0.5	($0.0)	$0.0	$0.0	($0.0)	$0.5	250	3
22	Edgemoor - Harmony	Line	DPL	$0.8	$0.3	$0.0	$0.5	($0.1)	($0.0)	($0.0)	($0.1)	$0.4	28	7
23	Red Lion At20	Transformer	DPL	$0.4	$0.1	$0.0	$0.4	$0.0	($0.0)	$0.0	$0.0	$0.4	45	6

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JCPL Control Zone

Table 7-27 JCPL Control Zone top congestion cost impacts (By facility): Calendar year 2010

				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	$22.2	$9.4	$0.1	$12.9	$1.1	($0.3)	($0.1)	$1.2	$14.1	1,644	605
2	Branchburg - Readington	Line	PSEG	$6.8	$0.4	$0.1	$6.5	($0.5)	($0.3)	$0.1	($0.2)	$6.3	1,235	185
3	West	Interface	500	$7.7	$4.0	$0.0	$3.7	$0.0	($0.1)	($0.0)	$0.1	$3.8	179	65
4	Redoak - Sayreville	Line	JCPL	($2.1)	($6.1)	$0.0	$3.9	$0.1	$0.7	$0.0	($0.6)	$3.3	898	57
5	Athenia - Saddlebrook	Line	PSEG	($3.8)	($1.1)	($0.0)	($2.7)	($0.2)	$0.0	$0.0	($0.2)	($2.9)	3,318	364
6	Brandon Shores - Riverside	Line	BGE	$4.5	$2.4	$0.0	$2.2	$0.1	($0.1)	($0.0)	$0.1	$2.3	344	162
7	Crete - St Johns Tap	Flowgate	Midwest ISO	$3.6	$1.5	($0.0)	$2.1	$0.0	($0.0)	($0.0)	$0.1	$2.1	2,066	823
8	Graceton - Raphael Road	Line	BGE	($4.6)	($2.5)	($0.0)	($2.2)	$0.3	$0.1	$0.0	$0.2	($2.0)	565	308
9	Wylie Ridge	Transformer	AP	$2.7	$1.0	$0.0	$1.7	$0.1	($0.0)	($0.0)	$0.1	$1.8	728	683
10	Bridgewater - Middlesex	Line	PSEG	$4.4	$1.7	$0.1	$2.7	($1.2)	($0.4)	($0.2)	($1.0)	$1.7	372	91
11	East Frankfort - Crete	Line	ComEd	$3.0	$1.4	($0.0)	$1.5	$0.0	($0.1)	$0.0	$0.1	$1.7	3,084	850
12	Tiltonsville - Windsor	Line	AP	$2.8	$1.5	$0.0	$1.3	($0.0)	($0.1)	($0.0)	$0.0	$1.4	2,723	506
13	East	Interface	500	$2.3	$1.1	$0.0	$1.2	($0.0)	($0.0)	($0.0)	($0.0)	$1.2	256	8
14	Erie West	Transformer	PENELEC	$1.7	$0.5	($0.0)	$1.2	($0.0)	$0.1	$0.0	($0.0)	$1.2	680	175
15	Cloverdale - Lexington	Line	AEP	$1.6	$0.7	$0.0	$0.9	$0.1	($0.1)	($0.0)	$0.1	$1.0	1,127	684
16	Atlantic - Larrabee	Line	JCPL	$0.9	$0.1	$0.0	$0.9	$0.0	($0.1)	($0.0)	$0.1	$0.9	123	12
37	Sayreville - Werner	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.1	($0.1)	$0.0	$0.3	$0.3	0	4
44	Franklin - West Wharton	Line	JCPL	$0.4	$0.2	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	61	0
46	Kilmer - Sayreville	Line	JCPL	$0.6	$0.3	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	130	0
197	Stoneybrook - W Wharton	Line	JCPL	($0.0)	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	8	0

Table 7-28 JCPL Control Zone top congestion cost impacts (By facility): Calendar year 2009

				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	$9.5	$4.0	$0.0	$5.5	$0.2	($1.0)	($0.0)	$1.2	$6.6	776	294
2	West	Interface	500	$10.4	$4.3	$0.0	$6.1	$0.1	($0.2)	($0.0)	$0.2	$6.3	504	87
3	Kammer	Transformer	500	$8.2	$3.5	$0.0	$4.8	$0.1	($0.6)	($0.0)	$0.7	$5.4	3,674	1,328
4	Wylie Ridge	Transformer	AP	$3.9	$1.4	$0.0	$2.5	$0.1	($0.6)	($0.0)	$0.7	$3.2	354	335
5	Atlantic - Larrabee	Line	JCPL	$2.6	$0.4	$0.0	$2.2	($0.6)	($0.4)	($0.0)	($0.2)	$2.0	284	73
6	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$3.0	$1.3	($0.1)	$1.6	($0.0)	($0.2)	$0.0	$0.2	$1.7	2,949	910
7	Sammis - Wylie Ridge	Line	AP	$1.7	$0.6	$0.0	$1.1	$0.0	($0.0)	($0.0)	$0.0	$1.2	806	157
8	Athenia - Saddlebrook	Line	PSEG	($1.3)	($0.3)	($0.0)	($1.0)	($0.0)	$0.1	$0.0	($0.1)	($1.1)	1,108	139
9	Graceton - Raphael Road	Line	BGE	($2.7)	($1.5)	($0.0)	($1.2)	$0.3	$0.2	$0.0	$0.1	($1.0)	527	152
10	East Frankfort - Crete	Line	ComEd	$1.6	$0.7	$0.0	$0.9	$0.0	($0.0)	($0.0)	$0.0	$1.0	2,163	605
11	Tiltonsville - Windsor	Line	AP	$1.5	$0.8	$0.0	$0.7	($0.0)	($0.1)	($0.0)	$0.0	$0.8	2,070	311
12	Cloverdale - Lexington	Line	AEP	$1.0	$0.4	$0.0	$0.6	$0.0	($0.0)	($0.0)	$0.1	$0.7	1,019	434
13	Crete - St Johns Tap	Flowgate	Midwest ISO	$1.1	$0.5	$0.0	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.7	1,571	306
14	Doubs	Transformer	AP	$1.7	$1.2	$0.0	$0.6	($0.0)	($0.1)	($0.0)	$0.1	$0.6	429	246
15	Krendale - Seneca	Line	AP	$0.9	$0.4	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	353	0
29	Gilbert - Morris Park	Line	JCPL	$0.2	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	38	0
46	Redoak - Sayreville	Line	JCPL	($0.0)	($0.1)	$0.0	$0.1	($0.0)	$0.0	$0.0	($0.0)	$0.1	59	7
80	Deep Run - Englishtown	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	0	2
86	Franklin - West Wharton	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	35	0
91	Kilmer - Sayreville	Line	JCPL	$0.4	$0.2	$0.0	$0.2	($0.0)	$0.2	$0.0	($0.2)	$0.0	23	16

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Met-Ed Control Zone

Table 7-29 Met-Ed Control Zone top congestion cost impacts (By facility): Calendar year 2010

				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	Brunner Island - Yorkana	Line	Met-Ed	$1.9	($4.1)	$0.1	$6.1	$0.0	$0.2	($0.0)	($0.2)	$6.0	237	180
2	Hunterstown	Transformer	Met-Ed	$4.2	($0.6)	$0.1	$4.9	$0.0	$0.0	($0.0)	($0.0)	$4.8	317	26
3	Graceton - Raphael Road	Line	BGE	($3.2)	($4.7)	($0.0)	$1.4	$0.2	$0.4	$0.1	($0.0)	$1.4	565	308
4	Wylie Ridge	Transformer	AP	$1.8	$2.9	$0.1	($1.1)	($0.1)	$0.0	($0.1)	($0.2)	($1.3)	728	683
5	Crete - St Johns Tap	Flowgate	Midwest ISO	$2.3	$3.5	$0.0	($1.1)	($0.1)	($0.0)	($0.0)	($0.1)	($1.2)	2,066	823
6	West	Interface	500	$4.3	$5.6	$0.0	($1.2)	$0.0	($0.1)	($0.1)	$0.1	($1.1)	179	65
7	Doubs	Transformer	AP	$3.6	$2.6	$0.1	$1.1	($0.1)	($0.2)	($0.3)	($0.2)	$0.9	920	525
8	AP South	Interface	500	$5.4	$4.6	$0.2	$1.0	($0.1)	($0.1)	($0.2)	($0.2)	$0.8	4,645	1,528
9	Jackson - TMI	Line	Met-Ed	$0.5	($0.6)	$0.1	$1.2	($0.1)	$0.3	($0.0)	($0.4)	$0.8	37	54
10	5004/5005 Interface	Interface	500	$13.4	$14.2	$0.0	($0.8)	($0.4)	($0.7)	($0.2)	$0.2	($0.6)	1,644	605
11	Erie West	Transformer	PENELEC	$0.9	$1.5	$0.0	($0.5)	($0.0)	($0.1)	($0.0)	($0.0)	($0.6)	680	175
12	Middletown Jct	Transformer	Met-Ed	$0.6	($0.1)	$0.0	$0.7	($0.1)	$0.1	$0.0	($0.1)	$0.6	11	12
13	Middletown Jct - Yorkhaven	Line	Met-Ed	$0.6	$0.1	$0.0	$0.6	($0.0)	$0.0	$0.0	($0.0)	$0.5	190	12
14	Collins - Middletown Jct	Line	Met-Ed	$0.3	($0.3)	$0.0	$0.6	($0.0)	$0.1	($0.0)	($0.1)	$0.5	191	42
15	Brandon Shores - Riverside	Line	BGE	$3.3	$3.8	$0.0	($0.5)	($0.0)	($0.1)	($0.0)	$0.0	($0.5)	344	162
26	Jackson - North Hanover	Line	Met-Ed	$0.2	($0.0)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	21	13
33	Lincoln Jct. - Lincoln	Line	Met-Ed	$0.2	($0.0)	($0.0)	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	57	9
51	Cly - Collins	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	19	0
77	Yorkana A	Transformer	Met-Ed	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	0	5
79	Glendon - Hosensack	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.1)	($0.0)	31	39

Table 7-30 Met-Ed Control Zone top congestion cost impacts (By facility): Calendar year 2009

				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	Kammer	Transformer	500	$6.0	$7.9	$0.1	($1.8)	($0.0)	($0.3)	($0.1)	$0.2	($1.6)	3,674	1,328
2	Brunner Island - Yorkana	Line	Met-Ed	$0.3	($0.7)	$0.0	$1.0	$0.0	$0.0	($0.0)	$0.0	$1.0	86	27
3	Graceton - Raphael Road	Line	BGE	($2.1)	($3.0)	($0.0)	$0.9	$0.1	$0.3	$0.0	($0.2)	$0.7	527	152
4	AP South	Interface	500	$2.5	$1.8	$0.0	$0.7	($0.0)	($0.0)	($0.0)	($0.0)	$0.7	3,549	604
5	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$2.0	$2.5	$0.0	($0.5)	($0.0)	($0.0)	($0.0)	$0.0	($0.5)	2,949	910
6	5004/5005 Interface	Interface	500	$5.9	$6.6	$0.0	($0.6)	($0.1)	($0.3)	($0.0)	$0.2	($0.4)	776	294
7	Hunterstown	Transformer	Met-Ed	$0.3	($0.1)	($0.0)	$0.4	($0.0)	($0.0)	$0.0	($0.0)	$0.4	53	1
8	West	Interface	500	$7.4	$7.2	$0.0	$0.3	$0.0	($0.1)	($0.0)	$0.1	$0.3	504	87
9	Tiltonsville - Windsor	Line	AP	$1.0	$1.4	$0.0	($0.4)	$0.0	($0.1)	($0.0)	$0.1	($0.3)	2,070	311
10	Wylie Ridge	Transformer	AP	$3.1	$2.8	$0.0	$0.3	($0.1)	($0.2)	($0.0)	$0.0	$0.3	354	335
11	Middletown Jct - Yorkhaven	Line	Met-Ed	$0.2	$0.0	$0.0	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	32	2
12	Conastone	Transformer	BGE	($0.1)	($0.3)	($0.0)	$0.2	($0.0)	$0.0	($0.0)	($0.0)	$0.2	75	12
13	Hummelstown - Middletown Jct	Line	Met-Ed	$0.1	$0.3	$0.0	($0.2)	$0.0	($0.0)	($0.0)	$0.0	($0.2)	51	14
14	Middletown Jct	Transformer	Met-Ed	$0.3	($0.0)	$0.0	$0.3	($0.1)	$0.0	($0.0)	($0.1)	$0.2	62	12
15	East Frankfort - Crete	Line	ComEd	$1.1	$1.3	$0.0	($0.2)	$0.0	($0.0)	($0.0)	$0.0	($0.1)	2,163	605
32	Collins - Middletown Jct	Line	Met-Ed	$0.1	($0.1)	$0.0	$0.1	($0.0)	$0.0	$0.0	($0.1)	$0.1	103	16
36	Ironwood - South Lebanon	Line	Met-Ed	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	20	0
42	Cly - Newberry	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	13	0
67	Middletown Jct - S Lebanon	Line	Met-Ed	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	4	0
154	Germantown	Transformer	Met-Ed	($0.0)	($0.0)	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	10	0

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PECO Control Zone

Table 7-31 PECO Control Zone top congestion cost impacts (By facility): Calendar year 2010

				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	$15.1	$23.2	$0.0	($8.0)	($0.5)	$1.4	($0.1)	($2.0)	($10.0)	1,644	605
2	Eddystone - Island Road	Line	PECO	$3.8	($4.4)	($0.0)	$8.1	($0.0)	$0.0	$0.0	($0.0)	$8.1	186	3
3	Limerick	Transformer	PECO	$3.0	$0.6	$0.0	$2.4	$0.1	($3.8)	($0.0)	$3.8	$6.3	53	18
4	AP South	Interface	500	$2.7	$8.3	$0.1	($5.5)	($0.1)	$0.3	($0.0)	($0.5)	($5.9)	4,645	1,528
5	Graceton - Raphael Road	Line	BGE	($2.4)	($6.1)	($0.0)	$3.6	$0.4	$0.4	$0.0	$0.1	$3.7	565	308
6	Bedington - Black Oak	Interface	500	$2.1	$4.8	$0.0	($2.7)	($0.0)	$0.1	($0.0)	($0.1)	($2.8)	2,291	212
7	West	Interface	500	$4.9	$7.4	$0.0	($2.5)	($0.0)	($0.0)	($0.0)	($0.0)	($2.5)	179	65
8	Crete - St Johns Tap	Flowgate	Midwest ISO	$2.2	$4.2	($0.0)	($2.0)	($0.1)	($0.1)	$0.0	($0.0)	($2.0)	2,066	823
9	East	Interface	500	$2.9	$0.9	($0.0)	$1.9	($0.0)	($0.0)	($0.0)	($0.0)	$1.9	256	8
10	Wylie Ridge	Transformer	AP	$1.8	$2.7	$0.0	($0.9)	($0.3)	$0.5	($0.0)	($0.8)	($1.7)	728	683
11	Doubs	Transformer	AP	$1.3	$2.9	$0.0	($1.5)	($0.3)	($0.3)	($0.0)	($0.1)	($1.6)	920	525
12	Tiltonsville - Windsor	Line	AP	$1.7	$2.8	$0.0	($1.1)	($0.2)	($0.0)	($0.0)	($0.2)	($1.3)	2,723	506
13	Peachbottom	Transformer	PECO	$0.0	$0.0	$0.0	$0.0	($0.7)	$0.1	($0.4)	($1.2)	($1.2)	0	14
14	East Frankfort - Crete	Line	ComEd	$2.5	$3.7	($0.0)	($1.1)	($0.1)	($0.1)	$0.0	$0.0	($1.1)	3,084	850
15	Millville - Old Chapel	Line	AP	$1.1	$1.3	$0.0	($0.2)	($0.5)	$0.4	($0.1)	($0.9)	($1.1)	210	303
16	Plymouth Meeting - Whitpain	Line	PECO	$1.1	$0.2	$0.0	$0.9	($0.0)	($0.0)	$0.0	($0.0)	$0.9	36	3
21	Eddystone - Saville	Line	PECO	$0.5	($0.3)	$0.0	$0.7	$0.0	$0.0	($0.0)	$0.0	$0.7	206	40
26	Burlington - Croydon	Line	PECO	($0.3)	($0.8)	($0.0)	$0.5	$0.0	($0.1)	($0.0)	$0.1	$0.5	1,500	33
36	Buckingham - Pleasant Valley	Line	PECO	($0.7)	($0.4)	($0.0)	($0.4)	$0.0	($0.0)	$0.0	$0.0	($0.4)	139	11
45	Jenkintown - Tabor	Line	PECO	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.2	$0.0	($0.3)	($0.3)	0	10

Table 7-32 PECO Control Zone top congestion cost impacts (By facility): Calendar year 2009

				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	Kammer	Transformer	500	$3.7	$9.8	$0.0	($6.0)	($0.2)	($0.0)	$0.0	($0.2)	($6.2)	3,674	1,328
2	West	Interface	500	$3.3	$7.1	$0.0	($3.8)	($0.0)	($0.1)	($0.0)	$0.0	($3.7)	504	87
3	AP South	Interface	500	$0.5	$3.7	$0.0	($3.1)	($0.0)	$0.0	$0.0	($0.1)	($3.2)	3,549	604
4	5004/5005 Interface	Interface	500	$4.9	$7.9	$0.0	($3.0)	$0.0	($0.0)	$0.0	$0.1	($3.0)	776	294
5	Graceton - Raphael Road	Line	BGE	($1.4)	($4.4)	($0.0)	$2.9	$0.5	$0.5	($0.0)	($0.0)	$2.9	527	152
6	Doubs	Transformer	AP	$1.0	$3.3	$0.0	($2.3)	($0.2)	$0.2	$0.0	($0.3)	($2.6)	429	246
7	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$1.5	$3.6	($0.0)	($2.0)	($0.1)	$0.1	($0.0)	($0.1)	($2.1)	2,949	910
8	East Frankfort - Crete	Line	ComEd	$0.7	$1.8	($0.0)	($1.1)	($0.0)	$0.0	($0.0)	($0.0)	($1.1)	2,163	605
9	Crete - St Johns Tap	Flowgate	Midwest ISO	$0.4	$1.4	($0.0)	($1.0)	($0.0)	$0.0	($0.0)	($0.1)	($1.1)	1,571	306
10	Tiltonsville - Windsor	Line	AP	$0.7	$1.8	$0.0	($1.1)	($0.0)	($0.0)	$0.0	$0.0	($1.1)	2,070	311
11	Wylie Ridge	Transformer	AP	$1.3	$2.3	$0.0	($0.9)	($0.1)	$0.0	($0.1)	($0.1)	($1.1)	354	335
12	Conastone	Transformer	BGE	($0.1)	($1.0)	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	75	12
13	Sammis - Wylie Ridge	Line	AP	$0.6	$1.4	$0.0	($0.9)	($0.0)	$0.0	($0.0)	($0.1)	($0.9)	806	157
14	Cloverdale - Lexington	Line	AEP	$0.4	$1.2	$0.0	($0.7)	($0.0)	($0.0)	($0.0)	($0.0)	($0.8)	1,019	434
15	Holmesburg - Richmond	Line	PECO	($0.2)	($0.7)	($0.0)	$0.5	($0.0)	($0.1)	$0.0	$0.1	$0.6	428	40
19	Burlington - Croydon	Line	PECO	($0.3)	($0.7)	($0.0)	$0.4	($0.0)	($0.0)	$0.0	$0.0	$0.4	2,805	3
22	Emilie	Transformer	PECO	$0.3	($1.9)	($0.0)	$2.2	($0.2)	$1.7	$0.0	($1.9)	$0.3	281	247
27	Eddystone - Scott Paper	Line	PECO	$0.2	($0.0)	$0.0	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	30	2
39	Buckingham - Pleasant Valley	Line	PECO	($0.4)	($0.4)	($0.0)	($0.0)	($0.0)	$0.1	$0.0	($0.1)	($0.1)	131	60
42	Bryn Mawr - Plymouth Meeting	Line	PECO	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	5	0

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PENELEC Control Zone

Table 7-33 PENELEC Control Zone top congestion cost impacts (By facility): Calendar year 2010

				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	($55.2)	($84.6)	($0.1)	$29.3	$6.9	$1.4	$0.1	$5.6	$34.8	4,645	1,528
2	5004/5005 Interface	Interface	500	($13.0)	($44.0)	($0.4)	$30.7	$4.5	$2.3	$0.1	$2.3	$33.0	1,644	605
3	Bedington - Black Oak	Interface	500	($19.0)	($29.6)	($0.1)	$10.5	$0.6	$0.1	$0.1	$0.5	$11.1	2,291	212
4	Wylie Ridge	Transformer	AP	$2.4	$7.7	$0.3	($5.0)	($0.8)	($0.4)	($0.5)	($0.8)	($5.8)	728	683
5	West	Interface	500	($3.6)	($8.9)	($0.0)	$5.3	$0.3	$0.3	$0.0	$0.0	$5.3	179	65
6	Mount Storm - Pruntytown	Line	AP	($3.5)	($5.7)	$0.0	$2.2	$2.8	$0.2	$0.1	$2.7	$4.9	571	574
7	Crete - St Johns Tap	Flowgate	Midwest ISO	$6.5	$9.9	($0.0)	($3.4)	($0.4)	$0.3	($0.0)	($0.7)	($4.1)	2,066	823
8	Seward	Transformer	PENELEC	$11.9	$7.1	$0.0	$4.8	($0.2)	$0.5	($0.0)	($0.8)	$4.0	371	63
9	Erie West	Transformer	PENELEC	$17.2	$11.0	$0.6	$6.8	($2.7)	$0.1	($0.5)	($3.3)	$3.5	680	175
10	Altoona - Bear Rock	Line	PENELEC	($2.8)	($5.6)	($0.0)	$2.7	$0.5	($0.1)	$0.0	$0.5	$3.2	295	55
11	Tiltonsville - Windsor	Line	AP	$4.1	$6.3	$0.1	($2.1)	($1.0)	($0.0)	($0.1)	($1.1)	($3.2)	2,723	506
12	Bear Rock - Johnstown	Line	PENELEC	($2.2)	($4.2)	($0.0)	$2.0	$1.1	$0.0	$0.0	$1.1	$3.1	210	61
13	East Frankfort - Crete	Line	ComEd	$5.8	$8.1	$0.0	($2.3)	($0.7)	$0.1	($0.0)	($0.7)	($3.0)	3,084	850
14	AEP-DOM	Interface	500	($5.8)	($8.1)	($0.0)	$2.2	$0.2	($0.1)	($0.0)	$0.3	$2.5	691	187
15	Elrama - Mitchell	Line	AP	$1.3	$3.3	$0.0	($1.9)	($0.0)	($0.1)	($0.2)	($0.1)	($2.1)	581	357
16	Johnstown - Seward	Line	PENELEC	$2.7	$0.7	$0.0	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	52	0
21	Homer City - Seward	Line	PENELEC	$4.6	$3.3	$0.0	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	83	0
25	Keystone - Shelocta	Line	PENELEC	$1.1	($0.1)	($0.0)	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	86	0
36	Homer City - Shelocta	Line	PENELEC	($6.4)	($6.8)	($0.1)	$0.4	$0.2	$0.1	$0.1	$0.3	$0.6	339	76
37	Blairsville - Shelocta	Line	PENELEC	$1.7	$1.1	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	24	0

Table 7-34 PENELEC Control Zone top congestion cost impacts (By facility): Calendar year 2009

				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	($17.8)	($35.0)	($0.1)	$17.1	$0.7	($0.2)	$0.1	$1.0	$18.2	3,549	604
2	West	Interface	500	($2.4)	($16.3)	($0.0)	$13.9	$0.0	$0.1	$0.0	($0.0)	$13.9	504	87
3	5004/5005 Interface	Interface	500	($3.5)	($18.7)	($0.0)	$15.2	$0.3	$1.6	$0.1	($1.3)	$13.9	776	294
4	Kammer	Transformer	500	$4.8	$15.9	$0.2	($10.8)	($0.5)	($0.9)	($0.1)	$0.2	($10.6)	3,674	1,328
5	Wylie Ridge	Transformer	AP	$1.5	$10.3	$0.1	($8.8)	($0.6)	($0.7)	($0.0)	$0.1	($8.7)	354	335
6	Seward	Transformer	PENELEC	$8.0	$4.6	($0.0)	$3.4	$0.0	$0.0	$0.0	$0.0	$3.4	283	0
7	Sammis - Wylie Ridge	Line	AP	$1.2	$4.5	$0.1	($3.3)	($0.1)	($0.1)	$0.0	($0.0)	($3.3)	806	157
8	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$4.1	$7.6	($0.0)	($3.5)	$0.2	($0.5)	$0.0	$0.6	($2.9)	2,949	910
9	Mount Storm - Pruntytown	Line	AP	($2.4)	($4.6)	($0.0)	$2.2	$0.3	($0.1)	$0.0	$0.5	$2.7	525	132
10	Tiltonsville - Windsor	Line	AP	$1.3	$3.6	$0.0	($2.2)	$0.1	($0.0)	($0.0)	$0.1	($2.2)	2,070	311
11	Bedington - Black Oak	Interface	500	($2.3)	($4.4)	($0.0)	$2.2	($0.0)	($0.0)	$0.0	$0.0	$2.2	669	73
12	East Frankfort - Crete	Line	ComEd	$2.2	$3.8	$0.0	($1.6)	$0.0	($0.0)	($0.0)	$0.0	($1.6)	2,163	605
13	Homer City - Seward	Line	PENELEC	$2.9	$1.6	($0.0)	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	67	0
14	Homer City - Shelocta	Line	PENELEC	($3.9)	($5.5)	($0.1)	$1.6	($0.2)	$0.1	$0.0	($0.3)	$1.3	386	103
15	Krendale - Seneca	Line	AP	$1.4	$2.6	$0.0	($1.2)	$0.0	$0.0	$0.0	$0.0	($1.2)	353	0
16	Homer City	Transformer	PENELEC	$1.4	$0.2	($0.0)	$1.1	($0.0)	$0.0	$0.0	($0.0)	$1.1	260	2
18	Altoona - Bear Rock	Line	PENELEC	($1.9)	($3.0)	($0.0)	$1.1	($0.1)	($0.1)	$0.0	($0.1)	$1.1	176	32
26	Keystone - Shelocta	Line	PENELEC	($0.4)	($0.8)	($0.0)	$0.4	$0.1	$0.1	$0.0	($0.0)	$0.4	104	43
27	Altoona - Raystown	Line	PENELEC	($0.8)	($1.1)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	55	0
34	Bear Rock - Johnstown	Line	PENELEC	($0.5)	($0.7)	($0.0)	$0.2	($0.1)	($0.1)	$0.0	($0.0)	$0.2	80	45

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Pepco Control Zone

Table 7-35 Pepco Control Zone top congestion cost impacts (By facility): Calendar year 2010

				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	$124.6	$92.3	$2.1	$34.4	($4.6)	($2.8)	($1.8)	($3.6)	$30.7	4,645	1,528
2	Bedington - Black Oak	Interface	500	$47.6	$33.8	$0.9	$14.8	($0.8)	($1.1)	($0.3)	$0.0	$14.8	2,291	212
3	Doubs	Transformer	AP	$41.9	$26.7	$0.8	$16.0	($4.1)	$0.7	($1.8)	($6.7)	$9.4	920	525
4	Graceton - Raphael Road	Line	BGE	$11.1	$7.1	$0.2	$4.2	($0.9)	($0.8)	($0.2)	($0.4)	$3.8	565	308
5	Cloverdale - Lexington	Line	AEP	$10.9	$7.8	$0.1	$3.3	($1.0)	($1.0)	($0.3)	($0.3)	$3.0	1,127	684
6	Millville - Sleepy Hollow	Line	Dominion	$8.6	$6.2	$0.1	$2.5	$0.0	$0.0	$0.0	$0.0	$2.5	401	0
7	Crete - St Johns Tap	Flowgate	Midwest ISO	$6.8	$4.5	$0.0	$2.3	($0.1)	($0.3)	($0.0)	$0.1	$2.5	2,066	823
8	5004/5005 Interface	Interface	500	$8.0	$5.4	$0.2	$2.8	($0.3)	($0.1)	($0.1)	($0.4)	$2.4	1,644	605
9	Brandon Shores - Riverside	Line	BGE	($13.6)	($10.2)	($0.2)	($3.5)	$1.2	$0.5	$0.3	$1.1	($2.4)	344	162
10	East Frankfort - Crete	Line	ComEd	$6.7	$4.2	$0.0	$2.5	($0.4)	($0.2)	($0.0)	($0.2)	$2.4	3,084	850
11	Reid - Ringgold	Line	AP	$5.3	$3.3	$0.2	$2.2	($0.1)	($0.1)	($0.0)	$0.0	$2.2	345	42
12	AEP-DOM	Interface	500	$10.7	$8.8	$0.1	$2.0	$0.0	($0.2)	($0.1)	$0.1	$2.1	691	187
13	West	Interface	500	$6.3	$4.2	$0.0	$2.1	($0.2)	($0.1)	($0.0)	($0.1)	$2.0	179	65
14	Mount Storm - Pruntytown	Line	AP	$9.4	$6.7	$0.1	$2.7	($2.0)	($1.6)	($0.4)	($0.9)	$1.9	571	574
15	Tiltonsville - Windsor	Line	AP	$5.6	$3.8	$0.1	$1.9	($0.4)	($0.2)	($0.1)	($0.4)	$1.5	2,723	506
18	Bowie	Line	Pepco	$2.3	$1.1	$0.1	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	44	0
20	Bowie - Lanham	Line	Pepco	$2.2	$0.9	$0.1	$1.4	($0.3)	($0.2)	($0.1)	($0.2)	$1.1	36	13
24	Dickerson - Pleasant View	Line	Pepco	($2.4)	($1.5)	($0.0)	($1.0)	$0.1	$0.2	$0.1	($0.0)	($1.0)	185	97
30	Benning - Ritchie	Line	Pepco	$0.8	$0.2	$0.1	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	78	0
37	Buzzard - Ritchie	Line	Pepco	$0.5	$0.0	$0.0	$0.5	($0.0)	($0.0)	($0.0)	($0.0)	$0.5	59	1

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Table 7-36 Pepco Control Zone top congestion cost impacts (By facility): Calendar year 2009

				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	$57.5	$42.6	$1.1	$16.0	($1.7)	($3.5)	($1.1)	$0.7	$16.7	3,549	604
2	Kammer	Transformer	500	$21.9	$15.1	$0.3	$7.1	($1.1)	($2.0)	($0.4)	$0.5	$7.6	3,674	1,328
3	Doubs	Transformer	AP	$16.2	$8.7	$0.3	$7.8	($1.7)	($0.2)	($0.3)	($1.7)	$6.0	429	246
4	Buzzard - Ritchie	Line	Pepco	$25.3	$3.2	$0.2	$22.3	($13.9)	$1.9	($0.6)	($16.4)	$5.9	421	149
5	Graceton - Raphael Road	Line	BGE	$6.7	$4.2	$0.2	$2.6	($0.7)	($1.0)	($0.2)	$0.2	$2.8	527	152
6	Bedington - Black Oak	Interface	500	$8.5	$6.0	$0.2	$2.6	($0.0)	($0.1)	($0.0)	$0.1	$2.7	669	73
7	West	Interface	500	$8.9	$6.5	$0.1	$2.4	($0.1)	($0.2)	($0.0)	$0.0	$2.5	504	87
8	Mount Storm - Pruntytown	Line	AP	$7.5	$5.8	$0.1	$1.9	($0.2)	($0.8)	($0.1)	$0.5	$2.4	525	132
9	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$6.3	$4.2	($0.0)	$2.1	($0.2)	($0.5)	$0.0	$0.3	$2.4	2,949	910
10	Cloverdale - Lexington	Line	AEP	$6.0	$4.3	$0.1	$1.8	($0.2)	($0.5)	($0.1)	$0.2	$1.9	1,019	434
11	Wylie Ridge	Transformer	AP	$6.2	$4.9	$0.0	$1.3	($0.3)	($0.7)	($0.0)	$0.3	$1.7	354	335
12	East Frankfort - Crete	Line	ComEd	$3.1	$2.0	$0.0	$1.1	($0.1)	($0.1)	($0.0)	$0.1	$1.1	2,163	605
13	Sammis - Wylie Ridge	Line	AP	$3.1	$2.2	$0.1	$1.0	($0.1)	($0.2)	($0.0)	$0.0	$1.0	806	157
14	Tiltonsville - Windsor	Line	AP	$2.3	$1.5	$0.1	$0.9	($0.0)	($0.1)	($0.1)	($0.0)	$0.9	2,070	311
15	Mount Storm	Transformer	AP	$2.1	$1.5	$0.0	$0.7	$0.0	($0.3)	($0.1)	$0.2	$0.9	151	80
19	Alabama Ave. - Palmers Corner	Line	Pepco	$0.5	$0.0	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	12	0
24	Brighton	Transformer	Pepco	$0.7	$0.4	$0.0	$0.3	$0.0	($0.0)	$0.0	$0.0	$0.3	43	1
28	Dickerson - Pleasant View	Line	Pepco	$0.8	$0.5	$0.0	$0.3	($0.3)	($0.2)	($0.1)	($0.1)	$0.2	54	30
36	Burtonsville - Oak Grove	Line	Pepco	($0.3)	($0.4)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	29	0
47	Oak Grove - Ritchie	Line	Pepco	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	($0.0)	$0.1	$0.1	0	6

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PPL Control Zone

Table 7-37 PPL Control Zone top congestion cost impacts (By facility): Calendar year 2010

				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	$40.8	$53.1	$1.0	($11.3)	$3.3	$1.3	($0.4)	$1.5	($9.8)	1,644	605
2	Brunner Island - Yorkana	Line	Met-Ed	($5.2)	($9.5)	($0.1)	$4.1	$0.3	$0.2	$0.1	$0.1	$4.2	237	180
3	West	Interface	500	$9.7	$12.6	$0.2	($2.8)	$0.1	$0.2	($0.0)	($0.1)	($2.9)	179	65
4	AP South	Interface	500	$2.5	$1.1	$0.6	$2.0	$0.4	($0.1)	($0.1)	$0.3	$2.4	4,645	1,528
5	Graceton - Raphael Road	Line	BGE	($7.1)	($10.3)	($0.1)	$3.1	($0.4)	$0.4	$0.1	($0.7)	$2.4	565	308
6	Crete - St Johns Tap	Flowgate	Midwest ISO	$5.8	$8.7	($0.1)	($3.0)	$0.4	($0.2)	$0.0	$0.6	($2.3)	2,066	823
7	East Frankfort - Crete	Line	ComEd	$4.9	$7.3	($0.0)	($2.4)	$0.2	($0.2)	$0.0	$0.4	($2.0)	3,084	850
8	Harwood - Susquehanna	Line	PPL	$0.2	($1.4)	($0.0)	$1.6	$0.3	$0.5	($0.1)	($0.2)	$1.4	58	30
9	Millville - Sleepy Hollow	Line	Dominion	$2.4	$3.8	$0.1	($1.2)	$0.0	$0.0	$0.0	$0.0	($1.2)	401	0
10	Harwood - Siegfried	Line	PPL	($0.2)	($1.8)	$0.0	$1.5	($0.3)	$2.2	($0.1)	($2.6)	($1.1)	94	118
11	Tiltonsville - Windsor	Line	AP	$3.9	$5.3	$0.1	($1.3)	$0.5	$0.2	($0.0)	$0.3	($1.0)	2,723	506
12	Juniata	Transformer	PENELEC	$0.0	$0.0	$0.0	$0.0	$0.7	$0.2	$0.4	$0.9	$0.9	0	27
13	Eldred - Sunbury	Line	PPL	$0.6	($0.1)	$0.0	$0.7	$0.1	($0.1)	($0.0)	$0.1	$0.8	72	33
14	Bedington - Black Oak	Interface	500	$2.6	$2.2	$0.3	$0.6	$0.1	($0.1)	($0.0)	$0.1	$0.8	2,291	212
15	East	Interface	500	($0.1)	($0.8)	$0.0	$0.7	$0.0	$0.0	$0.0	($0.0)	$0.7	256	8
16	Susquehanna	Transformer	PPL	$1.0	$0.3	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	39	0
19	East Palmerton - Siegfried	Line	PPL	($0.1)	($0.7)	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	70	0
21	East Palmerton - Harwood	Line	PPL	($0.0)	($0.5)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	51	0
26	Frackville - Siegfried	Line	PPL	($0.1)	($0.6)	$0.0	$0.4	($0.0)	$0.0	($0.0)	($0.0)	$0.4	48	7
35	Eldred - Frackville	Line	PPL	$0.1	($0.2)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	20	0

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Table 7-38 PPL Control Zone top congestion cost impacts (By facility): Calendar year 2009

				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	Kammer	Transformer	500	$1.7	$5.5	$0.6	($3.2)	($0.2)	($0.2)	($0.1)	($0.0)	($3.2)	3,674	1,328
2	5004/5005 Interface	Interface	500	$2.9	$7.0	$0.5	($3.5)	$0.0	($0.8)	($0.0)	$0.7	($2.8)	776	294
3	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.6	$2.3	($0.1)	($1.8)	($0.2)	($0.2)	$0.0	$0.0	($1.8)	2,949	910
4	AP South	Interface	500	$0.5	($0.6)	$0.3	$1.4	$0.1	($0.1)	$0.1	$0.3	$1.7	3,549	604
5	Graceton - Raphael Road	Line	BGE	($0.9)	($2.3)	($0.1)	$1.3	$0.1	$0.1	$0.0	$0.1	$1.4	527	152
6	Hummelstown - Middletown Jct	Line	Met-Ed	$1.0	($0.0)	$0.0	$1.1	$0.0	($0.0)	($0.0)	$0.0	$1.1	51	14
7	West	Interface	500	$3.0	$4.6	$0.5	($1.1)	($0.0)	($0.2)	($0.0)	$0.1	($0.9)	504	87
8	Brunner Island - Yorkana	Line	Met-Ed	($0.0)	($0.9)	($0.0)	$0.8	$0.0	$0.1	($0.0)	($0.0)	$0.8	86	27
9	Sammis - Wylie Ridge	Line	AP	$0.2	$1.0	$0.1	($0.7)	$0.0	($0.0)	$0.0	$0.0	($0.7)	806	157
10	Harwood - Susquehanna	Line	PPL	$0.2	($0.5)	$0.0	$0.7	($0.0)	$0.0	$0.0	($0.1)	$0.7	31	10
11	East Frankfort - Crete	Line	ComEd	$0.4	$1.0	$0.0	($0.6)	($0.1)	($0.1)	$0.0	($0.0)	($0.6)	2,163	605
12	Crete - St Johns Tap	Flowgate	Midwest ISO	$0.4	$0.8	($0.0)	($0.4)	($0.1)	($0.1)	$0.0	($0.0)	($0.5)	1,571	306
13	Tiltonsville - Windsor	Line	AP	$0.5	$0.9	$0.1	($0.3)	($0.1)	($0.0)	$0.0	($0.1)	($0.4)	2,070	311
14	Atlantic - Larrabee	Line	JCPL	$0.1	$0.1	($0.0)	($0.0)	($0.1)	$0.1	$0.0	($0.3)	($0.3)	284	73
15	Wylie Ridge	Transformer	AP	$1.1	$1.8	$0.3	($0.4)	$0.2	$0.1	$0.0	$0.1	($0.3)	354	335
16	PL North	Interface	PPL	$0.0	$0.0	$0.0	$0.0	$0.4	$0.6	($0.0)	($0.3)	($0.3)	0	176
27	Jenkins - Susquehanna	Line	PPL	$0.1	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	12	0
45	Dauphin - Juniata	Line	PPL	$0.0	($0.0)	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	6	4
55	Eldred - Sunbury	Line	PPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	4	0
57	Harwood	Transformer	PPL	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.0)	$0.0	15	1

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PSEG Control Zone

Table 7-39 PSEG Control Zone top congestion cost impacts (By facility): Calendar year 2010

				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	Branchburg - Readington	Line	PSEG	$9.0	$1.2	$0.6	$8.4	($0.0)	$0.9	($0.5)	($1.4)	$6.9	1,235	185
2	Leonia - New Milford	Line	PSEG	$1.2	$0.7	$1.7	$2.3	($3.6)	$1.9	($0.8)	($6.3)	($4.0)	1,241	50
3	AP South	Interface	500	$0.4	$6.0	$2.8	($2.8)	$0.2	($0.4)	($1.7)	($1.1)	($3.8)	4,645	1,528
4	Hawthorn - Waldwick	Line	PSEG	$0.1	($0.0)	$0.0	$0.1	($0.7)	$1.1	($1.7)	($3.4)	($3.3)	499	39
5	Hillsdale - New Milford	Line	PSEG	$1.4	$0.7	$2.2	$2.9	$0.0	$0.0	($0.1)	($0.1)	$2.8	1,022	23
6	5004/5005 Interface	Interface	500	$29.8	$28.1	$2.4	$4.1	$2.0	$2.2	($1.9)	($2.1)	$2.0	1,644	605
7	Wylie Ridge	Transformer	AP	$3.8	$3.9	$0.3	$0.2	$0.2	$1.6	($0.8)	($2.2)	($2.0)	728	683
8	Millville - Old Chapel	Line	AP	$1.0	$1.4	$0.1	($0.4)	$0.1	$1.0	($0.6)	($1.5)	($1.9)	210	303
9	Eddystone - Island Road	Line	PECO	$1.0	($0.7)	$0.0	$1.7	$0.0	$0.0	($0.0)	$0.0	$1.7	186	3
10	Hawthorn - Hinchmans Ave	Line	PSEG	($0.0)	($0.0)	($0.2)	($0.2)	($0.1)	$0.4	($1.0)	($1.5)	($1.7)	209	38
11	Redoak - Sayreville	Line	JCPL	$1.3	($0.3)	$0.1	$1.6	$0.0	($0.0)	($0.0)	($0.0)	$1.6	898	57
12	Bedington - Black Oak	Interface	500	$2.0	$4.3	$1.1	($1.2)	($0.0)	($0.0)	($0.3)	($0.3)	($1.5)	2,291	212
13	Buckingham - Pleasant Valley	Line	PECO	$1.8	$0.7	$0.1	$1.2	($0.0)	$0.0	($0.0)	($0.0)	$1.2	139	11
14	Bayway - Federal Square	Line	PSEG	$0.7	($0.4)	$0.0	$1.1	($0.0)	($0.0)	$0.0	$0.0	$1.2	613	9
15	Doubs	Transformer	AP	$2.3	$2.1	$0.3	$0.4	($0.3)	$0.5	($0.7)	($1.6)	($1.1)	920	525
16	North Ave - Pvsc	Line	PSEG	$0.2	($0.8)	$0.1	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	664	0
19	Athenia - Saddlebrook	Line	PSEG	$14.8	$3.4	$8.5	$20.0	($10.0)	$3.0	($6.1)	($19.0)	$1.0	3,318	364
21	Cedar Grove - Clifton	Line	PSEG	$1.0	$0.4	$0.5	$1.1	($0.1)	$0.2	($0.1)	($0.3)	$0.8	205	8
22	Bergen - Hoboken	Line	PSEG	$0.1	($0.2)	$0.4	$0.7	($0.2)	($0.1)	$0.1	$0.1	$0.8	508	29
23	Bayonne - PVSC	Line	PSEG	$0.1	($0.6)	$0.1	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	834	0

Table 7-40 PSEG Control Zone top congestion cost impacts (By facility): Calendar year 2009

				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	Leonia - New Milford	Line	PSEG	$2.1	$0.8	$3.1	$4.4	($0.0)	$0.0	($0.3)	($0.3)	$4.1	3,847	39
2	Athenia - Saddlebrook	Line	PSEG	$3.2	$0.6	$1.3	$4.0	($0.2)	$0.1	($0.5)	($0.8)	$3.2	1,108	139
3	Plainsboro - Trenton	Line	PSEG	$3.5	($0.1)	$0.1	$3.8	($0.3)	$0.4	($0.1)	($0.7)	$3.1	389	164
4	Cedar Grove - Clifton	Line	PSEG	$2.3	$0.5	$1.0	$2.8	($0.1)	$0.0	($0.1)	($0.2)	$2.6	1,194	38
5	AP South	Interface	500	$0.2	$3.5	$1.1	($2.2)	$0.1	($0.2)	($0.5)	($0.2)	($2.4)	3,549	604
6	Fairlawn - Saddlebrook	Line	PSEG	$1.1	$0.2	$0.6	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	946	0
7	West	Interface	500	$11.8	$13.8	$0.9	($1.1)	($0.1)	$0.1	($0.2)	($0.3)	($1.4)	504	87
8	Wylie Ridge	Transformer	AP	$4.3	$5.4	$0.5	($0.6)	$0.0	$0.1	($0.6)	($0.7)	($1.3)	354	335
9	Hillsdale - Waldwick	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.4	($0.5)	($1.0)	($1.0)	0	59
10	Monroe - New Freedom	Line	AECO	($0.1)	($1.1)	($0.0)	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	584	0
11	Bayway - Federal Square	Line	PSEG	$0.5	($0.3)	$0.0	$0.8	($0.0)	($0.0)	($0.0)	$0.0	$0.8	220	11
12	Buckingham - Pleasant Valley	Line	PECO	$0.9	($0.1)	$0.0	$1.0	($0.0)	$0.2	($0.0)	($0.3)	$0.7	131	60
13	Atlantic - Larrabee	Line	JCPL	$0.6	($0.7)	$0.0	$1.3	($0.0)	$0.6	($0.1)	($0.7)	$0.7	284	73
14	Brunswick - Edison	Line	PSEG	$1.0	($0.0)	$0.0	$1.1	($0.1)	$0.2	($0.2)	($0.5)	$0.6	138	76
15	Cedar Grove - Roseland	Line	PSEG	$0.4	$0.0	$0.0	$0.4	($0.2)	$0.5	($0.2)	($0.9)	($0.5)	64	71
16	Bayonne - PVSC	Line	PSEG	$0.0	($0.4)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	686	0
17	Branchburg - Flagtown	Line	PSEG	$0.6	($0.0)	$0.1	$0.7	($0.0)	$0.1	($0.1)	($0.2)	$0.4	161	16
18	Athenia - Fairlawn	Line	PSEG	$0.4	$0.0	$0.0	$0.4	$0.0	$0.0	($0.0)	($0.0)	$0.4	165	6
22	East Windsor - Windsor	Line	PSEG	$0.1	($0.3)	$0.0	$0.3	($0.0)	($0.0)	($0.0)	$0.0	$0.4	107	3
24	Sewaren	Transformer	PSEG	$0.3	($0.0)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	89	0

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RECO Control Zone

Table 7-41 RECO Control Zone top congestion cost impacts (By facility): Calendar year 2010

				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	$1.1	$0.1	$0.0	$1.0	$0.2	($0.1)	($0.0)	$0.3	$1.3	1,644	605
2	Branchburg - Readington	Line	PSEG	$0.6	$0.0	$0.0	$0.5	$0.1	($0.0)	($0.0)	$0.1	$0.6	1,235	185
3	West	Interface	500	$0.4	$0.0	$0.0	$0.4	$0.0	($0.0)	($0.0)	$0.0	$0.4	179	65
4	Athenia - Saddlebrook	Line	PSEG	$0.2	$0.0	($0.0)	$0.2	$0.1	($0.1)	$0.0	$0.1	$0.3	3,318	364
5	AP South	Interface	500	($0.2)	($0.0)	$0.0	($0.2)	($0.0)	$0.0	($0.0)	($0.1)	($0.3)	4,645	1,528
6	Brandon Shores - Riverside	Line	BGE	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)	$0.0	$0.0	$0.3	344	162
7	Graceton - Raphael Road	Line	BGE	($0.2)	($0.0)	($0.0)	($0.2)	($0.1)	$0.0	$0.0	($0.1)	($0.3)	565	308
8	Crete - St Johns Tap	Flowgate	Midwest ISO	$0.2	$0.0	$0.0	$0.2	$0.1	($0.0)	($0.0)	$0.1	$0.2	2,066	823
9	Wylie Ridge	Transformer	AP	$0.1	$0.0	$0.0	$0.1	$0.1	($0.0)	($0.0)	$0.1	$0.2	728	683
10	Tiltonsville - Windsor	Line	AP	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	2,723	506
11	East Frankfort - Crete	Line	ComEd	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.2	3,084	850
12	Hillsdale - New Milford	Line	PSEG	($0.2)	($0.0)	($0.0)	($0.2)	($0.0)	$0.0	$0.0	($0.0)	($0.2)	1,022	23
13	Erie West	Transformer	PENELEC	$0.1	$0.0	($0.0)	$0.1	$0.1	($0.0)	($0.0)	$0.0	$0.1	680	175
14	Brunner Island - Yorkana	Line	Met-Ed	($0.1)	($0.0)	($0.0)	($0.1)	($0.0)	$0.0	$0.0	($0.0)	($0.1)	237	180
15	Doubs	Transformer	AP	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.1	$0.1	920	525

Table 7-42 RECO Control Zone top congestion cost impacts (By facility): Calendar year 2009

				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	West	Interface	500	$0.5	$0.0	$0.0	$0.6	($0.0)	($0.0)	($0.0)	($0.0)	$0.5	504	87
2	5004/5005 Interface	Interface	500	$0.5	$0.0	$0.0	$0.5	($0.0)	($0.0)	($0.0)	($0.1)	$0.4	776	294
3	Kammer	Transformer	500	$0.4	$0.0	$0.0	$0.4	$0.0	($0.0)	($0.0)	$0.0	$0.4	3,674	1,328
4	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.2	$0.0	($0.0)	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	2,949	910
5	Wylie Ridge	Transformer	AP	$0.2	$0.0	$0.0	$0.2	($0.0)	($0.0)	($0.0)	($0.0)	$0.2	354	335
6	Graceton - Raphael Road	Line	BGE	($0.2)	($0.0)	($0.0)	($0.2)	$0.0	$0.0	$0.0	$0.0	($0.2)	527	152
7	AP South	Interface	500	($0.1)	($0.0)	($0.0)	($0.1)	($0.0)	$0.0	$0.0	($0.0)	($0.1)	3,549	604
8	Athenia - Saddlebrook	Line	PSEG	$0.1	($0.0)	$0.0	$0.1	($0.0)	($0.0)	$0.0	($0.0)	$0.1	1,108	139
9	East Frankfort - Crete	Line	ComEd	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	2,163	605
10	Doubs	Transformer	AP	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	429	246
11	Sammis - Wylie Ridge	Line	AP	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	($0.0)	$0.1	806	157
12	Tiltonsville - Windsor	Line	AP	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	($0.0)	$0.0	$0.1	2,070	311
13	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	1,571	306
14	Fairlawn - Saddlebrook	Line	PSEG	($0.1)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	946	0
15	Krendale - Seneca	Line	AP	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	353	0

Western Region Congestion-Event Summaries

AEP Control Zone

Table 7-43 AEP Control Zone top congestion cost impacts (By facility): Calendar year 2010

				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	($41.2)	($98.5)	$0.3	$57.6	($3.8)	$4.4	$1.7	($6.5)	$51.0	4,645	1,528
2	AEP-DOM	Interface	500	$9.8	($27.6)	$1.8	$39.2	($1.1)	$1.5	($1.3)	($4.0)	$35.2	691	187
3	Bedington - Black Oak	Interface	500	($16.3)	($32.7)	($0.0)	$16.4	($0.1)	$0.6	$0.4	($0.4)	$16.0	2,291	212
4	Kanawha - Kincaid	Line	AEP	$9.6	$0.2	$1.0	$10.4	$0.0	$0.0	$0.0	$0.0	$10.4	534	0
5	Belmont	Transformer	AP	$7.8	($3.3)	$1.5	$12.6	($2.5)	($0.8)	($1.0)	($2.7)	$9.8	1,887	203
6	5004/5005 Interface	Interface	500	($22.9)	($33.6)	($0.5)	$10.2	($0.3)	$2.9	$0.6	($2.6)	$7.6	1,644	605
7	Kanawha River - Kincaid	Line	AEP	$0.0	$0.0	$0.0	$0.0	($5.0)	$1.1	($1.2)	($7.3)	($7.3)	0	200
8	Kanawha River	Transformer	AEP	$3.6	($0.8)	$0.6	$5.1	($0.2)	($0.4)	($0.1)	($0.0)	$5.0	327	18
9	Mount Storm - Pruntytown	Line	AP	($2.9)	($8.1)	($0.1)	$5.1	($0.7)	$1.5	$0.5	($1.8)	$3.3	571	574
10	Mahans Lane - Tidd	Line	AEP	($1.4)	($4.7)	($0.3)	$3.0	$0.3	$0.1	$0.0	$0.2	$3.2	646	207
11	Brues - West Bellaire	Line	AEP	$0.0	$0.0	$0.0	$0.0	($2.1)	$0.8	($0.2)	($3.2)	($3.2)	0	78
12	West	Interface	500	($5.8)	($9.2)	($0.1)	$3.3	($0.2)	$0.3	$0.1	($0.4)	$2.9	179	65
13	East Frankfort - Crete	Line	ComEd	$8.8	$7.8	$2.4	$3.4	$0.0	($0.0)	($1.4)	($1.4)	$2.1	3,084	850
14	Doubs	Transformer	AP	($11.6)	($14.7)	($0.2)	$2.8	($0.0)	$1.2	$0.4	($0.8)	$2.0	920	525
15	Electric Jct - Nelson	Line	ComEd	$0.4	$0.6	$5.7	$5.5	($0.1)	($0.0)	($7.3)	($7.4)	($1.9)	1,495	258
17	Culloden - Wyoming	Line	AEP	$0.6	($0.8)	$0.5	$1.9	$0.0	$0.0	$0.0	$0.0	$1.9	46	0
18	Cloverdale - Ivy Hill	Line	AEP	$0.0	$0.0	$0.0	$0.0	($1.4)	$0.2	($0.1)	($1.7)	($1.7)	0	142
20	Kammer - Natrium	Line	AEP	$1.5	($0.4)	$0.2	$2.0	($0.3)	$0.1	($0.1)	($0.4)	$1.6	308	48
24	Breed - Wheatland	Line	AEP	$0.0	($1.6)	($0.1)	$1.5	$0.0	$0.0	$0.0	($0.0)	$1.5	150	1
25	Ruth - Turner	Line	AEP	$1.5	($0.9)	$0.2	$2.6	($0.5)	$0.4	($0.2)	($1.2)	$1.4	234	113

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Table 7-44 AEP Control Zone top congestion cost impacts (By facility): Calendar year 2009

				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	($20.1)	($39.8)	$1.2	$20.9	($1.2)	$0.4	$0.5	($1.1)	$19.7	3,549	604
2	Kammer	Transformer	500	($20.6)	($34.6)	($0.6)	$13.4	($0.8)	$2.5	$0.4	($2.9)	$10.6	3,674	1,328
3	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$17.5	$8.9	$1.1	$9.7	($2.6)	($1.1)	($2.4)	($3.9)	$5.8	2,949	910
4	Ruth - Turner	Line	AEP	$4.9	($1.6)	$0.5	$7.0	($1.4)	($0.4)	($0.1)	($1.2)	$5.8	704	313
5	Kanawha - Kincaid	Line	AEP	$2.8	($2.1)	$0.2	$5.1	$0.0	$0.0	$0.0	$0.0	$5.1	291	0
6	Kammer - Ormet	Line	AEP	$7.8	$1.1	$0.3	$6.9	($1.6)	$0.5	($0.1)	($2.2)	$4.7	552	509
7	AEP-DOM	Interface	500	$1.3	($3.7)	$0.4	$5.3	($0.2)	$0.5	($0.0)	($0.8)	$4.5	335	136
8	Kanawha River	Transformer	AEP	$3.3	($0.3)	$0.5	$4.1	$0.1	($0.3)	($0.1)	$0.4	$4.4	163	37
9	Kanawha River - Bradley	Line	AEP	$1.3	($2.2)	$0.2	$3.8	($0.0)	$0.1	$0.0	($0.1)	$3.7	24	15
10	Breed - Wheatland	Line	AEP	$0.1	($3.9)	($0.5)	$3.5	$0.0	$0.0	$0.0	$0.0	$3.5	591	2
11	5004/5005 Interface	Interface	500	($9.2)	($12.9)	$0.0	$3.7	$0.1	$0.6	$0.1	($0.3)	$3.4	776	294
12	Sammis - Wylie Ridge	Line	AP	($5.0)	($3.1)	($0.1)	($2.0)	($0.3)	$0.2	($0.0)	($0.5)	($2.6)	806	157
13	Bedington - Black Oak	Interface	500	($2.8)	($5.1)	$0.1	$2.4	($0.1)	($0.0)	$0.0	($0.0)	$2.3	669	73
14	Mount Storm - Pruntytown	Line	AP	($3.1)	($5.2)	$0.2	$2.3	$0.0	$0.2	$0.1	($0.1)	$2.2	525	132
15	East Frankfort - Crete	Line	ComEd	$4.6	$2.9	$1.5	$3.2	($0.0)	$0.1	($0.9)	($1.0)	$2.1	2,163	605
18	Cloverdale - Lexington	Line	AEP	($7.0)	($5.1)	($0.4)	($2.3)	$0.4	$0.2	$0.2	$0.4	($1.9)	1,019	434
21	Axton	Transformer	AEP	$0.3	($0.8)	$0.1	$1.2	($0.1)	$0.1	$0.0	($0.2)	$1.1	116	12
27	Poston - Postel Tap	Line	AEP	$0.4	($0.6)	$0.2	$1.2	$0.1	$0.5	($0.0)	($0.4)	$0.8	148	118
28	Marquis - Waverly	Line	AEP	$0.7	$0.0	$0.1	$0.7	($0.0)	$0.0	($0.0)	($0.0)	$0.7	74	14
31	Kanawha River - Kincaid	Line	AEP	$0.0	$0.0	$0.0	$0.0	$0.3	($0.1)	$0.1	$0.5	$0.5	0	105

AP Control Zone

Table 7-45 AP Control Zone top congestion cost impacts (By facility): Calendar year 2010

				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	($36.1)	($148.5)	($11.0)	$101.4	$5.8	$6.1	$9.1	$8.9	$110.3	4,645	1,528
2	Bedington - Black Oak	Interface	500	($11.7)	($48.2)	($2.6)	$33.9	$0.8	$3.2	$1.0	($1.4)	$32.5	2,291	212
3	Doubs	Transformer	AP	$13.9	($10.9)	($0.2)	$24.6	$3.2	$1.1	$0.2	$2.4	$27.0	920	525
4	Belmont	Transformer	AP	$15.9	($2.1)	$0.7	$18.6	($1.7)	($0.0)	($0.6)	($2.2)	$16.4	1,887	203
5	Tiltonsville - Windsor	Line	AP	$18.1	$4.2	$1.6	$15.5	($2.7)	($0.7)	($1.9)	($3.9)	$11.7	2,723	506
6	Mount Storm - Pruntytown	Line	AP	($2.8)	($11.2)	($0.4)	$8.0	$2.4	$1.6	$2.0	$2.8	$10.7	571	574
7	5004/5005 Interface	Interface	500	($21.7)	($33.5)	($2.1)	$9.7	$2.0	$2.9	$1.7	$0.8	$10.5	1,644	605
8	AEP-DOM	Interface	500	($2.9)	($10.4)	$0.4	$7.9	$0.4	($0.2)	($0.1)	$0.5	$8.4	691	187
9	Millville - Old Chapel	Line	AP	($1.0)	($2.4)	($0.3)	$1.1	($1.7)	$5.8	$0.6	($7.0)	($5.9)	210	303
10	Millville - Old Chapel	Line	Dominion	$1.8	($2.7)	$0.2	$4.8	$0.0	$0.0	$0.0	$0.0	$4.8	269	0
11	Wylie Ridge	Transformer	AP	$2.5	$4.7	$1.8	($0.4)	($1.2)	($0.8)	($4.0)	($4.3)	($4.7)	728	683
12	Kingwood - Pruntytown	Line	AP	$5.4	$1.4	$0.6	$4.6	$0.0	($0.1)	($0.2)	($0.0)	$4.6	502	49
13	Halfway - Marlowe	Line	AP	$0.8	($3.8)	($0.7)	$3.8	$0.7	$1.4	$1.4	$0.8	$4.6	157	73
14	Cloverdale - Lexington	Line	AEP	$1.5	($3.4)	$0.9	$5.8	($0.1)	$0.4	($1.9)	($2.3)	$3.5	1,127	684
15	Yukon	Transformer	AP	$3.3	$0.2	$0.1	$3.3	$0.1	$0.2	$0.1	$0.0	$3.3	195	38
16	Albright - Mt. Zion	Line	AP	$1.7	($0.8)	$0.1	$2.6	$0.2	($0.6)	($0.5)	$0.3	$3.0	727	193
18	Nipetown - Reid	Line	AP	($0.1)	($3.1)	($0.1)	$2.9	$0.1	$0.2	($0.0)	($0.1)	$2.8	352	63
20	Fort Martin - Ronco	Line	AP	$0.2	$0.2	$0.1	$0.2	($0.2)	$0.9	($1.4)	($2.5)	($2.3)	31	42
21	Middlebourne - Willow	Line	AP	$2.0	($0.2)	$0.3	$2.5	($0.2)	($0.1)	($0.2)	($0.3)	$2.2	333	81
22	Hamilton - Weirton	Line	AP	$3.2	$1.1	$0.2	$2.4	($0.1)	$0.1	($0.1)	($0.3)	$2.1	533	18

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Table 7-46 AP Control Zone top congestion cost impacts (By facility): Calendar year 2009

				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	($17.3)	($65.9)	($4.6)	$44.0	$2.6	$2.6	$3.3	$3.4	$47.4	3,549	604
2	Kammer	Transformer	500	$17.8	$27.8	$6.8	($3.2)	($3.0)	($0.9)	($8.2)	($10.3)	($13.5)	3,674	1,328
3	Mount Storm - Pruntytown	Line	AP	($2.0)	($10.1)	($0.6)	$7.4	$0.8	$0.8	$0.5	$0.5	$7.9	525	132
4	Doubs	Transformer	AP	$1.9	($6.6)	($0.2)	$8.4	($0.2)	$1.2	$0.2	($1.1)	$7.3	429	246
5	Bedington - Black Oak	Interface	500	($1.9)	($8.5)	($0.2)	$6.3	($0.3)	$0.2	$0.4	($0.2)	$6.2	669	73
6	Tiltonsville - Windsor	Line	AP	$9.1	$2.5	$0.5	$7.1	($0.5)	($0.3)	($0.8)	($1.1)	$6.0	2,070	311
7	5004/5005 Interface	Interface	500	($9.9)	($13.9)	($1.3)	$2.7	$1.0	$0.9	$1.8	$1.9	$4.6	776	294
8	Wylie Ridge	Transformer	AP	$6.1	$7.4	$5.4	$4.1	($1.1)	($0.5)	($7.2)	($7.7)	($3.6)	354	335
9	Belmont	Transformer	AP	$3.5	$0.2	$0.6	$4.0	($0.2)	$0.5	($0.1)	($0.7)	$3.2	1,029	76
10	Bedington - Harmony	Line	AP	$2.1	($0.1)	$0.5	$2.8	$0.0	$0.0	($0.0)	($0.1)	$2.7	280	28
11	Cloverdale - Lexington	Line	AEP	$1.3	($1.5)	$0.8	$3.6	($0.1)	$0.0	($0.9)	($1.0)	$2.6	1,019	434
12	Carroll - Catoctin	Line	AP	$0.4	$0.0	($0.0)	$0.3	$0.7	($0.8)	$0.2	$1.6	$2.0	99	22
13	Yukon	Transformer	AP	$2.2	$0.4	$0.0	$1.9	$0.0	$0.2	$0.1	($0.1)	$1.7	149	39
14	Krendale - Seneca	Line	AP	$1.6	$0.1	$0.2	$1.7	$0.0	$0.0	$0.0	$0.0	$1.7	353	0
15	Mount Storm	Transformer	AP	($0.5)	($2.2)	($0.3)	$1.4	$0.2	$0.5	$0.3	($0.1)	$1.4	151	80
17	Sammis - Wylie Ridge	Line	AP	$3.9	$2.9	$1.6	$2.6	($0.3)	($0.1)	($1.2)	($1.4)	$1.2	806	157
18	Kingwood - Pruntytown	Line	AP	$1.0	($0.1)	($0.0)	$1.1	$0.0	($0.0)	($0.0)	$0.0	$1.2	161	10
19	Middlebourne - Willow	Line	AP	$1.3	$0.1	($0.1)	$1.1	($0.1)	($0.1)	($0.0)	$0.0	$1.1	348	45
20	Elrama - Mitchell	Line	AP	$2.5	$1.2	$0.1	$1.5	($0.2)	$0.0	($0.2)	($0.4)	$1.1	367	198
22	Bedington	Transformer	AP	$4.3	($0.8)	$0.1	$5.1	($3.7)	$0.0	($2.2)	($6.0)	($0.8)	354	149

ComEd Control Zone

Table 7-47 ComEd Control Zone top congestion cost impacts (By facility): Calendar year 2010

				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	($68.4)	($106.2)	($12.0)	$25.8	$0.6	($3.6)	$6.6	$10.8	$36.6	2,066	823
2	East Frankfort - Crete	Line	ComEd	($48.6)	($88.9)	($6.2)	$34.1	($3.2)	($0.7)	$1.2	($1.4)	$32.7	3,084	850
3	AP South	Interface	500	($89.1)	($120.4)	($1.0)	$30.4	($2.6)	$0.2	($0.0)	($2.8)	$27.6	4,645	1,528
4	Electric Jct - Nelson	Line	ComEd	$1.1	($24.9)	$6.7	$32.7	$1.3	$4.3	($9.4)	($12.4)	$20.3	1,495	258
5	Pleasant Valley - Belvidere	Line	ComEd	($3.8)	($23.9)	$2.6	$22.7	$0.1	$2.9	($2.9)	($5.7)	$17.0	2,553	467
6	Nelson - Cordova	Line	ComEd	$8.7	($3.0)	$4.0	$15.8	$0.8	$1.7	($3.5)	($4.4)	$11.3	1,546	95
7	Bedington - Black Oak	Interface	500	($31.9)	($42.8)	($0.3)	$10.7	($0.5)	($0.2)	$0.1	($0.2)	$10.4	2,291	212
8	5004/5005 Interface	Interface	500	($32.1)	($44.3)	($0.1)	$12.1	($4.2)	($0.9)	$0.2	($3.1)	$9.0	1,644	605
9	Waterman - West Dekalb	Line	ComEd	($2.2)	($9.2)	$1.3	$8.3	$0.8	$0.6	($0.5)	($0.2)	$8.1	3,002	343
10	AEP-DOM	Interface	500	($14.8)	($22.3)	($0.6)	$7.0	($0.0)	($0.2)	$0.2	$0.4	$7.4	691	187
11	Cherry Valley	Transformer	ComEd	$2.4	($3.6)	$0.6	$6.6	$0.1	$0.1	($0.1)	($0.1)	$6.5	535	39
12	Glidden - West Dekalb	Line	ComEd	($0.2)	($5.3)	$0.7	$5.8	$0.1	$0.0	($0.5)	($0.4)	$5.4	1,090	21
13	Rising	Flowgate	Midwest ISO	($3.1)	($8.6)	($0.1)	$5.4	($0.1)	$0.5	$0.2	($0.4)	$4.9	875	80
14	Cloverdale - Lexington	Line	AEP	($11.6)	($17.9)	($0.4)	$5.9	($1.6)	($0.1)	$0.4	($1.1)	$4.8	1,127	684
15	Goose Creek - Rising	Flowgate	Midwest ISO	($7.0)	($12.5)	($1.0)	$4.5	($0.2)	$0.4	($0.1)	($0.6)	$3.9	439	200
31	Electric Junction - Aurora	Line	ComEd	$1.3	$0.2	$0.0	$1.1	$0.0	$0.1	$0.1	$0.1	$1.2	136	35
33	Woodstock - 12205	Line	ComEd	($0.0)	($1.0)	$0.1	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	91	0
40	Belvidere - Woodstock	Line	ComEd	$0.3	($0.6)	$0.1	$1.0	$0.0	$0.1	($0.0)	($0.1)	$0.9	100	11
46	Burnham - Munster	Line	ComEd	($0.0)	($0.0)	($0.0)	$0.0	($0.0)	$0.6	($0.0)	($0.7)	($0.7)	1	82
47	Burnham - Sheffield	Line	ComEd	($1.1)	($1.8)	($0.0)	$0.8	($0.6)	($0.3)	$0.1	($0.1)	$0.6	41	162

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Table 7-48 ComEd Control Zone top congestion cost impacts (By facility): Calendar year 2009

				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	Pleasant Valley - Belvidere	Line	ComEd	($4.7)	($42.8)	($0.0)	$38.1	($0.2)	$2.4	$0.1	($2.5)	$35.6	3,648	405
2	East Frankfort - Crete	Line	ComEd	($20.1)	($41.5)	($0.3)	$21.1	($0.7)	$0.5	$0.1	($1.1)	$19.9	2,163	605
3	Dunes Acres - Michigan City	Flowgate	Midwest ISO	($46.2)	($70.5)	($3.1)	$21.3	($3.4)	($1.1)	$0.9	($1.4)	$19.8	2,949	910
4	Kammer	Transformer	500	($30.8)	($49.7)	($0.1)	$18.7	($0.4)	($0.9)	($0.0)	$0.4	$19.1	3,674	1,328
5	AP South	Interface	500	($34.7)	($53.5)	($0.1)	$18.7	($1.1)	($0.1)	($0.1)	($1.0)	$17.6	3,549	604
6	Crete - St Johns Tap	Flowgate	Midwest ISO	($14.7)	($30.3)	($0.4)	$15.2	($0.4)	$0.1	$0.1	($0.4)	$14.8	1,571	306
7	Electric Jct - Nelson	Line	ComEd	$0.2	($7.9)	$0.1	$8.2	$2.1	$1.4	($0.1)	$0.6	$8.8	823	202
8	5004/5005 Interface	Interface	500	($12.4)	($17.6)	($0.0)	$5.1	($0.6)	($1.1)	($0.0)	$0.4	$5.6	776	294
9	Glidden - West Dekalb	Line	ComEd	($0.4)	($5.7)	$0.1	$5.4	$0.1	($0.0)	$0.0	$0.2	$5.6	1,166	21
10	Paddock - Townline	Flowgate	Midwest ISO	($0.8)	($5.0)	($0.1)	$4.0	$0.5	$0.2	$0.1	$0.4	$4.4	404	215
11	Sliver Lake - Cherry Valley	Line	ComEd	$0.1	($3.7)	$0.1	$3.9	$0.8	$0.2	($0.1)	$0.5	$4.3	340	41
12	West	Interface	500	($12.4)	($16.6)	($0.0)	$4.1	($0.1)	($0.1)	($0.0)	$0.0	$4.1	504	87
13	Wylie Ridge	Transformer	AP	($7.9)	($10.9)	($0.0)	$3.0	($0.8)	($1.5)	$0.0	$0.8	$3.8	354	335
14	Doubs	Transformer	AP	($7.5)	($11.8)	($0.0)	$4.3	($0.7)	$0.1	$0.0	($0.7)	$3.6	429	246
15	Cloverdale - Lexington	Line	AEP	($5.1)	($9.0)	($0.0)	$3.9	($0.5)	($0.1)	$0.0	($0.3)	$3.5	1,019	434
20	Cherry Valley	Transformer	ComEd	$0.4	($2.4)	$0.0	$2.8	$0.0	$0.0	$0.0	($0.0)	$2.8	25	6
23	Waterman - West Dekalb	Line	ComEd	($0.6)	($2.4)	$0.0	$1.9	$0.3	($0.1)	($0.0)	$0.3	$2.2	1,499	57
24	Wilton Center - Pontiac	Line	ComEd	$1.6	$0.4	$0.0	$1.3	$0.1	$0.7	$0.0	($0.6)	$0.7	205	55
29	Quad Cities - Cordova	Line	ComEd	$0.2	($1.0)	$0.0	$1.3	($0.0)	$0.1	$0.0	($0.1)	$1.2	115	15
30	Burnham - Munster	Line	ComEd	($2.1)	($3.4)	($0.0)	$1.3	($0.0)	$0.0	($0.0)	($0.1)	$1.2	140	15

DAY Control Zone

Table 7-49 DAY Control Zone top congestion cost impacts (By facility): Calendar year 2010

				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	($1.7)	($3.2)	($0.2)	$1.2	$0.3	$0.1	$0.4	$0.6	$1.8	1,644	605
2	AP South	Interface	500	($5.5)	($7.6)	($1.0)	$1.0	$0.1	$0.3	$0.7	$0.5	$1.5	4,645	1,528
3	AEP-DOM	Interface	500	($1.0)	($2.0)	($0.0)	$1.0	$0.0	($0.1)	($0.0)	$0.2	$1.1	691	187
4	Crete - St Johns Tap	Flowgate	Midwest ISO	$0.6	$1.1	($0.5)	($1.0)	($0.1)	$0.1	$0.1	($0.0)	($1.1)	2,066	823
5	Cloverdale - Lexington	Line	AEP	($0.5)	($1.5)	($0.2)	$0.7	$0.1	($0.0)	$0.2	$0.3	$1.0	1,127	684
6	Pleasant Prairie - Zion	Flowgate	Midwest ISO	$0.0	($0.0)	$0.5	$0.5	($0.0)	$0.0	($1.4)	($1.4)	($0.9)	1,321	404
7	Mount Storm - Pruntytown	Line	AP	($0.4)	($0.5)	($0.0)	$0.1	$0.2	$0.3	$0.7	$0.6	$0.7	571	574
8	Branchburg - Flagtown	Line	PSEG	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.6)	($0.6)	($0.6)	0	0
9	Tiltonsville - Windsor	Line	AP	($0.7)	($1.1)	($0.3)	$0.1	$0.1	($0.0)	$0.4	$0.5	$0.6	2,723	506
10	Doubs	Transformer	AP	($0.9)	($1.4)	($0.1)	$0.4	$0.1	$0.1	$0.1	$0.1	$0.5	920	525
11	Bedington - Black Oak	Interface	500	($1.8)	($2.7)	($0.4)	$0.5	$0.0	$0.2	$0.1	($0.1)	$0.5	2,291	212
12	Harrison - Pruntytown	Line	500	($0.1)	($0.2)	($0.0)	$0.0	$0.1	$0.1	$0.4	$0.4	$0.5	231	224
13	Waterman - West Dekalb	Line	ComEd	$0.0	$0.0	$0.5	$0.5	$0.0	$0.0	($0.1)	($0.1)	$0.4	3,002	343
14	Pleasant Valley - Belvidere	Line	ComEd	$0.0	$0.0	$0.8	$0.8	($0.0)	$0.0	($1.2)	($1.2)	($0.4)	2,553	467
15	Clover	Transformer	Dominion	($0.2)	($0.5)	$0.1	$0.3	$0.0	($0.0)	($0.1)	$0.0	$0.3	514	259
162	Hutchings - Sugarcreek	Line	DAY	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	0	1
621	Greene - Clark	Line	DAY	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	1	0

Table 7-50 DAY Control Zone top congestion cost impacts (By facility): Calendar year 2009

				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	Kammer	Transformer	500	($1.9)	($4.5)	($0.1)	$2.6	$0.4	($0.1)	$0.0	$0.5	$3.1	3,674	1,328
2	AP South	Interface	500	($2.6)	($3.9)	($0.0)	$1.3	$0.0	$0.3	($0.0)	($0.3)	$1.0	3,549	604
3	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.4	$1.0	($0.5)	($1.1)	($0.0)	($0.0)	$0.1	$0.2	($0.9)	2,949	910
4	Doubs	Transformer	AP	($0.4)	($1.3)	$0.0	$0.9	$0.0	$0.1	$0.0	($0.1)	$0.8	429	246
5	West	Interface	500	($0.9)	($1.5)	($0.0)	$0.7	$0.0	$0.0	$0.0	($0.0)	$0.7	504	87
6	Cloverdale - Lexington	Line	AEP	($0.3)	($0.9)	$0.0	$0.6	$0.0	$0.1	$0.0	($0.1)	$0.6	1,019	434
7	Wylie Ridge	Transformer	AP	($0.6)	($1.1)	($0.0)	$0.5	$0.2	$0.2	$0.0	($0.0)	$0.4	354	335
8	Tiltonsville - Windsor	Line	AP	($0.3)	($0.8)	($0.0)	$0.5	$0.0	$0.1	$0.0	($0.1)	$0.4	2,070	311
9	5004/5005 Interface	Interface	500	($0.8)	($1.2)	($0.0)	$0.4	$0.1	$0.1	$0.0	($0.0)	$0.4	776	294
10	East Frankfort - Crete	Line	ComEd	$0.2	$0.5	$0.0	($0.3)	($0.0)	($0.0)	($0.0)	$0.0	($0.3)	2,163	605
11	Marquis - Waverly	Line	AEP	$0.0	($0.3)	($0.0)	$0.3	($0.0)	$0.0	$0.0	($0.0)	$0.2	74	14
12	Elrama - Mitchell	Line	AP	($0.1)	($0.3)	($0.0)	$0.2	$0.1	$0.0	$0.0	$0.1	$0.2	367	198
13	Sammis - Wylie Ridge	Line	AP	($0.3)	($0.5)	($0.0)	$0.2	$0.0	$0.1	($0.0)	($0.0)	$0.2	806	157
14	AEP-DOM	Interface	500	($0.2)	($0.3)	$0.0	$0.2	$0.0	($0.0)	$0.0	$0.0	$0.2	335	136
15	Pierce - Foster	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	($0.0)	($0.2)	($0.2)	0	5

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DLCO Control Zone

Table 7-51 DLCO Control Zone top congestion cost impacts (By facility): Calendar year 2010

				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	$13.1	($0.7)	$0.3	$14.1	($0.1)	($0.4)	($0.3)	$0.1	$14.2	740	174
2	AP South	Interface	500	($41.7)	($49.3)	($0.3)	$7.2	($2.6)	($0.3)	$0.3	($2.0)	$5.2	4,645	1,528
3	Collier - Elwyn	Line	DLCO	$4.8	$0.1	$0.1	$4.9	($0.2)	($0.0)	($0.0)	($0.2)	$4.7	510	127
4	Elrama - Mitchell	Line	AP	($4.2)	($3.0)	($0.3)	($1.5)	($0.7)	$1.4	$0.3	($1.8)	($3.4)	581	357
5	Carson - Oakland	Line	DLCO	$3.0	($0.0)	$0.0	$3.0	$0.0	($0.0)	($0.0)	$0.0	$3.1	218	10
6	Bedington - Black Oak	Interface	500	($13.6)	($15.4)	($0.1)	$1.7	($0.4)	($0.0)	$0.0	($0.3)	$1.5	2,291	212
7	AEP-DOM	Interface	500	($5.8)	($7.5)	$0.0	$1.7	($0.3)	($0.1)	($0.0)	($0.3)	$1.4	691	187
8	Sammis - Wylie Ridge	Line	AP	($1.8)	($3.2)	($0.0)	$1.4	($0.1)	$0.2	$0.0	($0.2)	$1.2	524	60
9	East Frankfort - Crete	Line	ComEd	$1.6	$2.5	($0.0)	($0.8)	$0.1	($0.1)	($0.0)	$0.2	($0.7)	3,084	850
10	5004/5005 Interface	Interface	500	($13.3)	($15.1)	($0.1)	$1.8	($1.3)	($0.1)	$0.1	($1.1)	$0.6	1,644	605
11	Crete - St Johns Tap	Flowgate	Midwest ISO	$2.1	$3.0	($0.0)	($0.9)	$0.3	($0.0)	$0.0	$0.3	($0.6)	2,066	823
12	Cloverdale - Lexington	Line	AEP	($1.4)	($2.1)	$0.0	$0.7	($0.2)	($0.0)	($0.0)	($0.2)	$0.5	1,127	684
13	Arsenal - Highland	Line	DLCO	$0.5	($0.0)	$0.0	$0.5	($0.0)	$0.0	($0.0)	($0.0)	$0.5	48	7
14	Yukon	Transformer	AP	$0.5	$0.2	$0.0	$0.3	$0.1	($0.1)	($0.0)	$0.1	$0.4	195	38
15	Erie West	Transformer	PENELEC	($2.3)	($3.0)	($0.1)	$0.6	($0.3)	($0.0)	$0.0	($0.2)	$0.4	680	175
16	Arsenal - Oakland	Line	DLCO	$0.1	($0.1)	$0.0	$0.3	($0.3)	$0.3	($0.0)	($0.6)	($0.4)	89	54
18	Collier	Transformer	DLCO	$0.3	$0.0	$0.0	$0.3	$0.0	($0.1)	($0.0)	$0.1	$0.4	8	8
19	Beaver - Mansfield	Line	DLCO	($0.1)	($0.4)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	175	0
27	Crescent - Sewickly	Line	DLCO	$0.2	$0.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	12	0
29	Cheswick - Logan's Ferry	Line	DLCO	($0.0)	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	35	0

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Table 7-52 DLCO Control Zone top congestion cost impacts (By facility): Calendar year 2009

				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	($15.3)	($21.2)	($0.1)	$5.8	($0.8)	$0.4	$0.1	($1.1)	$4.7	3,549	604
2	Sammis - Wylie Ridge	Line	AP	($5.2)	($10.0)	($0.0)	$4.7	($0.2)	$0.6	$0.0	($0.7)	$4.0	806	157
3	Elrama - Mitchell	Line	AP	($3.1)	($2.0)	($0.0)	($1.1)	($0.2)	$0.9	$0.0	($1.1)	($2.2)	367	198
4	West	Interface	500	($4.3)	($6.0)	($0.0)	$1.8	($0.1)	$0.0	$0.0	($0.1)	$1.6	504	87
5	Logans Ferry - Universal	Line	DLCO	$0.2	($1.3)	$0.0	$1.5	$0.0	$0.1	($0.0)	($0.1)	$1.4	395	156
6	Collier	Transformer	DLCO	$1.4	$0.3	$0.0	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	46	0
7	Wylie Ridge	Transformer	AP	($8.5)	($12.9)	($0.0)	$4.4	($1.2)	$2.2	$0.0	($3.3)	$1.1	354	335
8	Kammer	Transformer	500	($3.6)	($4.8)	$0.0	$1.3	($0.4)	($0.1)	($0.0)	($0.4)	$0.9	3,674	1,328
9	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$1.7	$2.6	($0.0)	($0.9)	$0.2	$0.1	($0.0)	$0.1	($0.8)	2,949	910
10	Krendale - Seneca	Line	AP	($1.7)	($2.3)	($0.0)	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	353	0
11	Doubs	Transformer	AP	($1.9)	($1.4)	($0.0)	($0.5)	($0.1)	$0.0	$0.0	($0.2)	($0.7)	429	246
12	Mount Storm - Pruntytown	Line	AP	($1.9)	($2.8)	($0.0)	$0.9	($0.2)	$0.1	$0.0	($0.3)	$0.6	525	132
13	Kammer - West Bellaire	Line	AP	$1.2	$1.0	$0.0	$0.3	$0.2	($0.1)	($0.0)	$0.3	$0.6	227	54
14	Bedington - Black Oak	Interface	500	($1.8)	($2.4)	($0.0)	$0.6	($0.0)	$0.0	$0.0	($0.1)	$0.5	669	73
15	5004/5005 Interface	Interface	500	($4.8)	($6.1)	($0.0)	$1.3	($0.4)	$0.5	$0.0	($0.9)	$0.4	776	294
19	Collier - Elwyn	Line	DLCO	$0.3	$0.0	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	30	0
20	Beaver - Clinton	Line	DLCO	$0.1	($0.2)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	20	0
25	Cheswick - Logans Ferry	Line	DLCO	$0.0	($0.1)	$0.0	$0.1	($0.0)	($0.0)	($0.0)	$0.0	$0.1	49	3
26	Crescent	Transformer	DLCO	$0.1	$0.0	$0.0	$0.1	$0.2	$0.1	($0.0)	$0.0	$0.1	18	23
29	Cheswick - Evergreen	Line	DLCO	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	($0.0)	$0.1	35	5

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Southern Region Congestion-Event Summaries

Dominion Control Zone

Table 7-53 Dominion Control Zone top congestion cost impacts (By facility): Calendar year 2010

				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	$94.4	($48.7)	($1.0)	$142.1	$3.6	$8.6	$0.6	($4.4)	$137.7	4,645	1,528
2	Cloverdale - Lexington	Line	AEP	$18.2	$5.2	$2.1	$15.2	($1.8)	($2.5)	($2.7)	($2.0)	$13.1	1,127	684
3	Doubs	Transformer	AP	($0.9)	($12.3)	($0.1)	$11.2	$1.4	$0.5	$0.7	$1.6	$12.8	920	525
4	Bedington - Black Oak	Interface	500	$30.0	$19.8	$4.0	$14.3	($0.7)	$0.0	($1.6)	($2.3)	$12.0	2,291	212
5	Clover	Transformer	Dominion	$6.2	($2.4)	$1.6	$10.3	($0.3)	$0.3	($1.8)	($2.5)	$7.7	514	259
6	Pleasant View	Transformer	Dominion	$0.3	$0.0	$0.0	$0.3	($4.2)	$1.4	($0.6)	($6.2)	($6.0)	31	101
7	AEP-DOM	Interface	500	$19.3	$14.6	$1.3	$6.0	($0.0)	$0.2	($0.2)	($0.4)	$5.5	691	187
8	Millville - Sleepy Hollow	Line	Dominion	$1.2	($4.1)	($0.2)	$5.2	$0.0	$0.0	$0.0	$0.0	$5.2	401	0
9	Pleasantville - Ashburn	Line	Dominion	$6.7	$0.1	($0.2)	$6.4	($1.0)	$0.2	($0.1)	($1.3)	$5.0	94	35
10	Dooms	Transformer	Dominion	$4.1	($0.6)	($0.0)	$4.7	($0.6)	($0.9)	$0.1	$0.4	$5.0	107	31
11	Ox - Francona	Line	Dominion	$3.3	($0.6)	$0.0	$3.9	$0.0	$0.0	$0.0	$0.0	$3.9	66	0
12	Dickerson - Pleasant View	Line	Pepco	$3.9	$0.6	$0.1	$3.4	($0.1)	($0.3)	($0.2)	$0.0	$3.4	185	97
13	Ox - Glebe	Line	Dominion	$2.5	($0.7)	$0.0	$3.2	$0.0	$0.0	$0.0	$0.0	$3.2	30	0
14	East Frankfort - Crete	Line	ComEd	$5.7	$2.8	$0.2	$3.1	($0.2)	($0.5)	($0.2)	$0.1	$3.2	3,084	850
15	Millville - Old Chapel	Line	AP	$0.3	($3.0)	($0.4)	$3.0	($0.2)	$1.5	$1.7	$0.1	$3.0	210	303
17	Chuckatuck - Benns Church	Line	Dominion	$2.5	($0.2)	$0.0	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	76	0
19	Millville - Old Chapel	Line	Dominion	($0.5)	($3.4)	($0.5)	$2.4	$0.0	$0.0	$0.0	$0.0	$2.4	269	0
21	Endless Caverns	Transformer	Dominion	$0.8	($1.2)	$0.0	$2.0	($0.0)	($0.0)	$0.0	$0.0	$2.0	541	3
22	Chesapeake - Reeves Ave.	Line	Dominion	$0.2	($1.8)	$0.0	$2.0	($0.0)	$0.0	$0.0	($0.0)	$2.0	178	49
25	Greenwich - Elizabeth River	Line	Dominion	$1.6	($0.2)	$0.0	$1.8	$0.1	$0.0	($0.0)	$0.0	$1.8	32	22

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Table 7-54 Dominion Control Zone top congestion cost impacts (By facility): Calendar year 2009

				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	$37.3	($31.2)	($0.3)	$68.2	$1.6	$1.2	$0.4	$0.8	$69.0	3,549	604
2	Doubs	Transformer	AP	$0.4	($5.5)	$0.0	$5.8	$0.3	$0.1	$0.1	$0.3	$6.1	429	246
3	Cloverdale - Lexington	Line	AEP	$7.0	$2.7	$1.1	$5.4	($0.0)	($1.8)	($1.4)	$0.4	$5.8	1,019	434
4	Kammer	Transformer	500	$10.3	$8.3	$2.1	$4.2	($0.0)	($0.8)	($2.0)	($1.2)	$3.0	3,674	1,328
5	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$4.4	$2.1	$0.1	$2.4	($0.2)	($0.6)	($0.1)	$0.3	$2.7	2,949	910
6	Bedington - Black Oak	Interface	500	$4.3	$2.5	$0.7	$2.6	($0.1)	($0.1)	($0.2)	($0.1)	$2.4	669	73
7	Beechwood - Kerr Dam	Line	Dominion	$1.5	($0.8)	($0.1)	$2.3	($0.2)	$0.1	$0.1	($0.2)	$2.1	665	234
8	Bristers - Ox	Line	Dominion	($0.1)	($1.9)	$0.0	$1.8	$0.1	$0.4	$0.0	($0.2)	$1.6	63	42
9	Chuckatuck - Benns Church	Line	Dominion	$1.5	($0.0)	$0.0	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	45	0
10	AEP-DOM	Interface	500	$1.7	$1.1	$0.1	$0.7	($0.2)	($0.7)	($0.1)	$0.3	$1.1	335	136
11	East Frankfort - Crete	Line	ComEd	$1.9	$1.0	$0.1	$1.1	($0.1)	($0.2)	($0.1)	$0.0	$1.1	2,163	605
12	West	Interface	500	($2.6)	($3.6)	$0.0	$1.0	$0.1	$0.2	$0.1	$0.0	$1.0	504	87
13	Wylie Ridge	Transformer	AP	$2.5	$1.7	$0.4	$1.2	($0.1)	($0.2)	($0.4)	($0.2)	$1.0	354	335
14	Ox	Transformer	Dominion	$0.8	($0.1)	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	8	0
15	Crete - St Johns Tap	Flowgate	Midwest ISO	$1.6	$0.8	$0.2	$0.9	($0.1)	($0.3)	($0.2)	$0.0	$0.9	1,571	306
17	Crozet - Dooms	Line	Dominion	$0.7	($0.3)	$0.0	$1.0	($0.3)	($0.2)	($0.0)	($0.1)	$0.9	55	37
20	Beaumeade - Ashburn	Line	Dominion	$0.8	$0.0	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	25	0
21	Chickahominy - Lanexa	Line	Dominion	$0.5	($0.0)	$0.0	$0.6	($0.1)	($0.3)	$0.0	$0.1	$0.7	42	19
22	Clover - Farmville	Line	Dominion	($0.0)	($0.7)	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	41	0
23	Crozet - Barracks Rd	Line	Dominion	$0.8	$0.3	($0.0)	$0.4	$0.1	($0.1)	$0.0	$0.2	$0.6	47	11

Generation and Transmission Interconnection Planning Process

Participation in the PJM Capacity Market requires procurement of capacity interconnection rights. These rights persist during the unit's lifetime, and expire one year after a unit is retired.

Any entity (developer or applicant) that requests interconnection of a generating facility, including increases to the capacity of an existing generating unit, or requests interconnection of a merchant transmission facility, must follow the PJM interconnection process.[26] With the assumption that a facilities study is not required, and accounting for the time required by PJM to complete the required studies, it takes approximately ten months from the initial request for interconnection to the point where the applicant can begin to negotiate an Interconnection Service Agreement. Upon execution of the Interconnection Service Agreement, the parties can then develop an Interconnection Construction Service Agreement, which is used to develop an agreed upon schedule of work for construction (Table 7-55).

26 The material in this section is based on PJM Manual M-14A: Generation and Transmission Interconnection Process. "M-14A: Generation and Transmission Interconnection Process", Revision 8 (May 1, 2009).

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Table 7-55 Generation and transmission interconnection timeline

Process Step	Start on	Complete by	Days to complete	Days to decide whether to continue
Feasibility Study	January 31	April 30	90	30
	April 30	July 31		
	October 31	October 31		
	January 31	January 31		
System Impact Study	January 31	June 01	120	30
	April 30	September 01		
	July 31	December 01		
	October 31	March 01		
Facilities Study	Upon acceptance of the Facilities Study Agreement	Varies	Varies	60
Interconnection Service Agreement	Upon acceptance of an Interconnection Service Agreement	Varies	Varies	60
Interconnection Construction Service Agreement	Upon acceptance of Interconnection Construction Service Agreement	Varies	Varies	NA

Initiating the Planning Process

To initiate the interconnection planning process, a developer must submit a Feasibility Study Agreement to PJM for execution along with required information about the project and the appropriate fees.[27] The applicant is obligated to pay the actual costs of studies conducted by PJM on its behalf. The feasibility study fees depend on when the request is submitted and the size of the interconnection request but the initial deposit cannot exceed $100,000. Resources that are 20 MW or less, or qualify as small resources, can often use an expedited queue process, under which a small resource can receive interim Capacity Interconnection Rights if a queue project is ready to be put in service ahead of other queued projects.

Feasibility Study

A developer is required to elect capacity resource status or energy only resource status. Capacity resource status allows the generator to meet capacity obligations through RPM, while energy resource status allows the unit to participate in the energy market only. In order to qualify as a capacity resource, sufficient transmission capability must exist to ensure the deliverability of the generator output to network load and to satisfy the reliability requirements of the NERC region in which the generator is located.[28]

27 The Feasibility Study Agreements are identified as Attachment N of the PJM Open Access Transmission Tariff (OATT) for generation interconnection requests and Attachment S of the PJM OATT for merchant transmission interconnection requests.

28 The PJM footprint includes all or part of Reliability*First* and the SERC Reliability Corporation (SERC) NERC regions.

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Feasibility studies are performed four times each year. The feasibility studies are performed by PJM staff, with input by the affected Transmission Owners (TO), who provide verification of PJM results. The TOs also provide preliminary cost estimates for the project. The feasibility study is limited to short-circuit studies and load-flow analysis of probable contingencies, and does not include a stability analysis. In general, the feasibility study will be completed within 90 days.

System Impact Study

If the developer decides to proceed with the System Impact Study, they must pay the transmission provider a deposit (Table 7-56).[29]

Table 7-56 Impact Study Agreement deposit requirements

Project Size	Non-Refundable Deposit	Non-Refundable Cost per MW	Refundable Cost per MW	Maximum Deposit
<= 2MW	$5,000	$0	$0	NA
> 2 MW, <= 20 MW	$10,000	$0	$0	NA
> 20 MW, <= 100 MW	$0	$500	$0	NA
> 100 MW	$50,000	$0	$300	$300,000

The System Impact Study is a comprehensive regional analysis of the impact of adding the new generation or transmission facility to the system including the impact on deliverability to PJM load in the region where the generator or transmission facility is located. The System Impact Study identifies the system constraints relating to the new project and the necessary attachment facilities, local upgrades and network upgrades required to maintain reliability and deliverability in the region. The System Impact Studies are performed by PJM staff, with input by the affected TOs, who provide verification of PJM results. The TOs also provide more comprehensive cost estimates for the project than provided with the feasibility studies. System Impact Studies are performed four times each year.

The System Impact Study considers relationships among the new generator or transmission facility, other planned generators in the queue, and the existing system. The System Impact Study includes projects that were in the queue ahead of the project being studied. The Study attempts to model each project in the queue to appropriately identify the dependencies among the projects.

Facilities Study

If the developer decides to proceed with a Facilities Study, the applicant must submit a required refundable deposit in the amount of $100,000 or the estimated amount of its Facilities Study cost responsibility for the first three months of work on the study, whichever is greater. If the developer requests a Facilities Study, the results of the System Impact Study are incorporated in the Regional Transmission Expansion Plan (RTEP) Process.

29 See PJM. "PJM Open Access Transmission Tariff", Third Revised Sheet No. 224N (Effective April 27, 2009) Section VI.204.3A.

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The Facilities Study provides an estimate of the cost to the applicant for attachment facilities, local upgrades and network upgrades necessary to accommodate the project, and an estimate of the time required to complete the design and construction of the facilities and upgrades. The Facilities Studies are performed by the affected TOs. The TOs also provide more accurate cost estimates for the project than provided with feasibility studies and system impact studies. The time to complete a Facilities Study varies depending on the elements under study.

Interconnection Service Agreement

If the developer decides to proceed with an Interconnection Service Agreement, they must provide PJM with a letter of credit or other acceptable form of security in the amount equal to the estimated costs of new facilities or upgrades for which the applicant is responsible. The applicant must also demonstrate: completion of a fuel deliverability agreement and water agreement (if necessary); control of any necessary rights-of-way for fuel and water interconnections (if necessary); acquisition of any necessary local, county and state site permits; and a signed memorandum of understanding for the acquisition of major equipment. PJM may also request milestone dates for permitting, regulatory certifications, or third party financial arrangements.

Interconnection Construction Service Agreement

Once an Interconnection Service Agreement is executed, PJM is required to tender an Interconnection Construction Service Agreement among the applicant, PJM and the affected Interconnection Transmission Owner(s) within 45 days. The applicant then has 60 days to execute the Interconnection Construction Service Agreement. If the Transmission Owner and the developer cannot agree upon the terms of the Interconnection Construction Service Agreement, dispute resolution may be requested, and the customer has the option to design and install all or any portion of the Transmission Owner Interconnection Facilities under the "Option to Build" clause.[30]

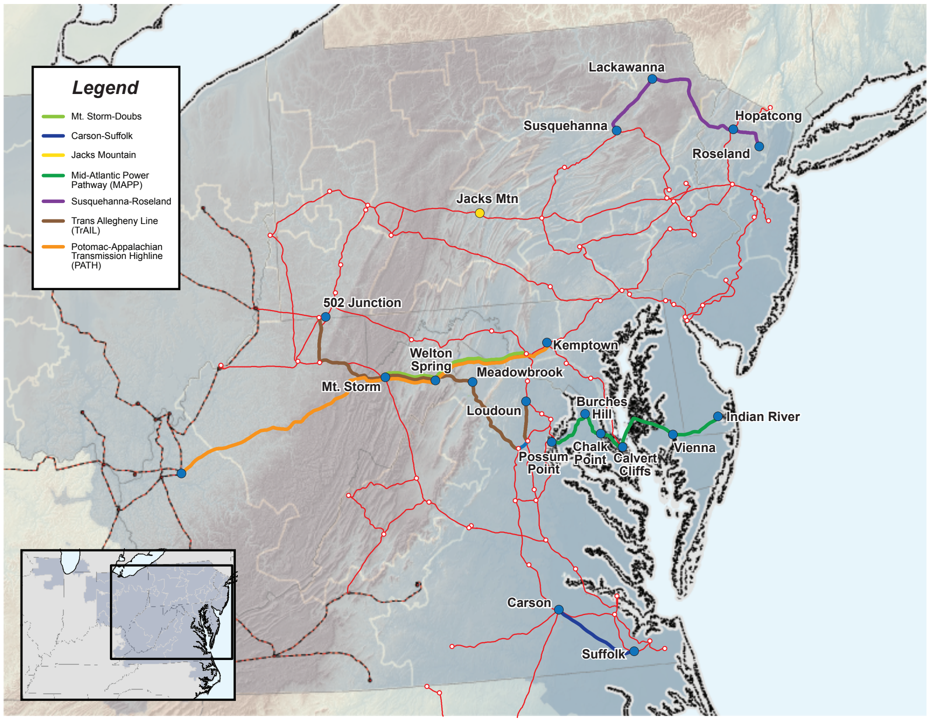
Key Backbone Facilities

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) (Figure 7-1). The total planned costs for all of these projects are $6,048.4 million.[31]

30 See PJM. "PJM Open Access Transmission Tariff", Sixth Revised Sheet No. 224CC (Effective March 1, 2007) Section VI.212.6.

31 Total estimated cost calculated from the backbone project cost estimates found in the "Construction Status Database" located at <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status.aspx>.

Figure 7-1 Map of Backbone Projects[32]



Mount Storm – Doubs

The Mount Storm – Doubs transmission line includes 65.7 miles in West Virginia, 30.7 miles in Virginia and 2.8 miles in Maryland. Under this project, the existing transmission towers will be replaced, resulting in an increase in capacity of about 60 percent. The construction will occur within the existing right-of-way. The required in-service date for this project is June 2020. Engineering estimates are currently being developed.[33]

Carson – Suffolk

The Carson – Suffolk 500 kV project, located in southeastern Virginia, will result in the installation of a new 500/230 kV #2 transformer at Suffolk, and a new 230 kV line from Suffolk to the Thrasher substation. The required in-service date for this project is June 1, 2011. Nearly all of the right-of-way requirements have been acquired and all of the rights of entry have been secured. The line foundation design, the line structure and conductor design, and the substation designs at all the Carson, Suffolk and Thrasher buses have been completed. All contracts have been executed for line construction, tree trimming and materials. The Suffolk transformer delivery is scheduled for February 2011.[34]

32 Source: PJM © 2011. All rights reserved.
33 See pjm.com. <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/mount-storm-doubs.aspx>.
34 See pjm.com. <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/carson-suffolk.aspx>.

Jacks Mountain

The Jacks Mountain project includes a new 500 kV substation at Jacks Mountain and 1,000 MVARs of capacitors. The project requires the replacement of a wave trap (a device used to divert communication signals sent on the transmission line from the remote substation to the telecommunications/protection panel in the substation control room) and an upgrade of a section at the Keystone 500 kV bus, the replacement of two wave traps at the Juniata 500 kV bus as well as relay changes at the Juniata 500 kV substation. This project has been deemed necessary to resolve voltage problems for load deliverability reliability criteria violations starting on June 1, 2013, and is required to be in service by that date.

Currently, all land required for this project has been procured. The transmission line engineering design is in process, and the detailed substation engineering design is expected to be completed in the summer of 2011. The procurement of transmission line hardware and substation equipment has been delayed until the middle of 2011, for delivery in 2012. The 500 kV breakers have been ordered, and are scheduled for delivery in October 2012 and January 2013. The necessary 500 kV capacitor banks are also on order, with a scheduled delivery of January 2013. The 500 kV disconnect switches are on order, with a scheduled delivery of October 2012.[35]

Mid-Atlantic Power Pathway (MAPP)

The MAPP transmission project will serve the District of Columbia, Maryland and Delaware. This project will consist of approximately 69 miles of alternating current lines and 83 miles of direct current lines. The majority of this line will be built on, or adjacent to, existing transmission lines. The project requires a new 500 kV transmission line from the Possum Point to the Calvert Cliffs substations, and two 500 kV High Voltage Direct Current (HVDC) circuits from a new substation in Calvert Cliffs, MD, to a new substation in Wicomico County, MD and to a new substation in Sussex County, DE. Included in these circuits is a submarine cable crossing of the Chesapeake Bay.[36]

The Mid-Atlantic Power Pathway (MAPP) project is required to resolve reliability criteria violations starting June 1, 2014. While the current required in-service date is June 1, 2014, PJM is in the process of considering new information, including fuel cost estimates, emissions costs, future generation scenarios, load forecast updates and demand response projections, and will be reviewing the need date as part of the 2010 Regional Transmission Expansion Plan (RTEP). The results of this analysis will be presented to the PJM Transmission Expansion Advisory Committee (TEAC) and the PJM Board of Managers in the first quarter of 2011.

Currently, the majority of the necessary right-of-way is under contract. The Possum Point to Calvert Cliffs line will follow existing right-of-way as will the section from Vienna to Indian River. The engineering design for the Possum Point to Calvert Cliffs section is completed, and the design for the Calvert Cliffs to Indian River section is ongoing. Proposals for the direct current system have been received from bidders and are currently being evaluated.[37]

35 See pjm.com. <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/jacks-mountain.aspx>.

36 See webapps.powerpathways.com. "MAPP_Overview" (November 8, 2010) (Accessed February 27, 2011) <http://webapps.powerpathway.com/file_depot/0-10000000/0-10000/41/folder/66/MAPP_Overview.pdf>. (385 KB)

37 See pjm.com <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/mapp.aspx>.

Potomac – Appalachian Transmission Highline (PATH)

The Potomac - Appalachian Transmission Highline (PATH) project is required to resolve reliability criteria violations. The PATH project consists of a 765 kV transmission line extending approximately 275 miles from the Amos Substation, which is located in southwestern West Virginia, to the proposed Kemptown (765/500 kV) Substation, located in central Virginia. The project also includes a new Welton Spring (765/500 kV) Substation.

Currently, right-of-way issues are being discussed in West Virginia, Virginia and Maryland. The property for the Welton Spring and Kemptown substations has been acquired. The preliminary engineering design work, as well as the preliminary procurement activities, is in progress. Construction will be scheduled to begin following receipt of state commission approvals to construct. The required in-service date for the PATH line is June 1, 2015.[38]

Susquehanna – Roseland (S-R)

The Susquehanna - Roseland project is a new 500 kV transmission line from Susquehanna, located in central eastern Pennsylvania, to Roseland, located in north central New Jersey, which is required to resolve reliability criteria violations starting on June 1, 2012. The project will require an upgrade of seven 230 kV and one 500 kV substations, as well as three new 500 kV substations, two with a 500/230 kV transformers.

Currently, construction and right-of-way permit applications have been submitted with the National Park Service (NPS). A decision on the applications is not expected from the NPS until October of 2012. Additionally, the issuance of a New Jersey Department of Environmental Protection (NJDEP) Wetland and Flood Hazard Area Permit has also been delayed. While PJM has required an in-service date of June 1, 2012, construction of the project has been delayed as a result. The expected in-service date for the Roseland to Hopatcong portion is June 2014, with the remainder of the project to be completed by June 2015.[39]

Trans Allegheny Line (TrAIL)

The Trans Allegheny Line (TrAIL) project is necessary to meet growing demand in the Mid-Atlantic region and is required to resolve reliability criteria violations starting June 1, 2011. The project will include a new 500 kV transmission line extending from 502 Junction to Loudoun substation, and will include: a 76.8 mile segment from the 502 Junction bus to the Mt. Storm bus; a 60.1 mile segment from the Mt. Storm bus to the Meadowbrook bus; and an 80.8 mile segment from the Meadowbrook bus to the Loudoun bus.

The in-service dates for the three segments of the TrAIL project are: Meadowbrook to Loudoun on April 8, 2011; Meadowbrook to Mt. Storm on May 13, 2011 and Mt. Storm to 502 Junction on May 20, 2011. With the exception of a small portion of the new Mt. Storm to 502 Junction, all right-of-way

38 See pjm.com. <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/path.aspx>.

39 See pjm.com. <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/susquehanna-roseland.aspx>.

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has been secured. The engineering and design of project is complete, with the exception of the on-going detailed protection and controls engineering designs. All equipment has been procured for transmission line work, and the substation materials are on order. Construction is in progress on all segments of the new transmission line.[40]

Economic Planning Process

Transmission system investments can be evaluated on a reliability basis or on an economic basis. The reliability evaluation examines whether a transmission upgrade is required in order to maintain reliability on the system in a particular area or areas, using specific planning and reliability criteria.[41] The economic evaluation examines whether a transmission upgrade, including reliability upgrades, results in positive economic benefits. The economic evaluation is more complex than a reliability evaluation because there is more judgment involved in the choice of relevant metrics for both benefits and costs. PJM's responsibility as an RTO requires PJM to constantly evaluate the need for transmission investments related to reliability and to help ensure the construction of needed facilities. As the operator and designer of markets, PJM also needs to consider the appropriate role for the economic evaluation of transmission system investments.

As a general matter, transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require competition between transmission and generation to meet loads in an area. While the RPM construct does provide that qualifying transmission upgrades may be submitted as offers, there have been no such offers. More generally, network transmission is not built based directly on market signals because the owners of network transmission are compensated through a non-market mechanism. Although the PJM Tariff does not yet comprehensively address the issue of competition between transmission and generation projects to solve congestion problems, PJM has taken a first step towards integrating transmission investments into the market through the use of economic evaluation metrics. Economic evaluation metrics can be used to determine whether there are positive economic benefits associated with an investment in transmission that might warrant the investment even when it is not required for reliability.

In 2009, FERC approved an approach to the economic evaluation of transmission projects using defined cost-benefit test metrics including changes in production costs, the costs of complying with environmental regulations, generation availability and demand-response availability.[42,43]

PJM performs a market efficiency analysis to compare the costs and benefits of (i) accelerating reliability-based enhancements or expansions already included in the regional transmission plan that, if accelerated, also could relieve one or more economic constraints; (ii) modifying reliability-based enhancements or expansions already included in the regional transmission plan that, as modified, would relieve one or more economic constraints; (iii) new enhancements or expansions that could relieve one or more economic constraints, but for which no reliability-based need has

40 See pjm.com. <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/trail.aspx>.
41 See PJM OA Schedule 6.
42 PJM initial filing, and first, second and third compliance filings submitted in Docket No. ER06-1474, respectively, on September 8, 2006, March 21, 2007, October 9, 2007 and June 16, 2008.
43 126 FERC ¶ 61,152.

been identified.[44] These economic constraints include, but are not limited to, constraints that cause significant historical gross congestion, significant historical unhedgeable congestion, pro-ration of Stage 1B ARR requests or significant congestion as forecasted in the market efficiency analysis. The market efficiency analysis uses the Benefit/Cost Ratio, defined as the present value of the total annual project benefit for each of the first 15 years divided by the present value of the project cost for the first 15 years of the project. To be included in the RTEP, the benefit/cost ratio must be greater than or equal to 1.25.

In the event that the annual review shows changes in the costs and benefits of particular projects, PJM reviews the changes with the TEAC and recommends to the PJM Board whether the project continues to provide measurable benefits and should remain in the RTEP. This yearly evaluation includes changes in cost estimates of the economic-based enhancement or expansion and changes in system conditions such as load forecasts, anticipated merchant transmission facilities, generation and demand response.

This annual review process has the potential to create substantial uncertainty for those building transmission facilities and for all market participants affected by the changes to the transmission system that would result from the completion of these facilities. Significant transmission projects, like the backbone facilities, have substantial impacts on energy and capacity markets and thus on the economics of both generation and load. The locational supply and demand of energy are affected and thus locational energy prices are affected. Changes in expected energy prices determine expected revenues from the energy market and expected payments to the energy market. The locational supply and demand of capacity are affected and thus locational capacity prices are affected. Changes in expected capacity prices determine expected revenues from the capacity market and expected payments to the capacity market. The uncertainty about transmission projects affects decisions about whether to invest in new generation and whether to continue to invest in existing generation. The uncertainty about transmission projects affects decisions about where to locate new load and decisions about whether to invest in demand side resources.

The MMU recommends that PJM propose modifications to the transmission planning process that would limit significant changes in the status of major transmission projects after they have been approved, and thus limit the uncertainty imposed on markets by the use of evaluation criteria that are very sensitive to changes in forecasts of economic variables.

44 The process is defined in Section 1. 5.7 of the PJM Tariff. See PJM. "PJM Open Access Transmission Tariff" (September 17, 2010) (Accessed February 1, 2011) <http://www.pjm.com/documents/~/media/documents/agreements/tariff.ashx> (32,881 KB). Each year, the assumptions to be used in performing the market efficiency analysis are presented to the PJM Transmission Expansion Advisory Committee (TEAC) for review and comment and the PJM Board approves the assumptions in June of each year.

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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 *2010 State of the Market Report for PJM* focuses on the annual ARR allocations, the Annual FTR Auctions and the Monthly Balance of Planning Period FTR Auctions during two FTR/ARR planning periods: the 2009 to 2010 planning period which covers June 1, 2009, through May 31, 2010, and the 2010 to 2011 planning period which covers June 1, 2010, through May 31, 2011. The *2010 State of the Market Report for PJM* also analyzes the results of the 2011 to 2014 Long Term FTR Auction that covers three consecutive planning periods: June 1, 2011 through May 31, 2012, June 1, 2012 through May 31, 2013 and June 1, 2013 through May 31, 2014.

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**

1 87 FERC ¶ 61,054 (1999).

- 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 2010 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 and New Analysis

- FTRs were paid at 96.9 percent of the target allocation level for the 2009 to 2010 planning period and were paid at 85.2 percent of the target allocation level for the 2010 to 2011 planning period through December 31, 2010.

- The net revenue from the 2011 to 2014 Long Term FTR Auction increased 60 percent ($18.7 million) from the 2010 to 2013 Long Term FTR Auction. In contrast, the net revenue from the 2010 to 2011 Annual FTR Auction decreased 21 percent ($280 million) from the 2009 to 2010 Annual FTR Auction.

- The percent of ARRs self-scheduled as FTRs in the Annual FTR Auction decreased by 8 percent from the 2009 to 2010 planning period, to the 2010 to 2011 planning period.

- The total secondary bilateral FTR obligation market volume increased from 8,810 MW in the 2009 to 2010 planning period to 24,034 MW in the first seven months of the 2010 to 2011 planning period.

- The buy bid prices for 24 hour counter flow FTRs were negative and greater in magnitude than the buy bid prices for prevailing flow FTRs in the 2011 to 2014 Long Term Auction with the result that the total weighted-average cleared price for all 24 hour buy bid FTRs was negative (-$0.16). The weighted-average cleared price for all 24 hour buy bid FTRs in the 2010 to 2013 Long Term Auction was $0.53.

- No ARRs were prorated in Stage 1A and Stage 1B for the 2010 to 2011 planning period.

- FTRs were profitable overall and were profitable for both physical entities and financial entities in 2010. Total FTR profits in 2010 were $909.6 million for physical entities and $138.7 million for financial entities. Self scheduled FTRs account for a large portion of the FTR profits of physical entities.

- On July 23, 2010, PJM reported that it had settled litigation brought against the Tower Companies arising from the default of their affiliate Power Edge, LLC in 2007, in Federal Court

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and at the FERC.[2] The FERC's investigation of whether manipulation of the FTR markets occurred continues.[3]

Recommendations

- The MMU continues to recommend the complete elimination of unsecured credit, over an appropriate transition period, based on the MMU's view of PJM's role in evaluating the credit worthiness of complex corporate entities and due to a concern about inappropriate shifts of risks and costs among PJM members.

- The MMU recommends that when load switches among LSEs during the planning period, a proportional share of the underlying self scheduled FTRs follow the load in the same manner that ARRs do.

- The MMU recommends that PJM provide more comprehensive explanations to members regarding the reasons for FTR underfunding.

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. The principal binding constraints limiting the supply of FTRs in the 2011 to 2014 Long Term FTR Auction include the Millville – Old Chapel Line and the Lovettsville – Millville Line. The principal binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2010 to 2011 planning period include the Doubs Transformer and the Messick Road - Ridgeley

2 See FERC Docket No. EL08-44-000 and the Federal Court proceedings in United States District Counts in Delaware and Pennsylvania, DE No. 08-216-JJF and Eastern Dist PA, C.A. No. 08-CV-3649-NS.

3 See 127 FERC ¶ 61,007 at PP 2&5 (2009).

line. Market participants can also sell FTRs. In the 2011 to 2014 Long Term FTR Auction, total FTR sell offers were 177,540 MW, up from 51,582 MW during the 2010 to 2013 Long Term FTR Auction. In the Annual FTR Auction for the 2010 to 2011 planning period, total FTR sell offers were 178,428. In the Monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2010) of the 2010 to 2011 planning period, there were 2,766,728 MW of FTR sell offers.

- **Demand.** There is no limit on FTR demand in any FTR auction. In the 2011 to 2014 Long Term FTR Auction, total FTR buy bids were 1,996,084 MW. In the Annual FTR Auction for the 2010 to 2011 planning period, total FTR buy bids were 1,708,556 MW, up from 1,436,335 MW during the 2009 to 2010 planning period. Total FTR self scheduled bids were 55,732 MW for the 2010 to 2011 planning period, a decrease from 68,589 MW for the 2009 to 2010 planning period. In the Monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2010) of the 2010 to 2011 planning period, total FTR buy bids were 8,973,645 MW.

- **FTR Credit Issues.** There were no participant defaults in 2010. The MMU continues to recommend the complete elimination of unsecured credit from PJM markets, over an appropriate transition period, based on the MMU's view of PJM's role in evaluating the credit worthiness of complex corporate entities and due to a concern about inappropriate shifts of risks and costs among PJM members.

- **Tower Companies Litigation and Investigation.** On July 23, 2010, PJM reported that it had settled litigation brought against the Tower Companies arising from the default of their affiliate Power Edge, LLC in 2007, in Federal Court and at the FERC.[4] This matter concerned in part allegations that the Tower Companies "manipulated PJM's Day-ahead energy and Financial Transmission Rights (FTR) markets."[5] The FERC also commenced its own independent investigation.[6] The Market Monitor had been scheduled to testify in the Court proceeding as a fact witness and as a non-retained or employed expert witness on the basis of the MMU's extensive non-public analysis. Under the terms of the settlement, the Tower Companies paid $18 million in return for PJM withdrawing its civil complaint and the remainder of its complaint at the FERC related to this matter. In September 2010, the PJM Members Committee adopted and then implemented the following resolution: "The PJM Members Committee resolves to request the chair of the Members Committee to send a letter to FERC Office of Enforcement to request expeditious conclusion of the investigation of Tower affiliates in the matter of alleged improper use of virtual trades and make public the results of that investigation consistent with FERC practices and procedures."[7]

- **Patterns of Ownership.** The ownership concentration of cleared FTR buy bids resulting from the 2010 to 2011 Annual FTR Auction was low to moderate for FTR obligations and moderate to high for FTR options. 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 Market Monitoring Unit (MMU) categorized all participants owning FTRs

4 See FERC Docket No. EL08-44-000 and the Federal Court proceedings in United States District Counts in Delaware and Pennsylvania, DE No. 08-216-JJF and Eastern Dist PA, C.A. No. 08-CV-3649-NS.

5 See 127 FERC ¶ 61,007 at P 1 (2009).

6 *Id.*

7 See letter from Edward D. Tatum, Chair, PJM Members Committee, to Norman Bay, Director, Office of Enforcement (FERC) dated September 27, 2010, which can be accessed at <http://www.pjm.com/~/media/committees-groups/committees/mc/20100923/20100923-item-05-mc-chair-letter-to-ferc-oe.ashx>.

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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. During the 2010 to 2011 planning period, physical entities own 54 percent of prevailing flow Annual cleared buy bid FTRs while financial entities own 72 percent of counter flow Annual cleared buy bid FTRs. Overall, financial entities own 53 percent of all FTRs bought in the Annual Auction. Financial entities own 84 percent of FTRs bought and sold in the Long Term FTR Auction. Financial entities own 77 percent of prevailing flow and 88 percent of counter flow FTRs bought in the Monthly Balance of Planning Period Auctions. Overall, financial entities own 82 percent of all Monthly Balance of Planning Period cleared buy bid FTRs. Physical entities owned 49 percent of all FTRs in 2010. Financial entities owned 68 percent of all counter flow FTRs and 46 percent of all prevailing flow FTRs in 2010.

Market Performance

- **Volume.** The 2011 to 2014 Long Term FTR Auction cleared 238,681 MW (12.0 percent of demand) of FTR buy bids, up from 86,108 MW (8.1 percent) in the 2010 to 2013 Long Term FTR Auction. The 2011 to 2014 Long Term FTR Auction also cleared 12,501 MW (7.0 percent) of FTR sell offers, up from 5,147 MW (10.0 percent) in the 2010 to 2013 Long Term FTR Auction. For the 2010 to 2011 planning period, the Annual FTR Auction cleared 231,663 MW (13.6 percent) of FTR buy bids, up from 155,612 MW (10.8 percent) for the 2009 to 2010 planning period. The Annual FTR Auction also cleared 10,315 MW (5.8 percent) of FTR sell offers for the 2010 to 2011 planning period, up from 7,399 MW (5.2 percent) for the 2009 to 2010 planning period. For the first seven months of the 2010 to 2011 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 1,092,956 MW (12.2 percent) of FTR buy bids and 292,530 MW (10.6 percent) of FTR sell offers.

- **Price.** In the 2011 to 2014 Long Term FTR Auction, 93.3 percent of the Long Term FTRs were purchased for less than $1 per MWh and 96.7 percent for less than $2 per MWh. The weighted-average prices paid for Long Term buy-bid FTRs in the 2011 to 2014 Long Term FTR Auction were -$0.16 per MWh for 24-hour FTRs, $0.10 per MWh for on peak FTRs and $0.06 per MWh for off peak FTRs. The buy bid prices for 24 hour counter flow FTRs were negative and greater in magnitude than buy bid prices for prevailing flow FTRs in the 2011 to 2014 Long Term Auction which made the total weighted-average cleared price for 24 hour buy bid FTRs negative. Weighted-average prices paid for Long Term buy-bid FTRs in the 2010 to 2013 Long Term FTR Auction were $0.53 per MWh for 24-hour FTRs, $0.03 per MWh for on peak FTRs and $0.10 per MWh for off peak FTRs. For the 2010 to 2011 planning period, 87.4 percent of the Annual FTRs were purchased for less than $1 per MWh and 93.5 percent for less than $2 per MWh. For the 2010 to 2011 planning period, the weighted-average prices paid for annual buy-bid FTR obligations were $0.43 per MWh for 24-hour FTRs, $0.35 per MWh for on peak FTRs and $0.32 per MWh for off peak FTRs. Weighted-average prices paid for annual buy-bid FTR obligations for the 2009 to 2010 planning period were $0.66 per MWh for 24-hour FTRs and $0.57 per MWh for on peak FTRs and $0.40 per MWh for off peak FTRs. The weighted-average prices paid for 2010 to 2011 planning period annual buy-bid FTR obligations and options were $0.35 per MWh and $0.26 per MWh, respectively, compared to $0.53 per MWh and $0.35 per MWh, respectively, in the 2009 to 2010 planning period.[8] The weighted-average price paid for buy-bid FTRs in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2010 to 2011 planning period was $0.17 per MWh, compared with $0.18 per MWh in the Monthly Balance of Planning Period FTR Auctions for the full 12-month 2009 to 2010 planning period.

- **Revenue.** The 2011 to 2014 Long Term FTR Auction generated $49.8 million of net revenue for all FTRs, up from $31.1 million in the 2010 to 2013 Long Term FTR Auction. The Annual FTR Auction generated $1,049.8 million of net revenue for all FTRs during the 2010 to 2011 planning period, down from $1,329.8 million for the 2009 to 2010 planning period. The Monthly Balance of Planning Period FTR Auctions generated $16.7 million in net revenue for all FTRs during the first seven months of the 2010 to 2011 planning period.

- **Revenue Adequacy.** FTRs were 96.9 percent revenue adequate for the 2009 to 2010 planning period. FTRs were paid at 85.2 percent of the target allocation level for the first seven months of the 2010 to 2011 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $981.4 million of FTR revenues during the first seven months of the 2010 to 2011 planning period and $878.4 million during the 2009 to 2010 planning period. For the first seven 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 was the Western Hub.

- **Profitability.** FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. The cost of self scheduled FTRs is zero in the FTR profitability calculation. FTRs were profitable overall and were profitable for both physical entities and financial entities in 2010. FTR profits tended to increase in the summer and winter months when congestion was higher and decrease in the shoulder months when congestion was lower.

Auction Revenue Rights

Market Structure

- **Supply.** ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs and the numerous combinations of feasible ARRs. The principal binding constraints that limited supply in the annual ARR allocation for the 2010 to 2011 planning period were the AP South Interface and the Electric Junction — Nelson line. Long Term ARRs are in effect for 10 consecutive planning periods and are available in Stage 1A of the annual ARR allocation. Residual ARRs are available to holders with prorated Stage 1A or 1B ARRs if additional transmission capability is added during the planning period.

8 Weighted-average prices for FTRs in the Long Term FTR Auction, Annual FTR Auction and Monthly Balance of Planning Period FTR Auctions are the average prices weighted by the MW and hours in a time period (planning period or month) for each FTR class type: 24-hour, on peak and off peak. For example, FTRs in the 2010 to 2011 Annual FTR Auction would be weighted by their MW and the hours in that time period for each FTR class type: 24-hour (8,760 hours), on peak (4,112 hours) and off peak (4,648 hours).

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- **Demand.** Total demand in the annual ARR allocation was 135,614 MW for the 2010 to 2011 planning period with 61,793 MW bid in Stage 1A, 27,850 MW bid in Stage 1B and 45,971 MW bid in Stage 2. This is down from 140,037 MW for the 2009 to 2010 planning period with 64,987 MW bid in Stage 1A, 26,517 MW bid in Stage 1B and 48,533 MW bid in Stage 2. ARR demand is limited by the total amount of network service and firm point-to-point transmission service.

- **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. There were 17,831 MW of ARRs associated with approximately $269,600 per MW-day of revenue that were reassigned in the first seven months of the 2010 to 2011 planning period. There were 19,061 MW of ARRs associated with approximately $362,400 per MW-day of revenue that were reassigned for the full 2009 to 2010 planning period.

Market Performance

- **Volume.** Of 135,614 MW in ARR requests for the 2010 to 2011 planning period, 101,843 MW (75.1 percent) were allocated. There were 61,793 MW allocated in Stage 1A, 27,850 MW allocated in Stage 1B and 12,200 MW allocated in Stage 2. Eligible market participants self scheduled 55,732 MW (54.6 percent) of these allocated ARRs as Annual FTRs. Of 140,037 MW in ARR requests for the 2009 to 2010 planning period, 109,413 MW (78.1 percent) were allocated. There were 64,913 MW allocated in Stage 1A, 26,514 MW allocated in Stage 1B and 17,986 MW allocated in Stage 2. Eligible market participants self scheduled 68,589 MW (62.6 percent) of these allocated ARRs as Annual FTRs.

- **Revenue.** As ARRs are allocated to qualifying customers rather than sold, there is no ARR revenue comparable to the revenue that results from the FTR auctions.

- **Revenue Adequacy.** During the 2010 to 2011 planning period, ARR holders will receive $1,028.8 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 $1,028.8 million while PJM collected $1,066.9 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions through December 2010, 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 $1,273.5 million while PJM collected $1,349.3 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.

- **ARR Proration.** No ARRs were prorated in Stage 1A and Stage 1B for the 2010 to 2011 planning period since there were no constraints limiting the allocation in these two stages. Some of the requested ARRs were prorated in Stage 2 as a result of binding transmission constraints. For the 2009 to 2010 planning period, no ARRs were prorated in Stage 1A and Stage 1B of the annual ARR allocation.

- **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 seven months of the 2010 to 2011 planning period, total ARR and FTR revenues hedged 78.7 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 4.2 percent of the total real time energy charges in calendar year 2010.

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.

The MMU recommends that when load switches among LSEs during the planning period, a proportional share of the underlying self scheduled FTRs follow the load in the same manner that ARRs do. ARRs are assigned to firm transmission service customers because these customers pay the costs of the transmission system that enables firm energy delivery. Positively valued ARRs follow load when load switches between suppliers. The self scheduled FTRs are obtained as the direct result of the ARR assignment and should therefore follow the reassignment of ARRs when load switches in order to ensure that the new LSE is in the same competitive position as the LSE that lost load.

ARRs were 100 percent revenue adequate for both the 2009 to 2010 and the 2010 to 2011 planning periods. 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 85.2 percent of the target allocation level for the first seven months of the 2010 to 2011 planning period. Revenue adequacy for a planning period is not final until the end of the period. The MMU recommends that PJM provide more comprehensive explanations to members regarding the reasons for FTR underfunding.

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 96.2 percent of the congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2009 to 2010 planning period and 78.7 percent of the congestion costs in PJM for the first seven months of the

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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

While FTRs have been available to eligible participants since the 1998 introduction of LMP, the Annual FTR Auction was first implemented for the 2003 to 2004 planning period. Since the 2006 to 2007 planning period, the auction has covered all control zones.

FTRs are financial instruments that entitle their holders to receive revenue or require them to pay charges based on locational congestion price differences in the Day-Ahead Energy Market across specific FTR transmission paths. Effective June 1, 2007, PJM added marginal losses as a component in the calculation of LMP.[9] The value of an FTR reflects the difference in congestion prices rather than the difference in LMPs, which includes both congestion and marginal losses. Auction market participants are free to request FTRs between any pricing nodes on the system, including hubs, control zones, aggregates, generator buses, load buses and interface pricing points. FTRs are available to the nearest 0.1 MW. The FTR target allocation is calculated hourly and is equal to the product of the FTR MW and the congestion price difference between sink and source that occurs in the Day-Ahead Energy Market. The value of an FTR can be positive or negative depending on the sink minus source congestion price difference, with a negative difference resulting in a liability for the holder. The FTR target allocation represents what the holders would receive if sufficient revenues are collected to fund FTRs.

Depending on the amount of FTR revenues collected, FTR holders with a positively valued FTR may receive congestion credits between zero and their target allocations. FTR holders with a negatively valued FTR are required to pay charges equal to their target allocations. When FTR holders receive their target allocations, the associated FTRs are fully funded. The objective function of all FTR auctions is to maximize the bid-based value of FTRs awarded in each auction.

FTRs can be bought, sold and self scheduled. Buy bids are FTRs that are bought in the auctions; sell offers are existing FTRs that are sold in the auctions; and self scheduled bids are FTRs that have been directly converted from ARRs in the Annual FTR Auction.

There are two FTR hedge type products: obligations and options. An obligation provides a credit, positive or negative, equal to the product of the FTR MW and the congestion price difference between FTR sink (destination) and source (origin) that occurs in the Day-Ahead Energy Market. An option provides only positive credits and options are available for only a subset of the possible FTR transmission paths.

There are three FTR class type products: 24-hour, on peak and off peak. The 24-hour products are effective 24 hours a day, seven days a week, while the on peak products are effective during on peak periods defined as the hours ending 0800 through 2300, Eastern Prevailing Time (EPT) Mondays through Fridays, excluding North American Electric Reliability Council (NERC) holidays.

9 For additional information on marginal losses, see the *2010 State of the Market Report for PJM*, Volume II, Section 2, “Energy Market, Part 1,” at “Marginal Losses.”

The off peak products are effective during hours ending 2400 through 0700, EPT, Mondays through Fridays, and during all hours on Saturdays, Sundays and NERC holidays.

FTR buy bids and sell offers may be made as obligations or options and as any of the three class types. FTR self scheduled bids are available only as obligations and 24-hour class types, consistent with the associated ARRs.

Market Structure

Prior to implementation of the Annual FTR Auction, only network service and long-term, firm, point-to-point transmission service customers were able to directly obtain Annual FTRs. Now all transmission service customers and PJM members can participate in the Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions.

Supply

Throughout the year, PJM oversees the process of selling and buying FTRs through FTR Auctions. Market participants purchase FTRs by participating in Long Term, Annual and Monthly Balance of Planning Period FTR Auctions.[10] The Annual FTR Auction includes the ability to directly convert allocated ARRs into self scheduled FTRs. Total FTR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested FTRs and the numerous combinations of FTRs that are feasible. For the Annual FTR Auction, known transmission outages that are expected to last for two months or more are included, while known outages of five days or more are included for the Monthly Balance of Planning Period FTR Auctions as well as any outages of a shorter duration that PJM determines would cause FTR revenue inadequacy if not modeled.[11] But, the auction process does not account for the fact that significant transmission outages, which have not been provided to PJM by transmission owners prior to the auction date, will occur during the periods covered by the auctions. Such transmission outages may not be planned in advance or may be emergency in nature. FTRs can be traded between market participants through bilateral transactions.

During the 2010 to 2011 planning period, binding transmission constraints prevented the award of all requested FTRs in the Long Term FTR Auction, the Annual FTR Auction and Monthly Balance of Planning Period FTR Auctions.[12] Table 8-2 and Table 8-3 list the top 10 binding constraints along with their corresponding control zones in the Long Term FTR Auction and the Annual FTR Auction, respectively. They are listed in order of severity, irrespective of auction round. For each of the top 10 binding constraints, a numerical ranking in order of severity for each auction round is also listed. The order of severity is determined by the marginal value of the binding constraint. The marginal value measures the value gained by relieving a constraint by 1 MW. The marginal value is computed and generated in the optimization engine for both on peak and off peak hours.[13] Table 8-2 and Table 8-3 demonstrate the marginal value for on peak hours only.

10 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 38.
11 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 54.
12 Binding constraints for Monthly Balance of Planning Period Auctions are posted to the PJM website in monthly files at <http://www.pjm.com/markets-and-operations/ftr/auction-user-info/historical-ftr-auction.aspx>.
13 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 57.

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Table 8-2 Top 10 principal binding transmission constraints limiting the Long Term FTR Auction: Planning periods 2011 to 2014

			Severity Ranking by Auction Round		
Constraint	Type	Control Zone	1	2	3
Millville - Old Chapel	Line	AP	24	NA	1
Lovettsville - Millville	Line	AP	NA	NA	2
Doubs	Transformer	AP	1	1	NA
Rising	Flowgate	Midwest ISO	2	3	10
Bartonsville - Meadow Brook	Line	AP	3	6	13
Meadow Brook	Transformer	AP	4	7	4
Tiltonsville - West Bellaire	Line	AEP	19	2	3
Hamilton - Weirton	Line	AP	5	4	11
Roxbury - Shade Gap	Line	PENELEC	12	9	5
Millville - Sleepy Hollow	Line	AP	7	14	NA

Table 8-3 Top 10 principal binding transmission constraints limiting the Annual FTR Auction: Planning period 2010 to 2011

			Severity Ranking by Auction Round			
Constraint	Type	Control Zone	1	2	3	4
Doubs	Transformer	AP	2	1	2	1
Messick Road - Ridgeley	Line	AP	1	2	1	5
Mahans Lane - Tidd	Line	AEP	3	5	8	10
Middlebourne - Willow Island	Line	AP	4	4	4	3
AP South	Interface	AP	5	3	3	2
Endless Caverns	Transformer	Dominion	8	6	6	4
Tiltonsville - Windsor	Line	AP	43	29	7	6
Smith - Wylie Ridge	Line	AP	13	7	5	7
Roxbury - Shade Gap	Line	PENELEC	6	8	12	16
Krendale - Seneca	Line	AP	7	9	10	9

Long Term FTR Auction

PJM conducts a Long Term FTR Auction for the three consecutive planning periods immediately following the planning period during which the Long Term FTR Auction is conducted. The capacity offered for sale in Long Term FTR Auctions is the residual system capability after the assumption that all ARRs allocated in the immediately prior annual ARR allocation process are self scheduled as FTRs. These ARRs are modeled as fixed injections and withdrawals in the Long Term FTR Auction. Future transmission upgrades are not included in the model. The 2009 to 2012 and 2010 to 2013 Long Term FTR Auctions consisted of two rounds. FERC approved, on December 7, 2009, the addition of an additional round to the Long Term FTR Auction and the change in the percentage of feasible FTR available capability awarded in each round from 50 percent to one third.[14] The 2011 to 2014 Long Term FTR Auction consisted of three rounds. In each round one third of the feasible FTR available capability was awarded. FTRs purchased in prior rounds may be offered for sale in subsequent rounds.

- **Round 1.** The first round is conducted approximately 11 months prior to the start of the term covered by the Long Term FTR Auction. Market participants make offers for FTRs between any source and sink. These offers can be 24-hour, on peak or off peak FTR obligations. FTR option products are not available in Long Term FTR Auctions.

- **Round 2.** The second round is conducted approximately three months after the first round.

- **Round 3.** The third round is conducted approximately three months after the second round.

FTRs obtained in the Long Term Auctions may have terms of one year or a term of three years.

Annual FTR Auction

Each April, PJM conducts an Annual FTR Auction during which all eligible market participants may bid on FTRs for the next planning period consistent with total transmission system capability, excluding the FTRs approved in prior Long Term FTR Auctions. The auction takes place over four rounds with 25 percent of the feasible transmission system capability awarded in each round:

- **Round 1.** Market participants make offers for FTRs between any source and sink. These offers can be 24-hour, on peak or off peak FTR obligations or FTR options. Locational prices are determined by maximizing the net revenue based on offer-based value of FTRs.[15] Any transmission service customer or PJM member can bid for available FTRs. ARR holders wishing to directly convert their previously allocated ARRs into self scheduled FTRs must initiate that process in this round. One quarter of each self scheduled FTR clears as a 24-hour FTR in each of the four rounds. Self scheduled FTRs must have the same source and sink as the corresponding ARR. Self scheduled FTRs clear as price-taking FTR bids that are not eligible to set auction price.

- **Rounds 2 to 4.** Market participants make offers for FTRs. Locational prices are determined by maximizing the offer-based value of FTRs cleared. FTRs purchased in earlier rounds can be offered for sale in later rounds.

By self scheduling ARRs as price-taking bids in the Annual FTR Auction, customers with ARRs receive FTRs for their ARR paths. ARR holders are guaranteed that they will receive their requested FTRs. ARRs can be self scheduled only as 24-hour FTR obligations. ARR holders that self schedule ARRs as FTRs still hold the associated ARR. Self scheduling transactions net out such that the ARR holder buys the FTR in the auction, receives the corresponding revenue based on holding the ARR and is left with ownership of the FTR as a hedge. The following is an illustrative example of

14 FERC order accepting PJM Interconnection, L.L.C.'s revisions to Long-Term Financial Transmission Rights Auctions to its Amended and Restated Operating Agreement and Open Access Transmission Tariff, Docket No. ER10-82-000 (December 7, 2009).

15 Long Term, Annual and Monthly Balance of Planning Period FTR Auctions determine nodal prices as a function of market participants' FTR bids and binding transmission constraints. An optimization algorithm selects the set of feasible FTR bids that produces maximum net revenue, thus maximizing the value of transmission assets. A feasible set of FTR bids is a set that does not impose a flow on any transmission facility in excess of its rating.

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self scheduling ARRs as FTRs. An ARR holder has received an allocation of 1 MW from source A to sink B. The ARR holder self schedules the 1 MW allocated ARR as an FTR. In the Annual FTR Auction, the price for a 1 MW FTR from A to B is $100. The ARR holder pays $100 to buy the 1 MW FTR in the Annual FTR Auction, but receives a $100 ARR target credit based on the associated 1 MW ARR. In addition, the ARR holder obtains the corresponding FTR target allocation as a hedge.

Monthly Balance of Planning Period FTR Auctions

The Monthly Balance of Planning Period FTR Auctions make available the residual FTR capability on the PJM transmission system after the Long Term and Annual FTR Auctions are concluded. They are single-round monthly auctions that allow any transmission service customers or PJM members to bid for any FTR or to offer for sale any FTR that they currently hold. Market participants can bid for or offer monthly FTRs for any of the next three months remaining in the planning period, or quarterly FTRs for any of the quarters remaining in the balance of the planning period. FTRs in the auctions can be either obligations or options and can be 24-hour, on peak or off peak products.[16]

Under the auction rules, market participants may bid to buy or offer to sell FTRs that have the following two terms. The first term is for one month for any of the next three months remaining in the planning period. For example, if the auction is conducted in May, any FTR valid for the months of June, July and August is included in the auction. The second term is for three months for any of the quarters remaining in the planning period (if technically feasible within the specified market time frame). For example, for planning period quarter 1 (Q1), the auction period would be June, July and August. For planning period quarter 2 (Q2), the auction period would be September, October and November. Similarly, December, January and February would be for planning period quarter 3 (Q3) and March, April and May would be for planning period quarter 4 (Q4). For example, an auction held in May would have all four quarters available, while an auction held in June would include quarter 2, quarter 3 and quarter 4, but not quarter 1.

Secondary Bilateral Market

Market participants can buy and sell existing FTRs through the PJM-administered, bilateral market, or market participants can trade FTRs among themselves without PJM involvement. Bilateral transactions that are not done through PJM can involve parties that are not PJM members. PJM has no knowledge of bilateral transactions that are done outside of PJM's secondary bilateral market system.

For bilateral trades done through PJM, the FTR transmission path must remain the same; FTR obligations must remain obligations and FTR options must remain options. However, an individual FTR may be split up into multiple, smaller FTRs, down to increments of 0.1 MW. FTRs can also be given different start and end times, but the start time cannot be earlier than the original FTR start time and the end time cannot be later than the original FTR end time.

16 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 39.

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Demand

Under current rules, participants may submit unlimited bids for FTRs for any single auction round in the Long Term FTR Auction, Annual FTR Auction or for any single Monthly Balance of Planning Period FTR Auction.

FTR Credit Issues

Default

No participants defaulted in 2010.

FTR Credit Rules

Following a series of high profile defaults, PJM made significant reforms to its credit policies in 2007–2009.[17] Among other things, PJM reduced available unsecured credit, and eliminated the FTR Unsecured Credit Allowance in PJM's FTR markets.[18] On May 4, 2010, PJM submitted a filing[19] that would have restored an FTR Unsecured Credit Allowance "as it relates to certain LSE transactions involving counterflow FTRs."[20] The Commission rejected the proposal because PJM did not explain how it protects PJM from "the unbounded energy price risk that is solely the result of the LSE holding the counterflow FTR, a risk that should be collateralized in the same way it would be if the counterflow FTR was held by any other entity."[21]

The current rules continue to allow Seller Credit, a form of unsecured credit, to cover obligations in the FTR and other markets and permit an Unsecured Credit Allowance up to $50 million to cover non FTR obligations.[22] The MMU continues to recommend the complete elimination of unsecured credit, over an appropriate transition period, based on the MMU's view of PJM's role in evaluating the credit worthiness of complex corporate entities and due to a concern about inappropriate shifts of risks and costs among PJM members. For the same reasons, the MMU recommends that PJM not reintroduce any additional allowance for unsecured credit in the FTR markets.

Patterns of Ownership

The overall ownership structure of FTRs and the ownership of prevailing flow and counter flow FTRs is descriptive and is not necessarily a measure of actual or potential FTR market structure issues, as the ownership positions result from competitive auctions. The percentage of FTR ownership shares may change when FTR owners buy or sell FTRs in the Monthly Balance of Planning Period FTR Auctions or secondary bilateral market.

17 *See* 127 FERC ¶ 61,017 (2009).

18 *Id.* at PP 36–37.

19 PJM compliance filing in ER09-650-002. In response to the assertions of certain LSEs that "PJM's elimination of unsecured credit for LSEs that use counterflow FTRs to hedge purchases to serve load far exceed the risks attendant to this practice because the LSEs have physical assets that reduce the risk of default," PJM answered that "a modification to its collateral provisions with respect to LSEs is warranted." 127 FERC ¶ 61,017 at P 37. The Commission took note and required PJM to file "an explanation of what reductions are appropriate for LSEs along with the proposed tariff revisions it believes are warranted." *Id.*

20 See 131 FERC ¶ 61,017 at P 31 (2010).

21 *Id.* at PP 33–34.

22 See OATT Attachment Q § V.A & II.B; see also 127 FERC ¶ 61,017 at P 34.

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The ownership concentration of cleared FTR buy bids resulting from the 2010 to 2011 Annual FTR Auction was low to moderate for FTR obligations and moderate to high for FTR options.

For cleared FTR buy-bid obligations in the 2010 to 2011 Annual FTR Auction, the HHIs were 1518 for 24-hour, 615 for on peak and 674 for off peak FTR products while maximum market shares were 25 percent for 24-hour, which is associated with a physical entity, 14 percent for on peak, which is associated with a financial entity, and 15 percent for off peak FTR products, which is associated with a financial entity, and 15 percent for off peak FTR products, which is associated with a financial entity.

For cleared FTR buy-bid options in the 2010 to 2011 Annual FTR Auction, HHIs were 2517 for 24-hour, 1602 for on peak and 2232 for off peak products while maximum market shares were 28 percent for 24-hour, which is associated with a physical entity, 28 percent for on peak, which is associated with a physical entity, and 42 percent for off peak FTR products, which is associated with a physical entity.

In order to evaluate the ownership of prevailing flow and counter flow FTRs, the MMU categorized all participants owning FTRs in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 8-4 presents the 2011 to 2014 Long Term FTR Auction market cleared FTRs by trade type, organization type and FTR direction. The results show that financial entities own 80 percent of prevailing flow cleared buy bid FTRs and 89 percent of counter flow cleared buy bid FTRs. Overall, financial entities own about 84 percent of all Long Term cleared buy bid FTRs.

Table 8-4 Long Term FTR Auction patterns of ownership by FTR direction: Planning periods 2011 to 2014[23]

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	20.3%	11.5%	16.2%
	Financial	79.7%	88.5%	83.8%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	14.9%	25.4%	16.5%
	Financial	85.1%	74.6%	83.5%
	Total	100.0%	100.0%	100.0%

23 Table 8-4, Table 8-5 and Table 8-6 are updated from previous State of the Market Reports to include trade type. Previous versions of these tables netted the buy and sell MW by FTR and organization. This created organizations with FTRs that had a net negative MW volume in the respective auction.

Table 8-5 presents the Annual FTR Auction market cleared FTRs in the 2010 to 2011 planning period by trade type, organization type and FTR direction. The results show that physical entities own 54 percent of prevailing flow cleared buy bid FTRs while financial entities own 72 percent of counter flow cleared buy bid FTRs. In the 2010 to 2011 Annual FTR Auction physical entities own 13 percent of all sold FTRs while financial entities own 87 percent of all sold FTRs.

Table 8-5 Annual FTR Auction patterns of ownership by FTR direction: Planning period 2010 to 2011

			FTR Direction		
Trade Type	Organization Type	Self-Scheduled FTRs	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	Yes	26.0%	2.8%	19.4%
		No	27.9%	25.5%	27.2%
		Total	53.9%	28.2%	46.6%
	Financial	No	46.1%	71.8%	53.4%
	Total		100.0%	100.0%	100.0%
Sell Offers	Physical		10.8%	21.4%	13.3%
	Financial		89.2%	78.6%	86.7%
	Total		100.0%	100.0%	100.0%

Table 8-6 presents the Monthly Balance of Planning Period FTR Auction market cleared FTRs in calendar year 2010 by trade type, organization type and FTR direction. The results show that physical entities own only 13 percent of counter flow cleared buy bid FTRs while financial entities own 87 percent. Overall, financial entities own 82 percent of all Monthly Balance of Planning Period cleared buy bid FTRs.

Table 8-6 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: Calendar year 2010

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	22.8%	12.6%	17.6%
	Financial	77.2%	87.4%	82.4%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	47.2%	26.6%	43.7%
	Financial	52.8%	73.4%	56.3%
	Total	100.0%	100.0%	100.0%

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Table 8-7 presents the daily FTR net position ownership in 2010 by FTR direction. The net position of all FTRs, including all auctions, is calculated for every organization each day. The data is summarized for the 2010 calendar year to show the ownership patterns by FTR direction. Physical entities owned 54 percent of all prevailing flow FTRs and 32 percent of counter flow FTRs in 2010.

Table 8-7 Daily FTR net position ownership by FTR direction: Calendar year 2010

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	54.2%	31.7%	48.5%
Financial	45.8%	68.3%	51.5%
Total	100.0%	100.0%	100.0%

Market Performance

Volume

Table 8-8 shows the 2011 to 2014 Long Term FTR Auction volume by trade type, FTR direction and period type.[24] The total volume was 1,996,084 MW for FTR buy bids and 177,540 MW for FTR sell offers in the 2011 to 2014 Long Term FTR Auction. This is up from the total volume of 1,064,620 MW for FTR buy bids and 51,582 MW for FTR sell offers in the 2010 to 2013 Long Term FTR Auction.

The 2011 to 2014 Long Term FTR Auction cleared 238,681 MW (12.0 percent) leaving 1,757,403 MW (88.0 percent) of uncleared FTR buy bids. There were 12,501 MW (7.0 percent) of cleared FTR sell offers leaving 165,039 MW (93.0 percent) of uncleared FTR sell offers. This is up from the total of 86,108 MW (8.1 percent) of cleared FTR buy bids and 5,147 MW (10.0 percent) of cleared FTR sell offers in the 2010 to 2013 Long Term FTR Auction.

In the 2011 to 2014 Long Term FTR Auction, there were 111,913 MW (31.9 percent) cleared out of 350,458 MW counter flow FTR buy bids and 126,769 MW (7.7 percent) cleared out of 1,645,626 MW prevailing flow FTR buy bids. In the 2011 to 2014 Long Term FTR Auction, there were 1,938 MW (3.2 percent) cleared out of 61,079 MW counter flow FTR sell offers and 10,564 MW (9.1 percent) cleared out of 116,461 MW prevailing flow FTR offers.

24 Calculated values shown in Section 8, "Financial Transmission and Auction Revenue Rights," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Table 8-8 Long Term FTR Auction market volume: Planning periods 2011 to 2014

Trade Type	FTR Direction	Period Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Counter Flow	Year 1	44,923	156,093	52,811	33.8%	103,283	66.2%
		Year 2	34,337	113,985	38,863	34.1%	75,122	65.9%
		Year 3	24,013	79,930	20,036	25.1%	59,893	74.9%
		Year All	13	451	203	45.0%	248	55.0%
		Total	103,286	350,458	111,913	31.9%	238,546	68.1%
	Prevailing Flow	Year 1	127,194	682,654	57,130	8.4%	625,525	91.6%
		Year 2	96,216	521,894	37,764	7.2%	484,130	92.8%
		Year 3	73,515	441,043	31,874	7.2%	409,169	92.8%
		Year All	11	35	1	2.9%	34	97.1%
		Total	296,936	1,645,626	126,769	7.7%	1,518,857	92.3%
	Total		400,222	1,996,084	238,681	12.0%	1,757,403	88.0%
Sell offers	Counter Flow	Year 1	8,733	31,541	1,172	3.7%	30,370	96.3%
		Year 2	6,024	19,553	672	3.4%	18,881	96.6%
		Year 3	2,606	9,985	95	0.9%	9,891	99.1%
		Year All	NA	NA	NA	NA	NA	NA
		Total	17,363	61,079	1,938	3.2%	59,142	96.8%
	Prevailing Flow	Year 1	15,074	58,542	5,886	10.1%	52,656	89.9%
		Year 2	11,484	44,735	4,195	9.4%	40,539	90.6%
		Year 3	3,949	13,184	482	3.7%	12,702	96.3%
		Year All	NA	NA	NA	NA	NA	NA
		Total	30,507	116,461	10,564	9.1%	105,897	90.9%
	Total		47,870	177,540	12,501	7.0%	165,039	93.0%

Table 8-9 shows the Annual FTR Auction volume by trade type, hedge type and FTR direction for the 2010 to 2011 planning period. The total volume was 1,708,556 MW for FTR buy bids and 178,428 MW for FTR sell offers for the 2010 to 2011 planning period. This is up from the total volume of 1,436,335 MW for FTR buy bids and up from 142,154 MW for FTR sell offers for the 2009 to 2010 planning period.

There were 231,663 MW (13.6 percent) of cleared FTR buy bids and 10,315 MW (5.8 percent) of cleared FTR sell offers for the 2010 to 2011 planning period. This is up from the total of 155,612 MW (10.8 percent) of cleared FTR buy bids and up from 7,399 MW (5.2 percent) of cleared FTR sell offers for the 2009 to 2010 planning period.

For the 2010 to 2011 planning period, there were 79,411 MW (25.5 percent) cleared out of 310,940 MW counter flow FTR buy bids and 152,251 MW (10.9 percent) cleared out of 1,397,616 MW prevailing flow FTR buy bids. During the 2010 to 2011 planning period, there were 2,360 MW

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(3.7 percent) cleared out of 64,026 MW counter flow FTR sell offers and 7,955 MW (7.0 percent) cleared out of 114,402 MW prevailing flow FTR offers.

Table 8-9 Annual FTR Auction market volume: Planning period 2010 to 2011

Trade Type	Hedge Type	FTR Direction	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Obligations	Counter Flow	76,794	300,085	73,956	24.6%	226,129	75.4%
		Prevailing Flow	195,599	1,233,329	127,366	10.3%	1,105,963	89.7%
		Total	272,393	1,533,414	201,322	13.1%	1,332,092	86.9%
	Options	Counter Flow	100	10,855	5,455	50.3%	5,400	49.7%
		Prevailing Flow	7,569	164,287	24,885	15.1%	139,402	84.9%
		Total	7,669	175,142	30,340	17.3%	144,802	82.7%
	Total	Counter Flow	76,894	310,940	79,411	25.5%	231,529	74.5%
		Prevailing Flow	203,168	1,397,616	152,251	10.9%	1,245,365	89.1%
		Total	280,062	1,708,556	231,663	13.6%	1,476,893	86.4%
Self-scheduled bids	Obligations	Counter Flow	160	2,253	2,253	100.0%	0	0.0%
		Prevailing Flow	8,644	53,479	53,479	100.0%	0	0.0%
		Total	8,804	55,732	55,732	100.0%	0	0.0%
Buy and self-scheduled bids	Obligations	Counter Flow	76,954	302,338	76,209	25.2%	226,129	74.8%
		Prevailing Flow	204,243	1,286,808	180,845	14.1%	1,105,963	85.9%
		Total	281,197	1,589,146	257,054	16.2%	1,332,092	83.8%
	Options	Counter Flow	100	10,855	5,455	50.3%	5,400	49.7%
		Prevailing Flow	7,569	164,287	24,885	15.1%	139,402	84.9%
		Total	7,669	175,142	30,340	17.3%	144,802	82.7%
	Total	Counter Flow	77,054	313,193	81,664	26.1%	231,529	73.9%
		Prevailing Flow	211,812	1,451,095	205,730	14.2%	1,245,365	85.8%
		Total	288,866	1,764,288	287,394	16.3%	1,476,893	83.7%
Sell offers	Obligations	Counter Flow	18,898	60,966	2,360	3.9%	58,606	96.1%
		Prevailing Flow	28,599	106,947	7,914	7.4%	99,033	92.6%
		Total	47,497	167,912	10,274	6.1%	157,638	93.9%
	Options	Counter Flow	136	3,060	0	0.0%	3,060	100.0%
		Prevailing Flow	1,747	7,455	41	0.5%	7,415	99.5%
		Total	1,883	10,515	41	0.4%	10,475	99.6%
	Total	Counter Flow	19,034	64,026	2,360	3.7%	61,666	96.3%
		Prevailing Flow	30,346	114,402	7,955	7.0%	106,447	93.0%
		Total	49,380	178,428	10,315	5.8%	168,113	94.2%

Table 8-10 shows that for the 2010 to 2011 planning period, eligible market participants converted 55,732 MW of ARRs out of a possible 102,046 MW into Annual FTRs. In comparison, during the

2009 to 2010 planning period, eligible market participants converted 68,589 MW of ARRs out of a possible 109,612 MW.

Table 8-10 Comparison of self scheduled FTRs: Planning periods 2008 to 2009, 2009 to 2010 and 2010 to 2011[25]

Planning Period	Self-Scheduled FTRs (MW)	Maximum Possible Self-Scheduled FTRs (MW)	Percent of ARRs Self-Scheduled as FTRs
2008/2009	72,851	112,011	65.0%
2009/2010	68,589	109,612	62.6%
2010/2011	55,732	102,046	54.6%

Table 8-11 shows that there were 7,952,347 MW of FTR buy bid obligations and 2,367,724 MW of FTR sell offer obligations for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the 2010 to 2011 planning period through December 31, 2010. The monthly auctions cleared 1,058,610 MW (13.3 percent) leaving 6,893,737 MW (86.7 percent) of uncleared FTR buy bid obligations. There were 196,280 MW (8.3 percent) of cleared FTR sell offer obligations leaving 2,171,444 MW (91.7 percent) of uncleared FTR sell offer obligations.

There were 1,021,298 MW of FTR buy bid options and 399,004 MW of FTR sell offer options for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the 2010 to 2011 planning period through December 31, 2010. The monthly auctions cleared 34,346 MW (3.4 percent) leaving 986,952 MW (96.6 percent) of uncleared FTR buy bid options. There were 96,250 MW (24.1 percent) of cleared FTR sell offer options leaving 302,754 MW (75.9 percent) of uncleared FTR sell offer options.

The Monthly Balance of Planning Period FTR Auctions for the full 12-month 2009 to 2010 planning period had a total demand of 8,219,996 MW for FTR buy bids and 2,795,964 MW for FTR sell offers. The monthly auctions cleared 963,301 MW (11.7 percent) of FTR buy bids and 254,145 MW (9.1 percent) of FTR sell offers.

25 The column Maximum Possible Self-Scheduled FTRs in Table 8-4 is updated from the *2009 State of the Market Report* to include RTEP IARR MW. RTEP IARRs and ARRs can be self-scheduled in round 1 of the Annual FTR Auction.

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Table 8-11 Monthly Balance of Planning Period FTR Auction market volume: Calendar year 2010

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-10	Obligations	Buy bids	156,274	716,812	79,724	11.1%	637,088	88.9%
		Sell offers	46,206	165,858	11,224	6.8%	154,635	93.2%
	Options	Buy bids	391	11,953	1,621	13.6%	10,332	86.4%
		Sell offers	1,579	33,020	5,686	17.2%	27,334	82.8%
Feb-10	Obligations	Buy bids	129,946	656,279	78,354	11.9%	577,925	88.1%
		Sell offers	40,605	146,757	10,364	7.1%	136,393	92.9%
	Options	Buy bids	622	13,993	1,119	8.0%	12,874	92.0%
		Sell offers	1,702	33,125	6,955	21.0%	26,170	79.0%
Mar-10	Obligations	Buy bids	120,727	607,270	90,189	14.9%	517,081	85.1%
		Sell offers	56,858	201,797	12,542	6.2%	189,255	93.8%
	Options	Buy bids	331	8,420	749	8.9%	7,672	91.1%
		Sell offers	1,224	23,960	5,326	22.2%	18,634	77.8%
Apr-10	Obligations	Buy bids	104,078	483,995	78,853	16.3%	405,142	83.7%
		Sell offers	30,097	127,238	9,844	7.7%	117,394	92.3%
	Options	Buy bids	185	5,643	481	8.5%	5,161	91.5%
		Sell offers	980	17,098	3,474	20.3%	13,6 25	79.7%
May-10	Obligations	Buy bids	83,069	372,583	63,260	17.0%	309,323	83.0%
		Sell offers	16,709	74,617	8,385	11.2%	66,233	88.8%
	Options	Buy bids	396	3,229	209	6.5%	3,020	93.5%
		Sell offers	623	9,657	3,049	31.6%	6,609	68.4%
Jun-10	Obligations	Buy bids	204,305	998,923	107,676	10.8%	891,247	89.2%
		Sell offers	94,433	417,735	24,228	5.8%	393,507	94.2%
	Options	Buy bids	1,725	66,735	2,932	4.4%	63,804	95.6%
		Sell offers	11,073	69,691	15,816	22.7%	53,874	77.3%
Jul-10	Obligations	Buy bids	225,737	1,108,721	146,069	13.2%	962,652	86.8%
		Sell offers	75,886	359,722	29,406	8.2%	330,316	91.8%
	Options	Buy bids	878	37,271	2,304	6.2%	34,967	93.8%
		Sell offers	8,089	66,097	16,084	24.3%	50,013	75.7%
Aug-10	Obligations	Buy bids	222,224	1,118,261	126,436	11.3%	991,825	88.7%
		Sell offers	65,197	300,616	23,909	8.0%	276,706	92.0%
	Options	Buy bids	2,532	83,876	4,233	5.0%	79,643	95.0%
		Sell offers	6,321	42,262	13,534	32.0%	28,728	68.0%
Sep-10	Obligations	Buy bids	232,043	1,282,913	185,736	14.5%	1,097,177	85.5%
		Sell offers	76,919	364,793	31,628	8.7%	333,165	91.3%
	Options	Buy bids	1,681	227,899	5,366	2.4%	222,533	97.6%
		Sell offers	8,339	66,072	15,052	22.8%	51,020	77.2%
Oct-10	Obligations	Buy bids	235,014	1,203,102	161,265	13.4%	1,041,838	86.6%
		Sell offers	70,209	338,218	33,245	9.8%	304,973	90.2%
	Options	Buy bids	1,602	224,392	4,815	2.1%	219,577	97.9%
		Sell offers	6,527	47,851	12,554	26.2%	35,297	73.8%
Nov-10	Obligations	Buy bids	206,106	1,077,866	143,928	13.4%	933,938	86.6%
		Sell offers	60,323	285,972	25,150	8.8%	260,822	91.2%
	Options	Buy bids	1,476	184,103	3,277	1.8%	180,826	98.2%
		Sell offers	5,111	53,552	10,613	19.8%	42,940	80.2%
Dec-10	Obligations	Buy bids	197,579	1,162,560	187,500	16.1%	975,061	83.9%
		Sell offers	59,942	300,668	28,713	9.5%	271,955	90.5%
	Options	Buy bids	1,493	197,022	11,418	5.8%	185,604	94.2%
		Sell offers	3,780	53,478	12,596	23.6%	40,882	76.4%
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	1,523,008	7,952,347	1,058,610	13.3%	6,893,737	86.7%
		Sell offers	502,909	2,367,724	196,280	8.3%	2,171,444	91.7%
	Options	Buy bids	11,387	1,021,298	34,346	3.4%	986,952	96.6%
		Sell offers	49,240	399,004	96,250	24.1%	302,754	75.9%

* Shows Twelve Months for 2009/2010; ** Shows seven months ended 31-Dec-2010 for 2010/2011

Table 8-12 shows the bid and cleared volume for FTR buy bids in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2010 through December 2010.

Table 8-12 Monthly Balance of Planning Period FTR Auction buy-bid bid and cleared volume (MW per period): Calendar year 2010

Monthly Auction	MW Type	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-10	Bid	393,426	127,235	90,338				117,766	728,765
	Cleared	55,052	10,039	5,963				10,290	81,345
Feb-10	Bid	363,548	100,591	91,281				114,853	670,272
	Cleared	53,791	9,948	6,304				9,430	79,473
Mar-10	Bid	374,155	108,329	106,100				27,107	615,690
	Cleared	66,676	10,555	9,864				3,842	90,938
Apr-10	Bid	366,026	123,612						489,638
	Cleared	67,471	11,863						79,334
May-10	Bid	375,812							375,812
	Cleared	63,469							63,469
Jun-10	Bid	398,343	134,107	127,474	27,614	129,012	126,849	122,260	1,065,658
	Cleared	65,245	9,590	9,386	2,996	10,408	7,927	5,054	110,608
Jul-10	Bid	529,368	142,953	88,143		129,524	130,924	125,079	1,145,991
	Cleared	86,820	15,281	8,068		13,336	12,559	12,309	148,373
Aug-10	Bid	566,562	113,783	102,176		130,975	140,738	147,904	1,202,137
	Cleared	76,858	10,504	9,822		8,898	11,733	12,854	130,669
Sep-10	Bid	618,218	186,274	173,686		96,649	215,233	220,751	1,510,812
	Cleared	117,485	18,384	18,820		6,981	13,593	15,840	191,103
Oct-10	Bid	622,634	198,680	148,300			222,780	235,100	1,427,494
	Cleared	106,177	19,546	7,534			14,624	18,198	166,080
Nov-10	Bid	589,936	166,937	162,232			158,176	184,688	1,261,969
	Cleared	103,683	9,552	10,198			9,967	13,805	147,205
Dec-10	Bid	688,892	207,805	208,802			48,339	205,745	1,359,582
	Cleared	130,921	22,546	23,781			4,320	17,351	198,918

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Table 8-13 shows the secondary bilateral FTR market volume by hedge type and class type for the 2009 to 2010 and the 2010 to 2011 planning periods. There were 24,054 MW of total bilateral FTR activity for the 2010 to 2011 planning period through December 31, 2010, while there were 8,840 MW during the 2009 to 2010 planning period. Price data is not meaningful as PJM market participants enter zero as the price for more than 93 percent of secondary bilateral FTR transactions.

Table 8-13 Secondary bilateral FTR market volume : Planning periods 2009 to 2010 and 2010 to 2011[26]

Planning Period	Hedge Type	Class Type	Volume (MW)
2009/2010	Obligation	24-Hour	1,468
		On Peak	3,544
		Off Peak	3,798
		Total	8,810
	Option	24-Hour	30
		On Peak	0
		Off Peak	0
		Total	30
2010/2011*	Obligation	24-Hour	1,687
		On Peak	10,035
		Off Peak	12,313
		Total	24,034
	Option	24-Hour	20
		On Peak	0
		Off Peak	0
		Total	20

* Shows seven months ended 31-Dec-2010

Price

Table 8-14 shows the cleared, weighted-average prices by trade type, FTR direction, period type and class type for the 2011 to 2014 Long Term FTR Auction. Only FTR obligation products are available in Long Term FTR Auctions. In this auction, weighted-average, buy-bid FTR prices were $0.06 per MWh while weighted-average sell offer FTR prices were $0.30 per MWh. Comparable weighted-average, buy-bid FTR prices were $0.10 per MWh while weighted-average sell offer FTR prices were $0.35 per MWh in the 2010 to 2013 Long Term FTR Auction.

26 The 2010 to 2011 planning period covers the 2010 to 2011 Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions through the December 2010 FTR Auction.

Table 8-14 Long Term FTR Auction weighted-average cleared prices (Dollars per MWh): Planning periods 2011 to 2014

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($1.57)	($0.28)	($0.24)	($0.36)
		Year 2	($1.20)	($0.26)	($0.21)	($0.32)
		Year 3	($1.21)	($0.48)	($0.35)	($0.51)
		Year All	NA	($0.46)	($0.02)	($0.27)
		Total	($1.36)	($0.31)	($0.25)	($0.38)
	Prevailing Flow	Year 1	$0.80	$0.45	$0.38	$0.45
		Year 2	$1.22	$0.45	$0.31	$0.44
		Year 3	$1.05	$0.49	$0.32	$0.46
		Year All	NA	$3.63	NA	$3.63
		Total	$0.98	$0.46	$0.34	$0.45
	Total		($0.16)	$0.10	$0.06	$0.06
Sell offers	Counter Flow	Year 1	($0.14)	($0.37)	($0.72)	($0.51)
		Year 2	($0.28)	($0.21)	($0.11)	($0.16)
		Year 3	NA	($0.34)	($0.16)	($0.27)
		Year All	NA	NA	NA	NA
		Total	($0.24)	($0.32)	($0.44)	($0.37)
	Prevailing Flow	Year 1	$0.20	$0.60	$0.34	$0.47
		Year 2	$0.09	$0.47	$0.24	$0.36
		Year 3	NA	$0.64	$0.27	$0.38
		Year All	NA	NA	NA	NA
		Total	$0.15	$0.55	$0.30	$0.42
	Total		($0.04)	$0.40	$0.19	$0.30

The 2011 to 2014 Long Term FTR Auction price duration curve for cleared buy bids in Figure 8-1 shows that 93.3 percent of Long Term FTRs were purchased for less than $1 per MWh, 96.7 percent for less than $2 per MWh and 98.4 percent for less than $3 per MWh. Negative prices occur because some FTRs are bid with negative prices and some winning FTR bidders are paid to take FTRs (counter flow FTRs).

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Figure 8-1 Long Term FTR auction clearing price duration curve: Planning periods 2011 to 2014

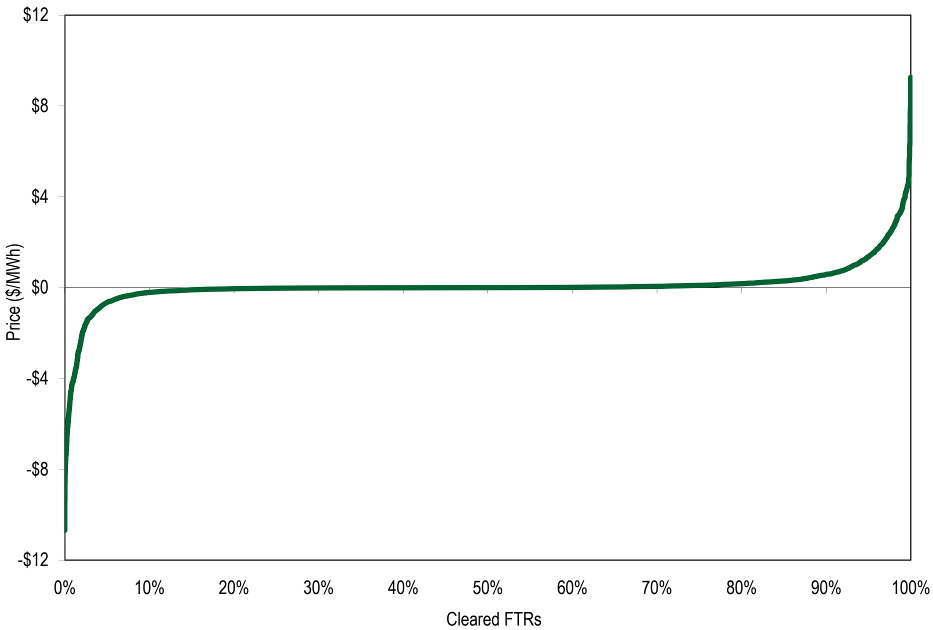

Table 8-15 shows the cleared, weighted-average prices by trade type, hedge type, FTR direction and class type for Annual FTRs during the 2010 to 2011 planning period. For the 2010 to 2011 planning period, weighted-average, buy-bid FTR obligation prices were $0.35 per MWh while weighted-average, buy-bid FTR option prices were $0.26 per MWh. Comparable weighted-average prices for the 2009 to 2010 planning period were $0.53 per MWh for buy-bid FTR obligations and $0.35 per MWh for buy-bid FTR options.

During the 2010 to 2011 planning period, weighted-average sell offer FTR obligation prices were $0.22 per MWh while weighted-average sell offer FTR option prices were $0.66 per MWh. Comparable weighted-average prices for the 2009 to 2010 planning period were $0.28 per MWh for sell offer FTR obligations and $0.11 per MWh for sell offer FTR options.

On average during the 2010 to 2011 planning period in the Annual FTR Auction, self scheduled FTRs were priced $1.06 per MWh higher than buy-bid obligation FTRs. They were priced $1.05 per MWh less than the cleared, weighted-average price of self scheduled FTRs during the 2009 to 2010 planning period.

During the 2010 to 2011 planning period, weighted-average, buy-bid FTR obligation prices were -$0.35 per MWh for counter flow FTRs and $0.75 per MWh for prevailing flow FTRs. Weighted-average sell offer FTR obligation prices were -$0.47 per MWh for counter flow FTRs and $0.43 per MWh for prevailing flow FTRs during the 2010 to 2011 planning period. On average during the 2010 to 2011 planning period in the Annual FTR Auction, self scheduled counter flow FTRs were priced $0.20 per MWh higher than buy-bid counter flow obligation FTRs and self scheduled prevailing FTRs were priced $0.72 per MWh higher than buy-bid prevailing flow obligation FTRs.

Table 8-15 Annual FTR Auction weighted-average cleared prices (Dollars per MWh): Planning period 2010 to 2011

			Class Type			
Trade Type	Hedge Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($0.56)	($0.34)	($0.28)	($0.35)
		Prevailing Flow	$0.97	$0.73	$0.69	$0.75
		Total	$0.43	$0.35	$0.32	$0.35
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$1.00	$0.41	$0.17	$0.31
		Total	$1.00	$0.33	$0.14	$0.26
Self-scheduled bids	Obligations	Counter Flow	($0.15)	NA	NA	($0.15)
		Prevailing Flow	$1.48	NA	NA	$1.48
		Total	$1.41	NA	NA	$1.41
Buy and self-scheduled bids	Obligations	Counter Flow	($0.46)	($0.34)	($0.28)	($0.34)
		Prevailing Flow	$1.38	$0.73	$0.69	$1.07
		Total	$1.17	$0.35	$0.32	$0.71
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$1.00	$0.41	$0.17	$0.31
		Total	$1.00	$0.33	$0.14	$0.26
Sell offers	Obligations	Counter Flow	($0.15)	($0.57)	($0.43)	($0.47)
		Prevailing Flow	$0.45	$0.53	$0.32	$0.43
		Total	$0.22	$0.32	$0.12	$0.22
	Options	Counter Flow	NA	NA	NA	NA
		Prevailing Flow	$0.00	$1.11	$0.33	$0.66
		Total	$0.00	$1.11	$0.33	$0.66

The 2010 to 2011 planning period price duration curve for cleared buy bids in Figure 8-2 shows that 87.4 percent of Annual FTRs were purchased for less than $1 per MWh, 93.5 percent for less than $2 per MWh and 96.3 percent for less than $3 per MWh. Negative prices occur because some FTRs are bid with negative prices and some winning FTR bidders are paid to take FTRs (counter flow FTRs). The 2010 to 2011 planning period FTR obligation price duration curve for cleared buy bids in Figure 8-2 shows that 86.2 percent of annual FTR obligations were purchased for less than $1 per MWh, 92.7 percent for less than $2 per MWh and 95.9 percent for less than $3 per MWh. The 2010 to 2011 planning period FTR option price duration curve for cleared buy bids in Figure 8-2 shows that 95 percent of annual FTR options were purchased for less than $1 per MWh, 98.6 percent for less than $2 per MWh and 99.1 percent for less than $3 per MWh.

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Figure 8-2 Annual FTR auction clearing price duration curves: Planning period 2010 to 2011

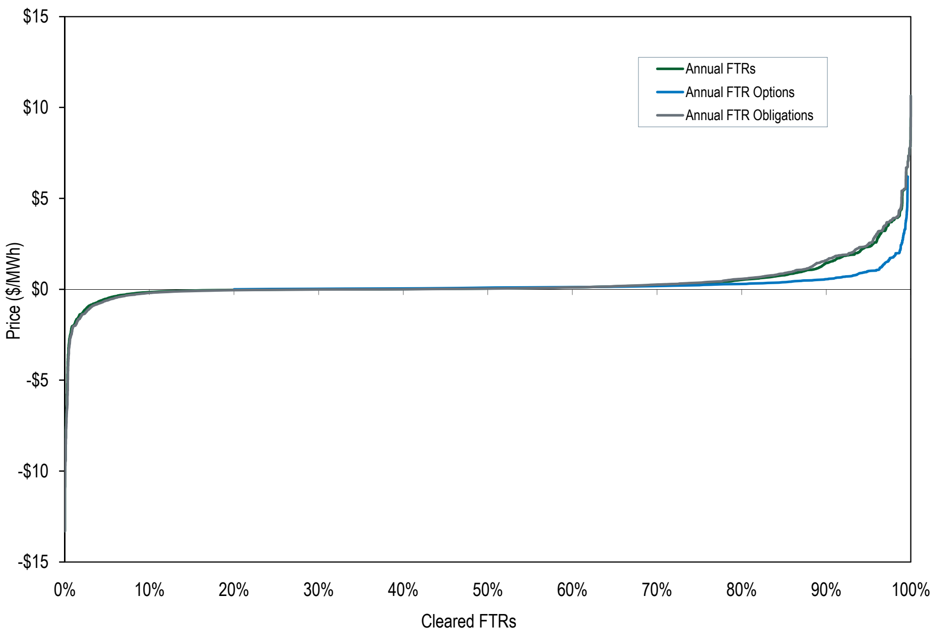

Table 8-16 shows the weighted-average cleared buy-bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2010 through December 2010. For example, for the June 2010 Monthly Balance of Planning Period FTR Auction, the current month column is June, the second month column is July and the third month column is August. Quarters 1 through 4 are represented in the Q1, Q2, Q3 and Q4 columns. The total column represents all of the activity within the June 2010 Monthly Balance of Planning Period FTR Auction.

The cleared, weighted-average price paid in the Monthly Balance of Planning Period FTR Auctions during the first seven months of the 2010 to 2011 planning period was $0.17 per MWh, compared with $0.18 per MWh for the full 12-month 2009 to 2010 planning period.

Table 8-16 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MWh): Calendar year 2010

Monthly Auction	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-10	$0.09	$0.34	($0.01)				$0.16	$0.13
Feb-10	$0.09	$0.31	$0.17				$0.31	$0.19
Mar-10	$0.14	$0.30	$0.34				($0.07)	$0.15
Apr-10	$0.10	$0.24						$0.12
May-10	$0.06							$0.06
Jun-10	$0.11	$0.36	$0.35	$0.80	$0.33	$0.40	$0.37	$0.29
Jul-10	$0.14	$0.46	$0.04		$0.19	$0.16	$0.15	$0.17
Aug-10	$0.19	$0.36	$0.18		$0.20	$0.35	$0.13	$0.22
Sep-10	$0.13	$0.17	$0.15		$0.09	$0.20	$0.14	$0.14
Oct-10	$0.13	$0.18	$0.01			$0.15	$0.09	$0.13
Nov-10	$0.13	$0.19	$0.19			$0.22	$0.21	$0.17
Dec-10	$0.10	$0.23	$0.18			$0.33	$0.16	$0.14

Revenue

Long Term FTR Auction Revenue

Table 8-17 shows Long Term FTR Auction revenue data by trade type, FTR direction, period type, and class type. The 2011 to 2014 Long Term FTR Auction netted $49.80 million in revenue, with buyers paying $66.20 million and sellers receiving $16.40 million. The 2010 to 2013 Long Term FTR Auction netted $31.14 million in revenue, with buyers paying $39.12 million and sellers receiving $7.97 million.

For the 2011 to 2014 Long Term FTR Auction, the counter flow FTRs netted -$189.67 million in revenue, with buyers receiving $192.81 million and sellers paying $3.14 million, and the prevailing flow FTRs netted $239.47 million in revenue, with buyers paying $259.01 million and sellers receiving $19.54 million.

Table 8-17 Long Term FTR Auction revenue: Planning periods 2011 to 2014

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($29,698,450)	($28,139,840)	($29,384,704)	($87,222,995)
		Year 2	($19,181,431)	($21,548,424)	($16,822,643)	($57,552,498)
		Year 3	($13,015,646)	($20,938,271)	($13,385,773)	($47,339,690)
		Year All	$0	($675,365)	($23,149)	($698,514)
		Total	($61,895,527)	($71,301,900)	($59,616,270)	($192,813,696)
	Prevailing Flow	Year 1	$17,659,087	$52,520,425	$46,201,694	$116,381,205
		Year 2	$17,140,359	$34,083,294	$25,225,411	$76,449,064
		Year 3	$12,356,411	$33,193,204	$20,590,182	$66,139,797
		Year All	$0	$44,582	$0	$44,582
		Total	$47,155,857	$119,841,504	$92,017,287	$259,014,648
	Total		($14,739,670)	$48,539,604	$32,401,018	$66,200,952
Sell offers	Counter Flow	Year 1	($1,818)	($1,149,506)	($1,413,501)	($2,564,825)
		Year 2	($9,872)	($284,126)	($173,171)	($467,169)
		Year 3	0	($88,598)	($22,229)	($110,827)
		Year All	NA	NA	NA	NA
		Total	($11,690)	($1,522,230)	($1,608,901)	($3,142,821)
	Prevailing Flow	Year 1	$5,305	$7,874,897	$4,196,589	$12,076,791
		Year 2	$2,314	$4,582,634	$2,057,947	$6,642,894
		Year 3	0	$423,284	$398,511	$821,795
		Year All	NA	NA	NA	NA
		Total	$7,619	$12,880,814	$6,653,047	$19,541,480
	Total		($4,072)	$11,358,584	$5,044,146	$16,398,659

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Figure 8-3 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue from the 2011 to 2014 Long Term FTR Auction.[27] The top 10 positive revenue producing FTR sinks accounted for $91.11 million of the total revenue of $49.80 million paid in the auction.[28] They also comprised 9.7 percent of all FTRs bought in the auction. The sinks with the highest positive auction revenue are all control zones or large aggregates. The top 10 negative revenue producing FTR sinks accounted for -$60.00 million of revenue and constituted 2.5 percent of all FTRs bought in the auction.

Figure 8-3 Ten largest positive and negative revenue producing FTR sinks purchased in the Long Term FTR Auction: Planning periods 2011 to 2014[29]

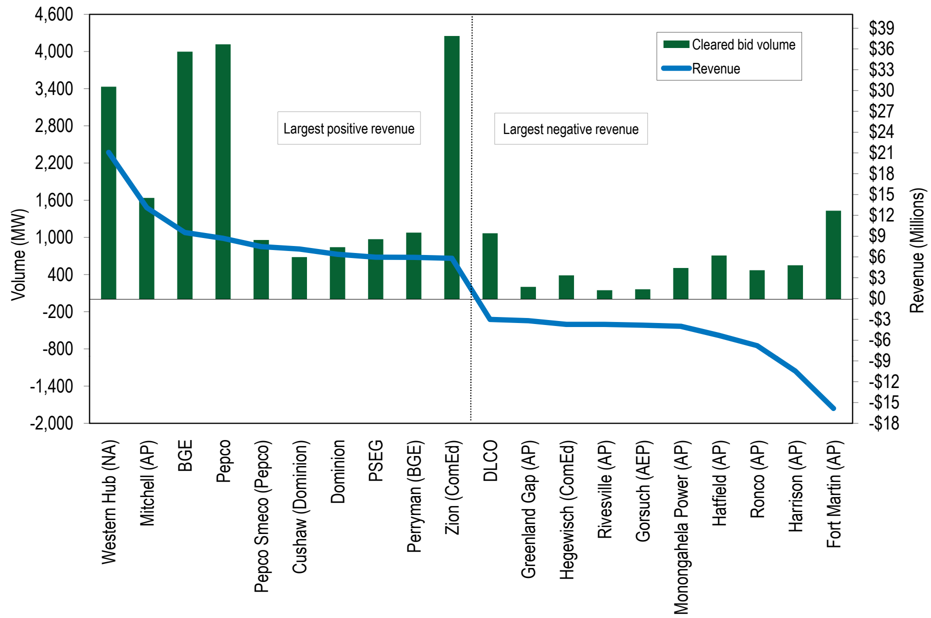


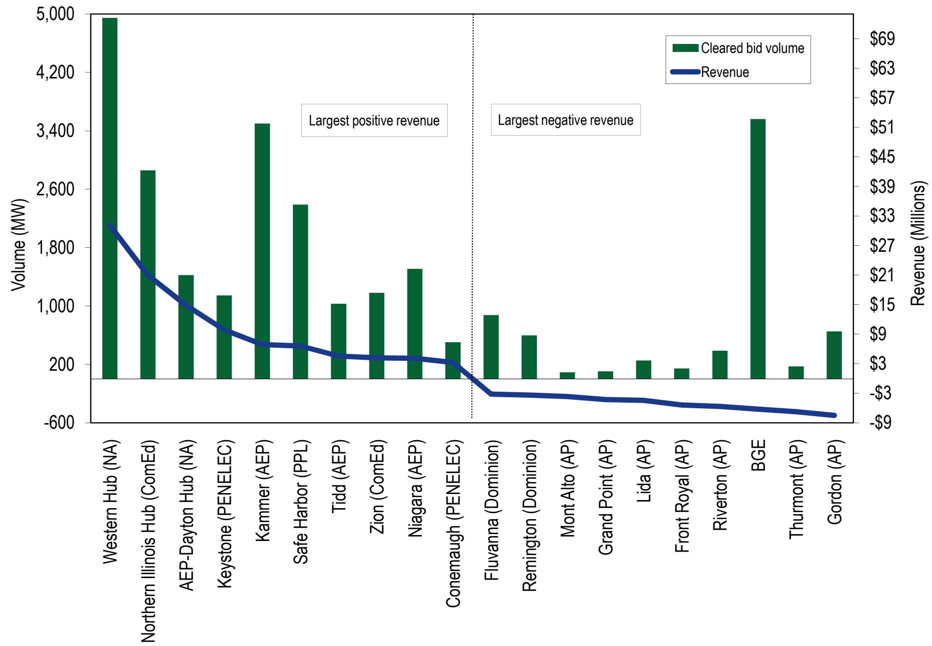
Figure 8-4 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the 2011 to 2014 Long Term FTR Auction. The top 10 positive revenue producing FTR sources accounted for $106.22 million of the total revenue of $49.80 million paid in the auction. They also comprised 9.1 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sources accounted for -$50.59 million of revenue and constituted 3.0 percent of all FTRs bought in the auction.

27 As some FTRs are bid with negative prices, some winning FTR bidders are paid to take FTRs. These are counter flow FTRs. These payments reduce net auction revenue. Therefore, the sum of the highest revenue producing FTRs can exceed net auction revenue.

28 The total positive revenue producing FTR sinks was $184.31 million and the total negative revenue producing FTR sinks was -$134.50 million. The overall revenue paid in the auction was $49.80 million.

29 For Figure 8-3 through Figure 8-11, each FTR sink and source that is not a control zone has its corresponding control zone listed in parentheses after its name. Most FTR sink and source control zone identifications for hubs and interface pricing points are listed as NA because they cannot be assigned to a specific control zone.

Figure 8-4 Ten largest positive and negative revenue producing FTR sources purchased in the Long Term FTR Auction: Planning periods 2011 to 2014



Annual FTR Auction Revenue

Table 8-18 shows Annual FTR Auction revenue data by trade type, hedge type, FTR direction and class type. For the 2010 to 2011 planning period, the Annual FTR Auction netted $1,049.83 million in revenue, with buyers paying $1,060.00 million and sellers receiving $10.17 million. For the 2009 to 2010 planning period, the Annual FTR Auction netted $1,329.80 million in revenue, with buyers paying $1,338.88 million and sellers receiving $9.09 million.

For the 2010 to 2011 planning period, the counter flow FTRs in the Annual FTR Auction netted -$120.97 million in revenue, with buyers receiving $125.98 million and sellers paying $5.00 million, and the prevailing flow FTRs in the Annual FTR Auction netted $1,170.80 million in revenue, with buyers paying $1,185.98 million and sellers receiving $15.18 million.

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Table 8-18 Annual FTR Auction revenue: Planning period 2010 to 2011

			Class Type			
Trade Type	Hedge Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($31,703,144)	($48,028,679)	($43,231,947)	($122,963,770)
		Prevailing Flow	$101,156,043	$184,829,000	$172,777,067	$458,762,110
		Total	$69,452,899	$136,800,321	$129,545,120	$335,798,340
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$4,190,505	$20,643,158	$9,781,679	$34,615,342
		Total	$4,190,505	$20,643,158	$9,781,679	$34,615,342
	Total	Counter Flow	($31,703,144)	($48,028,679)	($43,231,947)	($122,963,770)
		Prevailing Flow	$105,346,548	$205,472,159	$182,558,746	$493,377,453
		Total	$73,643,404	$157,443,479	$139,326,799	$370,413,682
Self-scheduled bids	Obligations	Counter Flow	($3,013,115)	NA	NA	($3,013,115)
		Prevailing Flow	$692,601,292	NA	NA	$692,601,292
		Total	$689,588,178	NA	NA	$689,588,178
Buy and self-scheduled bids	Obligations	Counter Flow	($34,716,259)	($48,028,679)	($43,231,947)	($125,976,885)
		Prevailing Flow	$793,757,336	$184,829,000	$172,777,067	$1,151,363,403
		Total	$759,041,077	$136,800,321	$129,545,120	$1,025,386,518
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$4,190,505	$20,643,158	$9,781,679	$34,615,342
		Total	$4,190,505	$20,643,158	$9,781,679	$34,615,342
	Total	Counter Flow	($34,716,259)	($48,028,679)	($43,231,947)	($125,976,885)
		Prevailing Flow	$797,947,840	$205,472,159	$182,558,746	$1,185,978,745
		Total	$763,231,581	$157,443,479	$139,326,799	$1,060,001,860
Sell offers	Obligations	Counter Flow	($100,949)	($2,404,436)	($2,499,147)	($5,004,532)
		Prevailing Flow	$492,925	$9,363,404	$5,201,761	$15,058,090
		Total	$391,976	$6,958,967	$2,702,614	$10,053,558
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$0	$85,206	$34,159	$119,365
		Total	$0	$85,206	$34,159	$119,365
	Total	Counter Flow	($100,949)	($2,404,436)	($2,499,147)	($5,004,532)
		Prevailing Flow	$492,925	$9,448,610	$5,235,920	$15,177,455
		Total	$391,976	$7,044,173	$2,736,773	$10,172,923

Figure 8-5 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue from the Annual FTR Auction for the 2010 to 2011 planning period. The top 10 positive revenue producing FTR sinks accounted for $934.75 million (89.0 percent) of the total revenue of $1,049.83 million paid in the auction. They also comprised 33.7 percent of all FTRs bought in the auction. The sinks with the highest positive auction revenue are all control zones or large aggregates. The top 10 negative revenue producing

FTR sinks accounted for -$39.66 million of revenue and constituted 3.2 percent of all FTRs bought in the auction.

Figure 8-5 Ten largest positive and negative revenue producing FTR sinks purchased in the Annual FTR Auction: Planning period 2010 to 2011

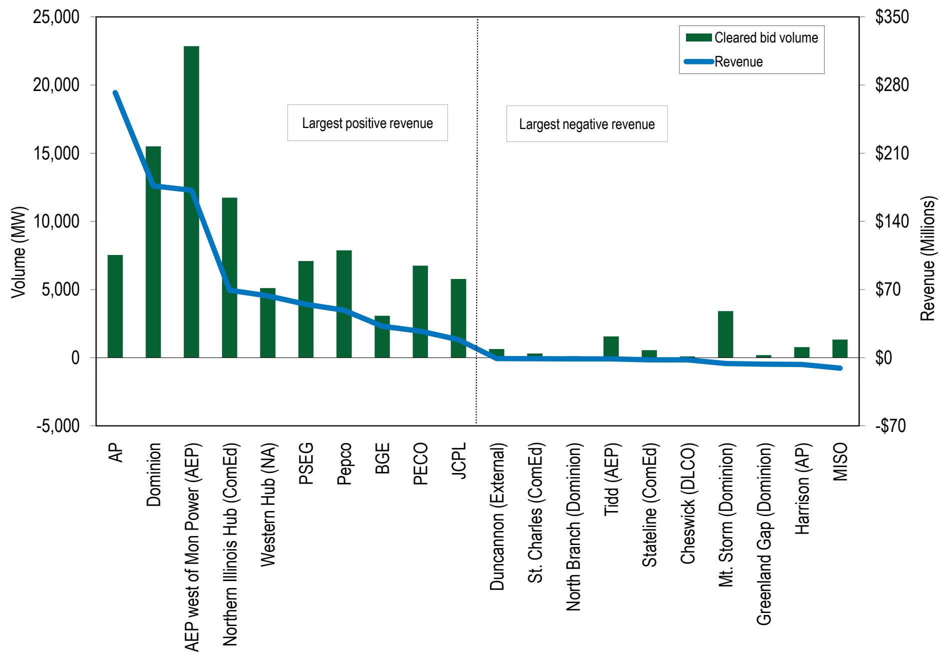

Figure 8-6 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the Annual FTR Auction for the 2010 to 2011 planning period. The top 10 positive revenue producing FTR sources accounted for $591.32 million (56.3 percent) of the total revenue of $1,049.83 million paid in the auction. They also comprised 15.3 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sources accounted for -$30.02 million of revenue and constituted 3.2 percent of all FTRs bought in the auction.

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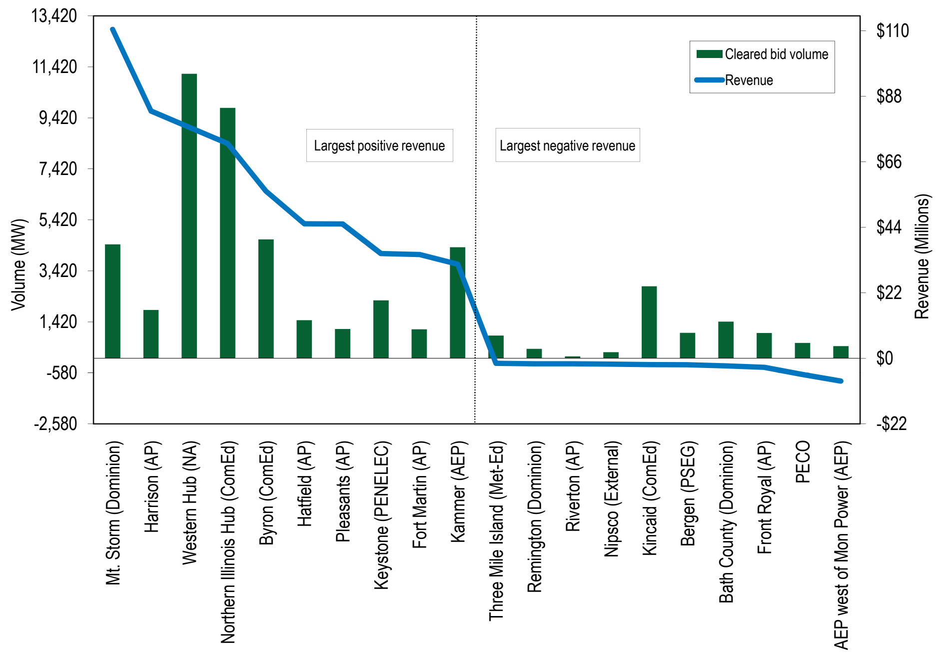
Figure 8-6 Ten largest positive and negative revenue producing FTR sources purchased in the Annual FTR Auction: Planning period 2010 to 2011



Monthly Balance of Planning Period FTR Auction Revenue

Table 8-19 shows Monthly Balance of Planning Period FTR Auction revenue data by trade type, hedge type and class type. For the 2010 to 2011 planning period through December 31, 2010, the Monthly Balance of Planning Period FTR Auctions netted $16.67 million in revenue, with buyers paying $97.53 million and sellers receiving $80.87 million. For the 2009 to 2010 planning period, the Monthly Balance of Planning Period FTR Auctions netted $19.49 million in revenue, with buyers paying $82.12 million and sellers receiving $62.63 million.

Table 8-19 Monthly Balance of Planning Period FTR Auction revenue: Calendar year 2010

			Class Type			
Monthly Auction	Hedge Type	Trade Type	24-Hour	On Peak	Off Peak	All
Jan-10	Obligations	Buy bids	($358,507)	$3,027,607	$1,763,504	$4,432,604
		Sell offers	$383,960	$1,556,699	$561,863	$2,502,522
	Options	Buy bids	$0	$341,524	$118,211	$459,735
		Sell offers	$83,413	$542,599	$261,153	$887,164
Feb-10	Obligations	Buy bids	$530,509	$2,872,273	$2,657,432	$6,060,214
		Sell offers	($116,080)	$1,524,315	$1,983,143	$3,391,378
	Options	Buy bids	$0	$241,692	$234,325	$476,018
		Sell offers	$8,606	$825,079	$709,563	$1,543,248
Mar-10	Obligations	Buy bids	($549,382)	$4,005,065	$2,109,386	$5,565,069
		Sell offers	$565,634	$1,299,894	$578,118	$2,443,646
	Options	Buy bids	$972	$27,948	$25,433	$54,353
		Sell offers	$80,862	$900,428	$434,215	$1,415,505
Apr-10	Obligations	Buy bids	($455,673)	$1,949,169	$1,914,146	$3,407,643
		Sell offers	$411,821	$303,177	$711,735	$1,426,734
	Options	Buy bids	$0	$31,664	$7,685	$39,348
		Sell offers	$397	$619,455	$222,426	$842,278
May-10	Obligations	Buy bids	($174,016)	$796,256	$742,930	$1,365,170
		Sell offers	$55,656	$98,700	$324,803	$479,159
	Options	Buy bids	$0	$38,754	$2,044	$40,798
		Sell offers	$30	$400,162	$143,440	$543,632
Jun-10	Obligations	Buy bids	$3,248,555	$8,066,567	$6,097,873	$17,412,995
		Sell offers	$953,733	$3,876,255	$3,725,334	$8,555,322
	Options	Buy bids	$5,802	$158,851	$116,761	$281,415
		Sell offers	$16,839	$4,265,630	$2,393,988	$6,676,457
Jul-10	Obligations	Buy bids	($524,716)	$8,542,586	$5,945,266	$13,963,136
		Sell offers	$6,087	$2,569,941	$1,806,154	$4,382,181
	Options	Buy bids	$17,289	$270,145	$135,568	$423,002
		Sell offers	$1,672,986	$2,791,024	$2,166,674	$6,630,683
Aug-10	Obligations	Buy bids	$1,995,876	$8,489,218	$5,226,059	$15,711,153
		Sell offers	$78,088	$6,252,007	$3,227,745	$9,557,840
	Options	Buy bids	$0	$197,801	$157,086	$354,887
		Sell offers	$30,431	$1,626,257	$1,836,640	$3,493,328
Sep-10	Obligations	Buy bids	$590,917	$6,987,726	$5,639,454	$13,218,098
		Sell offers	$135,907	$3,907,689	$2,637,138	$6,680,733
	Options	Buy bids	$0	$333,742	$312,661	$646,403
		Sell offers	$123,445	$1,921,160	$2,853,356	$4,897,961
Oct-10	Obligations	Buy bids	($249,561)	$5,623,697	$4,521,315	$9,895,451
		Sell offers	$268,353	$2,510,800	$3,344,531	$6,123,684
	Options	Buy bids	$0	$350,232	$466,829	$817,061
		Sell offers	$4,951	$1,416,747	$1,146,768	$2,568,466
Nov-10	Obligations	Buy bids	($35)	$6,554,668	$4,843,680	$11,398,312
		Sell offers	$448,438	$3,944,079	$3,535,186	$7,927,704
	Options	Buy bids	$0	$308,719	$217,288	$526,007
		Sell offers	$8,192	$1,284,796	$1,008,824	$2,301,813
Dec-10	Obligations	Buy bids	($243,480)	$7,603,208	$5,024,487	$12,384,214
		Sell offers	$3,607,375	$2,926,895	$1,961,215	$8,495,485
	Options	Buy bids	$0	$343,419	$163,999	$507,419
		Sell offers	$10,466	$1,642,922	$925,082	$2,578,471
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	$4,817,556	$51,867,670	$37,298,133	$93,983,359
		Sell offers	$5,497,980	$25,987,666	$20,237,303	$51,722,948
	Options	Buy bids	$23,091	$1,962,910	$1,570,193	$3,556,193
		Sell offers	$1,867,311	$14,948,536	$12,331,333	$29,147,179

* Shows Twelve Months for 2009/2010; ** Shows seven months ended 31-Dec-2010 for 2010/2011

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Figure 8-7 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue in the Monthly Balance of Planning Period FTR Auctions during the first seven months of the 2010 to 2011 planning period. The top 10 positive revenue producing FTR sinks accounted for $39.76 million of revenue and 7.3 percent of all FTRs bought in the Monthly Balance of Planning Period FTR Auctions. The top 10 negative revenue producing FTR sinks accounted for -$12.55 million of revenue and constituted 0.5 percent of all FTRs bought in the auctions. The MW volume is the net of all buys and sells from the Monthly Balance of Planning Period FTR Auctions during the 2010 to 2011 planning period. The net market volume sinking at the West Interface Hub was negative since the total cleared volume of the monthly FTR buy bids sinking at the West Interface Hub was less than the total cleared volume of the monthly FTR sell offers sinking at the West Interface Hub.

Figure 8-7 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 December 31, 2010

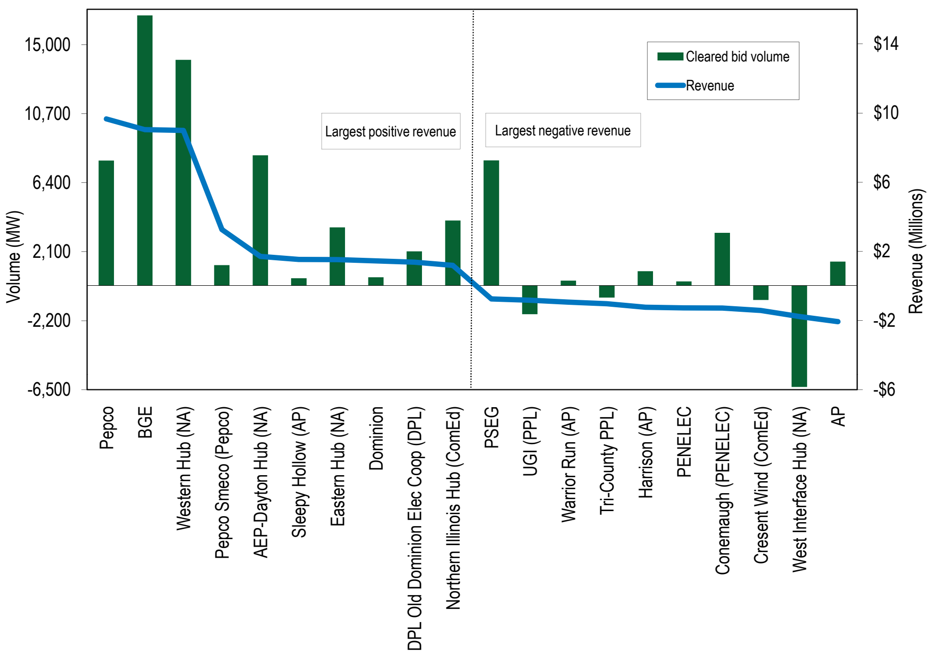
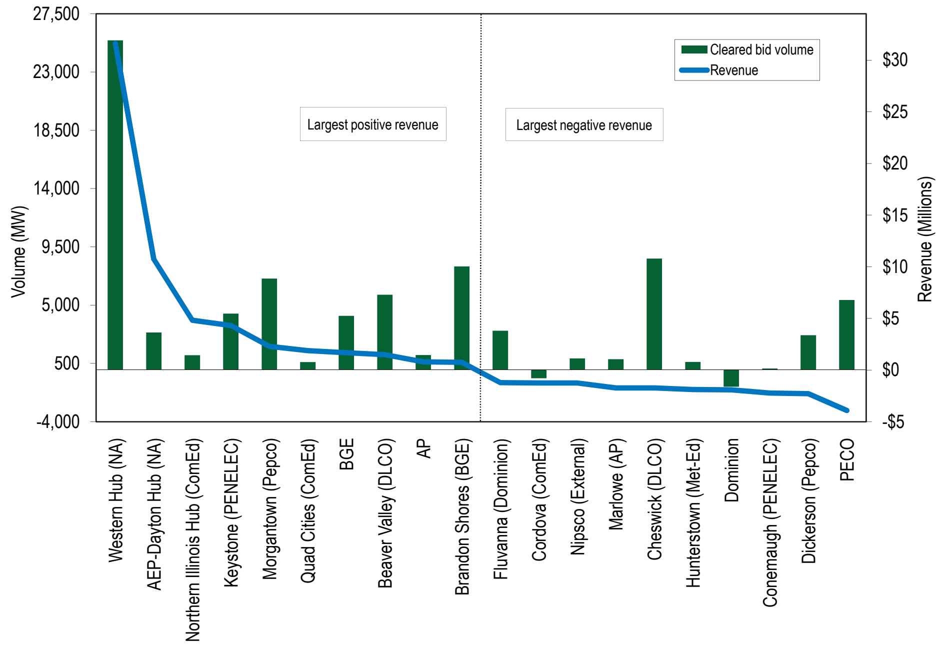


Figure 8-8 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the Monthly Balance of Planning Period FTR Auctions during the first seven months of the 2010 to 2011 planning period. The top 10 positive revenue producing FTR sources accounted for $60.36 million and 7.6 percent of all FTRs bought in the auctions. The top 10 negative revenue producing FTR sources accounted for -$19.42 million of revenue and constituted 2.5 percent of all FTRs bought in the auctions.

Figure 8-8 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 December 31, 2010



Revenue Adequacy

Congestion revenue is created in an LMP system when all loads pay and all generators receive their respective LMPs. When load pays more than the amount that generators receive, excluding losses, positive congestion revenue exists and is available to cover the target allocations of FTR holders. The load MW exceed the generation MW in constrained areas because part of the load is served by imports using transmission capability into the constrained areas. Generating units that are the source of such imports are paid the price at their own bus which does not reflect congestion in constrained areas. Generation in a constrained area receives the congestion price and all load in the constrained area pays the congestion price. As a result, load congestion payments are usually greater than the congestion-related payments to generation.[30] In general, FTR revenue adequacy exists when the sum of congestion credits is as great as the sum of congestion across the positively valued FTRs.

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 adequacy of FTRs as a hedge against congestion compares FTR revenues to total congestion on the system as a measure of the extent to which FTRs hedged market participants against actual, total congestion across all paths, regardless of the availability or purchase of FTRs.

30 For an illustration of how total congestion revenue is generated and how FTR target allocations and congestion receipts are determined, see Table 3-1, "Congestion revenue, FTR target allocations and FTR congestion credits: Illustration," *Technical Reference for PJM Markets,* Section 3 "Financial Transmission and Auction Revenue Rights. "

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FTRs are paid out for each month from congestion revenues, FTR auction revenues and excess revenues carried forward from prior months and distributed back from later months. At the end of a planning period, if some months remain not fully funded, an uplift charge is collected from any FTR market participants that hold FTRs during the planning period based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning year. For the 2009 to 2010 planning period, FTRs were not fully funded and thus an uplift charge was collected. Table 8-20 shows the composition of FTR target allocations and FTR revenues for the 2009 to 2010 and the 2010 to 2011 planning periods, with the latter shown through December 31, 2010. FTR targets are composed of FTR target allocations and associated adjustments. Other adjustments may be made for items such as modeling changes or errors.

FTR revenues are primarily comprised of hourly congestion revenue and net negative congestion. FTR revenues also include ARR excess which is the difference between ARR target allocations and FTR auction revenues. Competing use revenues are based on the Unscheduled Transmission Service Agreement between the New York Independent System Operator (NYISO) and PJM. This agreement sets forth the terms and conditions under which compensation is provided for transmission service in connection with transactions not scheduled directly or otherwise prearranged between NYISO and PJM. Congestion revenues appearing in Table 8-20 include both congestion charges associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the Midwest ISO whose operating limits are respected by PJM.[31] The operating protocol governing the wheeling contracts between Public Service Electric and Gas Company (PSE&G) and Consolidated Edison Company of New York (Con Edison) resulted in a reimbursement of $0.8 million in congestion charges to Con Edison in the 2010 to 2011 planning period through December 31, 2010.[32,33] November 2010 FTR revenue adjustments included a charge to the Day-Ahead Operating Reserves of $1.4 million. This charge was necessary because the amount of hourly net negative congestion revenues could not be offset by positive congestion revenues at the end of the month and therefore was allocated as additional Day-Ahead Operating Reserves charges during the month. This means that within an hour, the congestion dollars collected by load were less than the congestion dollars paid to generation. This is accounted for as a charge, which is allocated to Day-Ahead Operating Reserves. This type of adjustment is infrequent.

31 See “Joint Operating Agreement between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C.” (December 11, 2008) (Accessed January 19, 2010), Section 6.1 <http://www.pjm.com/~/Media/documents/agreements/joa-complete.ashx> (1,528 KB).

32 111 FERC ¶ 61,228 (2005).

33 See the *2010 State of the Market Report for PJM*, Volume II, Section 4, “Interchange Transactions,” at “Con Edison and PSE&G Wheeling Contracts” and Appendix E, “Interchange Transactions” at Table E-2, “Con Edison and PSE&G wheel settlements data: Calendar year 2010.”

Table 8-20 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2009 to 2010 and 2010 to 2011

Accounting Element	2009/2010	2010/2011*
ARR information		
ARR target allocations	$1,276.9	$603.5
FTR auction revenue	$1,368.7	$640.6
ARR excess	$91.9	$37.2
FTR targets		
FTR target allocations	$908.1	$1,153.4
Adjustments:		
Adjustments to FTR target allocations	($1.5)	($1.1)
Total FTR targets	$906.6	$1,152.3
FTR revenues		
ARR excess	$91.9	$37.2
Competing uses	$0.0	$0.0
Congestions		
Net Negative Congestion (enter as negative)	($37.8)	($26.1)
Hourly congestion revenue	$854.9	$997.8
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($31.0)	($28.3)
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	$9.2	$1.8
Other adjustments to FTR revenues	$2.4	$0.1
Total FTR revenues	$923.5	$981.8
Excess revenues distributed to other months	($45.1)	($1.8)
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	$981.4
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$880.3	$982.2
Remaining deficiency	$28.3	$170.9

* Shows seven months ended 31-Dec-10

FTR target allocations are based on hourly prices in the Day-Ahead Energy Market for the respective FTR paths and equal the revenue required to compensate FTR holders fully for congestion on those specific paths. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations. Table 8-21 lists the FTR revenues, target allocations, credits, payout ratios, congestion credit deficiencies and excess congestion charges by month. At

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the end of the 12-month planning period, excess congestion charges are used to offset any monthly congestion credit deficiencies.

The total row in Table 8-21 is not the simple sum of each of the monthly rows because the monthly rows may include excess revenues carried forward from prior months and excess revenues carried back from later months. For example, August 2009 FTR revenues are shown as $90.0 million, which includes revenues from congestion charges for the month, excess revenues carried forward from prior months ($12.8 million) and excess revenues carried back from later months ($4.5 million). For the 2009 to 2010 planning period, the total FTR revenues and FTR credits were $878.4 million which was $28.3 million deficient of the total FTR Target Allocations. For the first seven months of the 2010 to 2011 planning period, there is a credit deficiency of $170.9 million to the $1,152.0 million in FTR target allocations.

Table 8-21 Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2008 to 2009 and 2009 to 2010

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-09	$54.6	$43.9	100.0%	$43.9	100.0%	$0.0
Jul-09	$53.2	$40.4	100.0%	$40.4	100.0%	$0.0
Aug-09	$92.4	$92.4	81.3%	$92.4	100.0%	$0.0
Sep-09	$31.4	$31.4	87.4%	$31.4	100.0%	$0.0
Oct-09	$57.8	$57.8	83.4%	$57.8	100.0%	$0.0
Nov-09	$38.2	$37.9	100.0%	$37.9	100.0%	$0.0
Dec-09	$101.9	$93.7	100.0%	$93.7	100.0%	$0.0
Jan-10	$223.7	$213.0	100.0%	$213.0	100.0%	$0.0
Feb-10	$113.3	$111.0	100.0%	$111.0	100.0%	$0.0
Mar-10	$29.0	$35.8	73.9%	$29.0	81.1%	($6.8)
Apr-10	$47.7	$68.5	69.3%	$47.7	69.7%	($20.8)
May-10	$80.2	$80.9	99.1%	$80.2	99.1%	($0.7)
Summary for Planning Period 2009 to 2010						
Total	$878.4	$906.6		$878.4	96.9%	($28.3)
Jun-10	$193.9	$196.1	97.8%	$193.9	98.9%	($2.2)
Jul-10	$274.8	$273.0	100.0%	$273.0	100.0%	$0.0
Aug-10	$111.1	$119.2	93.2%	$111.1	93.2%	($8.1)
Sep-10	$116.0	$165.3	70.0%	$116.0	70.2%	($49.2)
Oct-10	$52.2	$67.4	77.4%	$52.2	77.5%	($15.1)
Nov-10	$51.1	$80.0	61.9%	$51.1	63.9%	($28.9)
Dec-10	$184.1	$251.5	73.2%	$184.1	73.2%	($67.4)
Summary for Planning Period 2010 to 2011 through December 31, 2010						
Total	$981.4	$1,152.3		$981.4	85.2%	($170.9)

Figure 8-9 shows the FTR payout ratio by month from June 2003 through December 2010. The monthly percentages include the distribution of excess congestion charges. The monthly FTR payout ratio for the months in the 2010 to 2011 planning period may change if excess congestion charges are collected in the remainder of the planning period. November 2010 has the lowest monthly payout ratio of 62 percent since June 2003. The data in Figure 8-9 begins at June 1, 2003, when PJM replaced the allocation of FTRs with an allocation of ARRs and an associated Annual FTR Auction.

Figure 8-9 FTR payout ratio by month: June 2003 to December 2010[34]

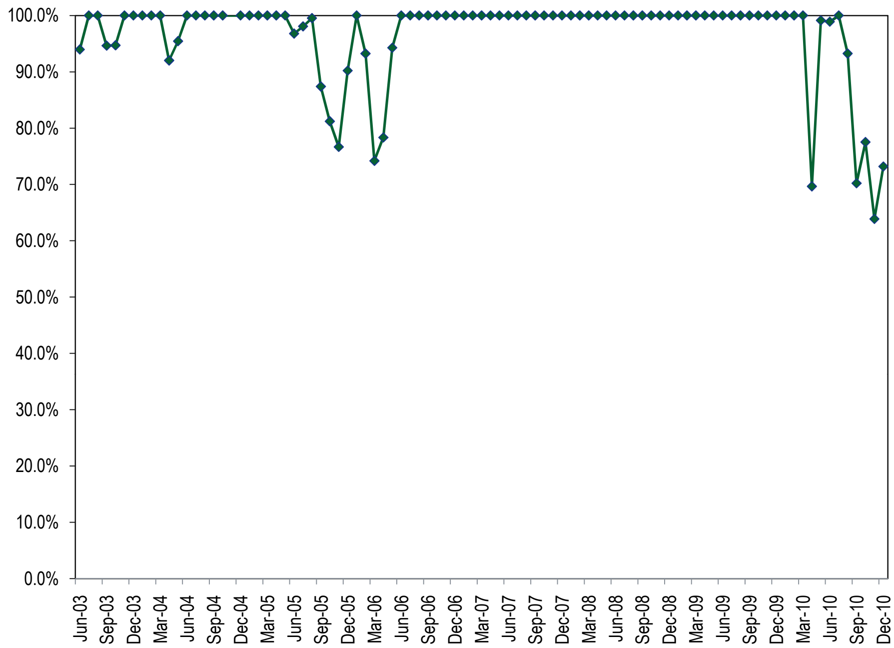

Table 8-22 shows the FTR payout ratio by planning period. FTRs were paid at 96.9 percent of the target allocation level for the 2009 to 2010 planning period and were paid at 85.2 percent of the target allocation level for the 2010 to 2011 planning period through December 31, 2010.

Table 8-22 FTR payout ratio by planning period

Planning Period	FTR Payout Ratio
2003/2004	97.7%
2004/2005	100.0%
2005/2006	90.7%
2006/2007	100.0%
2007/2008	100.0%
2008/2009	100.0%
2009/2010	96.9%
2010/2011*	85.2%

* through December 31, 2010

34 The underlying data for Figure 8-9 and Table 8-22 is from the "FTR Credit" spreadsheet posted on PJM's website at <http://www.pjm.com/markets-and-operations/ftr/revenue-adequacy.aspx>.

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FTR target allocations were examined separately. Hourly FTR target allocations were divided into those that were benefits and liabilities and summed by sink and by source for the 2010 to 2011 planning period through December 31, 2010. Figure 8-10 shows the FTR sinks with the largest positive and negative target allocations. The top 10 sinks that produced a financial benefit accounted for 33.8 percent of total positive target allocations during the first seven months of the 2010 to 2011 planning period. FTRs with the AP Control Zone as the sink included 9.3 percent of all positive target allocations. The sinks with the highest positive target allocations are all control zones or large aggregates. The top 10 sinks that created liability accounted for 13.8 percent of total negative target allocations. FTRs with the Western Hub as the sink encompassed 2.8 percent of all negative target allocations.

Figure 8-10 Ten largest positive and negative FTR target allocations summed by sink: Planning period 2010 to 2011 through December 31, 2010

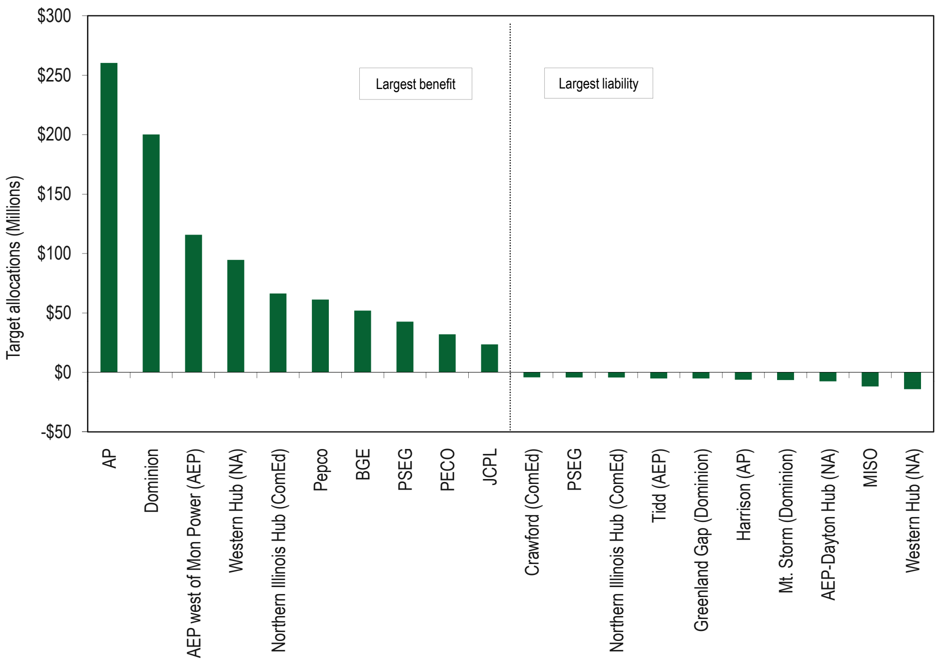
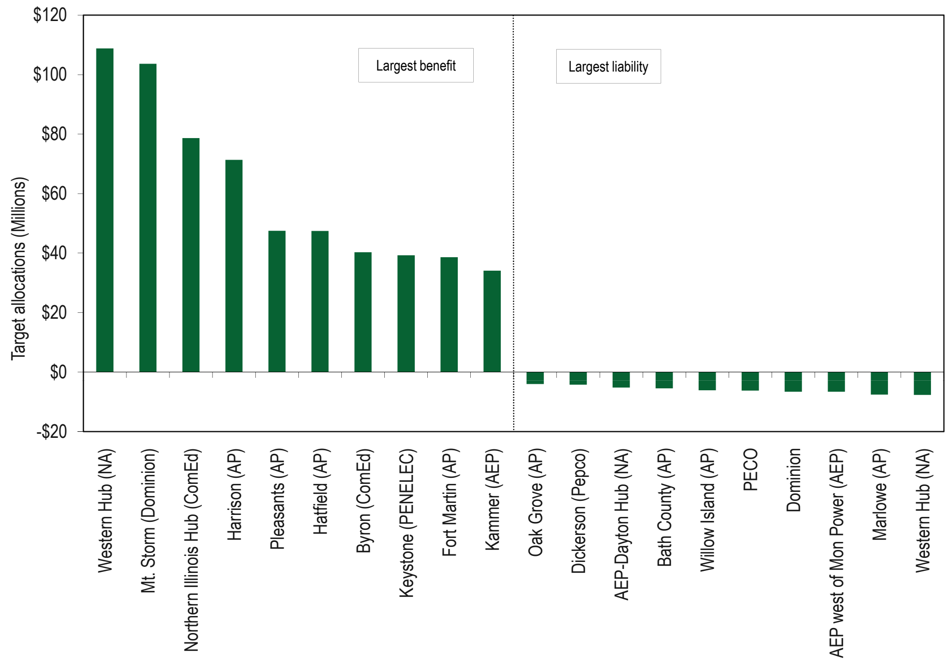


Figure 8-11 shows the FTR sources with the largest positive and negative target allocations during the first seven months of the 2010 to 2011 planning period. The top 10 sources with a positive target allocation accounted for 21.8 percent of total positive target allocations. FTRs with the Western Hub as their source included 3.9 percent of all positive target allocations. The top 10 sources with a negative target allocation accounted for 12.0 percent of total negative target allocations. FTRs with the Western Hub as the source encompassed 1.5 percent of all negative target allocations.

Figure 8-11 Ten largest positive and negative FTR target allocations summed by source: Planning period 2010 to 2011 through December 31, 2010



Profitability

FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. For a prevailing flow FTR, the FTR credits represent the revenue that an FTR holder should receive and the auction price paid represents the cost. For a counter flow FTR, the auction price represents the revenue that an FTR holder receives and the FTR credits represent the cost. The cost of self scheduled FTRs is zero. ARR holders that self schedule FTRs purchase the FTRs in the Annual FTR Auction but ARR holders receive ARR credits that equal the purchase price of the FTRs. Table 8-23 lists FTR profits by organization type and FTR direction for the 2010 calendar year. FTR profits are the sum of the daily FTR credits minus the daily FTR auction costs for each FTR held by an organization. FTR credits are the product of the FTR target allocations and the FTR payout ratio for the respective planning period. The FTR payout ratio was 96.9 percent of the target allocation for the 2009 to 2010 planning period and 85.2 percent for the first seven months of the 2010 to 2011 planning period. The FTR target allocation is equal to the product of the FTR MW and congestion price differences between sink and source in the Day-Ahead Energy Market. The FTR credits do not include after the fact adjustments. The daily FTR auction costs are the product of the FTR MW and the auction price divided by the time period of the FTR in days. The results indicate the total FTR profits in 2010 were $138.7 million for financial entities and $909.6 million for physical entities. Self scheduled FTRs account for a large portion of the FTR profits of physical entities.

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Table 8-23 FTR profits by organization type and FTR direction: Calendar year 2010

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	$884,347,111	$25,203,961	$909,551,072
Financial	$72,482,324	$66,229,890	$138,712,214
Total	$956,829,435	$91,433,851	$1,048,263,286

Table 8-24 lists the monthly FTR profits in 2010 calendar year by organization type. FTR profits were positive and larger in magnitude during the winter and summer months when congestion tended to be higher. The three most profitable months for FTRs were July, December and January. FTR profits decrease during the shoulder months when congestion is less.

Table 8-24 Monthly FTR profits by organization type: Calendar year 2010

	Organization Type		
Month	Physical	Financial	Total
Jan	$171,049,354	($1,214,796)	$169,834,558
Feb	$73,488,400	$972,526	$74,460,927
Mar	($77,576)	($2,155,466)	($2,233,042)
Apr	$27,429,595	$3,747,527	$31,177,122
May	$37,696,949	$4,273,858	$41,970,807
Jun	$112,263,355	$21,073,562	$133,336,918
Jul	$142,003,516	$54,182,662	$196,186,178
Aug	$58,797,492	$7,018,763	$65,816,255
Sep	$83,007,153	$22,306,544	$105,313,697
Oct	$23,554,381	($2,044,975)	$21,509,405
Nov	$30,044,673	$4,095,797	$34,140,470
Dec	$150,293,779	$26,456,212	$176,749,991
Total	$909,551,072	$138,712,214	$1,048,263,286

Auction Revenue Rights

FTRs and ARRs are both financial instruments that entitle the holder to receive revenues or to pay charges based on nodal price differences. FTRs provide holders with revenues or charges based on the locational congestion price differences actually experienced in the Day-Ahead Energy Market while ARRs are financial instruments that entitle their holders to receive revenue or to pay charges based on prices determined in the Annual FTR Auction.[35] These price differences are based on the bid prices of participants in the Annual FTR Auction which relate to their expectations about the level of congestion in the Day-Ahead Energy Market. The auction clears the set of feasible

35 These nodal prices are a function of the market participants' annual FTR bids and binding transmission constraints. An optimization algorithm selects the set of feasible FTR bids that produces the most net revenue.

FTR bids which produce the highest net revenue. In other words, ARR revenues are a function of FTR auction participants' expectations of locational congestion price differences in the Day-Ahead Energy Market.

ARRs are available to the nearest 0.1 MW. The ARR target allocation is equal to the product of the ARR MW and the price difference between sink and source from the Annual FTR Auction. An ARR value can be positive or negative depending on the sink-minus-source price difference, with a negative difference resulting in a liability for the holder. The ARR target allocation represents the revenue that an ARR holder should receive. All ARR holders receive ARR credits equal to their target allocations if total net revenues from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions are greater than, or equal to, the sum of all ARR target allocations. ARR credits can be positive or negative and can range from zero to the ARR target allocation. If the combined net revenues from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions are less than that, available revenue is proportionally allocated among all ARR holders.

ARRs are available only as obligation hedge type and 24-hour class type products. An ARR obligation provides a credit, positive or negative, equal to the product of the ARR MW and the price difference between ARR sink and source that occurs in the Annual FTR Auction. The 24-hour products are effective 24 hours a day, seven days a week.

When a new control zone is integrated into PJM, the participants in that control zone must choose to receive either an FTR allocation or an ARR allocation before the start of the Annual FTR Auction for two consecutive planning periods following their integration date. After the transition period, such participants receive ARRs from the annual allocation process and are ineligible for directly allocated FTRs.

Market Structure

ARRs have been available to network service and firm, point-to-point transmission service customers since June 1, 2003, when the annual ARR allocation was first implemented for the 2003 to 2004 planning period. The initial allocation covered the Mid-Atlantic Region and the AP Control Zone. For the 2006 to 2007 planning period, the choice of ARRs or direct allocation FTRs was available to eligible market participants in the AEP, DAY, DLCO and Dominion control zones. For the 2007 to 2008 and subsequent planning periods, all eligible market participants were allocated ARRs.

Supply

ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs and the numerous combinations of ARRs that are feasible.

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ARR Allocation

For the 2007 to 2008 planning period, the annual ARR allocation process was revised to include Long Term ARRs that would be in effect for 10 consecutive planning periods.[36] Long Term ARRs can give LSEs the ability to hedge their congestion costs on a long-term basis by providing price certainty throughout the 10 planning period time frame. Long Term ARR holders can opt out of any planning period during the 10 planning period timeline and self schedule their Long Term ARRs as FTRs.

Each March, PJM allocates ARRs to eligible customers in a three-stage process, whereby the first and second stages are each one round and the third stage is a three-round allocation procedure:

- **Stage 1A.** In the first stage of the allocation, network transmission service customers can obtain Long Term ARRs, up to their share of the zonal base load, after taking into account generation resources that historically have served load in each control zone and up to 50 percent of their historical nonzone network load. Nonzone network load is load that is located outside of the PJM footprint. Firm, point-to-point transmission service customers can obtain Long Term ARRs, based on up to 50 percent of the MW of long-term, firm, point-to-point transmission service provided between the receipt and delivery points for the historical reference year. Stage 1A ARR holders can also opt out of any planning period during the 10-planning-period timeline and self schedule their Long Term ARRs as FTRs.

- **Stage 1B.** ARRs unallocated in Stage 1A are available in the Stage 1B allocation. Network transmission service customers can obtain ARRs, up to their share of the zonal peak load, based on generation resources that historically have served load in each control zone and up to 100 percent of their transmission responsibility for nonzone network load. Firm, point-to-point transmission service customers can obtain ARRs based on the MW of long-term, firm, point-to-point service provided between the receipt and delivery points for the historical reference year. These long-term point-to-point service agreements must also remain in effect for the planning period covered by the allocation.

- **Stage 2.** The third stage of the annual ARR allocation is a three-step procedure, with one-third of the remaining system capability allocated in each step of the process. Network transmission service customers can obtain ARRs from any hub, control zone, generator bus or interface pricing point to any part of their aggregate load in the control zone or load aggregation zone for which an ARR was not allocated in Stage 1A or Stage 1B. Firm, point-to-point transmission service customers can obtain ARRs consistent with their transmission service as in Stage 1A and Stage 1B.

Prior to the start of the Stage 2 annual ARR allocation process, ARR holders can relinquish any portion of their ARRs resulting from the Stage 1A or Stage 1B allocation process, provided that all remaining outstanding ARRs are simultaneously feasible following the return of such ARRs.[37] Participants may seek additional ARRs in the Stage 2 allocation.

36 See the *2006 State of the Market Report* (March 8, 2007) for the rules of the annual ARR allocation process for the 2006 to 2007 and prior planning periods.
37 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), pp. 21.

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ARRs can also be traded between LSEs, but these trades must be made before the first round of the Annual FTR Auction. LSEs trading ARRs must trade all of their ARRs associated with a control zone and their zonal network service peak load is also reassigned to the new LSE. Traded ARRs are effective for the full 12-month planning period.

When ARRs are allocated, all ARRs must be simultaneously feasible to ensure that the physical transmission system can support the approved set of ARRs. In making simultaneous feasibility determinations, PJM utilizes a power flow model of security-constrained dispatch that takes into account generation and transmission facility outages and is based on reasonable assumptions about the configuration and availability of transmission capability during the planning period.[38] This simultaneous feasibility requirement is necessary to ensure that there are sufficient revenues from transmission congestion charges to satisfy all resulting ARR obligations, thereby preventing underfunding of the ARR obligations for a given planning period. If the requested set of ARRs is not simultaneously feasible, customers are allocated prorated shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints:

Equation 8-1 Calculation of prorated ARRs

Individual prorated MW = (Constraint capability) • (Individual requested MW / Total requested MW) • (1 / MW effect on line).[39]

The effect of an ARR request on a binding constraint is measured using the ARR's power flow distribution factor. An ARR's distribution factor is the percent of each requested MW of ARR that would have a power flow on the binding constraint. The PJM methodology prorates those ARR requests with the greatest impact on the binding constraint to avoid prorating more requests but having smaller or minimal impact on the binding constraint. PJM's method results in the prorating of ARRs that cause the greatest flows on the binding constraint instead of those that produce less flow on it. Were all ARR requests prorated equally, irrespective of their proportional impact on the binding constraints, the result would be a significant reduction in market participants' ARRs even when they have little impact on the binding constraints and the reduction of ARRs, and their associated benefits, with primary impacts on unrelated constraints.

Residual ARRs

On June 19, 2007, PJM submitted to the FERC revisions to the OATT to include a new type of ARR known as a residual ARR.[40] On August 13, 2007, the FERC issued an order accepting the revisions to the PJM OATT with an effective date of August 20, 2007.[41] Only ARR holders that had their Stage 1A or Stage 1B ARRs prorated are eligible to receive residual ARRs. Residual ARRs would be available if additional transmission system capability were added during the planning period after the annual ARR allocation. This additional transmission system capability would not have been accounted for in the initial annual ARR allocation, but it enables the creation of residual ARRs. Residual ARRs would be effective on the first day of the month in which the additional

38 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), pp. 54-55.

39 See the *Technical Reference for PJM Markets,* Section 3, "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining this calculation in greater detail.

40 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits revisions to its Amended and Restated Operating Agreement and Open Access Transmission Tariff pursuant to Section 205 of the Federal Power Act, Docket No. ER07-1053-000 (June 19, 2007).

41 *PJM Interconnection, L.L.C.*, Letter Order accepting PJM Interconnection, L.L.C.'s June 19, 2007, filing of Second Revised Sheet No. 6A *et al* to the Third Revised Rate Schedule, FERC No. 24 *et al*, Docket No. ER07-1053-000 (August 13, 2007).

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transmission system capability is included in FTR auctions and would exist until the end of the planning period. For the following planning period, any residual ARRs would be available as ARRs in the annual ARR allocation process as they would be included in the power flow model. The amount of a residual ARR would be the difference between the ARR holder's Stage 1A or Stage 1B request and their actual prorated Stage 1A or Stage 1B ARR MW. Stage 1 ARR holders have a priority right to ARRs and those holders who had ARRs prorated because of the simultaneous feasibility requirement previously had no recourse from the impact of proration. Residual ARRs are a separate product from incremental ARRs. No residual ARRs have been allocated to date.

Incremental ARRs

Market participants constructing generation interconnection or transmission expansion projects may request an allocation of incremental ARRs consistent with the project's increased transmission capability.[42] Incremental ARRs are available in a three-round allocation process with a single point-to-point combination requested and one-third of the incremental ARR MW allocated in each round. Incremental ARRs can be accepted or refused after rounds one and two. If accepted, that ARR is removed from availability in subsequent rounds; if it is refused, that ARR is available in the next rounds. Such incremental ARRs are effective for the lesser of 30 years or the life of the facility or upgrade. At any time during this 30-year period, in place of continuing this 30-year ARR, the participant has a single opportunity to replace the allocated ARRs with a right to request ARRs during the annual ARR allocation process between the same source and sink. Such participants can also permanently relinquish their incremental ARRs at any time during the life of the ARRs as long as overall the system simultaneous feasibility can be maintained.

Table 8-25 lists the incremental ARR allocation volume for the 2008 to 2009, 2009 to 2010 and the 2010 to 2011 planning periods. For the 2010 to 2011 planning period, there were bids for 531 MW and 100 percent of the bids were cleared. For the 2009 to 2010 planning period, there were bids for 531 MW and 100 percent of the bids were cleared.

Table 8-25 Incremental ARR allocation volume: Planning periods 2008 to 2009, 2009 to 2010 and 2010 to 2011

Planning Period	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2008/2009	15	891	891	100%	0	0%
2009/2010	14	531	531	100%	0	0%
2010/2011	14	531	531	100%	0	0%

Incremental ARRs (IARRs) for RTEP Upgrades

IARRs are allocated to Responsible Customers that have been assigned cost responsibility for upgrades included in the PJM's Regional Transmission Expansion Plan (RTEP) that are for a Regional Facility (at or above 500 kV) or a Necessary Lower Voltage Facility (Regionally Assigned Facilities). Responsible Customers as defined in Schedule 12 of the Tariff are network service

42 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 30.

customers and/or merchant transmission facility owners that are assigned the cost responsibility for upgrades included in the PJM RTEP. PJM calculates IARRs for each Regionally Assigned Facility and allocates the IARRs, if any are created by the upgrade, to eligible Responsible Customers based on their percentage of cost responsibility. The Responsible Customer may choose to decline the IARR allocation during the annual ARR allocation process.[43] Each network service customer within a zone is allocated a share of the IARRs identified in each zone based on their percentage share of the network service peak load of the zone. For the annual ARR allocation for the 2010/2011 planning period, 203.6 MWs of IARRs were allocated for RTEP upgrades. Table 8-26 lists the one RTEP upgrade project that was allocated IARRs.

Table 8-26 IARRs allocated for 2010 to 2011 Annual ARR Allocation for RTEP upgrades[44]

		IARR Parameters		
Project #	Project Description	Source	Sink	Total MW
B0287	Install 600 MVAR Dynamic Reactive Device at Elroy 500kV	RTEP B0287 Source	DPL	203.6

Table 8-27 lists the top 10 principal binding constraints, along with their corresponding control zones in order of severity that limited supply in the annual ARR allocation for the 2010 to 2011 planning period. The order of severity is determined by the violation degree of the binding constraint as computed in the simultaneous feasibility test.[45] The violation degree is a measure of the MW that a constraint is over the limit for a type of facility; a higher number indicates a more severe constraint.

Table 8-27 Top 10 principal binding transmission constraints limiting the annual ARR allocation: Planning period 2010 to 2011

Constraint	Type	Control Zone
AP South	Interface	AP
Electric Junction - Nelson	Line	ComEd
State Line - Wolf Lake	Line	Midwest ISO
Cedar Grove - Clifton	Line	PSEG
Roseland - Whippany	Line	PSEG
Brandon Shores - Riverside	Line	BGE
Waterman - West Dekalb	Line	ComEd
Linden - North Ave	Line	PSEG
Bayonne - PVSC	Line	PSEG
Cumberland - Juniata	Line	PPL

Demand

PJM's OATT specifies the types of transmission services that are available to eligible customers. Eligible customers submit requests to PJM for network and firm, point-to-point transmission service

43 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), pp. 31 and "IARRs for RTEP Upgrades Allocated for 2010/2011 Planning Period," <http://www.pjm.com/~/media/markets-ops/ftr/annual-arr-allocation/2010-2011/iarrs-rtep-upgrades-allocated-for-2010-11-planning-period.ashx>.

44 RTEP B0287 Source is a new aggregate comprised of an equal ten percent weighting of the following ten pnodes: MUDDYRN 13 KV Unit1, MUDDYRN 13 KV Unit2, MUDDYRN 13 KV Unit3, MUDDYRN 13 KV Unit4, MUDDYRN 13 KV Unit5, MUDDYRN 13 KV Unit6, MUDDYRN 13 KV Unit7, MUDDYRN 13 KV Unit8, PEACHBOT 22 KV UNIT02 and PEACHBOT 22 KV UNIT03.

45 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), pp. 54-55.

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through the PJM Open Access Same-Time Information System (OASIS). ARRs associated with firm transmission service that spans the entire next planning period, outside of the annual ARR allocation window, can also be requested through the PJM OASIS.[46] PJM evaluates each transmission service request for its impact on the system and approves or denies the request accordingly. All approved transmission services can be accommodated by the PJM transmission system. Theoretically, since total eligible ARR demand for the system cannot exceed the combined MW of network and firm, point-to-point transmission service, ARR supply should equal ARR demand if ARR nominations are consistent with the historic use of the transmission system. However, the demand for some ARRs could be left unmet if the same resources are nominated as ARR source points by multiple parties for delivery across shared paths and the result exceeds the stated capability of the transmission system to deliver from those sources to load. The combination might not be simultaneously feasible. When the requested set of ARRs is not simultaneously feasible, customers are allocated prorated shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints.

ARR Reassignment for Retail Load Switching

Current PJM rules provide that when load switches among LSEs during the planning period, a proportional share of associated ARRs that sink into a given control or load aggregation zone is automatically reassigned to follow that load.[47] ARR reassignment occurs daily only if the LSE losing load has ARRs with a net positive economic value to that control zone. An LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. ARRs are reassigned to the nearest 0.001 MW and any MW of load may be reassigned multiple times over a planning period. Residual ARRs are also subject to the rules of ARR reassignment. This practice supports competition by ensuring that the hedge against congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs. However, when ARRs are self scheduled as FTRs, these underlying self scheduled FTRs do not follow load that shifts while the ARRs do follow load that shifts, and this may diminish the value of the hedge.

The MMU recommends that when load switches among LSEs during the planning period, a proportional share of the underlying self scheduled FTRs follow the load in the same manner that ARRs do. ARRs are assigned to firm transmission service customers because these customers pay the costs of the transmission system that enables firm energy delivery. At the time of the FTR Annual Auction, ARR holders have the ability to acquire FTRs by choosing to self schedule in the annual FTR auction. When load switches among LSEs during the planning period, the LSE gaining load is reassigned its proportional share of the ARRs from the LSE losing load. After the Annual FTR Auction has occurred, the LSE gaining load does not have the ability to self schedule FTRs associated with the reassigned ARRs. The self scheduled FTRs are obtained as the direct result of the ARR assignment and should therefore follow the reassignment of ARRs when load switches in order to ensure that the new LSE is in the same competitive position as the LSE that lost load.

Table 8-28 summarizes ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2009 and December 2010.

46 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), pp. 16-17.
47 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 28.

About 17,831 MW of ARRs associated with $269,600 per MW-day of revenue were automatically reassigned in the first seven months of the 2010 to 2011 planning period. About 19,061 MW of ARRs with $362,400 per MW-day of revenue were reassigned for the entire 12-month 2009 to 2010 planning period.

Table 8-28 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2009, through December 31, 2010

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2009/2010 (12 months)	2010/2011 (7 months)*	2009/2010 (12 months)	2010/2011 (7 months)*
AECO	417	620	$7.6	$4.7
AEP	268	381	$6.3	$9.1
AP	629	906	$76.9	$101.0
BGE	3,162	2,707	$63.2	$41.2
ComEd	3,145	1,976	$10.1	$48.1
DAY	21	93	$0.1	$0.4
DLCO	371	233	$1.0	$1.8
Dominion	0	0	$0.0	$0.0
DPL	952	768	$10.9	$7.5
JCPL	1,151	1,818	$19.3	$19.3
Met-Ed	33	388	$0.8	$6.1
PECO	29	652	$0.5	$5.3
PENELEC	8	310	$0.2	$5.8
Pepco	2,511	1,874	$25.5	$21.6
PPL	4,489	2,279	$103.7	$37.8
PSEG	1,984	2,715	$49.6	$44.9
RECO	62	111	$0.0	$0.1
Total	19,230	17,831	$375.8	$354.5

* Through 31-Dec-10

Market Performance

Volume

Table 8-29 lists the annual ARR allocation volume by stage and round for the 2009 to 2010 and the 2010 to 2011 planning periods. For the 2010 to 2011 planning period, there were 61,793 MW (45.6 percent of total demand) bid in Stage 1A, 27,850 MW (20.5 percent of total demand) bid in Stage 1B and 45,971 MW (33.9 percent of total demand) bid in Stage 2. Of 135,614 MW in total ARR requests, 61,793 MW were allocated in Stage 1A and 27,850 MW were allocated in Stage 1B while 12,200 MW were allocated in Stage 2 for a total of 101,843 MW (75.1 percent) allocated. Eligible

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market participants subsequently converted 55,732 MW of these allocated ARRs into Annual FTRs (54.7 percent of total allocated ARRs), leaving 46,111 MW of ARRs outstanding. For the 2009 to 2010 planning period, there had been 64,987 MW (46.4 percent of total demand) bid in Stage 1A, 26,517 MW (18.9 percent of total demand) bid in Stage 1B and 48,533 MW (34.7 percent of total demand) bid in Stage 2. Of 140,037 MW in total ARR requests, 64,913 MW were allocated in Stage 1A and 26,514 MW were allocated in Stage 1B while 17,986 MW were allocated in Stage 2 for a total of 109,413 MW (78.1 percent) allocated. There were 68,589 MW or 62.7 percent of the allocated ARRs converted into FTRs. ARR holders did not relinquish any ARRs for the 2010 to 2011 planning period. In comparison, for the 2009 to 2010 planning period, ARR holders relinquished 2.9 MW of the allocated Stage 1B ARRs. The uncleared volume in Table 8-29 includes ARRs that were relinquished.

Table 8-29 Annual ARR allocation volume: Planning periods 2009 to 2010 and 2010 to 2011

Planning Period	Stage	Round	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2009/2010	1A	0	7,527	64,987	64,913	99.9%	74	0.1%
	1B	1	3,582	26,517	26,514	100.0%	3	0.0%
	2	2	1,580	16,521	5,680	34.4%	10,841	65.6%
		3	1,157	16,413	6,013	36.6%	10,400	63.4%
		4	994	15,599	6,293	40.3%	9,306	59.7%
		Total	3,731	48,533	17,986	37.1%	30,547	62.9%
	Total		14,840	140,037	109,413	78.1%	30,624	21.9%
2010/2011	1A	0	8,862	61,793	61,793	100.0%	0	0.0%
	1B	1	3,885	27,850	27,850	100.0%	0	0.0%
	2	2	1,901	15,333	4,161	27.1%	11,172	72.9%
		3	1,374	15,321	4,167	27.2%	11,154	72.8%
		4	1,247	15,317	3,872	25.3%	11,445	74.7%
		Total	4,522	45,971	12,200	26.5%	33,771	73.5%
	Total		17,269	135,614	101,843	75.1%	33,771	24.9%

Revenue

As ARRs are allocated to qualifying customers rather than sold, there is no ARR revenue comparable to the revenue that results from the FTR auctions.

Revenue Adequacy

The degree to which ARR credits provide a hedge against congestion on specific ARR paths is determined by the prices that result from the Annual FTR Auction. The resultant ARR credit could be greater than, less than, or equal to the actual congestion on the selected path. This is the same concept as FTR revenue adequacy.

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Customers that are allocated ARRs can choose to retain the underlying FTRs linked to their ARRs through a process termed self scheduling. Just like any other FTR, the underlying FTRs have a target hedge value based on actual day-ahead congestion on the selected path.

As with FTRs, revenue adequacy for ARRs must be distinguished from the adequacy of ARRs as a hedge against congestion. Revenue adequacy is a narrower concept that compares the revenues available to cover congestion across specific paths for which ARRs were available and allocated. The adequacy of ARRs as a hedge against congestion compares ARR revenues to total congestion sinking in the participant's load zone as a measure of the extent to which ARRs hedged market participants against actual, total congestion into their zone, regardless of the availability or allocation of ARRs.

ARR holders will receive $1,028.8 million in credits from the Annual FTR Auction during the 2010 to 2011 planning period, with an average hourly ARR credit of $1.15 per MWh. During the comparable 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.

Table 8-30 lists ARR target allocations and net revenue sources from the Annual and Monthly Balance of Planning Period FTR Auctions for the 2009 to 2010 and the 2010 to 2011 (through December 31, 2010) planning periods. Annual FTR Auction net revenue has been sufficient to cover ARR target allocations for both planning periods. The 2010 to 2011 planning period's Annual and Monthly Balance of Planning Period FTR Auctions generated a surplus of $38.1 million in auction net revenue through December 31, 2010, above the amount needed to pay 100 percent of ARR target allocations. The entire 2009 to 2010 planning period's Annual and Monthly Balance of Planning Period FTR Auctions generated a surplus of $75.8 million in auction net revenue, above the amount needed to pay 100 percent of ARR target allocations.

Table 8-30 ARR revenue adequacy (Dollars (Millions)): Planning periods 2009 to 2010 and 2010 to 2011

	2009/2010	2010/2011
Total FTR auction net revenue	$1,349.3	$1,066.9
Annual FTR Auction net revenue	$1,329.8	$1,050.1
Monthly Balance of Planning Period FTR Auction net revenue*	$19.5	$16.8
ARR target allocations	$1,273.5	$1,028.8
ARR credits	$1,273.5	$1,028.8
Surplus auction revenue	$75.8	$38.1
ARR payout ratio	100%	100%
FTR payout ratio*	96.9%	85.2%

* Shows twelve months for 2009/2010 and seven months ended 31-Dec-10 for 2010/2011

ARR Proration

During the annual ARR allocation process, all ARRs must be simultaneously feasible to ensure that the physical transmission system can support the approved set of ARRs. If all the ARR requests made during the annual ARR allocation process are not feasible, then ARRs are prorated and

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allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.[48,49]

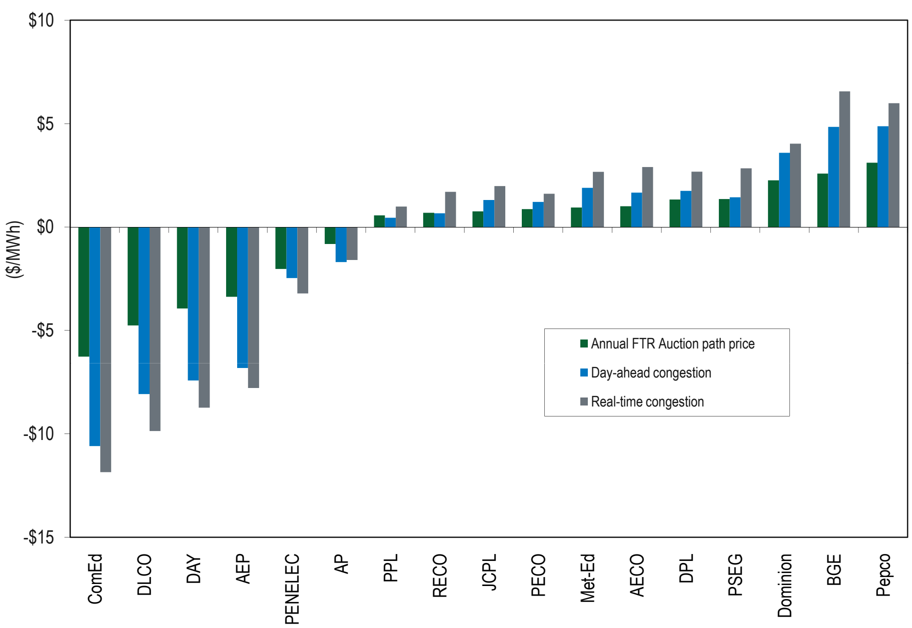
When ARRs were allocated for the 2010 to 2011 planning period, some of the requested ARRs were prorated in Stage 2 in order to ensure simultaneous feasibility. No ARRs were prorated in Stage 1A and Stage 1B since there were no constraints affecting the ARR allocation in these two stages.

ARR and FTR Revenue and Congestion

FTR Prices and Zonal Price Differences

As an illustration of the relationship between FTRs and congestion, Figure 8-12 shows Annual FTR Auction prices and an approximate measure of day-ahead and real-time congestion for each PJM control zone for the 2010 to 2011 planning period through December 31, 2010. The day-ahead and real-time congestion are based on the difference between zonal congestion prices and Western Hub congestion prices. The figure shows, for example, that an FTR from the Western Hub to the PECO Control Zone cost $0.87 per MWh in the Annual FTR Auction and that about $1.21 per MWh of day-ahead congestion and $1.60 per MWh of real-time congestion existed between the Western Hub and the PECO Control Zone. The data shows that congestion costs, approximated in this way, were positive for most control zones located east of the Western Hub while congestion costs were negative and were more negative than the price of FTRs for control zones that are located west of that Hub.

Figure 8-12 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 December 31, 2010



48 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), pp. 24-25.

49 See the *Technical Reference for PJM Markets,* Section 3, "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining the ARR prorating method.

Effectiveness of ARRs as a Hedge against Congestion

One measure of the effectiveness of ARRs as a hedge against congestion is a comparison of the revenue received by the holders of ARRs and the congestion across the corresponding paths in both the Day-Ahead Energy Market and the balancing energy market. The revenue which serves as a hedge for ARR holders comes from the FTR auctions while the revenue for FTR holders is provided by the congestion payments derived directly from the Day-Ahead Energy Market.

The comparison between the revenue received by ARR holders and the actual congestion experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market is presented by control zone in Table 8-31. ARRs and self scheduled FTRs that sink at an aggregate are assigned to a control zone if applicable.[50] Total revenue equals the ARR credits and the FTR credits from ARRs which are self scheduled as FTRs. The ARR credits do not include the credits for the portion of any ARR that was self scheduled as an FTR since ARR holders purchase self scheduled FTRs in the Annual FTR Auction and that revenue is then paid back to the ARR holders, netting the transaction to zero. ARR credits are calculated as the product of the ARR MW (excludes any self scheduled FTR MW) and the sink-minus-source price difference for the ARR path from the Annual FTR Auction.

FTR credits equal FTR target allocations adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and the congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are paid to FTR holders and, depending on market conditions, may be less than the target allocation. The FTR payout ratio equals the percentage of the target allocation that FTR holders actually receive as credits. The FTR payout ratio was 96.9 percent of the target allocation for the 2009 to 2010 planning period.

The “Congestion” column shows the amount of congestion in each control zone from the Day-Ahead Energy Market and the balancing energy market and includes only the congestion costs incurred by the organizations that hold ARRs or self scheduled FTRs. The last column shows the difference between the total revenue and the congestion for each ARR control zone sink.

Data shown are for the 2009 to 2010 planning period summed by ARR control zone sink. For example, the table shows that for the 2009 to 2010 planning period, ARRs allocated to the AECO Control Zone received a total of $16.9 million in revenue which was the sum of $16.3 million in ARR credits and $0.6 million in credits for self scheduled FTRs. This total revenue was $1.0 million less than the congestion costs of $17.9 million from the Day-Ahead Energy Market and the balancing energy market incurred by organizations in the AECO Control Zone that held ARRs or self scheduled FTRs.

50 For Table 8-31 through Table 8-33, aggregates are separated into their individual bus components and each bus is assigned to a control zone. The “PJM” Control Zone does not include all the buses in PJM, but does include all aggregate sinks that are external to PJM or buses that cannot otherwise be assigned to a specific control zone.

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Table 8-31 ARR and self scheduled FTR congestion hedging by control zone: Planning period 2009 to 2010

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference	Percent Hedged
AECO	$16,334,067	$594,669	$16,928,736	$17,916,307	($987,571)	94.5%
AEP	$4,284,698	$144,069,787	$148,354,485	$148,207,387	$147,098	>100%
AP	$45,451,856	$183,064,919	$228,516,775	$45,556,651	$182,960,124	>100%
BGE	$46,459,694	$2,847,697	$49,307,391	$19,446,235	$29,861,156	>100%
ComEd	$14,549,758	$30,963,973	$45,513,731	$80,554,940	($35,041,208)	56.5%
DAY	$6,207,117	$801,013	$7,008,130	$16,300,765	($9,292,635)	43.0%
DLCO	$2,450,918	$1,801	$2,452,719	$25,131,767	($22,679,048)	9.8%
Dominion	$6,134,065	$145,819,810	$151,953,875	$14,763,373	$137,190,503	>100%
DPL	$17,061,417	$799,792	$17,861,209	$32,381,921	($14,520,712)	55.2%
JCPL	$28,119,166	$954,861	$29,074,027	$23,686,835	$5,387,191	>100%
Met-Ed	$108,900	$11,784,177	$11,893,077	$19,927,580	($8,034,502)	59.7%
PECO	$1,932,121	$18,391,851	$20,323,972	($24,109,589)	$44,433,561	>100%
PENELEC	$22,966,832	$12,204,795	$35,171,627	$23,223,101	$11,948,527	>100%
Pepco	$21,798,040	$1,724,179	$23,522,219	$119,615,249	($96,093,030)	19.7%
PJM	$7,727,385	($153,147)	$7,574,238	$9,260,327	($1,686,090)	81.8%
PPL	$1,102,352	$14,750,503	$15,852,855	($25,146,383)	$40,999,238	>100%
PSEG	$83,906,675	$3,078,677	$86,985,352	$4,067,059	$82,918,293	>100%
RECO	($41,455)	$0	($41,455)	$1,429,306	($1,470,761)	0.0%
Total	$326,553,606	$571,699,358	$898,252,964	$552,212,831	$346,040,133	>100%

During the 2009 to 2010 planning period, congestion costs associated with the 109,612 MW of allocated ARRs were $552.2 million. As Table 8-10 indicates, 68,589 MW of ARRs were converted into FTRs through the self scheduling option, with 41,023 MW remaining as ARRs. The 41,023 MW of remaining ARRs provided $326.6 million of ARR credits, while the self scheduled FTRs provided $571.7 million of revenue. Total congestion was fully hedged by the combination of ARRs and self scheduled FTRs (Table 8-31). The effectiveness of ARRs as a hedge depends on the ARR value which is a function of the FTR auction prices, on FTR values for self scheduled FTRs, on congestion patterns in the Day-Ahead Energy Markets, and on the FTR payout ratio.

Effectiveness of ARRs and FTRs as a Hedge against Congestion

Table 8-32 compares the revenue for ARR and FTR holders and the congestion in both the Day-Ahead Energy Market and the balancing energy market for the 2009 to 2010 planning period. This compares the total hedge provided by all ARRs and all FTRs to the total congestion costs within each control zone. ARRs and FTRs that sink at an aggregate or a bus are assigned to a control zone if applicable. ARR credits are calculated as the product of the ARR MW and the price difference (sink minus source) for the ARR path from the Annual FTR Auction. The “FTR Credits” column represents the total FTR target allocation for FTRs that sink in each control zone from the applicable FTRs from the Long Term FTR Auction, Annual FTR Auction, the Monthly Balance

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of Planning Period FTR Auctions and any FTRs that were self scheduled from ARRs, adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are the product of the FTR target allocations and the FTR payout ratio. The FTR payout ratio was 96.9 percent of the target allocation for the 2009 to 2010 planning period. The “FTR Auction Revenue” column shows the amount paid for FTRs that sink in each control zone from the applicable FTRs from the Long Term FTR Auction, the Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions and any ARRs that were self scheduled as FTRs. ARR holders that self schedule FTRs purchased the FTRs in the Annual FTR Auction and that revenue was then paid back to those ARR holders through ARR credits on a monthly basis throughout the planning period, ultimately netting the transaction to zero. The total ARR and FTR hedge is the sum of the ARR credits and the FTR credits minus the FTR auction revenue. The “Congestion” column shows the total amount of congestion in the Day-Ahead Energy Market and the balancing energy market in each control zone. The last column shows the difference between the total ARR and FTR hedge and the congestion cost for each control zone.

The results indicate that the value of ARRs and FTRs together hedged 96.2 percent of total congestion costs. During the 2009 to 2010 planning period, the 109,413 MW of cleared ARRs produced $1,274.6 million of ARR credits while the total of all FTR credits was $879.8 million. Together, the ARR credits and FTR credits provided $2,154.4 million in total revenue. When calculating the total ARR and FTR hedge, the cost to obtain the FTRs must be subtracted from the total ARR and FTR revenue. This cost is the sum of the FTR auction revenues, which was $1,368.7 million for the 2009 to 2010 planning period. The total ARR and FTR value equals $785.7 million, which is less than the $817.0 million of congestion in the Day-Ahead Energy Market and the balancing energy market. For example, the table shows that all ARRs and FTRs that sink in the AP Control Zone received $365.0 million in ARR credits and $185.8 million in FTR credits. After subtracting the cost of the FTRs, the FTR auction revenue of $324.1 million, the total ARR and FTR hedge was $226.7 million. The total value of the ARRs and FTRs was $93.7 million higher than the $133.0 million of congestion in the Day-Ahead Energy Market and the balancing energy market.

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Table 8-32 ARR and FTR congestion hedging by control zone: Planning period 2009 to 2010

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
AECO	$19,253,322	$4,219,721	$25,540,714	($2,067,671)	$10,817,043	($12,884,714)	0.0%
AEP	$223,262,229	$157,919,018	$214,898,039	$166,283,208	$101,031,029	$65,252,179	>100%
AP	$365,048,488	$185,774,650	$324,136,428	$226,686,710	$132,996,453	$93,690,257	>100%
BGE	$52,131,739	$29,778,076	$34,611,142	$47,298,673	$40,787,754	$6,510,919	>100%
ComEd	$27,261,279	$61,701,901	$12,504,362	$76,458,818	$192,953,092	($116,494,274)	39.6%
DAY	$7,505,314	$1,208,852	($146,827)	$8,860,993	$7,993,310	$867,683	>100%
DLCO	$2,454,337	$10,773,597	($3,631,769)	$16,859,703	$25,084,077	($8,224,374)	67.2%
Dominion	$213,840,239	$156,718,198	$240,575,877	$129,982,560	$150,288,685	($20,306,125)	86.5%
DPL	$18,915,429	$13,281,446	$38,621,277	($6,424,402)	$28,398,375	($34,822,777)	0.0%
JCPL	$34,924,192	($890,074)	$44,362,866	($10,328,748)	$18,958,788	($29,287,536)	0.0%
Met-Ed	$27,312,021	$15,468,233	$35,876,903	$6,903,351	$4,609,666	$2,293,685	>100%
PECO	$49,863,646	$21,467,430	$56,377,913	$14,953,163	($22,617,637)	$37,570,800	>100%
PENELEC	$49,412,326	$61,808,839	$63,892,689	$47,328,476	$58,884,119	($11,555,643)	80.4%
Pepco	$23,702,306	$111,232,601	$102,336,490	$32,598,417	$66,040,760	($33,442,343)	49.4%
PJM	$9,979,482	($4,934,756)	($3,846,501)	$8,891,227	$8,551,453	$339,774	>100%
PPL	$55,143,860	$21,032,754	$65,711,467	$10,465,147	($8,203,127)	$18,668,274	>100%
PSEG	$94,609,270	$34,463,423	$119,797,997	$9,274,696	($1,140,092)	$10,414,788	>100%
RECO	($41,455)	($1,186,779)	($2,875,400)	$1,647,166	$1,562,712	$84,454	>100%
Total	$1,274,578,024	$879,837,129	$1,368,743,667	$785,671,486	$816,996,460	($31,324,974)	96.2%

Table 8-33 shows that for the 2009 to 2010 planning period, the total value of the ARR and FTR positions was $31.3 million less than the total congestion within PJM. All ARRs and FTRs hedged 96.2 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM. For the first seven months of the 2010 to 2011 planning period, the FTR payout ratio was 85.2 percent of the target allocation. All ARRs and FTRs covered 78.7 percent of the total congestion costs within PJM for the first seven months of the 2010 to 2011 planning period. The total value of the ARR and FTR positions was less than the cost of congestion by $207.7 million.

Table 8-33 ARR and FTR congestion hedging: Planning periods 2009 to 2010 and 2010 to 2011[51]

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*	$603,465,391	$804,051,163	$640,632,851	$766,883,703	$974,618,985	($207,735,282)	78.7%

* Shows seven months ended 31-Dec-10

51 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 seven months (June through December 2010) 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 seven months of this planning period and the portion of Annual FTR Auction revenue distributed to the first seven months.

ARRs and FTRs as a Hedge against Total Real Time Energy Charges

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 direct measure of the net price of energy rather than a comparison of the ARR/FTR credits to an accounting measure of congestion. This measures the value of the hedge against real time energy costs provided by ARRs and FTRs purchased for this period. Table 8-34 shows the total value of ARRs received by those who pay for the transmission system plus the total value of FTRs received by those who purchased FTRs in the FTR auctions. The combined ARR plus FTR credits covers the largest percentage of total energy charges in the AP Control Zone (16.8 percent), and the lowest percentage of total energy charges in the RECO Control Zone (0.7 percent).

Table 8-34 ARRs and FTRs as a hedge against energy charges by control zone: Calendar year 2010

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	$11,331,731	($1,253,200)	$10,078,531	$648,843,903	1.6%
AEP	$197,171,258	$19,086,147	$216,257,405	$5,446,688,183	4.0%
AP	$374,775,181	$1,694,199	$376,469,380	$2,236,317,432	16.8%
BGE	$41,961,361	$34,967,124	$76,928,485	$2,028,384,691	3.8%
ComEd	$70,826,510	$29,508,528	$100,335,037	$3,654,271,600	2.7%
DAY	$7,144,529	($27,716)	$7,116,813	$690,554,201	1.0%
DLCO	$3,976,605	$17,232,438	$21,209,043	$583,038,268	3.6%
Dominion	$247,160,002	$21,337,739	$268,497,741	$5,445,331,798	4.9%
DPL	$15,793,341	$1,609,810	$17,403,150	$1,063,993,554	1.6%
JCPL	$24,705,469	($678,592)	$24,026,877	$1,340,425,345	1.8%
Met-Ed	$15,378,117	$11,053,779	$26,431,896	$818,645,514	3.2%
PECO	$37,079,205	$5,585,082	$42,664,287	$2,257,763,964	1.9%
PENELEC	$30,547,049	$36,419,581	$66,966,631	$791,735,853	8.5%
Pepco	$23,617,240	$39,947,933	$63,565,173	$1,898,879,568	3.3%
PJM	$17,311,724	$413,799	$17,725,523	NA	NA
PPL	$25,599,188	($253,197)	$25,345,991	$2,113,296,887	1.2%
PSEG	$63,669,715	($9,370,259)	$54,299,456	$2,562,025,594	2.1%
RECO	$37,522	$589,661	$627,183	$84,770,663	0.7%
Total	$1,208,085,747	$207,862,855	$1,415,948,602	$33,717,296,942	4.2%

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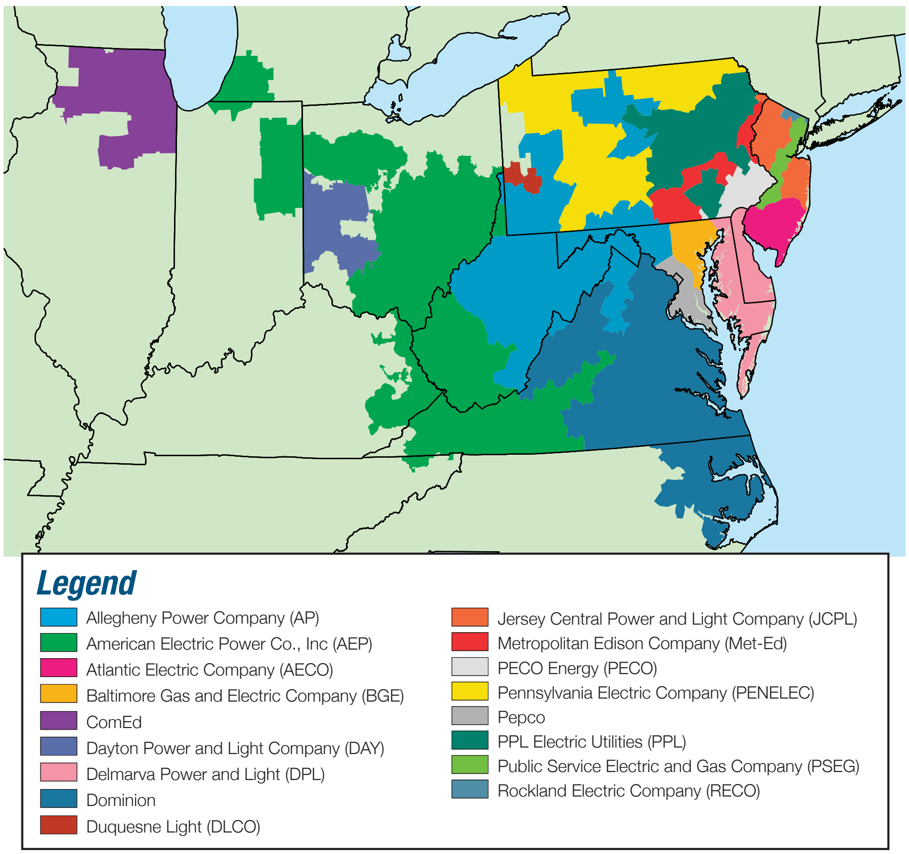
APPENDIX A – PJM GEOGRAPHY

During 2010, the PJM geographic footprint encompassed 17 control zones located in Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

Figure A-1 PJM's footprint and its 17 control zones



Analysis of 2010 market results requires comparison to 2009 and certain other prior years. During calendar years 2006 through 2010 the PJM footprint was stable. During calendar years 2004 and 2005, however, PJM integrated five new control zones, three in 2004 and two in 2005. When making comparisons involving this period, the 2004, 2005 and 2006 state of the market reports referenced phases, each corresponding to market integration dates:[1]

1 See the *2004 State of the Market Report* (March 8, 2005) for more detailed descriptions of Phases 1, 2 and 3 and the *2005 State of the Market Report* (March 8, 2006) for more detailed descriptions of Phases 4 and 5.

- **Phase 1 (2004).** The four-month period from January 1, through April 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones,[2] and the Allegheny Power Company (AP) Control Zone.[3]

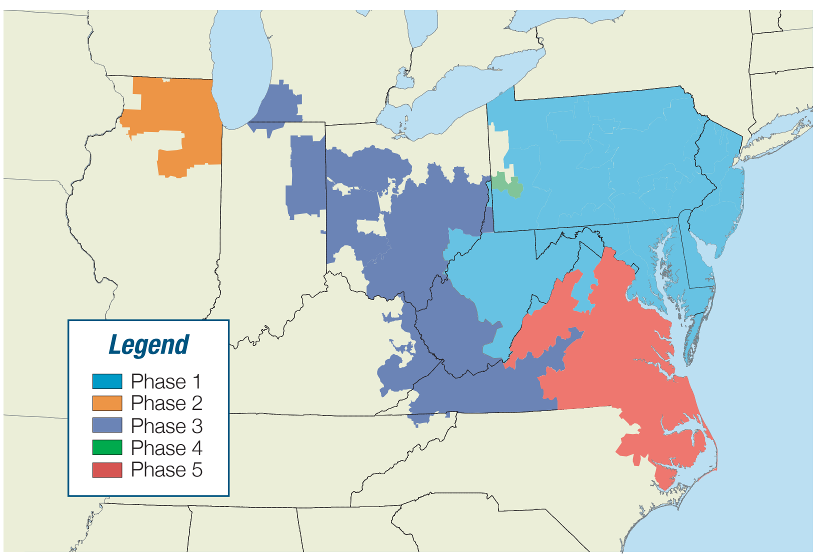
- **Phase 2 (2004).** The five-month period from May 1, through September 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the ComEd Control Area.[4]

- **Phase 3 (2004).** The three-month period from October 1, through December 31, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the ComEd Control Zone plus the American Electric Power Control Zone (AEP) and The Dayton Power & Light Company Control Zone (DAY). The ComEd Control Area became the ComEd Control Zone on October 1.

- **Phase 4 (2005).** The four-month period from January 1, through April 30, 2005, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone, the ComEd Control Zone, the AEP Control Zone and the DAY Control Zone plus the Duquesne Light Company (DLCO) Control Zone which was integrated into PJM on January 1, 2005.

- **Phase 5 (2005).** The eight-month period from May 1, through December 31, 2005, during which PJM was comprised of the Phase 4 elements plus the Dominion Control Zone which was integrated into PJM on May 1, 2005.

Figure A-2 PJM integration phases



2 The Mid-Atlantic Region is comprised of the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO control zones.

3 Zones, control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. Names apply to the geographic area, not to any single company. The geographic areas did not change with the formalization of these concepts during PJM integrations. For simplicity, zones are referred to as control zones for all phases. The only exception is ComEd which is called the ComEd Control Area for Phase 2 only.

4 During the five-month period May 1, through September 30, 2004, the ComEd Control Zone (ComEd) was called the Northern Illinois Control Area (NICA).

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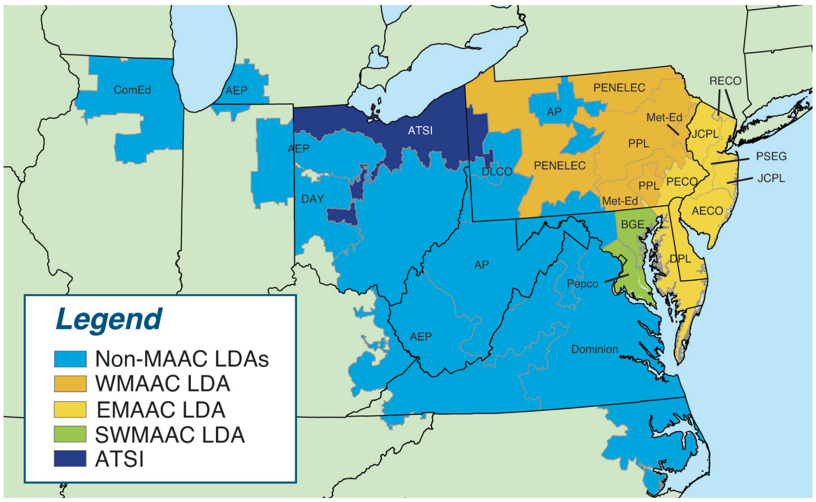
A locational deliverability area (LDA) is a geographic area within PJM that has limited transmission capability to import capacity in the RPM design to satisfy its reliability requirements, as determined by PJM in connection with the preparation of the Regional Transmission Expansion Plan[5] (RTEP) and as specified in Schedule 10.1 of the PJM "Reliability Assurance Agreement with Load-Serving Entities."[6]

Figure A-3 PJM locational deliverability areas[7]

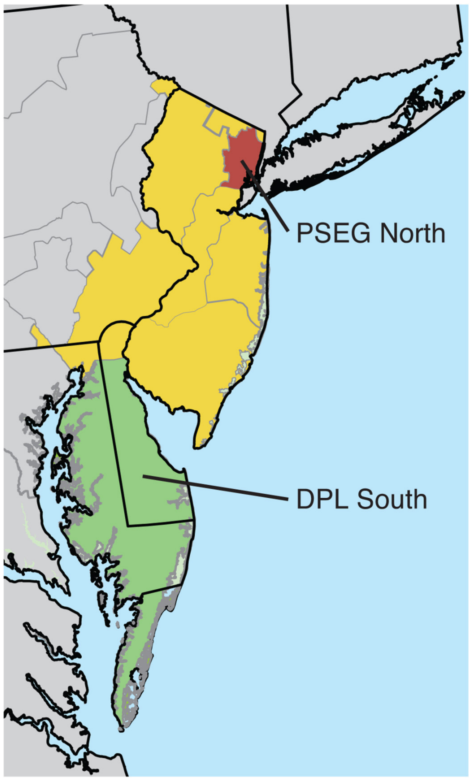


In PJM's Reliability Pricing Model (RPM) Auctions, markets are defined dynamically by LDA. The regional transmission organization (RTO) market comprises the entire PJM footprint, unless a modeled LDA is constrained. Each constrained LDA or group of LDAs is a separate market with a separate clearing price, and the RTO market is the balance of the footprint.

For the 2007/2008 and 2008/2009 Base Residual Auctions, the defined markets were RTO, EMAAC and SWMAAC. For the 2009/2010 Base Residual Auction, the defined markets were RTO, MAAC+APS and SWMAAC. The MAAC+APS LDA consists of the WMAAC, EMAAC, and SWMAAC LDAs, as shown in Figure A-3, plus the Allegheny Power System (APS or AP) zone as shown in Figure A-1. For the 2010/2011 Base Residual Auction, the defined markets were RTO and DPL South. The DPL South LDA is shown in Figure A-4. For the 2011/2012 Base Residual Auction, the only defined market was RTO. For the 2012/2013 Base Residual Auction, the defined markets were RTO, MAAC, EMAAC, PSEG North, and DPL South. The PSEG North LDA is shown in Figure A-4. For the 2013/2014 Base Residual Auction, the defined markets were RTO, MAAC, EMAAC, and Pepco.

5 See "Regional Transmission Expansion Plan Report," <http://www.pjm.com/documents/reports/rtep-report.aspx> (Accessed February 8, 2008).
6 See OATT Attachment DD: Reliability Pricing Model," § 2.59.
7 The ATSI zone integration into PJM is effective beginning with the 2011/2012 delivery year. The ATSI zone is considered a non-MAAC LDA.

Figure A-4 PJM RPM EMAAC locational deliverability area markets, including PSEG North and DPL South



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APPENDIX B – PJM MARKET MILESTONES

Year	Month	Event
1996	April	FERC Order 888, "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities"
1997	April	Energy Market with cost-based offers and market-clearing prices
	November	FERC approval of ISO status for PJM
1998	April	Cost-based Energy LMP Market
1999	January	Daily Capacity Market
	March	FERC approval of market-based rates for PJM
	March	Monthly and Multimonthly Capacity Market
	March	FERC approval of Market Monitoring Plan
	April	Offer-based Energy LMP Market
	April	FTR Market
2000	June	Regulation Market
	June	Day-Ahead Energy Market
	July	Customer Load-Reduction Pilot Program
2001	June	PJM Emergency and Economic Load-Response Programs
2002	April	Integration of AP Control Zone into PJM Western Region
	June	PJM Emergency and Economic Load-Response Programs
	December	Spinning Reserve Market
	December	FERC approval of RTO status for PJM
2003	May	Annual FTR Auction
2004	May	Integration of ComEd Control Area into PJM
	October	Integration of AEP Control Zone into PJM Western Region
	October	Integration of DAY Control Zone into PJM Western Region
2005	January	Integration of DLCO Control Zone into PJM
	May	Integration of Dominion Control Zone into PJM
2006	May	Balance of Planning Period FTR Auction
2007	April	First RPM Auction
	June	Marginal loss component in LMPs
2008	June	Day Ahead Scheduling Reserve (DASR) Market
	August	Independent, External MMU created as Monitoring Analytics, LLC
	October	Long Term FTR Auction
	December	Modified Operating Reserve Accounting Rules
	December	Three Pivotal Supplier Test in Regulation Market

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APPENDIX C - ENERGY MARKET

This appendix provides more detailed information about load, locational marginal prices (LMP) and offer-capped units.

Load

Frequency Distribution of Load

Table C-1 provides the frequency distributions of PJM accounting load by hour, for the calendar years 2006 to 2010.[1] The table shows the number of hours (frequency) and the percent of hours (cumulative percent) when the load was between 0 GWh and 20 GWh and then within a given 5-GWh load interval, or for the cumulative column, within the interval plus all the lower load intervals. The integrations of the AP Control Zone in 2002, the ComEd, AEP and DAY control zones in 2004 and the DLCO and Dominion control zones in 2005 mean that annual comparisons of load frequency are significantly affected by PJM's geographic growth.[2]

1 The definitions of load are discussed in the *Technical Reference for PJM Markets,* Section 5, "Load Definitions."
2 See the *2010 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

Table C-1 Frequency distribution of PJM real-time, hourly load: Calendar years 2006 to 2010

	2006		2007		2008		2009		2010	
Load (GWh)	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
0 to 20	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
20 to 25	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
25 to 30	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
30 to 35	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
35 to 40	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
40 to 45	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
45 to 50	2	0.02%	0	0.00%	0	0.00%	15	0.17%	12	0.14%
50 to 55	129	1.50%	79	0.90%	127	1.45%	376	4.46%	272	3.24%
55 to 60	504	7.25%	433	5.84%	517	7.33%	738	12.89%	582	9.89%
60 to 65	689	15.11%	637	13.12%	667	14.92%	836	22.43%	699	17.87%
65 to 70	967	26.15%	890	23.28%	941	25.64%	915	32.88%	805	27.05%
70 to 75	1,079	38.47%	878	33.30%	1,048	37.57%	1,342	48.20%	1,323	42.16%
75 to 80	1,501	55.61%	1,227	47.31%	1,535	55.04%	1,488	65.18%	1,272	56.68%
80 to 85	1,337	70.87%	1,338	62.58%	1,208	68.80%	966	76.21%	948	67.50%
85 to 90	943	81.63%	981	73.78%	916	79.22%	742	84.68%	794	76.56%
90 to 95	569	88.13%	741	82.24%	655	86.68%	549	90.95%	659	84.09%
95 to 100	295	91.50%	577	88.82%	457	91.88%	388	95.38%	487	89.65%
100 to 105	215	93.95%	382	93.18%	292	95.21%	205	97.72%	318	93.28%
105 to 110	161	95.79%	223	95.73%	181	97.27%	121	99.10%	195	95.50%
110 to 115	145	97.44%	179	97.77%	133	98.78%	48	99.65%	151	97.23%
115 to 120	102	98.61%	106	98.98%	58	99.44%	26	99.94%	108	98.46%
120 to 125	45	99.12%	43	99.47%	35	99.84%	5	100.00%	84	99.42%
125 to 130	27	99.43%	31	99.83%	14	100.00%	0	100.00%	40	99.87%
130 to 135	19	99.65%	12	99.97%	0	100.00%	0	100.00%	11	100.00%
135 to 140	19	99.86%	3	100.00%	0	100.00%	0	100.00%	0	100.00%
> 140	12	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

Off-Peak and On-Peak Load

Table C-2 presents summary load statistics for 1998 to 2010 for the off-peak and on-peak hours, while Table C-3 shows the percent change in load on a year-to-year basis. The on-peak period is defined for each weekday (Monday to Friday) as the hour ending 0800 to the hour ending 2300 Eastern Prevailing Time (EPT), excluding North American Electric Reliability Council (NERC) holidays. Table C-2 shows that on-peak load was 22.0 percent higher than off-peak load in 2010. Average load during on-peak hours in 2010 was 4.4 percent higher than in 2009. Off-peak load in 2010 was 5.0 percent higher than in 2009 (Table C-3).

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Table C-2 Off-peak and on-peak load (MW): Calendar years 1998 to 2010

	Average			Median			Standard Deviation		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
1998	25,269	32,344	1.28	24,729	31,081	1.26	4,091	4,388	1.07
1999	26,454	33,269	1.26	25,780	31,950	1.24	4,947	4,824	0.98
2000	26,917	33,797	1.26	26,313	32,757	1.24	4,466	4,181	0.94
2001	26,804	34,303	1.28	26,433	33,076	1.25	4,225	4,851	1.15
2002	31,734	40,314	1.27	30,590	38,365	1.25	6,111	7,464	1.22
2003	33,598	41,755	1.24	32,973	40,802	1.24	5,545	5,424	0.98
2004	44,631	56,020	1.26	43,028	56,578	1.31	10,845	12,595	1.16
2005	70,291	87,164	1.24	68,049	82,503	1.21	12,733	15,236	1.20
2006	71,810	88,323	1.23	70,300	84,810	1.21	11,348	12,662	1.12
2007	73,499	91,066	1.24	71,751	88,494	1.23	11,501	11,926	1.04
2008	72,175	87,915	1.22	70,516	85,431	1.21	11,378	11,205	0.98
2009	68,745	84,337	1.23	67,159	81,825	1.22	10,924	10,523	0.96
2010	72,186	88,066	1.22	70,318	85,435	1.21	12,942	13,753	1.06

Table C-3 Multiyear change in load: Calendar years 1998 to 2010

	Average			Median			Standard Deviation		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
1998	NA	NA	NA	NA	NA	NA	NA	NA	NA
1999	4.7%	2.9%	(1.7%)	4.3%	2.8%	(1.4%)	20.9%	9.9%	(9.1%)
2000	1.8%	1.6%	(0.2%)	2.1%	2.5%	0.5%	(9.7%)	(13.3%)	(4.0%)
2001	(0.4%)	1.5%	1.9%	0.5%	1.0%	0.5%	(5.4%)	16.0%	22.6%
2002	18.4%	17.5%	(0.7%)	15.7%	16.0%	0.2%	44.6%	53.9%	6.4%
2003	5.9%	3.6%	(2.2%)	7.8%	6.4%	(1.3%)	(9.3%)	(27.3%)	(19.9%)
2004	32.8%	34.2%	1.0%	30.5%	38.7%	6.3%	95.6%	132.2%	18.7%
2005	57.5%	55.6%	(1.2%)	58.2%	45.8%	(7.8%)	17.4%	21.0%	3.0%
2006	2.2%	1.3%	(0.8%)	3.3%	2.8%	(0.5%)	(10.9%)	(16.9%)	(6.8%)
2007	2.4%	3.1%	0.7%	2.1%	4.3%	2.2%	1.3%	(5.8%)	(7.1%)
2008	(1.8%)	(3.5%)	(1.7%)	(1.7%)	(3.5%)	(1.8%)	(1.1%)	(6.0%)	(5.0%)
2009	(4.8%)	(4.1%)	0.7%	(4.8%)	(4.2%)	0.6%	(4.0%)	(6.1%)	(2.2%)
2010	5.0%	4.4%	(0.6%)	4.7%	4.4%	(0.3%)	18.5%	30.7%	10.3%

Locational Marginal Price (LMP)

In assessing changes in LMP over time, the Market Monitoring Unit (MMU) examines three measures: simple LMP; load-weighted LMP; and fuel-cost-adjusted, load-weighted LMP. Differences in simple LMP measure the change in reported price. Differences in load-weighted LMP measure the change in reported price weighted by the actual hourly MWh load to reflect what customers actually pay for energy. Differences in fuel-cost-adjusted, load-weighted LMP measure the change in reported price actually paid by load after accounting for the change in price that reflects changes in fuel prices.[3]

Any Load Serving Entity (LSE) may request to settle at a bus LMP or aggregate LMP per rules in PJM Manual 27. The zonal LMP includes every bus in the zone and is not affected by the choices of LSEs. The zonal LMP is defined by weighting each load bus LMP by its hourly individual load bus contribution to the total zonal load. The LMP for a defined aggregate is calculated by weighting each included load bus LMP by its hourly contribution to the total load of the defined aggregate.

In the Day-Ahead Energy Market buyers may submit bids at specific locations such as a transmission zone, aggregate or a single bus. Price sensitive demand bids specify price and MW quantities and a location for the bid. Market participants may submit increment offers or decrement bids at any hub, transmission zone, aggregate, single bus or eligible external interfaces. PJM provides the definitions of the transmission zones, aggregates, and single buses.[4]

Real-Time LMP

Frequency Distribution of Real-Time LMP

Table C-4 provides frequency distributions of PJM real-time hourly LMP for the calendar years 2006 to 2010. The table shows the number of hours (frequency) and the percent of hours (cumulative percent) when the hourly PJM real-time LMP was within a given $10 per MWh price interval and lower than $300 per MWh, or within a given $100 per MWh price interval and higher than $300 per MWh, or for the cumulative column, within the interval plus all the lower price intervals.

3 See the *Technical Reference for PJM Markets,* Section 4, "Calculating Locational Marginal Price."
4 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 45 (June 23, 2010), Section 2, pp. 20.

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Table C-4 Frequency distribution by hours of PJM Real-Time Energy Market LMP (Dollars per MWh): Calendar years 2006 to 2010

	2006		2007		2008		2009		2010	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and less	85	0.97%	56	0.64%	94	1.07%	117	1.34%	65	0.74%
$10 to $20	247	3.79%	185	2.75%	129	2.54%	218	3.82%	127	2.19%
$20 to $30	1,958	26.14%	1,571	20.68%	490	8.12%	2,970	37.73%	1,810	22.85%
$30 to $40	1,840	47.15%	1,470	37.47%	1,443	24.54%	2,951	71.42%	3,150	58.81%
$40 to $50	1,405	63.18%	1,108	50.11%	1,533	42.00%	1,269	85.90%	1,462	75.50%
$50 to $60	1,040	75.06%	931	60.74%	1,212	55.79%	555	92.24%	766	84.25%
$60 to $70	662	82.61%	827	70.18%	845	65.41%	276	95.39%	427	89.12%
$70 to $80	479	88.08%	726	78.47%	709	73.49%	151	97.11%	274	92.25%
$80 to $90	347	92.04%	646	85.84%	502	79.20%	95	98.20%	165	94.13%
$90 to $100	230	94.67%	451	90.99%	385	83.58%	62	98.90%	134	95.66%
$100 to $110	162	96.52%	240	93.73%	352	87.59%	30	99.25%	82	96.60%
$110 to $120	95	97.60%	178	95.76%	265	90.61%	21	99.49%	71	97.41%
$120 to $130	61	98.30%	110	97.02%	199	92.87%	15	99.66%	61	98.11%
$130 to $140	46	98.82%	76	97.89%	144	94.51%	7	99.74%	44	98.61%
$140 to $150	27	99.13%	53	98.49%	111	95.78%	9	99.84%	29	98.94%
$150 to $160	16	99.32%	26	98.79%	102	96.94%	3	99.87%	22	99.19%
$160 to $170	11	99.44%	29	99.12%	68	97.71%	3	99.91%	11	99.32%
$170 to $180	6	99.51%	18	99.33%	52	98.30%	5	99.97%	13	99.46%
$180 to $190	3	99.54%	9	99.43%	45	98.82%	0	99.97%	12	99.60%
$190 to $200	5	99.60%	15	99.60%	29	99.15%	1	99.98%	9	99.70%
$200 to $210	3	99.63%	6	99.67%	20	99.37%	1	99.99%	7	99.78%
$210 to $220	7	99.71%	4	99.71%	11	99.50%	1	100.00%	4	99.83%
$220 to $230	1	99.73%	4	99.76%	14	99.66%	0	100.00%	3	99.86%
$230 to $240	1	99.74%	2	99.78%	10	99.77%	0	100.00%	5	99.92%
$240 to $250	1	99.75%	5	99.84%	2	99.80%	0	100.00%	3	99.95%
$250 to $260	1	99.76%	2	99.86%	5	99.85%	0	100.00%	1	99.97%
$260 to $270	0	99.76%	4	99.91%	4	99.90%	0	100.00%	0	99.97%
$270 to $280	3	99.79%	0	99.91%	1	99.91%	0	100.00%	0	99.97%
$280 to $290	1	99.81%	0	99.91%	1	99.92%	0	100.00%	1	99.98%
$290 to $300	0	99.81%	0	99.91%	0	99.92%	0	100.00%	0	99.98%
$300 to $400	11	99.93%	2	99.93%	6	99.99%	0	100.00%	2	100.00%
$400 to $500	2	99.95%	4	99.98%	1	100.00%	0	100.00%	0	100.00%
$500 to $600	1	99.97%	1	99.99%	0	100.00%	0	100.00%	0	100.00%
$600 to $700	1	99.98%	1	100.00%	0	100.00%	0	100.00%	0	100.00%
> $700	2	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

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Off-Peak and On-Peak, PJM Real-Time, Load-Weighted LMP

Table C-5 shows load-weighted, average real-time LMP for 2009 and 2010 during off-peak and on-peak periods.

Table C-5 Off-peak and on-peak, PJM load-weighted, average LMP (Dollars per MWh): Calendar years 2009 to 2010

	2009			2010			Difference 2009 to 2010		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
Average	$33.76	$43.95	1.30	$39.88	$56.25	1.41	18.1%	28.0%	8.3%
Median	$29.33	$38.46	1.31	$33.09	$45.28	1.37	12.8%	17.7%	4.4%
Standard deviation	$16.99	$17.93	1.06	$23.01	$31.48	1.37	35.5%	75.6%	29.6%

Off-Peak and On-Peak, Real-Time, Fuel-Cost-Adjusted, Load-Weighted, Average LMP

In a competitive market, changes in LMP result from changes in demand and changes in supply. As competitive offers are equivalent to the marginal cost of generation and fuel costs make up more than 80 percent of marginal cost on average for marginal units, fuel cost is a key factor affecting supply and, therefore, the competitive clearing price. In a competitive market, if fuel costs increase and nothing else changes, the competitive price also increases.

The impact of fuel cost on LMP depends on the fuel burned by the marginal units. To account for differences in the impact of fuel costs on prices between different time periods, the fuel-cost-adjusted, load-weighted LMP is used to compare load-weighted LMPs using fuel costs from a base period.[5]

Table C-6 shows the real-time, load-weighted, average LMP for 2009 and the real-time, fuel-cost-adjusted, load-weighted, average LMP for 2010 for on-peak and off-peak hours.

Table C-6 On-peak and off-peak real-time PJM fuel-cost-adjusted, load-weighted, average LMP (Dollars per MWh): Calendar year 2010

	2009 Load-Weighted LMP	2010 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
On Peak	$43.95	$53.64	22.0%
Off Peak	$33.76	$39.27	16.3%

PJM Real-Time, Load-Weighted LMP during Constrained Hours

Table C-7 shows the PJM load-weighted, average LMP during constrained hours for 2009 and 2010.[6,7]

5 See the *Technical Reference for PJM Markets*, Section 7, "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

6 A constrained hour, or a constraint hour, is any hour during which one or more facilities are congested. In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is consistent with the way in which PJM reports real-time congestion.

7 The average real-time, load-weighted LMP in constrained hours for 2009 changed from $40.88 to $40.92 and the median changed from $35.75 to $35.81 compared to what was reported in the *2009 State of the Market Report for PJM*. The change resulted from the correction of a data error.

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Table C-7 PJM real-time load-weighted, average LMP during constrained hours (Dollars per MWh): Calendar years 2009 to 2010

	2009	2010	Difference
Average	$40.92	$49.56	21.1%
Median	$35.81	$39.85	11.3%
Standard deviation	$19.02	$29.83	56.9%

Table C-8 provides a comparison of PJM load-weighted, average LMP during constrained and unconstrained hours for 2009 and 2010.[8]

Table C-8 PJM real-time load-weighted, average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar years 2009 to 2010

	2009			2010		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$32.34	$40.92	26.5%	$39.37	$49.56	25.9%
Median	$29.80	$35.81	20.1%	$35.34	$39.85	12.8%
Standard deviation	$12.90	$19.02	47.4%	$18.46	$29.83	61.6%

Table C-9 shows the number of hours and the number of constrained hours in each month in 2009 and 2010.[9]

Table C-9 PJM real-time constrained hours: Calendar years 2009 to 2010

	2009 Constrained Hours	2010 Constrained Hours	Total Hours
Jan	725	598	744
Feb	571	563	672
Mar	596	576	743
Apr	552	618	720
May	457	592	744
Jun	557	645	720
Jul	537	667	744
Aug	623	633	744
Sep	498	695	720
Oct	562	705	744
Nov	521	653	721
Dec	511	722	744
Avg	559	639	730

8 The average real-time, load-weighted LMP in constrained hours and unconstrained hours for 2009 changed compared to what was reported in the *2009 State of the Market Report for PJM*. The change resulted from the correction of a data error. The average real-time, load-weighted LMP in unconstrained hours for 2009 changed from $32.71 to $32.34, the median changed from $29.95 to $29.80 and the standard deviation changed from 13.26 to 12.90. As a result, the difference between the average real-time, load-weighted LMP in constrained and unconstrained hours as percent changed from 25.0 percent to 26.5 percent, the difference between the median changed from 19.3 percent to 20.1 percent, and the difference between the standard deviation changed from 43.4 percent to 47.4 percent.

9 The average number of constrained hours in 2009 changed compared to what was reported in the *2009 State of the Market Report for PJM*. The change resulted from the correction of a data error. The constrained hours in January changed from 701 hours to 725 hours, the constrained hours in May changed from 439 hours to 457 hours, the constrained hours in July changed from 536 hours to 537 hours, the constrained hours in September changed from 494 hours to 498 hours, the constrained hours in November changed from 520 hours to 521 hours, and the constrained hours in December changed from 506 hours to 511 hours. As a result, the average constrained hours changed from 555 hours to 559 hours.

Day-Ahead and Real-Time LMP

On average, prices in the Real-Time Energy Market in 2010 were slightly higher than those in the Day-Ahead Energy Market and real-time prices showed greater dispersion. This pattern of system average LMP distribution for 2010 can be seen by comparing Table C-4 and Table C-10. Table C-10 shows frequency distributions of PJM day-ahead hourly LMP for the calendar years 2006 to 2010. Together the tables show the frequency distribution by hours for the two markets. In the Real-Time Energy Market, prices reached a high for the year of $346.59 per MWh on August 11, 2010, in the hour ending 1600 EPT. In the Day-Ahead Energy Market, prices reached a high for the year of $199.82 per MWh on July 7, 2010, in the hour ending 1700 EPT.

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Table C-10 Frequency distribution by hours of PJM Day-Ahead Energy Market LMP (Dollars per MWh): Calendar years 2006 to 2010

	2006		2007		2008		2009		2010	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and less	11	0.13%	3	0.03%	0	0.00%	23	0.26%	5	0.06%
$10 to $20	147	1.80%	88	1.04%	19	0.22%	343	4.18%	31	0.41%
$20 to $30	1,610	20.18%	1,291	15.78%	320	3.86%	2,380	31.35%	1,502	17.56%
$30 to $40	1,747	40.13%	1,495	32.84%	1,148	16.93%	3,221	68.12%	2,851	50.10%
$40 to $50	1,890	61.70%	1,221	46.78%	1,546	34.53%	1,717	87.72%	2,131	74.43%
$50 to $60	1,364	77.27%	1,266	61.23%	1,491	51.50%	557	94.08%	954	85.32%
$60 to $70	905	87.60%	1,301	76.08%	1,107	64.11%	253	96.96%	471	90.70%
$70 to $80	524	93.58%	939	86.80%	942	74.83%	138	98.54%	302	94.14%
$80 to $90	237	96.29%	504	92.56%	682	82.59%	68	99.32%	193	96.35%
$90 to $100	145	97.95%	264	95.57%	542	88.76%	33	99.69%	125	97.77%
$100 to $110	65	98.69%	155	97.34%	289	92.05%	19	99.91%	86	98.76%
$110 to $120	38	99.12%	104	98.53%	193	94.25%	6	99.98%	46	99.28%
$120 to $130	11	99.25%	59	99.20%	131	95.74%	2	100.00%	29	99.61%
$130 to $140	8	99.34%	33	99.58%	112	97.02%	0	100.00%	14	99.77%
$140 to $150	8	99.43%	13	99.73%	67	97.78%	0	100.00%	7	99.85%
$150 to $160	7	99.51%	8	99.82%	54	98.39%	0	100.00%	6	99.92%
$160 to $170	6	99.58%	7	99.90%	46	98.92%	0	100.00%	3	99.95%
$170 to $180	6	99.65%	3	99.93%	23	99.18%	0	100.00%	2	99.98%
$180 to $190	3	99.68%	4	99.98%	20	99.41%	0	100.00%	0	99.98%
$190 to $200	3	99.71%	1	99.99%	16	99.59%	0	100.00%	2	100.00%
$200 to $210	3	99.75%	1	100.00%	8	99.68%	0	100.00%	0	100.00%
$210 to $220	3	99.78%	0	100.00%	9	99.78%	0	100.00%	0	100.00%
$220 to $230	1	99.79%	0	100.00%	4	99.83%	0	100.00%	0	100.00%
$230 to $240	3	99.83%	0	100.00%	3	99.86%	0	100.00%	0	100.00%
$240 to $250	2	99.85%	0	100.00%	2	99.89%	0	100.00%	0	100.00%
$250 to $260	1	99.86%	0	100.00%	0	99.89%	0	100.00%	0	100.00%
$260 to $270	2	99.89%	0	100.00%	4	99.93%	0	100.00%	0	100.00%
$270 to $280	1	99.90%	0	100.00%	0	99.93%	0	100.00%	0	100.00%
$280 to $290	1	99.91%	0	100.00%	2	99.95%	0	100.00%	0	100.00%
$290 to $300	1	99.92%	0	100.00%	2	99.98%	0	100.00%	0	100.00%
>$300	7	100.00%	0	100.00%	2	100.00%	0	100.00%	0	100.00%

Off-Peak and On-Peak, Day-Ahead and Real-Time, Simple Average LMP

Table C-11 shows PJM simple average LMP during off-peak and on-peak periods for the Day-Ahead and Real-Time Energy Markets in calendar year 2010. Figure C-1 and Figure C-2 show the difference between real-time and day-ahead LMP in calendar year 2010 during the on-peak and off-peak hours.

Table C-11 Off-peak and on-peak, simple average day-ahead and real-time LMP (Dollars per MWh): Calendar year 2010

	Day Ahead			Real Time			Difference in Real Time Relative to Day Ahead		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
Average	$37.46	$52.67	1.41	$37.44	$53.25	1.42	(0.1%)	1.1%	1.2%
Median	$33.73	$45.48	1.35	$31.83	$43.20	1.36	(5.6%)	(5.0%)	0.6%
Standard deviation	$14.27	$20.07	1.41	$20.93	$28.93	1.38	46.7%	44.1%	(1.8%)

Figure C-1 Hourly real-time LMP minus day-ahead LMP (On-peak hours): Calendar year 2010

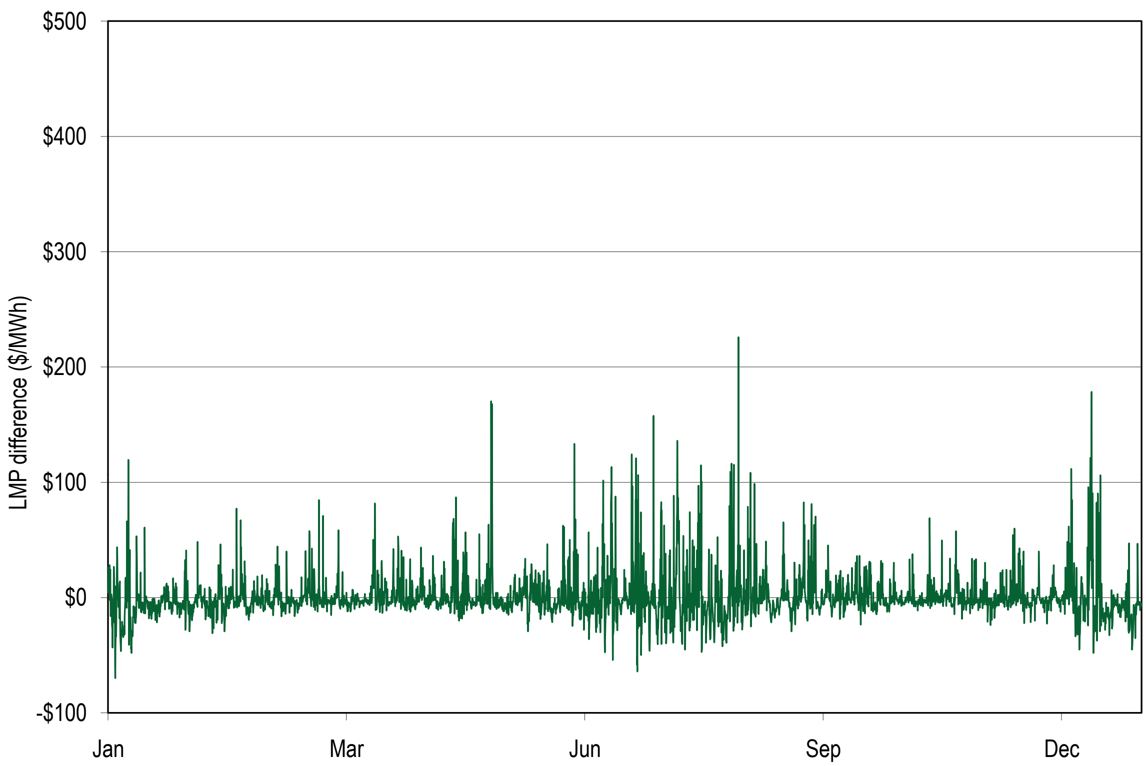

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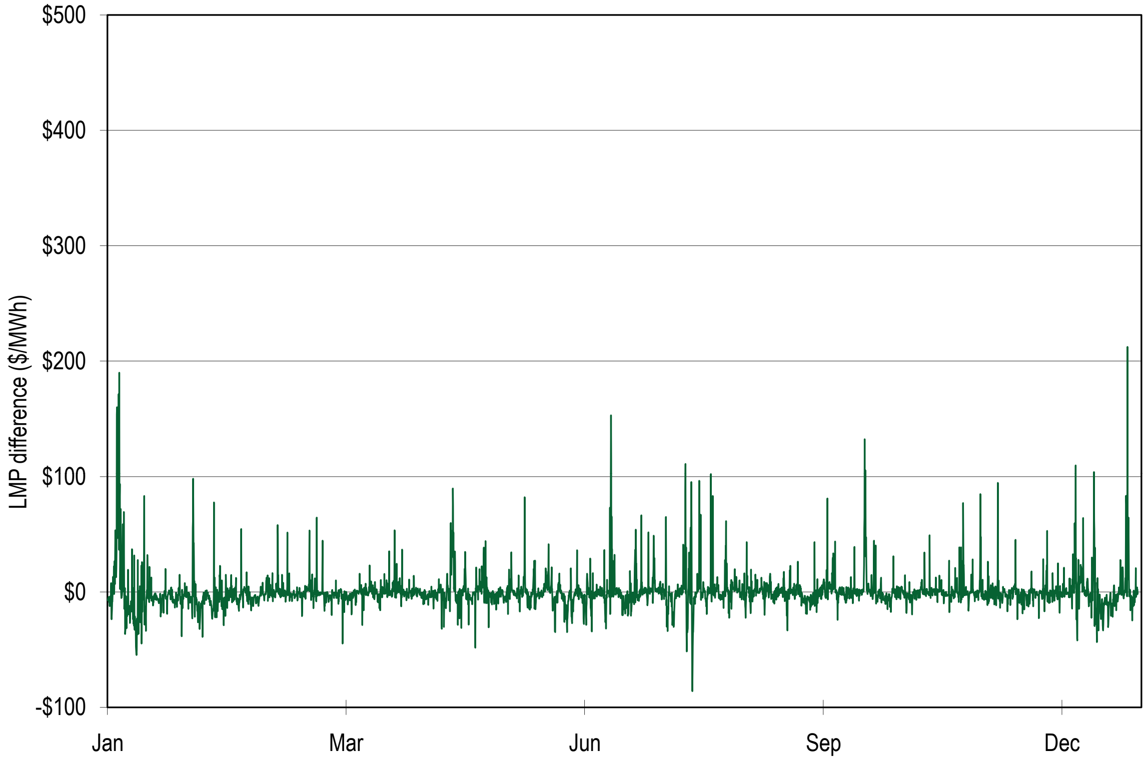
Figure C-2 Hourly real-time LMP minus day-ahead LMP (Off-peak hours): Calendar year 2010



On-Peak and Off-Peak, Zonal, Day-Ahead and Real-Time, Simple Average LMP

Table C-12 and Table C-13 show the on-peak and off-peak, simple average LMPs for each zone in the Day-Ahead and Real-Time Energy Markets in calendar year 2010.

Table C-12 On-peak, zonal, simple average day-ahead and real-time LMP (Dollars per MWh): Calendar year 2010

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$59.71	$60.32	$0.62	1.02%
AEP	$44.49	$44.68	$0.18	0.41%
AP	$52.18	$52.35	$0.17	0.32%
BGE	$63.27	$64.36	$1.08	1.68%
ComEd	$41.37	$41.82	$0.45	1.08%
DAY	$44.39	$44.67	$0.28	0.62%
DLCO	$45.34	$45.81	$0.47	1.03%
Dominion	$59.34	$59.28	($0.06)	(0.11%)
DPL	$59.93	$60.36	$0.44	0.72%
JCPL	$59.42	$59.50	$0.09	0.15%
Met-Ed	$58.18	$58.95	$0.77	1.30%
PECO	$58.41	$58.23	($0.19)	(0.32%)
PENELEC	$51.32	$50.30	($1.02)	(2.02%)
Pepco	$62.57	$62.88	$0.32	0.50%
PPL	$56.28	$56.89	$0.61	1.07%
PSEG	$60.23	$60.93	$0.70	1.14%
RECO	$58.67	$58.36	($0.31)	(0.54%)

Table C-13 Off-peak, zonal, simple average day-ahead and real-time LMP (Dollars per MWh): Calendar year 2010

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$42.31	$42.18	($0.13)	(0.30%)
AEP	$32.86	$32.82	($0.05)	(0.14%)
AP	$37.61	$37.84	$0.23	0.61%
BGE	$44.42	$44.21	($0.21)	(0.48%)
ComEd	$26.34	$25.90	($0.44)	(1.68%)
DAY	$32.34	$32.36	$0.02	0.07%
DLCO	$31.26	$29.52	($1.73)	(5.87%)
Dominion	$43.97	$43.62	($0.35)	(0.81%)
DPL	$42.78	$42.86	$0.08	0.19%
JCPL	$42.12	$41.42	($0.70)	(1.69%)
Met-Ed	$40.90	$40.53	($0.37)	(0.92%)
PECO	$41.83	$41.10	($0.72)	(1.75%)
PENELEC	$37.46	$36.71	($0.74)	(2.03%)
Pepco	$44.49	$44.05	($0.45)	(1.02%)
PPL	$40.11	$39.73	($0.38)	(0.96%)
PSEG	$42.68	$42.24	($0.45)	(1.06%)
RECO	$41.79	$41.11	($0.68)	(1.66%)

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PJM Day-Ahead and Real-Time, Simple Average LMP during Constrained Hours

Table C-14 shows the number of constrained hours for the Day-Ahead and Real-Time Energy Markets and the total number of hours in each month for 2010.

Table C-14 PJM day-ahead and real-time, market-constrained hours: Calendar year 2010

	DA Constrained Hours	RT Constrained Hours	Total Hours
Jan	741	598	744
Feb	168	563	672
Mar	670	576	743
Apr	719	618	720
May	744	592	744
Jun	720	645	720
Jul	720	667	744
Aug	744	633	744
Sep	720	695	720
Oct	744	705	744
Nov	721	653	721
Dec	720	722	744
Avg	678	639	730

Table C-15 shows PJM simple average LMP during constrained and unconstrained hours in the Day-Ahead and Real-Time Energy Markets.

Table C-15 PJM simple average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar year 2010

	Day Ahead			Real Time		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$47.44	$44.35	(6.5%)	$37.27	$45.91	23.2%
Median	$44.13	$39.57	(10.3%)	$34.02	$37.39	9.9%
Standard deviation	$15.12	$19.07	26.1%	$17.45	$27.05	55.1%

Offer-Capped Units

PJM's market power mitigation goals have focused on market designs that promote competition and that limit market power mitigation to situations where market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this situation occurs primarily in the case of local market power. Offer capping occurs only as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets.

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PJM has clear rules limiting the exercise of local market power.[10] The rules provide for offer capping when conditions on the transmission system create a structurally noncompetitive local market, when units in that local market have made noncompetitive offers and when such offers would set the price above the competitive level in the absence of mitigation. Offer caps are set at the level of a competitive offer. Offer-capped units receive the higher of the market price or their offer cap. Thus, if broader market conditions lead to a price greater than the offer cap, the unit receives the higher market price. The rules governing the exercise of local market power recognize that units in certain areas of the system would be in a position to extract monopoly profits, but for these rules.

Under existing rules, PJM suspends offer capping when structural market conditions, as determined by the three pivotal supplier test, indicate that suppliers are reasonably likely to behave in a competitive manner.[11] The goal is to apply a clear rule to limit the exercise of market power by generation owners in load pockets, but to apply the rule in a flexible manner in real time and to lift offer capping when the exercise of market power is unlikely based on the real-time application of the market structure screen.

Levels of offer capping have generally been low and stable over the last five years. Table C-16 through Table C-19 show offer capping by month, including the number of offer-capped units and the level of offer-capped MW in the Day-Ahead and Real-Time Energy Markets.

Table C-16 Average day-ahead, offer-capped units: Calendar years 2006 to 2010

	2006		2007		2008		2009		2010	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	0.1	0.0%	0.2	0.0%	0.5	0.0%	0.7	0.1%	0.3	0.0%
Feb	0.2	0.0%	0.8	0.1%	0.2	0.0%	0.3	0.0%	0.8	0.1%
Mar	0.7	0.1%	0.9	0.1%	0.0	0.0%	0.6	0.1%	1.2	0.1%
Apr	0.2	0.0%	0.2	0.0%	0.2	0.0%	0.0	0.0%	2.0	0.2%
May	0.1	0.0%	0.2	0.0%	0.6	0.1%	0.1	0.0%	2.8	0.3%
Jun	0.7	0.1%	0.8	0.1%	1.5	0.1%	0.3	0.0%	0.5	0.0%
Jul	4.1	0.4%	0.6	0.1%	1.7	0.2%	0.4	0.0%	0.5	0.0%
Aug	4.7	0.5%	1.0	0.1%	0.2	0.0%	0.2	0.0%	0.3	0.0%
Sep	0.6	0.1%	0.2	0.0%	0.4	0.0%	0.1	0.0%	0.3	0.0%
Oct	0.3	0.0%	0.8	0.1%	0.4	0.0%	0.3	0.0%	0.0	0.0%
Nov	0.3	0.0%	0.0	0.0%	0.5	0.0%	0.6	0.1%	0.0	0.0%
Dec	0.7	0.0%	0.1	0.0%	1.3	0.1%	0.6	0.1%	0.0	0.0%

10 See OA Schedule 1, §6.4.2
11 See the *Technical Reference for PJM Markets*, Section 8, "Three Pivotal Supplier Test."

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Table C-17 Average day-ahead, offer-capped MW: Calendar years 2006 to 2010

	2006		2007		2008		2009		2010	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	4	0.0%	23	0.0%	16	0.0%	98	0.1%	17	0.0%
Feb	6	0.0%	57	0.1%	11	0.0%	30	0.0%	98	0.1%
Mar	51	0.1%	86	0.1%	2	0.0%	47	0.1%	117	0.1%
Apr	31	0.0%	11	0.0%	31	0.0%	0	0.0%	129	0.1%
May	22	0.0%	38	0.0%	15	0.0%	9	0.0%	143	0.1%
Jun	164	0.2%	28	0.0%	91	0.1%	42	0.0%	61	0.1%
Jul	518	0.5%	45	0.0%	110	0.1%	35	0.0%	34	0.0%
Aug	398	0.4%	58	0.1%	35	0.0%	10	0.0%	26	0.0%
Sep	51	0.1%	14	0.0%	66	0.1%	3	0.0%	23	0.0%
Oct	27	0.0%	77	0.1%	39	0.0%	29	0.0%	0	0.0%
Nov	15	0.0%	4	0.0%	47	0.1%	50	0.1%	0	0.0%
Dec	40	0.0%	4	0.0%	187	0.2%	29	0.0%	0	0.0%

Table C-18 Average real-time, offer-capped units: Calendar years 2006 to 2010

	2006		2007		2008		2009		2010	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	1.9	0.2%	1.2	0.1%	3.1	0.3%	2.4	0.2%	2.3	0.2%
Feb	2.1	0.2%	4.2	0.4%	2.6	0.3%	1.1	0.1%	1.9	0.2%
Mar	2.3	0.2%	1.9	0.2%	2.7	0.3%	1.8	0.2%	2.5	0.2%
Apr	1.5	0.2%	1.3	0.1%	3.1	0.3%	1.8	0.2%	3.2	0.3%
May	3.4	0.3%	1.9	0.2%	2.1	0.2%	1.0	0.1%	4.5	0.4%
Jun	2.5	0.3%	6.0	0.6%	8.7	0.8%	1.3	0.1%	7.1	0.7%
Jul	8.6	0.9%	4.4	0.4%	5.7	0.6%	1.1	0.1%	9.3	0.9%
Aug	9.5	1.0%	9.6	0.9%	2.0	0.2%	3.0	0.3%	5.8	0.5%
Sep	1.8	0.2%	5.5	0.5%	4.8	0.5%	1.6	0.1%	6.2	0.6%
Oct	1.7	0.2%	5.0	0.5%	2.5	0.2%	1.2	0.1%	3.5	0.3%
Nov	1.1	0.1%	2.9	0.3%	2.2	0.2%	0.6	0.1%	3.1	0.3%
Dec	1.0	0.0%	4.7	0.5%	2.5	0.2%	1.3	0.1%	6.3	0.6%

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Table C-19 Average real-time, offer-capped MW: Calendar years 2006 to 2010

	2006		2007		2008		2009		2010	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	42	0.1%	50	0.1%	99	0.1%	158	0.2%	124	0.1%
Feb	67	0.1%	125	0.1%	92	0.1%	92	0.1%	117	0.1%
Mar	88	0.1%	142	0.2%	117	0.2%	147	0.2%	216	0.3%
Apr	75	0.1%	48	0.1%	125	0.2%	151	0.2%	251	0.4%
May	136	0.2%	68	0.1%	59	0.1%	64	0.1%	337	0.5%
Jun	160	0.2%	190	0.2%	415	0.5%	103	0.1%	382	0.4%
Jul	506	0.5%	160	0.2%	202	0.2%	74	0.1%	473	0.5%
Aug	518	0.6%	314	0.3%	99	0.1%	137	0.2%	253	0.3%
Sep	69	0.1%	218	0.3%	182	0.2%	95	0.1%	378	0.5%
Oct	49	0.1%	153	0.2%	177	0.3%	105	0.2%	345	0.5%
Nov	31	0.0%	104	0.1%	157	0.2%	60	0.1%	382	0.5%
Dec	12	0.0%	146	0.2%	211	0.3%	128	0.2%	538	0.6%

In order to help understand the frequency of offer capping in more detail, Table C-20 through Table C-24 show the number of generating units that met the specified criteria for total offer-capped run hours and percentage of offer-capped run hours for the years 2006 through 2010.

Table C-20 Offer-capped unit statistics: Calendar year 2006

	2006 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%	3	0	0	1	2	0
80% and < 90%	1	5	1	4	3	7
75% and < 80%	0	1	0	2	6	10
70% and < 75%	0	0	0	2	6	18
60% and < 70%	0	1	1	3	5	27
50% and < 60%	0	2	0	0	0	12
25% and < 50%	0	2	1	2	1	31
10% and < 25%	0	0	0	3	9	41

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Table C-21 Offer-capped unit statistics: Calendar year 2007

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2007 Offer-Capped Hours					
	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2	1	3	2	6	0
80% and < 90%	15	3	0	14	13	6
75% and < 80%	0	0	0	0	2	4
70% and < 75%	0	0	2	0	1	3
60% and < 70%	0	0	0	1	3	24
50% and < 60%	1	0	0	0	0	21
25% and < 50%	0	0	0	0	0	51
10% and < 25%	0	0	0	3	12	37

Table C-22 Offer-capped unit statistics: Calendar year 2008

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2008 Offer-Capped Hours					
	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	1	1	4
80% and < 90%	0	0	1	0	4	10
75% and < 80%	0	0	5	4	4	11
70% and < 75%	1	0	1	2	4	9
60% and < 70%	1	0	0	4	4	30
50% and < 60%	0	0	2	3	3	20
25% and < 50%	0	5	10	11	10	57
10% and < 25%	1	0	1	0	6	48

Table C-23 Offer-capped unit statistics: Calendar year 2009

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2009 Offer-Capped Hours					
	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	1	6
80% and < 90%	0	0	0	1	2	13
75% and < 80%	0	0	0	1	0	6
70% and < 75%	0	0	0	1	1	9
60% and < 70%	0	0	0	0	1	21
50% and < 60%	0	0	0	0	1	19
25% and < 50%	0	1	1	2	3	56
10% and < 25%	1	0	0	0	6	53

Table C-24 Offer-capped unit statistics: Calendar year 2010

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2010 Offer-Capped Hours					
	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2	0	0	0	1	13
80% and < 90%	0	2	1	7	8	13
75% and < 80%	0	0	0	0	3	7
70% and < 75%	3	0	0	0	4	13
60% and < 70%	0	1	1	1	0	34
50% and < 60%	1	0	0	5	0	22
25% and < 50%	4	2	4	9	17	41
10% and < 25%	2	0	0	4	2	37

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APPENDIX D - LOCAL ENERGY MARKET STRUCTURE: TPS RESULTS

The three pivotal supplier test is applied by PJM on an ongoing basis in order to determine whether offer capping is required to prevent the exercise of local market power for any constraint.[1]

The MMU analyzed the results of the three pivotal supplier tests conducted by PJM for the Real-Time Energy Market for the period January 1, 2010, through December 31, 2010. The three pivotal supplier test is applied every time the system solution indicates that out of merit resources are needed to relieve a transmission constraint. Only uncommitted resources, which would be started to relieve the transmission constraint, are subject to offer capping. Already committed units that can provide incremental relief cannot be offer capped. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and does not result in offer capping when that is not the case. Local markets are noncompetitive when the number of suppliers is relatively small. The results show that the percentage of tests where one or more suppliers pass the three pivotal supplier test increases as the number of suppliers increases and as the residual supply in the local market increases. The results also show that the percentage of tests where one or more suppliers fail the three pivotal supplier test increases as the number of suppliers decreases and the residual supply in the local market decreases.

This appendix provides data on the TPS tests that were applied in PJM control zones that had congestion from one or more constraints for 100 or more hours. In 2010, the AECO, AEP, AP, BGE, ComEd, DLCO, Dominion, DPL, Met-Ed, PENELEC, PPL and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 100 or more hours. Using the three pivotal supplier results for calendar year 2010, actual competitive conditions associated with each of these frequently binding constraints were analyzed in real time.[2] The DAY, JCPL, PECO, Pepco and RECO Control Zones were not affected by constraints binding for 100 or more hours. Information is provided, by qualifying zone, for each constraint including the number of tests applied, the number of tests that could have resulted in offer capping, and the number of tests in which one or more owners passed and/or failed the three pivotal supplier test.[3] Additional information is provided for each constraint including the average MW required to relieve a constraint, the average supply available, the average number of owners included in each test and the average number of owners that passed or failed each test.

AECO Control Zone Results

In 2010, there was only one constraint in the AECO Control Zone that occurred for more than 100 hours. Table D-1 and Table D-2 show the results of the three pivotal supplier test applied to this constraint. Table D-1 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-1 shows that all 1,913 on peak, and all 2,001 off peak tests resulted in one or more owners failing. Table D-2 shows the average constraint relief required on the constraint, the

1 The FERC eliminated the exemption of interfaces effective May 17, 2008. 123 FERC ¶ 61,169 (2008)

2 See the *Technical Reference for PJM Markets,* Section 8,"Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test.

3 The three pivotal supplier test in the Real-Time Energy Market is applied by PJM as necessary and may be applied multiple times within a single hour for a specific constraint. Each application of the test is done in a five-minute interval.

average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table D-2 shows that on average, there were two owners with available supply on peak and one owner off peak for the Shieldalloy – Vineland line. The three pivotal supplier test results reflect this, as all tests were failed.

Table D-1 Three pivotal supplier results summary for constraints located in the AECO Control Zone: Calendar year 2010

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
Shieldalloy - Vineland	Peak	1,913	0	0%	1,913	100%
	Off Peak	2,001	0	0%	2,001	100%

Table D-2 Three pivotal supplier test details for constraints located in the AECO Control Zone: Calendar year 2010

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Shieldalloy - Vineland	Peak	11	12	2	0	2
	Off Peak	9	11	1	0	1

Table D-3 shows the subset of three pivotal supplier tests from Table D-1 that could have resulted in the offer capping of uncommitted units and those tests that did result in offer capping for the Shieldalloy – Vineland line in the AECO zone. Only two out of 1,913 tests applied to units that were eligible for offer capping on peak. Only six out of 2,001 tests were applied to units that were eligible for offer capping off peak. None of the tests resulted in offer capping.

Table D-3 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the AECO Control Zone: Calendar year 2010

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
Shieldalloy - Vineland	Peak	1,913	2	0%	0	0%	0%
	Off Peak	2,001	6	0%	0	0%	0%

AEP Control Zone Results

In 2010, there were eight constraints that occurred for more than 100 hours in the AEP Control Zone. Table D-4 and Table D-5 show the results of the three pivotal supplier tests applied to the constraints in the AEP Control Zone. Table D-4 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of

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tests with one or more failing owners. Table D-4 shows that most of the tests resulted in one or more owners failing. Table D-5 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table D-5 shows that for five of the eight constraints, the average number of owners with available supply was one.

Table D-4 Three pivotal supplier results summary for constraints located in the AEP Control Zone: Calendar year 2010

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
Carnegie - Tidd	Peak	8,196	0	0%	8,196	100%
	Off Peak	3,060	0	0%	3,060	100%
Cloverdale	Peak	837	74	9%	820	98%
	Off Peak	2,798	75	3%	2,784	99%
Cloverdale - Ivy Hill	Peak	628	0	0%	628	100%
	Off Peak	633	0	0%	633	100%
Cloverdale - Lexington	Peak	2,797	433	15%	2,594	93%
	Off Peak	13,050	1,061	8%	12,764	98%
Dumont - Stillwell	Peak	168	19	11%	155	92%
	Off Peak	2,094	115	5%	2,008	96%
Kanawha River - Kincaid	Peak	2,866	0	0%	2,866	100%
	Off Peak	995	0	0%	995	100%
Mahans Lane - Tidd	Peak	2,801	0	0%	2,801	100%
	Off Peak	1,781	0	0%	1,781	100%
Ruth - Turner	Peak	2,101	0	0%	2,101	100%
	Off Peak	1,319	0	0%	1,319	100%

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Table D-5 Three pivotal supplier test details for constraints located in the AEP Control Zone: Calendar year 2010

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Carnegie - Tidd	Peak	31	54	1	0	1
	Off Peak	32	50	1	0	1
Cloverdale	Peak	178	1,107	11	1	10
	Off Peak	188	1,231	8	0	8
Cloverdale - Ivy Hill	Peak	3	3	1	0	1
	Off Peak	4	3	1	0	1
Cloverdale - Lexington	Peak	217	1,807	16	2	14
	Off Peak	204	1,841	12	1	11
Dumont - Stillwell	Peak	257	2,021	21	2	19
	Off Peak	227	1,652	15	1	14
Kanawha River - Kincaid	Peak	7	6	1	0	1
	Off Peak	7	6	1	0	1
Mahans Lane - Tidd	Peak	16	21	1	0	1
	Off Peak	14	19	1	0	1
Ruth - Turner	Peak	16	9	1	0	1
	Off Peak	13	6	1	0	1

Table D-6 shows the total tests applied for the eight constraints in the AEP zone, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping. Table D-6 shows that only a small fraction of the tests applied to the eight constraints in the AEP zone could have resulted in offer capping. For five of the eight constraints, none of the tests could have resulted in offer capping.

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Table D-6 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the AEP Control Zone: Calendar year 2010

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
Carnegie - Tidd	Peak	8,196	0	0%	0	0%	0%
	Off Peak	3,060	0	0%	0	0%	0%
Cloverdale	Peak	837	69	8%	30	4%	43%
	Off Peak	2,798	35	1%	7	0%	20%
Cloverdale - Ivy Hill	Peak	628	0	0%	0	0%	0%
	Off Peak	633	0	0%	0	0%	0%
Cloverdale - Lexington	Peak	2,797	321	11%	140	5%	44%
	Off Peak	13,050	182	1%	47	0%	26%
Dumont - Stillwell	Peak	168	36	21%	17	10%	47%
	Off Peak	2,094	42	2%	9	0%	21%
Kanawha River - Kincaid	Peak	2,866	0	0%	0	0%	0%
	Off Peak	995	3	0%	0	0%	0%
Mahans Lane - Tidd	Peak	2,801	0	0%	0	0%	0%
	Off Peak	1,781	0	0%	0	0%	0%
Ruth - Turner	Peak	2,101	0	0%	0	0%	0%
	Off Peak	1,319	4	0%	0	0%	0%

AP Control Zone Results

In 2010, there were ten constraints that occurred for more than 100 hours in the AP Control Zone. Table D-7 and Table D-8 show the results of the three pivotal supplier tests applied to the constraints in the AP Control Zone. Table D-7 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-7 shows that most of the tests resulted in one or more owners failing. Table D-8 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing. Table D-8 shows that for six of the ten constraints, the average number of owners with available supply was two or fewer.

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Table D-7 Three pivotal supplier results summary for constraints located in the AP Control Zone: Calendar year 2010

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
Albright - Mt. Zion	Peak	1,595	0	0%	1,595	100%
	Off Peak	1,283	0	0%	1,283	100%
Belmont	Peak	3,921	0	0%	3,921	100%
	Off Peak	769	0	0%	769	100%
Boonsboro - Marlowe	Peak	2,676	0	0%	2,676	100%
	Off Peak	726	0	0%	726	100%
Doubs	Peak	9,177	791	9%	8,700	95%
	Off Peak	1,552	119	8%	1,506	97%
Elrama - Mitchell	Peak	2,832	51	2%	2,800	99%
	Off Peak	9,225	65	1%	9,208	100%
Millvile - Sleepy Hollow	Peak	7,287	0	0%	7,287	100%
	Off Peak	2,001	0	0%	2,001	100%
Millville - Old Chapel	Peak	6,136	0	0%	6,136	100%
	Off Peak	3,157	0	0%	3,157	100%
Mount Storm - Pruntytown	Peak	9,092	1,034	11%	8,773	96%
	Off Peak	13,291	753	6%	13,089	98%
Tiltonsville - Windsor	Peak	5,859	0	0%	5,859	100%
	Off Peak	2,491	0	0%	2,491	100%
Wylie Ridge	Peak	9,846	1,113	11%	9,328	95%
	Off Peak	15,145	1,444	10%	14,445	95%

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Table D-8 Three pivotal supplier test details for constraints located in the AP Control Zone: Calendar year 2010

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Albright - Mt. Zion	Peak	8	10	1	0	1
	Off Peak	13	9	1	0	1
Belmont	Peak	23	18	1	0	1
	Off Peak	15	11	1	0	1
Boonsboro - Marlowe	Peak	36	13	2	0	2
	Off Peak	34	8	2	0	2
Doubs	Peak	25	87	5	1	4
	Off Peak	24	96	5	0	4
Elrama - Mitchell	Peak	90	260	7	0	6
	Off Peak	98	199	5	0	5
Millvile - Sleepy Hollow	Peak	41	25	2	0	2
	Off Peak	24	12	1	0	1
Millville - Old Chapel	Peak	35	16	2	0	2
	Off Peak	34	10	1	0	1
Mount Storm - Pruntytown	Peak	318	1,369	10	1	9
	Off Peak	335	1,393	9	0	8
Tiltonsville - Windsor	Peak	22	11	2	0	2
	Off Peak	16	10	2	0	2
Wylie Ridge	Peak	198	1,099	16	1	15
	Off Peak	201	1,018	14	1	13

Table D-9 shows the total tests applied for the ten constraints in the AP zone, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping. Table D-9 shows that only a small fraction of the tests applied to the ten constraints in the AP zone could have resulted in offer capping. Nine of the constraints had less than two percent of peak or off peak tests that could have resulted in offer capping. The remaining constraint, Mount Storm – Pruntytown, had six percent of its peak and two percent of its off peak tests that could have resulted in offer capping. None of the constraints, including Mount Storm – Pruntytown had more than three percent of its tests result in offer capping.

Table D-9 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the AP Control Zone: Calendar year 2010

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
Albright - Mt. Zion	Peak	1,595	2	0%	0	0%	0%
	Off Peak	1,283	1	0%	1	0%	100%
Belmont	Peak	3,921	0	0%	0	0%	0%
	Off Peak	769	0	0%	0	0%	0%
Boonsboro - Marlowe	Peak	2,676	7	0%	7	0%	100%
	Off Peak	726	1	0%	1	0%	100%
Doubs	Peak	9,177	110	1%	63	1%	57%
	Off Peak	1,552	13	1%	10	1%	77%
Elrama - Mitchell	Peak	2,832	28	1%	14	0%	50%
	Off Peak	9,225	41	0%	13	0%	32%
Millvile - Sleepy Hollow	Peak	7,287	14	0%	14	0%	100%
	Off Peak	2,001	9	0%	9	0%	100%
Millville - Old Chapel	Peak	6,136	5	0%	5	0%	100%
	Off Peak	3,157	1	0%	1	0%	100%
Mount Storm - Pruntytown	Peak	9,092	542	6%	246	3%	45%
	Off Peak	13,291	267	2%	60	0%	22%
Tiltonsville - Windsor	Peak	5,859	12	0%	7	0%	58%
	Off Peak	2,491	7	0%	7	0%	100%
Wylie Ridge	Peak	9,846	236	2%	85	1%	36%
	Off Peak	15,145	231	2%	56	0%	24%

BGE Control Zone Results

In 2010, there were two constraints that occurred for more than 100 hours in the BGE Control Zone. Table D-10 and Table D-11 show the results of the three pivotal supplier tests applied to the constraints in the BGE Control Zone. Table D-10 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-10 shows that about 85 percent of the tests resulted in one or more owners failing. Table D-11 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table D-11 shows that the average number of owners with available supply was 12 for the Brandon

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Shores – Riverside line and the Graceton – Raphael Road line on peak. The average number of owners with available supply were 11 and 10 the Brandon Shores – Riverside line and the Graceton - Raphael Road line off peak.

Table D-10 Three pivotal supplier results summary for constraints located in the BGE Control Zone: Calendar year 2010

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
Brandon Shores - Riverside	Peak	2,901	744	26%	2,473	85%
	Off Peak	498	125	25%	418	84%
Graceton - Raphael Road	Peak	5,776	1,604	28%	5,029	87%
	Off Peak	3,650	1,142	31%	3,153	86%

Table D-11 Three pivotal supplier test details for constraints located in the BGE Control Zone: Calendar year 2010

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Brandon Shores - Riverside	Peak	53	316	12	3	9
	Off Peak	47	341	11	3	8
Graceton - Raphael Road	Peak	89	703	12	3	9
	Off Peak	93	644	10	3	8

Table D-12 shows the total tests applied for the two constraints in the BGE zone, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping. Table D-12 shows that only a small fraction of the tests applied to the two constraints in the BGE zone could have resulted in offer capping. The two constraints in the BGE zone each had six percent or less of their tests that could have resulted in offer capping and each had two percent or less of their tests that resulted in offer capping.

Table D-12 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the BGE Control Zone: Calendar year 2010

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
Brandon Shores - Riverside	Peak	2,901	185	6%	69	2%	37%
	Off Peak	498	24	5%	2	0%	8%
Graceton - Raphael Road	Peak	5,776	96	2%	29	1%	30%
	Off Peak	3,650	93	3%	15	0%	16%

ComEd Control Zone Results

In 2010, there were six constraints that occurred for more than 100 hours in the ComEd Control Zone. Table D-13 and Table D-14 show the results of the three pivotal supplier tests applied to the constraints in the ComEd Control Zone. Table D-13 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-13 shows that most of the tests resulted in one or more owners failing for all constraints except for Wilton Center transformer during on-peak periods. Table D-14 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. The average number of owners with available supply was three or less for five out of six constraints. The average number of owners that passed is significant only for the Wilton Center transformer during on-peak periods.

Table D-13 Three pivotal supplier results summary for constraints located in the ComEd Control Zone: Calendar year 2010

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
Burnham - Sheffield	Peak	1,945	0	0%	1,945	100%
	Off Peak	3,625	2	0%	3,624	100%
East Frankfort - Crete	Peak	1,839	19	1%	1,829	99%
	Off Peak	11,080	195	2%	10,968	99%
Electric Jct - Nelson	Peak	1,622	3	0%	1,621	100%
	Off Peak	1,598	0	0%	1,598	100%
Pleasant Valley - Belvidere	Peak	1,784	0	0%	1,784	100%
	Off Peak	3,059	0	0%	3,059	100%
Waterman - West Dekalb	Peak	970	0	0%	970	100%
	Off Peak	1,293	0	0%	1,293	100%
Wilton Center	Peak	151	61	40%	100	66%
	Off Peak	1,162	96	8%	1,101	95%

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Table D-14 Three pivotal supplier test details for constraints located in the ComEd Control Zone: Calendar year 2010

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Burnham - Sheffield	Peak	108	1,233	2	0	2
	Off Peak	108	812	2	0	2
East Frankfort - Crete	Peak	107	810	3	0	3
	Off Peak	90	681	3	0	3
Electric Jct - Nelson	Peak	38	43	2	0	2
	Off Peak	17	10	2	0	2
Pleasant Valley - Belvidere	Peak	10	4	1	0	1
	Off Peak	5	2	1	0	1
Waterman - West Dekalb	Peak	6	5	1	0	1
	Off Peak	7	17	1	0	1
Wilton Center	Peak	52	139	10	7	3
	Off Peak	111	258	6	1	5

Table D-15 shows the total tests applied for the six constraints in the ComEd zone, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping. Table D-15 shows that only a small fraction of the tests applied to the six constraints in the ComEd zone could have resulted in offer capping. Three of the six constraints in the ComEd zone had no tests that could have resulted in offer capping. The other three constraints in the ComEd zone had seven percent or less of their tests that could have resulted in offer capping and each had one percent or less of their tests that resulted in offer capping.

Table D-15 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the ComEd Control Zone: Calendar year 2010

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
Burnham - Sheffield	Peak	1,945	0	0%	0	0%	0%
	Off Peak	3,625	0	0%	0	0%	0%
East Frankfort - Crete	Peak	1,839	11	1%	4	0%	36%
	Off Peak	11,080	16	0%	4	0%	25%
Electric Jct - Nelson	Peak	1,622	3	0%	1	0%	33%
	Off Peak	1,598	4	0%	0	0%	0%
Pleasant Valley - Belvidere	Peak	1,784	0	0%	0	0%	0%
	Off Peak	3,059	0	0%	0	0%	0%
Waterman - West Dekalb	Peak	970	0	0%	0	0%	0%
	Off Peak	1,293	0	0%	0	0%	0%
Wilton Center	Peak	151	10	7%	1	1%	10%
	Off Peak	1,162	9	1%	1	0%	11%

DLCO Control Zone Results

In 2010, there were two constraints that occurred for more than 100 hours in the DLCO Control Zone. Table D-16 and Table D-17 show the results of the three pivotal supplier tests applied to the constraints in the DLCO Control Zone. Table D-16 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-16 shows that all tests resulted in one or more owners failing. Table D-17 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. The average number of owners with available supply was one or two on peak and off peak for those two constraints.

Table D-16 Three pivotal supplier results summary for constraints located in the DLCO Control Zone: Calendar year 2010

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
Collier - Elwyn	Peak	1,412	0	0%	1,412	100%
	Off Peak	651	0	0%	651	100%
Crescent	Peak	3,704	0	0%	3,704	100%
	Off Peak	47	0	0%	47	100%

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Table D-17 Three pivotal supplier test details for constraints located in the DLCO Control Zone: Calendar year 2010

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Collier - Elwyn	Peak	14	6	1	0	1
	Off Peak	17	14	1	0	1
Crescent	Peak	14	7	1	0	1
	Off Peak	10	11	2	0	2

Table D-18 shows the total tests applied for the two constraints in the DLCO zone, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping. Table D-18 shows that only a small fraction of the tests applied to the two constraints in the DLCO zone could have resulted in offer capping. For the Collier – Elwyn constraint, only three of the 2,063 applied tests could have resulted in offer capping and two of those tests resulted in offer capping. For the Crescent constraint only 16 of the 3,751 applied tests could have resulted in offer capping and only 13 of those tests resulted in offer capping.

Table D-18 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the DLCO Control Zone: Calendar year 2010

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
Collier - Elwyn	Peak	1,412	2	0%	1	0%	50%
	Off Peak	651	1	0%	1	0%	100%
Crescent	Peak	3,704	16	0%	13	0%	81%
	Off Peak	47	0	0%	0	0%	0%

Dominion Control Zone Results

In 2010, there were five constraints that occurred for more than 100 hours in the Dominion Control Zone. Table D-19 and Table D-20 show the results of the three pivotal supplier tests applied to the constraints in the Dominion Control Zone. Table D-19 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-19 shows that most of the tests resulted in one or more owners failing for all constraints except for the Pleasant View transformer during on-peak periods. Table D-20 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. The average number of owners with available supply was less than five on peak and off peak for four out of five constraints. The average number of owners that passed is significant only for the Pleasant View transformer during on-peak periods.

Table D-19 Three pivotal supplier results summary for constraints located in the Dominion Control Zone: Calendar year 2010

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
Beechwood - Kerr Dam	Peak	5,740	0	0%	5,740	100%
	Off Peak	1,444	0	0%	1,444	100%
Bremo - Kidds Store	Peak	1,376	0	0%	1,376	100%
	Off Peak	329	0	0%	329	100%
Clover	Peak	6,809	132	2%	6,753	99%
	Off Peak	1,030	4	0%	1,029	100%
Danville - East Danville	Peak	1,266	15	1%	1,262	100%
	Off Peak	2,275	6	0%	2,275	100%
Pleasant View	Peak	968	440	45%	605	63%
	Off Peak	662	5	1%	659	100%

Table D-20 Three pivotal supplier test details for constraints located in the Dominion Control Zone: Calendar year 2010

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Beechwood - Kerr Dam	Peak	9	36	1	0	1
	Off Peak	7	25	1	0	1
Bremo - Kidds Store	Peak	17	49	1	0	1
	Off Peak	11	47	1	0	1
Clover	Peak	83	249	4	0	3
	Off Peak	97	236	3	0	3
Danville - East Danville	Peak	44	46	3	0	3
	Off Peak	45	39	2	0	2
Pleasant View	Peak	62	125	14	9	5
	Off Peak	55	26	3	0	3

Table D-21 shows the total tests applied for the five constraints in the Dominion zone, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping. Table D-21 shows that only a small fraction of the tests applied to the five constraints in the Dominion zone could have resulted in offer capping. Four of the five constraints in the Dominion zone had one percent or less of applied tests that could have resulted in offer capping. The remaining constraint, Pleasant View, had four percent or less of its applied peak period tests that could have resulted in offer capping.

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Table D-21 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the Dominion Control Zone: Calendar year 2010

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
Beechwood - Kerr Dam	Peak	5,740	0	0%	0	0%	0%
	Off Peak	1,444	1	0%	0	0%	0%
Bremo - Kidds Store	Peak	1,376	0	0%	0	0%	0%
	Off Peak	329	0	0%	0	0%	0%
Clover	Peak	6,809	96	1%	25	0%	26%
	Off Peak	1,030	14	1%	1	0%	7%
Danville - East Danville	Peak	1,266	10	1%	0	0%	0%
	Off Peak	2,275	17	1%	1	0%	6%
Pleasant View	Peak	968	36	4%	7	1%	19%
	Off Peak	662	6	1%	3	0%	50%

DPL Control Zone Results

In 2010, there was only one constraint that occurred for more than 100 hours in the DPL Control Zone. Table D-22 and Table D-23 show the results of the three pivotal supplier tests applied to the constraints in the DPL Control Zone. Table D-22 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-22 shows that all tests resulted in one or more owners failing. Table D-23 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. The average number of owners with available supply was one on peak and one off peak for this constraint.

Table D-22 Three pivotal supplier results summary for constraints located in the DPL Control Zone: Calendar year 2010

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
Kenney - Stockton	Peak	2,889	0	0%	2,889	100%
	Off Peak	418	0	0%	418	100%

Table D-23 Three pivotal supplier test details for constraints located in the DPL Control Zone: Calendar year 2010

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Kenney - Stockton	Peak	33	35	1	0	1
	Off Peak	12	12	1	0	1

Table D-24 shows the total tests applied for the one constraint in the DPL zone, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping. Table D-24 shows that only a small fraction of the tests applied to the one constraint in the DPL zone could have resulted in offer capping. Only 14 out of 2,889 tests could have resulted in offer capping on peak and five of those tests resulted in offer capping. None of the tests applied in the off peak period could have resulted in offer capping.

Table D-24 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the DPL Control Zone: Calendar year 2010

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
Kenney - Stockton	Peak	2,889	14	0%	5	0%	36%
	Off Peak	418	0	0%	0	0%	0%

Met-Ed Control Zone Results

In 2010, there was only one constraint that occurred for more than 100 hours in the Met-Ed Control Zone. Table D-25 and Table D-26 show the result of the three pivotal supplier tests applied to the constraints in the Met-Ed Control Zone. Table D-25 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-25 shows that most of tests resulted in one or more owners failing. Table D-26 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing.

Table D-25 Three pivotal supplier results summary for constraints located in the Met-Ed Control Zone: Calendar year 2010

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
Brunner Island - Yorkana	Peak	4,878	836	17%	4,499	92%
	Off Peak	1,378	20	1%	1,364	99%

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Table D-26 Three pivotal supplier test details for constraints located in the Met-Ed Control Zone: Calendar year 2010

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Brunner Island - Yorkana	Peak	69	467	11	2	9
	Off Peak	68	417	6	0	6

Table D-27 shows the total tests applied for the one constraint in the Met-Ed zone, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping. Table D-27 shows that only a small fraction of the tests applied to the one constraint in the Met-Ed zone could have resulted in offer capping. Only 94 out of 4,878 on peak tests could have resulted in offer capping. Only 36 out of 4,878 on peak tests resulted in offer capping. Only 19 out of 1,378 tests applied off peak could have resulted in offer capping. Only four of the off peak tests resulted in offer capping.

Table D-27 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the Met-Ed Control Zone: Calendar year 2010

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
Brunner Island - Yorkana	Peak	4,878	94	2%	36	1%	38%
	Off Peak	1,378	19	1%	4	0%	21%

PENELEC Control Zone Results

In 2010, there were two constraints that occurred for more than 100 hours in the PENELEC Control Zone. Table D-28 and Table D-29 show the results of the three pivotal supplier tests applied to the constraints in the PENELEC Control Zone. Table D-28 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-28 shows that all tests resulted in one or more owners failing. Table D-29 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. The average number of owners with available supply was two for both constraints.

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Table D-28 Three pivotal supplier results summary for constraints located in the PENELEC Control Zone: Calendar year 2010

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
Erie West	Peak	2,178	0	0%	2,178	100%
	Off Peak	1,814	0	0%	1,814	100%
Roxbury - Shade Gap	Peak	1,609	3	0%	1,608	100%
	Off Peak	1,278	0	0%	1,278	100%

Table D-29 Three pivotal supplier test details for constraints located in the PENELEC Control Zone: Calendar year 2010

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Erie West	Peak	34	13	2	0	2
	Off Peak	45	12	2	0	2
Roxbury - Shade Gap	Peak	12	13	2	0	2
	Off Peak	16	14	2	0	2

Table D-30 shows the total tests applied for the two constraints in the PENELEC zone, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping. Table D-30 shows that only a small fraction of the tests applied to the two constraints in the PENELEC zone could have resulted in offer capping. For the Erie West constraint, only one out of 2,178 on peak tests could have and did result in offer capping. For the Roxbury – Shade Gap constraint, only six out of 1,609 on peak tests could have resulted in offer capping and only five of the tests did result in offer capping. None of the off peak tests for either constraint could have resulted in offer capping.

Table D-30 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the PENELEC Control Zone: Calendar year 2010

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
Erie West	Peak	2,178	1	0%	1	0%	100%
	Off Peak	1,814	0	0%	0	0%	0%
Roxbury - Shade Gap	Peak	1,609	6	0%	5	0%	83%
	Off Peak	1,278	0	0%	0	0%	0%

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PPL Control Zone Results

In 2010, there was only one constraint that occurred for more than 100 hours in the PPL Control Zone. Table D-31 and Table D-32 how the results of the three pivotal supplier tests applied to the constraints in the PPL Control Zone. Table D-31 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-31 shows that most of tests resulted in one or more owners failing. Table D-32 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. The average number of owners with available supply was six on peak and off peak for this constraint.

Table D-31 Three pivotal supplier results summary for constraints located in the PPL Control Zone: Calendar year 2010

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
Harwood - Siegfried	Peak	2,892	53	2%	2,873	99%
	Off Peak	2,054	6	0%	2,053	100%

Table D-32 Three pivotal supplier test details for constraints located in the PPL Control Zone: Calendar year 2010

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Harwood - Siegfried	Peak	86	532	6	0	6
	Off Peak	96	570	6	0	6

Table D-33 shows the total ests applied for the one constraint in the PPL zone, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping. Table D-33 shows that only a small fraction of the tests applied to the one constraint in the PPL zone could have resulted in offer capping. Only nine out of 2,892 on peak tests could have resulted in offer capping. None of the on peak tests resulted in offer capping. Only six of the 2,054 off peak tests could have resulted in offer capping and only two of those tests did result in offer capping.

Table D-33 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the PPL Control Zone: Calendar year 2010

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
Harwood - Siegfried	Peak	2,892	9	0%	0	0%	0%
	Off Peak	2,054	6	0%	2	0%	33%

PSEG Control Zone Results

In 2010, there were two constraints that occurred for more than 100 hours in the PSEG Control Zone. Table D-34 and Table D-35 show the results of the three pivotal supplier tests applied to the constraints in the PSEG Control Zone. Table D-34 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-34 shows that all tests resulted in one or more owners failing. Table D-35 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. For both of the constraints, the average number of owners with available supply was three or less.

Table D-34 Three pivotal supplier results summary for constraints located in the PSEG Control Zone: Calendar year 2010

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
Athenia - Saddlebrook	Peak	2,233	2	0%	2,232	100%
	Off Peak	682	4	1%	681	100%
Branchburg - Readington	Peak	2,452	7	0%	2,449	100%
	Off Peak	922	0	0%	922	100%

Table D-35 Three pivotal supplier test details for constraints located in the PSEG Control Zone: Calendar year 2010

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Athenia - Saddlebrook	Peak	13	39	2	0	2
	Off Peak	29	66	2	0	2
Branchburg - Readington	Peak	39	65	3	0	3
	Off Peak	37	73	2	0	2

Table D-36 shows the total tests applied for the two constraints in the PSEG zone, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping. Table D-36 shows that only a small fraction of the tests applied to the two constraints in the PSEG zone could have resulted in offer capping. The two constraints in the PSEG zone each had four percent or less of their tests that could have resulted in offer capping. The Athenia – Saddlebook constraint had only 107 of its 2,915 applied tests that could have result in offer capping. Only 77 of the 2,915 applied tests did result in offer capping. The Branchburg – Readington constraint had only 53 of its 3,374 applied tests that could have result in offer capping. Only 21 of the 3,374 applied tests did result in offer capping.

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Table D-36 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the PSEG Control Zone: Calendar year 2010

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
Athenia - Saddlebrook	Peak	2,233	96	4%	70	3%	73%
	Off Peak	682	11	2%	7	1%	64%
Branchburg - Readington	Peak	2,452	39	2%	18	1%	46%
	Off Peak	922	14	2%	3	0%	21%

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APPENDIX E - INTERCHANGE TRANSACTIONS

Submitting Transactions into PJM

In competitive wholesale power markets, market participants' decisions to buy and sell power are based on actual and expected prices. If contiguous wholesale power markets incorporate security constrained nodal pricing, well designed interface pricing provides economic signals for import and export decisions by market participants, although those signals may be attenuated by a variety of institutional arrangements.

In order to understand the data on imports and exports, it is important to understand the institutional details of completing import and export transactions. These include the Open Access Same-time Information System (OASIS), North American Electric Reliability Council (NERC) Tags, neighboring balancing authority check out processes, and transaction curtailment rules.[1]

Real-Time Market

Market participants that wish to transact energy into, out of or through PJM in the Real-Time Energy Market are required to make their requests to PJM via the NERC Interchange Transaction Tag (NERC Tag). PJM's Enhanced Energy Scheduler (EES) software interfaces with NERC Tag to create an interface that both PJM market participants and PJM can use to evaluate and manage external transactions that affect the PJM RTO.

All PJM interchange transactions are required to be at least 45 minutes in duration. However, PJM system operators may make adjustments that cause a transaction or interval(s) of the transaction to violate this minimum duration.

Scheduling Requirements

External offers can be made either on the basis of an individual generator (resource specific offer) or an aggregate of generation supply (aggregate offer). Schedules are submitted to PJM by submitting a valid NERC Tag.

Specific timing requirements apply for the submission of schedules. Schedules can be submitted up to 20 minutes prior to the scheduled start time for hourly transactions. Schedules can be submitted up to 4 hours prior to the scheduled start time for transactions that are more than 24 hours in duration. For a schedule to be included in PJM's day-ahead checkout process, the NERC Tag must be approved by all entities who have approval rights, and be in a status of "Implemented", by 1400 (EPT) one day prior to start of schedule. Schedules utilizing the Real-Time with Price option, also known as dispatchable schedules, must be submitted prior to 1200 noon (EPT) the day prior to the scheduled start time. Schedules utilizing firm point-to-point transmission service must be submitted by 1000 (EPT) one day prior to start of schedule. Transactions utilizing firm point-to-point transmission submitted after 1000 (EPT) one day prior will be accommodated if practicable.

1 The material in this section is based in part on PJM Manual M-41: Managing Interchange. See PJM. "M-41: Managing Interchange", Revision 03 (November 24, 2008).

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Acquiring Ramp

PJM allows market participants to reserve ramp while they complete their scheduling responsibilities. The ramp reservation is validated against the submitted NERC Tag to ensure the energy profile and path matches. Upon submission of a ramp reservation request, if PJM verifies ramp availability, the ramp reservation will move into a status of "Pending Tag" which means that it is a valid reservation that can be associated with a NERC Tag to complete the scheduling process.

Specific timing requirements apply for the submission of ramp reservations. Ramp reservations can be made up to 30 minutes prior to the scheduled start time for hourly transactions. Ramp reservations can be made up to 4 hours prior to start time for transactions that are more than 24 hours in duration. Ramp reservations utilizing the Real-Time with Price option must be made prior to 1200 noon (EPT) the day prior to the scheduled start time. Ramp reservations expire if they are not used.

Acquiring Transmission

All external transaction requests require a confirmed transmission reservation from the PJM OASIS.[2] Due to ramp limitations, PJM may require market participants to shift their transaction requests. If the market participant shifts the request up to one hour in either direction, they are not required to purchase additional transmission. If the market participant chooses to fix a ramp violation by extending the duration of the transaction, they do not have to purchase additional transmission if the total MWh capacity of the transmission request is not exceeded, and the transaction does not extend beyond one hour prior to the start, or one hour past the end time of the transmission reservation.

Transmission Products

The OASIS products available for reservation include firm, network, non-firm and spot import service. The product type designated on the OASIS reservation determines when and how the transaction can be curtailed.

- **Firm.** Transmission service that is intended to be available at all times.
- **Network.** Transmission service that is for the sole purpose of serving network load. Network transmission service is only eligible to network customers.
- **Non-Firm.** Point-to-point transmission service under the PJM tariff that is reserved and scheduled on an as available basis and is subject to curtailment or interruption. Non-firm point-to-point transmission service is available for periods ranging from one hour to one month.
- **Spot Import.** The spot import service is an option for non-load serving entities to offer into the PJM spot market at the interface as price takers. Prior to April 2007, PJM did not limit spot import service. Effective April 2007, the availability of spot import service was limited by the Available Transmission Capacity (ATC) on the transmission path.

2 For additional details see PJM. "PJM Regional Practices document" http://oasis.pjm.com.

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Source and Sink

For a real-time import energy transaction, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, the source defaults to the associated interface price as defined by the POR/POD path. For example, if the selected POR is TVA and the POD is PJM, the source would initially default to TVA's Interface Pricing point (SouthIMP). At the time the energy is scheduled, if the Generation Control Area (GCA) on the NERC Tag represents physical flow entering PJM at an interface other than the SouthIMP Interface, the source would then default to that new interface. The sink bus is selected by the market participant at the time the OASIS reservation is made and can be any bus in the PJM footprint.

For a real-time export energy transaction, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, the sink defaults to the associated interface price as defined by the POR/POD path. For example, if the selected POR is PJM and the POD is TVA, the sink would initially default to TVA's Interface Pricing point (SouthEXP). At the time the energy is scheduled, if the Load Control Area (LCA) on the NERC Tag represents physical flow leaving PJM at an interface other than the SouthEXP Interface, the sink would then default to that new interface. The source bus is selected by the market participant at the time the OASIS reservation is made and can be any bus in the PJM footprint.

For a real-time wheel through energy transaction, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, both the source and sink default to the associated interface prices as defined by the POR/POD path. For example, if the selected POR is TVA and the POD is NYIS, the source would initially default to TVA's Interface Pricing point (SouthIMP), and the sink would initially default to NYIS's Interface Pricing point (NYIS). At the time the energy is scheduled, if the GCA on the NERC Tag represents physical flow entering PJM at an interface other than the SouthIMP Interface, the source would then default to that new interface. Similarly, if the LCA on the NERC Tag represents physical flow leaving PJM at an interface other than the NYIS Interface, the sink would then default to that new interface.

Real-Time Market Schedule Submission

Market participants enter schedules in PJM by submitting a valid NERC Tag. A NERC Tag can be submitted without a ramp reservation. When EES detects a NERC Tag that has been submitted without a ramp reservation, it will create a ramp reservation which will be evaluated against ramp, and approved or denied based on available ramp room at the time the NERC Tag is submitted.

Real-Time with Price Schedule Submission

Real-Time with Price schedules, also known as dispatchable schedules, differ from other schedules. To enter a Real-Time with Price schedule, the market participant must first make a ramp reservation in EES specifying "Real-Time with Price" and must enter a price associated with each energy block. Upon submission, the Real-Time with Price request will automatically move to the "Pending Tag" status, as Real-Time with Price schedules do not hold ramp. Once the information is entered in EES, a NERC Tag must be submitted with the ramp reservation associated on the NERC Tag. Upon implementation of the NERC Tag, PJM will curtail the tag to 0 MW. During the operating day, if the dispatchable transaction is to be loaded, PJM will then reload the tag. The process of issuing curtailments and reloading the tag continues through the operating day as the economics of the system dictate.

Dynamic Schedule Requirements

An entity that owns or controls a generating resource in the PJM Region may request that all or part of the generating resource's output be removed from the PJM Region via dynamic scheduling of the output to a load outside the PJM Region. An entity that owns or controls a generating resource outside of the PJM Region may request that all or part of the generating resource's output be added to the PJM Region via dynamic scheduling of the output to a load inside the PJM Region. Due to the complexity of these arrangements, requesting entities must coordinate with PJM and complete several steps before a dynamic schedule can be implemented. The requesting entity is responsible for submitting a dynamic NERC Tag to match the scheduled output of the generating resource.

Real-Time Evaluation and Checkout

PJM conducts an hourly checkout with each adjacent balancing authority using both the electronic approval of schedules and telephone calls. Once the tag has been approved by all parties with approval rights, the tag status moves to an "Implemented" status, and the schedule is ready for the adjacent balancing authority checkout.

PJM operators must verify all requested energy schedules with PJM's neighboring balancing authorities. Only if the neighboring balancing authority agrees with the expected interchange will the transaction flow. Both balancing authorities must enter the same values in their Energy Management Systems (EMS) to avoid inadvertent energy flows between balancing authorities.

With the exception of the New York Independent System Operator (NYISO), all neighboring balancing authorities handle transaction requests in the same way as PJM. While the NYISO also requires NERC Tags, the NYISO utilizes their Market Information System (MIS) as their primary scheduling tool. The NYISO's real-time commitment (RTC) tool evaluates all bids and offers each hour, performs a least cost economic dispatch solution, and accepts or denies individual transactions in whole or in part based on this evaluation. Upon market clearing, the NYISO implements NERC Tag adjustments to match the output of the RTC. PJM and the NYISO can verify interchange transactions once the NYISO Tag adjustments are sent and approved. The results of the adjustments made by the NYISO affect PJM operations, as the adjustments often cause large swings in expected ramp for the next hour.

Real-Time with Price Evaluation and Checkout

Real-time with price schedules, also known as dispatchable schedules, are evaluated hourly to determine whether or not they will be loaded for the upcoming hour. Since real-time with price schedules do not hold ramp room, there may be times when the schedule is economic but will not be loaded because ramp is not available.

Curtailment of Transactions

Once a transaction has been implemented, energy flows between balancing authorities. Transactions can be curtailed based on economic and reliability considerations. There are three types of economic curtailments: curtailments of dispatchable schedules based on price; curtailments of transactions based on their OASIS designation as not willing to pay congestion; and self curtailments by market

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participant. Reliability curtailments are implemented by the balancing authorities and are termed TLRs or transmission loading relief.

Dispatchable transactions will be curtailed if the system operator does not believe that the transaction will be economic for the next hour. Not willing to pay congestion transactions will be curtailed if there is realized congestion between the designated source and sink. Transactions utilizing spot import service will be curtailed if the interface price where the transaction enters PJM reaches zero. All self curtailments must be requested on 15 minute intervals and will be approved only if there is available ramp.

Transmission Loading Relief (TLR)

TLRs are called to control flows on transmission facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows related to external balancing authorities, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

There are seven TLR levels and additional sublevels, determined by the severity of system conditions and whether the interchange transactions contributing to congestion on the impacted flowgates are using firm or non-firm transmission. Reliability coordinators are not required to implement TLRs in order. The TLR levels are described below.[3]

- **TLR Level 0 – TLR concluded:** A TLR Level 0 is initiated when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) violations are mitigated and the system is returned to a reliable state. Upon initiation of a TLR Level 0, transactions with the highest transmission priorities are reestablished first when possible. The purpose of a TLR Level 0 is to inform all affected parties that the TLR has been concluded.

- **TLR Level 1 – Potential SOL or IROL Violations:** A TLR Level 1 is initiated when the transmission system is still in a secure state but a reliability coordinator anticipates a transmission or generation contingency or other operating problem that could lead to a potential violation. No actions are required during a TLR Level 1. The purpose of a TLR Level 1 is to inform other reliability coordinators of a potential SOL or IROL.

- **TLR Level 2 – Hold transfers at present level to prevent SOL or IROL Violations:** A TLR Level 2 is initiated when the transmission system is still in a secure state but one or more transmission facilities are expected to approach, are approaching or have reached their SOL or IROL. The purpose of a TLR Level 2 is to prevent additional transactions that have an adverse affect on the identified transmission facility(ies) from starting.

- **TLR Level 3a – Reallocation of transmission service by curtailing interchange transactions using non-firm point-to-point transmission service to allow interchange transactions using higher priority transmission service:** A TLR Level 3a is initiated when the transmission system is secure but one or more transmission facilities are expected to approach, or are approaching their SOL or IROL, when there are transactions using non-firm point-to-point transmission service that have a greater than 5 percent effect on the facility and

3 Additional details regarding the TLR procedure can be found in NERC. "Standard IRO-006-4 – Reliability Coordination – Transmission Loading Relief" (October 23, 2007) (Accessed January 26, 2010) <http://www.nerc.com/files/IRO-006-4.pdf>.

when there are transactions using a higher priority point-to-point transmission reservation that wish to begin. Curtailments to transactions in a TLR 3a begin on the top of the hour only. The purpose of TLR Level 3a is to curtail transactions using lower priority non-firm point-to-point transmission to allow transactions using higher priority transmission to flow.

- **TLR Level 3b – Curtail interchange transactions using non-firm transmission service arrangements to mitigate a SOL or IROL violation:** A TLR Level 3b is initiated when one or more transmission facilities is operating above their SOL or IROL; such operation is imminent and it is expected that facilities will exceed their reliability limits if corrective action is not taken; or one or more transmission facilities will exceed their SOL or IROL upon the removal from service of a generating unit or other transmission facility and transactions are flowing that are using non-firm point-to-point transmission service and have a greater than 5 percent impact on the facility. Curtailments of transactions in a TLR 3b can occur at any time within the operating hour. The purpose of a TLR Level 3b is to curtail transactions using non-firm point-to-point transmission service which impact the constraint by greater than 5 percent in order to mitigate a SOL or IROL.

- **TLR Level 4 – Reconfigure Transmission:** A TLR Level 4 is initiated when one or more transmission facilities are above their SOL or IROL limits or such operation is imminent and it is expected that facilities will exceed their reliability limits if corrective action is not taken. Upon issuance of a TLR Level 4, all transactions using non-firm point-to-point transmission service, in the current and next hour, with a greater than 5 percent impact on the facility, have been curtailed under the TLR 3b. The purpose of a TLR Level 4 is to request that the affected transmission operators reconfigure transmission on their system, or arrange for reconfiguration on other transmission systems, to mitigate the constraint if a SOL or IROL violation is imminent or occurring.

- **TLR Level 5a – Reallocation of transmission service by curtailing interchange transactions using firm point-to-point transmission service on a pro rata basis to allow additional interchange transactions using firm point-to-point transmission service:** A TLR Level 5a is initiated when one or more transmission facilities are at their SOL or IROL; all interchange transactions using non-firm point-to-point transmission service that affect the constraint by greater than 5 percent have been curtailed; no additional effective transmission configuration is available; and a transmission provider has been requested to begin an interchange transaction using previously arranged firm point-to-point transmission service. Curtailments to transactions in a TLR 5a begin on the top of the hour only. The purpose of a TLR Level 5a is to curtail existing interchange transactions, which are using firm point-to-point transmission service, on a pro rata basis to allow for the newly requested interchange transaction, also using firm point-to-point transmission service, to flow.

- **TLR Level 5b – Curtail transactions using firm point-to-point transmission service to mitigate an SOL or IROL violation:** A TLR Level 5b is initiated when one or more transmission facilities are operating above their SOL or IROL or such operation is imminent; one or more transmission facilities will exceed their SOL or IROL upon removal of a generating unit or another transmission facility; all interchange transactions using non-firm point-to-point transmission service that affect the constraint by greater than 5 percent have been curtailed; and no additional effective transmission configuration is available. Unlike a TLR 5a, curtailments to transactions

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in a TLR 5b can occur at any time within the operating hour. The purpose of a TLR Level 5b is to curtail transactions using firm point-to-point transmission service to mitigate a SOL or IROL.

- **TLR Level 6 – Emergency Procedures:** A TLR Level 6 is initiated when all interchange transactions using both non-firm and firm point-to-point transmission have been curtailed and one or more transmission facilities are above their SOL or IROL, or will exceed their SOL or IROL upon removal of a generating unit or other transmission facility. The purpose of a TLR Level 6 is to instruct balancing authorities and transmission providers to redispatch generation, reconfigure transmission or reduce load to mitigate the critical condition.

Table E-1 below shows the historic number of TLRs, by level, issued by reliability coordinators in the Eastern Interconnection since 2004.

Table E-1 TLRs by level and reliability coordinator: Calendar years 2004 through 2010

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2004	EES	47	15	88	1	3	0	154
	FPL	0	1	0	0	0	0	1
	IMO	33	2	0	0	0	0	35
	MAIN	8	3	0	0	0	0	11
	MISO	650	210	409	9	3	0	1,281
	PJM	270	115	35	4	5	0	429
	SOCO	1	0	0	0	0	0	1
	SWPP	185	107	14	5	6	0	317
	TVA	56	17	0	0	1	0	74
	VACN	8	1	0	0	0	0	9
Total		1,258	471	546	19	18	0	2,312
2005	EES	49	10	101	6	3	1	170
	IMO	57	2	0	0	0	0	59
	MISO	776	296	200	5	14	0	1,291
	PJM	201	94	29	1	1	0	326
	SWPP	193	78	19	4	2	0	296
	TVA	172	61	12	2	3	0	250
	VACN	0	3	0	0	0	0	3
	VACS	2	2	0	1	0	0	5
Total		1,450	546	361	19	23	1	2,400
2006	EES	71	20	93	5	1	0	190
	ICTE	11	6	14	0	1	0	32
	IMO	1	0	0	0	0	0	1
	MISO	414	214	136	17	19	0	800

Table E-1 continued next page

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2006	ONT	27	3		0	0	0	30
	PJM	88	30	18	0	0	0	136
	SWPP	189	121	201	11	13	0	535
	TVA	90	52	31	1	2	0	176
	VACS	0	1	0	0	0	0	1
Total		891	447	493	34	36	0	1,901
2007	ICTE	95	42	139	19	10	0	305
	MISO	414	273	89	17	26	0	819
	ONT	47	4	1	0	0	0	52
	PJM	46	31	1	1	1	0	80
	SWPP	777	935	35	53	24	0	1,824
	TVA	45	40	25	2	2	0	114
	VACS	4	1	0	0	0	0	5
Total		1428	1326	290	92	63	0	3199
2008	ICTE	132	41	112	43	25	0	353
	MISO	320	235	21	8	15	0	599
	ONT	153	7	1	0	0	0	161
	PJM	55	92	2	0	1	0	150
	SWPP	687	1,077	11	59	44	0	1,878
	TVA	48	72	29	5	4	0	158
Total		1,395	1,524	176	115	89	0	3,299
2009	ICTE	82	35	55	75	18	1	266
	MISO	199	140	2	15	25	0	381
	NYIS	101	8	0	0	0	0	109
	ONT	169	0	0	0	0	0	169
	PJM	61	68	0	0	0	0	129
	SWPP	383	1,466	33	77	24	0	1,983
	TVA	8	22	29	0	0	0	59
	VACS	0	1	0	0	0	0	1
Total		1,003	1,740	119	167	67	1	3,097
2010	ICTE	72	25	149	50	30	0	326
	MISO	123	93	0	15	18	0	249
	NYIS	104	0	0	0	0	0	104
	ONT	94	5	0	1	0	0	100
	PJM	65	45	0	0	0	0	110
	SWPP	244	1,049	19	63	32	0	1,407
	TVA	37	64	8	1	6	0	116
	VACS	1	1	0	0	0	0	2
Total		740	1,282	176	130	86	0	2,414

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Day-Ahead Market

For Day-Ahead Market scheduling, EES serves only as an interface to the eMarket application. Day-Ahead Market transactions are evaluated in the Day-Ahead Market, and the results sent to EES. No checkout is performed on Day-Ahead Market schedules as they are considered financially binding transactions and not physical schedules.

Submitting Day-Ahead Market Schedules

Market participants can submit Day-Ahead Market schedules to the eMarket application through EES. These schedules do not require a NERC Tag, as they are not physical schedules for actual flow. Day-Ahead Market schedules require an OASIS number to be associated upon submission.[4] The path is identified on the OASIS reservation. In addition to the selection of OASIS and pricing points, the market participant must enter their energy profile. "Fixed" act as a price taker, "dispatchable" set a floor or ceiling price criteria for acceptance and "up-to" set the maximum amount of congestion the market participant is willing to pay.

NYISO Issues

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-ISO power flows, and those price differentials.[5]

There are institutional differences between PJM and the NYISO markets that are relevant to observed differences in border prices.[6] The NYISO requires hourly bids or offer prices for each export or import transaction and clears its market for each hour based on hourly bids.[7] Import transactions to the NYISO are treated by the NYISO as generator bids at the NYISO/PJM proxy bus. Export transactions are treated by the NYISO as price-capped load offers. Competing bids and offers are evaluated along with other NYISO resources and a proxy bus price is derived. Bidders are notified of the outcome. This process is repeated, with new bids and offers each hour. A significant lag exists between the time when offers and bids are submitted to the NYISO and the time when participants are notified that they have cleared. The lag is a result of the Real-Time Commitment (RTC) system and the fact that transactions can only be scheduled at the beginning of the hour.

As a result of the NYISO's RTC timing, market participants must submit bids or offers by no later than 75 minutes before the operating hour. The bid or offer includes the MW volume desired and, for imports into NYISO, the asking price or, for exports out of the NYISO, the price the participants

4 On September 17, 2010, up-to congestion transactions no longer required a willing to pay congestion transmission reservation. Additional details can be found under the "Up-to Congestion" heading in *Section 4: Interchange Transactions* of this report.
5 See also the discussion of these issues in the *2005 State of the Market Report*, Section 4, "Interchange Transactions" (March 8, 2006).
6 See the *2005 State of the Market Report* (March 8, 2006), pp. 195-198.
7 See NYISO. "NYISO Transmission Services Manual," Version 2.0 (February 1, 2005) (Accessed January 26, 2010) <http://www.nyiso.com/public/webdocs/documents/manuals/operations/tran_ser_mnl.pdf> (463 KB).

are willing to pay. The required lead time means that participants make price and MW bids or offers based on expected prices. Transactions are accepted only for a single hour.

Under PJM operating practices, in the Real-Time Market, participants must make a request to import or export power at one of PJM's interfaces at least 20 minutes before the desired start which can be any quarter hour.[8] The duration of the requested transaction can vary from 45 minutes to an unlimited amount of time. Generally, PJM market participants provide only the MW, the duration and the direction of the real-time transaction. While bid prices for transactions are allowed in PJM, less than 1 percent of all transactions submit an associated price. Transactions are accepted, with virtually no lag, in order of submission, based on whether PJM has the capability to import or export the requested MW. If transactions do not submit a price, the transactions are priced at the real-time price for their scheduled imports or exports. As in the NYISO, the required lead time means that participants must make offers to buy or sell MW based on expected prices, but the required lead time is substantially shorter in the PJM market.

The NYISO rules provide that the RTC results should be available 45 minutes before the operating hour. Winning bidders then have 25 minutes from the time when the RTC results indicate that their transaction will flow to meet PJM's 20-minute notice requirement. To get a transaction cleared with PJM, the market participant must have a valid NERC Tag, an OASIS reservation and a PJM ramp reservation. Each of these requirements takes time to process.

The length of required lead times in both markets may be a contributor to the observed relationship between price differentials and flows. Market conditions can change significantly in a relatively short time. The resulting uncertainty could weaken the observed relationship between contemporaneous interface prices and flows.

Consolidated Edison Company (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts

To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New York and New Jersey. A common path is through Westchester County using lines controlled by the NYISO. Another path is through northern New Jersey using lines controlled by PJM. This wheeled power creates loop flow across the PJM system. The Con Edison/PSE&G contracts governing the New Jersey path evolved during the 1970s and were the subject of a Con Edison complaint to the FERC in 2001. In May 2005, the FERC issued an order setting out a protocol developed by the two companies, PJM and the NYISO.[9] In July 2005, the protocol was implemented. Con Edison filed a protest with the FERC regarding the delivery performance in January 2006.[10] In August 2007, the FERC denied a rehearing request on Con Edison's complaints regarding protocol performance and refunds.[11] PJM continued to operate under the terms of the protocol through 2010.

8 See PJM. "Manual 41: Managing Interchange" (November 24, 2008) (Accessed January 26, 2010) <http://www.pjm.com/documents/~/media/documents/manuals/m41.ashx> (291 KB).
9 111 FERC ¶ 61,228 (2005).
10 "Protest of the Consolidated Edison Company of New York, Inc.", Protest, Docket No. EL02-23-000 (January 30, 2006).
11 120 FERC ¶ 61,161

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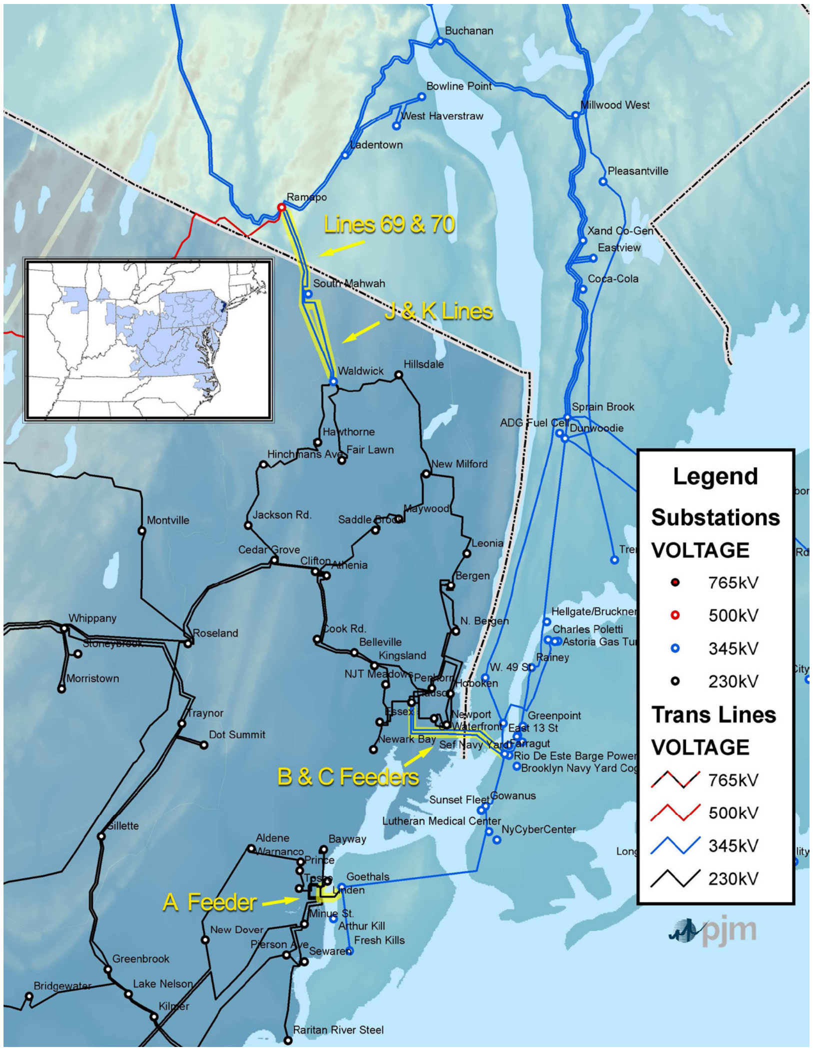
The contracts provide for the delivery of up to 1,000 MW of power from Con Edison's Ramapo Substation in Rockland County, New York, to PSE&G at its Waldwick Switching Substation in Bergen County, New Jersey. PSE&G wheels the power across its system and delivers it to Con Edison across lines connecting directly into New York City (Figure E-1). Two separate contracts cover these wheeling arrangements. A 1975 agreement covers delivery of up to 400 MW through Ramapo (New York) to PSE&G's Waldwick Switching Station (New Jersey) then to the New Milford Switching Station (New Jersey) via the J line and ultimately from the Linden Switching Station (New Jersey) to the Goethals Substation (New York) and from the Hudson Generating Station (New Jersey) to the Farragut Switching Station (New York), via the A and B feeders, respectively. A 1978 agreement covers delivery of up to an additional 600 MW through Ramapo to Waldwick then to Fair Lawn, via the K line, and ultimately through a second Hudson-to-Farragut line, the C feeder. In 2001, Con Edison alleged that PSE&G had under delivered on the agreements and asked the FERC to resolve the issue.

Figure E-1 Con Edison and PSE&G wheel



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Initial Implementation of the FERC Protocol

In May 2005, the FERC issued an order setting out a protocol developed by the four parties to address the issues raised by Con Edison.[12] The protocol was implemented in July 2005.

The Day-Ahead Energy Market Process

The protocol allows Con Edison to elect up to the flow specified in each contract through the PJM Day-Ahead Energy Market. These elections are transactions in the PJM Day-Ahead Energy Market. The 600 MW contract is for firm service and the 400 MW contract has a priority higher than non-firm service but less 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. The interface prices for this transaction are not defined PJM interface prices, but are defined in the protocol based on the actual facilities governed by the protocol.

Under the FERC order, PSE&G is assigned FTRs associated with the 600 MW contract. The PSE&G FTRs are treated like all other FTRs. In 2010, PSE&G's revenues were less than its congestion charges by $1,028,909 after adjustments ($5,417 in 2009.) Under the FERC order, Con Edison receives credits on an hourly basis for its elections under the 400 MW contract from a pool containing any excess congestion revenue after hourly FTRs are funded. In 2010, Con Edison's congestion credits were $3,066,001 less than its day-ahead congestion charges (Credits had been $232,745 less than charges in 2009). Table E-2 shows the monthly details for both PSE&G and Con Edison.

The protocol states:

> If there is congestion in PJM that affects the portion of the wheel that is associated with the 400 MW contract, PJM shall re-dispatch for the portion of the 400 MW contract for which ConEd specified it was willing to pay congestion, and ConEd shall pay for the re-dispatch. ConEd will be credited back for any congestion charges paid in the hour to the extent of any excess congestion revenues collected by PJM that remain after congestion credits are paid to all other firm transmission customers. Such credits to ConEd shall not exceed congestion payments owed or made by it.[13]

In effect, Con Edison has been given congestion credits that are the equivalent of a class of FTRs covering positive congestion with subordinated rights to revenue. However, Con Edison is not treated as having an FTR when congestion is negative. An FTR holder in that position would pay the negative congestion credits, but Con Edison does not. The protocol's provisions about congestion payments clearly cover congestion charges and offsetting congestion credits, but are not explicit on the treatment of Con Edison's negative congestion credits, which were -$178,749 in 2010. The parties should address this issue.

12 111 FERC ¶ 61,228 (2005).

13 PJM Interconnection, L.L.C., Operating Protocol for the Implementation of Commission Opinion No. 476, Docket No. EL02-23-000 (Phase II) (Effective: July 1, 2005), Original Sheet No. 6 <http://www.pjm.com/~/media/documents/agreements/20050701-attachment-iv-operating-protocol.ashx> (327 KB).

The Real-Time Energy Market Process

Under the terms of the protocol, Con Edison can make a real-time election of its desired flow for each hour in the Real-Time Energy Market. If this election differs from its day-ahead schedule, the company is subject to the resultant charges or credits. This occurred in five percent of the hours in 2010.

After years of litigation concerning whether or on what terms Con Edison's protocol would be renewed, PJM filed on February 23, 2009 a settlement on behalf of the parties to subsequent proceedings to resolve remaining issues with these contracts and their proposed rollover of the agreements under the PJM OATT.[14] By order issued September 16, 2010, the Commission approved this settlement,[15] which extends Con Edison's special protocol indefinitely. The Commission rejected objections raised first by NRG and FERC trial staff, and later by the MMU that this arrangement is discriminatory and inconsistent with the Commission's open access transmission policy.[16]

14 See Docket Nos. ER08-858-000, et al. The settling parties are the New York Independent System Operator, Inc. (NYISO), Con Ed, PSE&G, PSE&G Energy Resources & Trading LLC and the New Jersey Board of Public Utilities.

15 132 FERC ¶ 61,221.

16 *See*, *e.g.*, Motion to Intervene Out-of-Time and Comments of the Independent Market Monitor for PJM in Docket No. ER08-858-000, et al. (May 11, 2010).

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Table E-2 Con Edison and PSE&G wheel settlements data: Calendar year 2010

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
January	Congestion Charge	$480,875	($26,145)	$454,729	$721,312	$0	$721,312
	Congestion Credit			$481,563			$750,618
	Adjustments			$0			($831)
	Net Charge			($26,833)			($28,475)
February	Congestion Charge	$750,113	($301)	$749,813	$1,139,037	$0	$1,139,037
	Congestion Credit			$750,232			$1,141,484
	Adjustments			$0			$1,173
	Net Charge			($419)			($3,620)
March	Congestion Charge	$529,272	$0	$529,272	$803,998	$0	$803,998
	Congestion Credit			$101,432			$627,484
	Adjustments			$0			($1,313)
	Net Charge			$427,840			$177,827
April	Congestion Charge	$644,914	$5,079	$649,993	$1,321,568	$0	$1,321,568
	Congestion Credit			$74,000			$968,690
	Adjustments			$10,698			$2,426
	Net Charge			$565,295			$350,452
May	Congestion Charge	$224,672	$1,325	$225,996	$375,004	$0	$375,004
	Congestion Credit			$97,665			$372,773
	Adjustments			$888			$352,164
	Net Charge			$127,444			($349,933)
June	Congestion Charge	$174,627	($1,056)	$173,571	$293,644	$0	$293,644
	Congestion Credit			$64,239			$286,320
	Adjustments			$0			($1,060)
	Net Charge			$109,331			$8,385
July	Congestion Charge	$298,529	($15)	$298,514	$447,794	$0	$447,794
	Congestion Credit			$299,522			$450,663
	Adjustments			$4,473			$731
	Net Charge			($5,482)			($3,600)

Table E-2 continued next page

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
August	Congestion Charge	$154,773	($524)	$154,249	$233,724	$0	$233,724
	Congestion Credit			$81,466			$222,829
	Adjustments			$0			($967)
	Net Charge			$72,783			$11,863
September	Congestion Charge	$463,799	($5,328)	$458,471	$695,698	$0	$695,698
	Congestion Credit			$92,515			$523,723
	Adjustments			$117			($935)
	Net Charge			$365,839			$172,910
October	Congestion Charge	$329,383	$2,975	$332,357	$494,074	$0	$494,074
	Congestion Credit			$34,078			$357,859
	Adjustments			$1,133			$132
	Net Charge			$297,146			$136,083
November	Congestion Charge	$247,756	$0	$247,756	$371,634	$0	$371,634
	Congestion Credit			$34,006			$237,347
	Adjustments			$67			($175)
	Net Charge			$213,684			$134,461
December	Congestion Charge	$1,067,775	$0	$1,067,775	$1,601,662	$0	$1,601,662
	Congestion Credit			$189,768			$1,179,190
	Adjustments			$675			($83)
	Net Charge			$877,332			$422,555
Total	Congestion Charge	$5,366,488	($23,991)	$5,342,497	$8,499,150	$0	$8,499,150
	Congestion Credit			$2,300,487			$7,118,980
	Adjustments			$18,050			$351,261
	Net Charge			$3,023,960			$1,028,909

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APPENDIX F – ANCILLARY SERVICE MARKETS

This appendix covers two areas related to Ancillary Service Markets: area control error and the details of regulation availability and price determination.

Area Control Error (ACE)

Area control error (ACE) is a real-time metric used by PJM operators to measure the instantaneous MW imbalance between load plus net interchange and generation within PJM.[1] PJM dispatchers seek to ensure grid reliability by balancing ACE. A dispatcher's success in doing so is measured by control performance standard 1 (CPS1) and balancing authority ACE limit (BAAL) performance. These measurements are mandated by the North American Electric Reliability Council (NERC).

In the absence of a severe grid disturbance, the primary tool used by dispatchers to minimize ACE is regulation. Regulation is defined as a variable amount of energy under automatic control which is independent of economic cost signal and is obtainable within five minutes. Regulation contributes to maintaining the balance between load and generation by moving the output of selected generators up and down via an automatic generation control (AGC) signal.[2]

Resources wishing to participate in the Regulation Market must pass certification and submit to random testing. Certification requires that resources be capable of and responsive to AGC. After receiving certification, all participants in the Regulation Market are tested to ensure that regulation capacity is fully available at all times. Testing occurs at times of minimal load fluctuation. During testing, units must respond to a regulation test pattern for 40 minutes and must reach their offered regulation capacity levels, up and down, within five minutes. Units whose monitored response is less than their offered regulation capacity have their regulating capacity reduced by PJM.[3]

During 2008 an experimental battery-powered regulation unit was installed at the PJM facility. Observation of this unit reveals that new types of units will require that PJM's regulation unit certification testing procedure as administered by PJM's Performance Compliance group be modified, perhaps tailored to the specific unit types. The test as it is now designed measures the ability of the unit to respond to its regulation min/max within five minutes. This has always been the critical regulating metric for steam and CT units. But other types of units can meet this criterion easily yet still be inadequate for regulation because they lack the capacity to regulate for the entire hour in the event that regulation is almost completely above or below the regulation set point. Such units might include battery, pumped hydro, and inertial regulation units. During 2010, PJM modified its regulation rules to establish a minimum 1 MW capability for generating and storage units in order to qualify for regulation. For demand response resources the minimum is 0.5 MW. PJM is currently studying significant modifications to the regulation market clearing procedure and regulation resource qualifying rules to promote new sources of regulation.

1 "Two additional terms may be included in ACE under certain conditions – time error bias and manual add (a PJM dispatcher term). These provide for automatic inadvertent interchange payback and error compensation, respectively." See PJM. "Manual 12: Balancing Operations," Revision 21 (October 1, 2010), para. 3.1.1, "System Control" p. 11.

2 Regulation Market business rules are defined in PJM. "Manual 11: Scheduling Operations," Revision 45 (June 23, 2010), pp. 54-62.

3 See "Manual 12: Balancing Operations," Revision 21 (October 1, 2010), Section 4.5, pg. 49.

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Balancing Authority ACE Limit (BAAL)

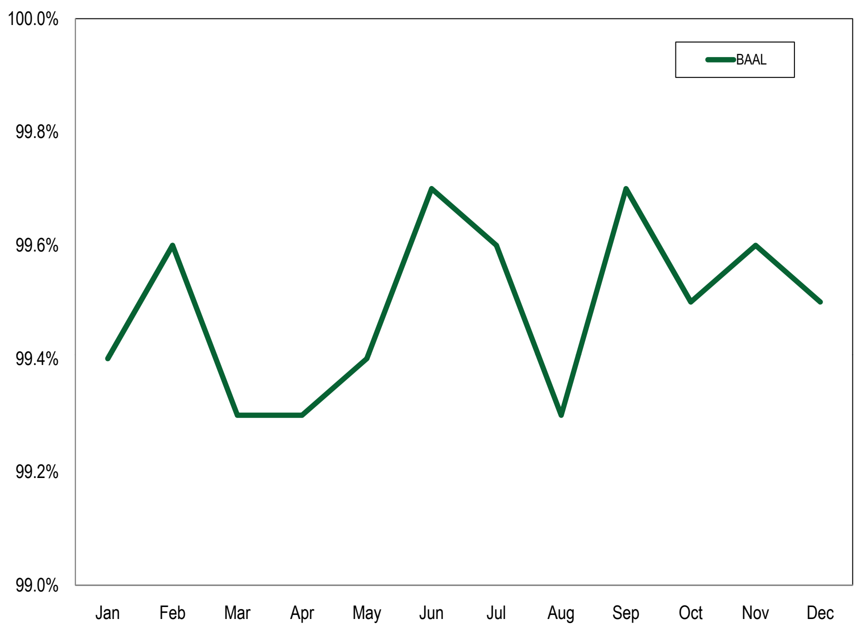
The purpose of the BAAL standard is to maintain interconnection frequency within a predefined frequency profile under all conditions (normal and abnormal), to prevent frequency-related instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages that adversely impact the reliability of the interconnection.

- **BAAL.** Since August 1, 2005, PJM has participated in the NERC "Balancing Standard Proof-of-Concept Field Test" which establishes a new metric, balancing authority ACE limit (BAAL), as a substitute for CPS2. PJM measures the total number of minutes the BAAL limit is exceeded (high or low) compared to the total number of minutes for a month, with a passing level for this goal being set at 99 percent for each month.

PJM's CPS/BAAL Performance

As Figure F-1 shows, PJM's performance for BAAL metrics was acceptable in calendar year 2010.

Figure F-1 PJM BAAL performance: Calendar year 2010



PJM dispatchers have to balance both ACE and frequency. Meeting the BAAL standard requires PJM dispatchers to maintain interconnection frequency within a predefined frequency profile under all conditions (normal and abnormal) to prevent frequency-related instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages that adversely impact the reliability of the interconnection.

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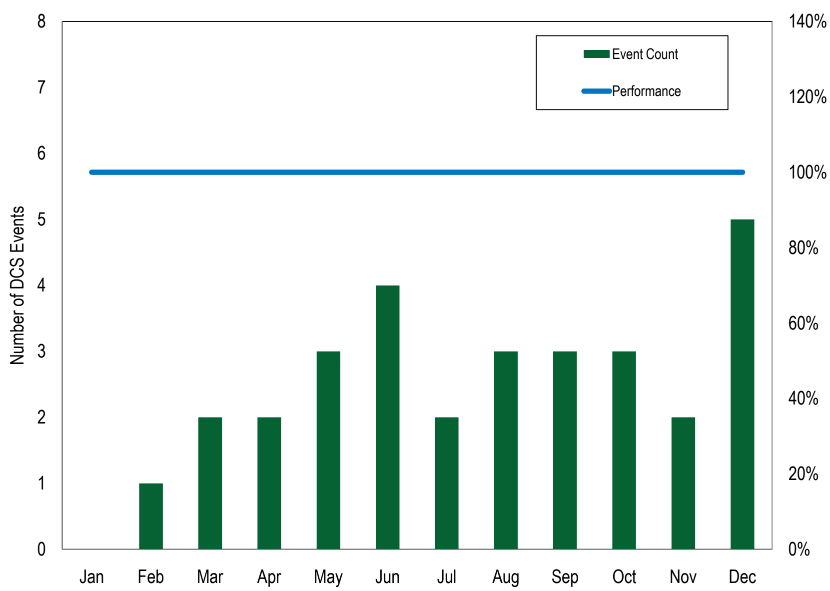
PJM's DCS Performance

A dispatch performance metric that is directly related to synchronized reserve is the disturbance control standard (DCS).[4] DCS measures how well PJM dispatch recovers from a disturbance. A disturbance is defined as any ACE deviation greater than, or equal to, 80 percent of the magnitude of PJM's most severe single contingency loss. PJM currently interprets this to be any ACE deviation greater than 800 MW. Compliance with the NERC DCS is recovery to zero or predisturbance level within 15 minutes.

PJM experienced 30 DCS events during calendar year 2010 and successfully recovered from all of them. All events were caused by the tripping of a major unit. Recovery times ranged from five minutes to 34 minutes. Figure F-2 illustrates the event count and performance by month. All of the events resulted in low ACE. The solution in all 30 events was to declare a spinning event.

Figure F-2 DCS event count and PJM performance (By month): Calendar year 2010



Regulation Capacity, Daily Offers, Offered and Eligible, Hourly Assigned

The regulation market-clearing price (RMCP) is determined algorithmically by the PJM Market Operations Group. The market clearing software (SPREGO) creates a regulation supply curve as part of a two product, and two constraint optimized solution. The price of the most expensive unit required to satisfy the regulation requirement is the RMCP. Calculating the supply curves for two products (regulation and synchronized reserve) with two constraints (energy and operating reserves) interactively is complicated, but necessary to achieve the lowest overall cost after first

4 For more information on the NERC DCS, see "Standard BAL-002-0 — Disturbance Control Performance" (April 1, 2005) <www.nerc.com/files/BAL-002-0.pdf> (61 KB).

taking into account units that self schedule. In the event it is not possible to satisfy both regulation and synchronized reserve, regulation has the higher priority.

- **Regulation Capacity.** The sum of the regulation MW capability of all generating units which have qualified to participate in the Regulation Market is the theoretical maximum regulation capacity. This maximum regulation capacity varies over time because units that are certified for regulation may be decommissioned, fail regulation testing or be removed from the Regulation Market by their owners.

- **Regulation Offers.** All owners of generating units qualified to provide regulation may, but are not required to, offer their regulation capacity daily into the Regulation Market using the PJM market user interface. Regulating units may also self-schedule. Self-scheduled units have zero lost opportunity cost (LOC) and are the first to be assigned. Demand resources were eligible to offer regulation although during 2010 none qualified to do so. Demand resources have an LOC of zero. Under PJM rules, no more than 25 percent of the total regulation requirement may be supplied by demand resources. Total regulation offers are the sum of all regulation-capable units that offer regulation into the market for the day and that are not out of service or fully committed to provide energy. Owners of units that have entered offers into the PJM market user interface system have the ability to set unit status to "unavailable" for regulation for the day, or for a specific hour or set of hours. They also have the ability to change the amount of regulation MW offered in each hour. Unit owners do not have the ability to change their regulation offer price during a day. Starting in December, 2008, the PJM Market Users Interface allows regulation owners to enter cost data. For cost-based offers above $12 per MWh owners are required to enter cost data. All regulation offers that are not set to "Unavailable" for the day are summed to calculate the total daily regulation offered, a figure that changes each hour.

- **Regulation Offered and Eligible.** Sixty minutes before the market hour, PJM runs synchronized reserve and regulation market-clearing software (SPREGO) to determine the amount of Tier 2 synchronized reserve required, to develop regulation and synchronized reserve supply curves, to assign regulation and synchronized reserve to specific units and to determine the RMCP. All regulation resource units which have made offers in the daily Regulation Market are evaluated by SPREGO for regulation. SPREGO then excludes units according to the following ordered criteria: a) Daily or hourly unavailable units; b) Units for which the economic minimum is set equal to economic maximum (unless the unit is a hydroelectric unit or has self-scheduled regulation); c) Units which are assigned synchronized reserve; d) Units for which regulation minimum is set equal to regulation maximum (unless the unit is a hydroelectric unit or has self-scheduled regulation); e) Units that are offline (except combustion turbine units).

Even after SPREGO has run and selected units for regulation, PJM dispatchers can dispatch units uneconomically for several reasons including: to control transmission constraints; to avoid overgeneration during periods of minimum generation alert; to remove a unit temporarily unable to regulate; or to remove a unit with a malfunctioning data link.

For each offered and eligible unit in the regulation supply, the regulation total offer price is calculated using the sum of the unit's regulation cost-based offer and the opportunity cost based on the forecast LMP, unit economic minimum and economic maximum, regulation

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minimum and regulation maximum, startup costs and relevant offer schedule.[5] Based on this result, SPREGO determines if the period has three or fewer pivotal suppliers. If it does, all owners who are pivotal have their offers limited to the lesser of their cost or price offer. SPREGO uses price-based offers for those operators not offer capped and re-solves. This solution is final. The MW offered and the calculated regulation offered prices are used to create a regulation supply curve. The Regulation and 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.

- **Cleared Regulation.** Regulation actually assigned by SPREGO is cleared regulation. The clearing price established by SPREGO becomes the final clearing price. In real time, units that have been assigned regulation and synchronized reserve are expected to provide regulation and synchronized reserve for the designated hour. At any time before or during the hour, PJM dispatchers can redispatch units for reliability reasons. Such redispatch leads to a disparity between cleared regulation and settled regulation.

- **Settled Regulation.** Units providing regulation are compensated at the clearing price times their actual MW provided (as opposed to cleared MW) plus any actual lost opportunity costs associated with providing regulation. The cost per MW of settled regulation can be higher than the regulation clearing price because there can be a difference between actual and cleared MW, as well as real-time versus forecast nodal prices.

5 See the *2010 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Services" for a full discussion of opportunity costs.

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APPENDIX G – GLOSSARY

Aggregate	Combination of buses or bus prices.
Ancillary Services	Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.
Area Control Error (ACE)	Area Control Error of the PJM RTO is the actual net interchange minus the biased scheduling net interchange, including time error. It is the sum of tie-in errors and frequency errors.
Associated unit (AU)	A unit that is located at the same site as a frequently mitigated unit (FMU) and which has identical electrical and economic impacts on the transmission system as an FMU but which does not qualify for FMU status.
Auction Revenue Right (ARR)	A financial instrument entitling its holder to auction revenue from Financial Transmission Rights (FTRs) based on locational marginal price (LMP) differences across a specific path in the Annual FTR Auction.
Automatic Generation Control (AGC)	An automatic control system comprised of hardware and software. Hardware is installed on generators allowing their output to be automatically adjusted and monitored by an external signal and software is installed facilitating that output adjustment.
Average hourly LMP	An LMP calculated by averaging hourly LMP with equal hourly weights; also referred to as a simple average hourly LMP.
Avoidable cost rate (ACR)	The costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the delivery year. The ACR calculation is based on the categories of cost that are specified in Section 6.8 of Attachment DD of the PJM Tariff.
Avoidable Project Investment Recovery Rate (APIR)	A component of the avoidable cost rate (ACR) calculation. Project investment is the capital reasonably required to enable a capacity resource to continue operating or improve availability during peak-hour periods during the delivery year.

Balancing energy market	Energy that is generated and financially settled during real time.
Base Residual Auction (BRA)	Reliability Pricing Model (RPM) auction held in May three years prior to the start of the delivery year. Allows for the procurement of resource commitments to satisfy the region's unforced capacity obligation and allocates the cost of those commitments among the LSEs through the Locational Reliability Charge.
Bilateral agreement	An agreement between two parties for the sale and delivery of a service.
Black Start Unit	A generating unit with the ability to go from a shutdown condition to an operating condition and start delivering power without any outside assistance from the transmission system or interconnection.
Bottled generation	Economic generation that cannot be dispatched because of local operating constraints.
Burner tip fuel price	The cost of fuel delivered to the generator site equaling the fuel commodity price plus all transportation costs.
Bus	An interconnection point.
Capacity deficiency rate (CDR)	The CDR was designed to reflect the annual fixed costs of a new combustion turbine (CT) in PJM and the annual fixed costs of the associated transmission investment, including a return on investment, depreciation and fixed operation and maintenance expense, net of associated energy revenues. The CDR is used in applying penalties for capacity deficiencies. To express the CDR in terms of unforced capacity, it must be further divided by the quantity 1 minus the EFORd.
Capacity Emergency Transfer Limit (CETL)	The capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.
Capacity queue	A collection of Regional Transmission Expansion Planning (RTEP) capacity resource project requests received during a particular timeframe and designating an expected in-service date.

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Combined Cycle (CC)	An electric generating technology in which electricity and process steam are produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a conventional steam turbine in the production of electricity. This process increases the efficiency of the electric generating facility.
Combustion Turbine (CT)	A generating unit in which a combustion turbine engine is the prime mover for an electrical generator.
Congestion Management Process (CMP)	A process used between neighboring balancing authorities to coordinate the re-dispatch of resources to relieve transmission constraints.
Control Zone	An area within the PJM Control Area, as set forth in the PJM Open Access Transmission Tariff and the RAA. Schedule 16 of the RAA defines the distinct zones that comprise the PJM Control Area.
Decrement Bids (DEC)	An hourly bid, expressed in MWh, to purchase energy in the PJM Day-Ahead Energy Market if the Day-Ahead LMP is less than or equal to the specified bid price. This bid must specify hourly quantity, bid price and location (transmission zone, hub, aggregate or single bus).
Demand deviations	Hourly deviations in the demand category, equal to the difference between the sum of cleared decrement bids, day-ahead load, day-ahead sales, and day-ahead-exports, to the sum of real-time load, real-time sales, and real-time exports.
Demand Resource	A capacity resource with a demonstrated capability to provide a reduction in demand or otherwise control load. A Demand Resource may be an existing or planned resource.
Dispatch Rate	The control signal, expressed in dollars per MWh, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by PJM in accordance with the Offer Data.
Disturbance Control Standard	A NERC-defined metric measuring the ability of a control area to return area control error (ACE) either to zero or to its predisturbance level after a disturbance such as a generator or transmission loss.

Eastern Prevailing Time (EPT)	Eastern Prevailing Time (EPT) is equivalent to Eastern Standard Time (EST) or Eastern Daylight Time (EDT) as is in effect from time to time.
Eastern Region	Defined region for purposes of allocating balancing operating reserve charges. Includes the BGE, Dominion, PENELEC, Pepco, Met-Ed, PPL, JCPL, PECO, DPL, PSEG, and RECO transmission zones.
Economic generation	Units producing energy at an offer price less than or equal to LMP.
End-use customer	Any customer purchasing electricity at retail.
Equivalent availability factor (EAF)	The proportion of hours in a year that a unit is available to generate at full capacity.
Equivalent demand forced outage rate (EFORd) deratings	A measure of the probability that a generating unit will not be available due to forced outages or forced when there is a demand on the unit to generate.
Equivalent forced outage factor (EFOF)	The proportion of hours in a year that a unit is unavailable because of forced outages.
Equivalent maintenance outage factor (EMOF)	The proportion of hours in a year that a unit is unavailable because of maintenance outages.
Equivalent planned outage factor (EPOF)	The proportion of hours in a year that a unit is unavailable because of planned outages.
External resource	A generation resource located outside metered boundaries of the PJM RTO.
Financial Transmission Right (FTR)	A financial instrument entitling the holder to receive revenues based on transmission congestion measured as hourly energy LMP differences in the PJM Day-Ahead Energy Market across a specific path.
Firm Point-to-Point Transmission Service	Transmission Service that is reserved and/or scheduled between specified Points of Receipt and Delivery.
Firm Transmission Service	Transmission service that is intended to be available at all times to the maximum extent practicable, subject to an emergency, and unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility, or the Office of the Interconnection.

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Fixed Demand Bid	Bid to purchase a defined MW level of energy, regardless of LMP.
Fixed Resource Requirement (FRR)	An alternative method for a party to satisfy its obligation to provide Unforced Capacity. Allows an LSE to avoid direct participation in the RPM Auctions by meeting their fixed capacity resource requirement using internally owned capacity resources.
Flowgate	A transmission facility or group of facilities that consist of the total interface between control areas, a partial interface, or an interface within a control area.
Frequently mitigated unit (FMU)	A unit that was offer-capped for more than a defined proportion of its real-time run hours in the most recent 12-month period. FMU thresholds are 60 percent, 70 percent and 80 percent of run hours. Such units are permitted a defined adder to their cost-based offers in place of the usual 10 percent adder.
Generation Control Area (GCA) and Load Control Area (LCA)	Designations used on a NERC Tag to describe the balancing authority where the energy is generated (GCA) and the balancing authority where the load is served (LCA). Note: the terms "Control Area" in these acronyms are legacy terms for balancing authority, and are expected to be changed in the future.
Generator deviations	Hourly deviations in the generator category, equal to the difference between a unit's cleared day-ahead generation, and a unit's hourly, integrated real-time generation.
Generation Offers	Schedules of MW offered and the corresponding offer price.
Generation owner	A PJM member that owns or leases, with rights equivalent to ownership, facilities for generation of electric energy that are located within PJM.
Gross export volume (energy)	The sum of all export transaction volume (MWh).
Gross import volume (energy)	The sum of all import transaction volume (MWh).
Gigawatt (GW)	A unit of power equal to 1,000 megawatts.
Gigawatt-day	One GW of energy flow or capacity for one day.
Gigawatt-hour (GWh)	One GWh is a gigawatt produced or consumed for one hour.

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Herfindahl-Hirschman Index (HHI)	HHI is calculated as the sum of the squares of the market share percentages of all firms in a market.
Hertz (Hz)	Electricity system frequency is measured in hertz.
HRSG	Heat recovery steam generator. An air-to-steam heat exchanger.
Increment offers (INC)	Financial offers in the Day-Ahead Energy Market to supply specified amounts of MW at, or above, a given price.
Incremental Auction	Reliability Pricing Model (RPM) auction to allow for an incremental procurement of resource commitments to satisfy an increase in the region's unforced capacity obligation due to a load forecast increase or a decrease in the amount of resource commitments due to a resource cancellation, delay, derating, EFORd increase, or decrease in the nominated value of a Planned Demand Resource.
Inframarginal unit	A unit that is operating, with an accepted offer that is less than the clearing price.
Installed capacity	Installed capacity is the as-tested maximum net dependable capability of the generator, measured in MW.
Load	Demand for electricity at a given time.
Load Management	Previously known as ALM (Active Load Management). ALM was a term that PJM used prior to the implementation of RPM where end use customer load could be reduced at the request of PJM. The ability to reduce metered load, either manually by the customer, after a request from the resource provider which holds the Load management rights or its agent (for Contractually Interruptible), or automatically in response to a communication signal from the resource provider which holds the Load management rights or its agent (for Direct Load Control).
Load-serving entity (LSE)	Load-serving entities provide electricity to retail customers. Load-serving entities include traditional distribution utilities and new entrants into the competitive power market.
Locational Deliverability Area (LDA)	Sub-regions used to evaluate locational constraints. LDAs include EDC zones, sub-zones, and combination of zones.

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Marginal unit	The last, highest cost, generation unit to supply power under a merit order dispatch system.
Market-clearing price	The price that is paid by all load and paid to all suppliers.
Market participant	A PJM market participant can be a market supplier, a market buyer or both. Market buyers and market sellers are members that have met creditworthiness standards as established by the PJM Office of the Interconnection.
Market user interface	A thin client application allowing generation sellers to provide and to view generation data, including bids, unit status and market results.
Maximum daily starts	The maximum number of times a unit can start in a day. An operating parameter incorporated in a unit's schedule.
Maximum weekly starts	The maximum number of times a unit can start in a week. An operating parameter incorporated in a unit's schedule.
Mean	The arithmetic average.
Median	The midpoint of data values. Half the values are above and half below the median.
Megawatt (MW)	A unit of power equal to 1,000 kilowatts.
Megawatt-day	One MW of energy flow or capacity for one day.
Megawatt-hour (MWh)	One MWh is a megawatt produced or consumed for one hour.
Megawatt-year	One MW of energy flow or capacity for one calendar year.
Minimum down time	The minimum amount of time that a unit has to stay off, or "down," before starting again. An operating parameter incorporated in a unit's schedule.
Minimum run time	The minimum amount of time that a unit has to stay on before shutting down. An operating parameter incorporated in a unit's schedule.
Monthly CCM	The capacity credits cleared each month through the PJM Monthly Capacity Credit Market (CCM).
Multimonthly CCM	The capacity credits cleared through PJM Multimonthly Capacity Credit Market (CCM).

Net excess (capacity)	The net of gross excess and gross deficiency, therefore the total PJM capacity resources in excess of the sum of load-serving entities' obligations.
Net exchange (capacity)	Capacity imports less exports.
Net interchange (energy)	Gross import volume less gross export volume in MWh.
Network Transmission Service	Transmission service that is for the sole purpose of serving network load. Network transmission service is only available to network customers.
Noneconomic generation	Units producing energy at an offer price greater than the LMP.
Non-Firm Transmission Service	Point-to-point transmission service under the PJM tariff that is reserved and scheduled on an as available basis and is subject to curtailment or interruption. Non-firm point to point transmission service is available on a stand-alone basis for periods ranging from one hour to one month.
North American Electric Reliability Council (NERC)	A voluntary organization of U.S. and Canadian utilities and power pools established to assure coordinated operation of the interconnected transmission systems.
Off peak	For the PJM Energy Market, off-peak periods are all NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) and weekend hours plus weekdays from the hour ending at midnight until the hour ending at 0700.
On peak	For the PJM Energy Market, on-peak periods are weekdays, except NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) from the hour ending at 0800 until the hour ending at 2300.
Opportunity cost	In general, the value of the opportunity foregone when a specific action is taken. In the ancillary services markets, the difference in compensation from the Energy Market between what a unit receives when providing regulation or synchronized reserve and what it would have received had it provided energy instead.

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Parameter-limited schedule	A schedule for a unit that has parameters that are used when the unit fails the three pivotal supplier test, or in a maximum generation emergency event. These parameters are pre-determined by the MMU based on unit class, unless an exception is otherwise granted.
PJM member	Any entity that has completed an application and satisfies the requirements of the PJM Board of Managers to conduct business with PJM, including transmission owners, generating entities, load-serving entities and marketers.
PJM planning year	The calendar period from June 1 through May 31.
Point of Receipt (POR) and Point of Delivery (POD) transmission	Designations used on a transmission reservation. The designations, when combined, determine the reservations' market path.
Pool-scheduled resource	A generating resource that the seller has turned over to PJM for scheduling and control.
Price duration curve	A graphic representation of the percent of hours that a system's price was at or below a given level during the year.
Price-sensitive bid	Purchases of a defined MW level of energy only up to a specified LMP. Above that LMP, the load bid is zero.
Primary operating interfaces	Primary operating interfaces are typically defined by a cross section of transmission paths or single facilities which affect a wide geographic area. These interfaces are modeled as constraints whose operating limits are respected in performing dispatch operations.
Ramp-limited desired (MW)	The achievable MW based on the UDS requested ramp rate.
Regional Transmission Expansion Planning (RTEP) Protocol	The process by which PJM recommends specific transmission facility enhancements and expansions based on reliability and economic criteria.

Reliability*First* Corporation	Reliability*First* Corporation (RFC) began operation January 1, 2006, as the successor to three other reliability organizations: the Mid-Atlantic Area Council (MAAC), the East Central Area Coordination Agreement (ECAR), and the Mid-American Interconnected Network (MAIN). PJM is registered with RFC to comply with its reliability standards for balancing authority (BA), planning coordinator (PC), reliability coordinator (RC), resource planner (RP), transmission operator (TOP), transmission planner (TP) and transmission service provider (TSP).
Reliability Pricing Model (RPM)	PJM's resource adequacy construct. The purpose of RPM is to develop a long term pricing signal for capacity resources and LSE obligations that is consistent with the PJM Regional Transmission Expansion Planning Process (RTEPP). RPM adds stability and a locational nature to the pricing signal for capacity.
Selective catalytic reduction (SCR)	NO_x reduction equipment usually installed on combined-cycle generators.
Self-scheduled generation	Units scheduled to run by their owners regardless of system dispatch signal. Self-scheduled units do not follow system dispatch signal and are not eligible to set LMP. Units can be submitted as a fixed block of MW that must be run, or as a minimum amount of MW that must run plus a dispatchable component above the minimum.
Shadow price	The constraint shadow price represents the incremental reduction in congestion cost achieved by relieving a constraint by 1 MW. The shadow price multiplied by the flow (in MW) on the constrained facility during each hour equals the hourly gross congestion cost for the constraint.
Short-Term Resource Procurement Target	The Short-Term Resource Procurement Target is equal to 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction for purposes of the First Incremental Auction, and 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction for purposes of the Second Incremental Auction. The stated rationale for this administrative reduction in demand is to permit short lead time resource procurement in later auctions for the delivery year.

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Sources and sinks	Sources are the origins or the injection end of a transmission transaction. Sinks are the destinations or the withdrawal end of a transaction.
Spot Import Transmission Service	Transmission service introduced as an option for non-load serving entities to offer into the PJM spot market at the border/interface as price takers.Spot market Transactions made in the Real-Time and Day-Ahead Energy Market at hourly LMP.
Static Var compensator	A static Var compensator (SVC) is an electrical device for providing fast-acting, reactive power compensation on high-voltage electricity transmission networks.
Summer Net Capability	The Summer Net Capability of each unit or station shall be based on summer conditions and on the power factor level normally expected for that unit or station at the time of the PJM summer peak load. Summer conditions shall reflect the 50% probability of occurrence (approximated by the mean) of temperature and humidity conditions of the time of the PJM summer peak load. Conditions shall be based on local weather bureau records of the past 15 years, updated at 5 year intervals. When local weather records are not available, the values shall be estimated from the best data available. For steam units, summer conditions shall mean, where applicable, the probable intake water temperature of once-through or open cooling systems experienced in June, July, and August at the time of the PJM peak each weekday. For combustion turbine units, summer conditions shall mean, where applicable, the probable ambient air temperature and humidity condition experienced at the unit location at the time of the annual summer PJM peak. The determination of the Summer Net Capability of hydro and pumped storage units shall be based on operational data or test results taken once each year at any time during the year. The same operational data or test results can be used for the determination of the Winter Net Capability. For combined-cycle units, summer conditions shall mean where applicable, the probable intake water temperature of once-through or open cooling systems experienced in June, July, and August at the time of the PJM peak each

	weekday, and the probable ambient air temperature and humidity condition experienced at the unit location at the time of the annual summer PJM peak.
Supply deviations	Hourly deviations in the supply category, equal to the difference between the sum of cleared increment offers, day-ahead purchases, and day-ahead imports, to the sum of real-time purchases and real-time imports.
Synchronized reserve	Reserve capability which is required in order to enable an area to restore its tie lines to the pre-contingency state within 10 minutes of a contingency that causes an imbalance between load and generation. During normal operation, these reserves must be provided by increasing energy output on electrically synchronized equipment, by reducing load on pumped storage hydroelectric facilities or by reducing the demand by demand-side resources. During system restoration, customer load may be classified as synchronized reserve.
System installed capacity	System total installed capacity measures the sum of the installed capacity (in installed, not unforced, terms) from all internal and qualified external resources designated as PJM capacity resources.
System lambda	The cost to the PJM system of generating the next unit of output.
Temperature-humidity index (THI)	A temperature-humidity index (THI) gives a single, numerical value reflecting the outdoor atmospheric conditions of temperature and humidity as a measure of comfort (or discomfort) during warm weather. THI is defined as: THI = $T_d - (0.55 - 0.55RH) * (T_d - 58)$ if T_d is > 58; else THI= T_d (where T_d is the dry-bulb temperature and RH is the percentage of relative humidity.)
Transmission Adequacy and Reliability Assessment (TARA)	An analysis tool that can calculate generation to load impacts. This tool is used to facilitate loop flow analysis across the Eastern Interconnection.
Turn down ratio	The ratio of dispatchable megawatts on a unit's schedule. Calculated by a unit's economic maximum MW divided by its economic minimum MW. An operating parameter of a unit's schedule.
Unforced capacity	Installed capacity adjusted by forced outage rates.

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Western region	Defined region for purposes of allocating balancing operating reserve charges. Includes the AEP, AP, ComEd, DLCO, and DAY transmission zones.
Wheel-through	An energy transaction flowing through a transmission grid whose origination and destination are outside of the transmission grid.
Winter Weather Parameter (WWP)	WWP is wind speed adjusted temperature. WWP is defined as: WWP = T_d - (0.5 * (WIND -10) if WIND > 10 mph; WWP = T_d if WIND <= 10 mph (where T_d is the dry-bulb temperature and WIND is the wind speed.)
Zone	See "Control zone" (above).

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APPENDIX H – LIST OF ACRONYMS

ACE	Area control error
ACR	Avoidable cost rate
AECI	Associated Electric Cooperative Inc.
AECO	Atlantic City Electric Company
AEG	Alliant Energy Corporation
AEP	American Electric Power Company, Inc.
AGC	Automatic generation control
ALM	Active load management
ALTE	Eastern Alliant Energy Corporation
ALTW	Western Alliant Energy Corporation
AMIL	Ameren - Illinois
AMRN	Ameren
AP	Allegheny Power Company
APIR	Avoidable Project Investment Recovery
ARR	Auction Revenue Right
ARS	Automatic reserve sharing
ATC	Available transfer capability
ATSI	American Transmission Systems, Inc.
AU	Associated unit
BA	Balancing authority
BAAL	Balancing authority ACE limit
BACT	Best Available Control Technology
BGE	Baltimore Gas and Electric Company

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BGS	Basic generation service
BME	Balancing market evaluation
BRA	Base Residual Auction
Btu	British thermal unit
C&I	Commercial and industrial customers
CAAA	Clean Air Act Amendments
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CATR	Clean Air Transport Rule
CBL	Customer base line
CC	Combined cycle
CCM	Capacity Credit Market
CDR	Capacity deficiency rate
CDTF	Cost Development Task Force
CETL	Capacity emergency transfer limit
CETO	Capacity emergency transfer objective
CF	Coordinated flowgate under the Joint Operating Agreement between PJM and the Midwest Independent Transmission System Operator, Inc.
CILC	Central Illinois Light Company Interface
CILCO	Central Illinois Light Company
CIN	Cinergy Corporation
CLMP	Congestion component of LMP
CMP	Congestion management process
CMR	Congestion Management Report

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ComEd	The Commonwealth Edison Company
Con Edison	The Consolidated Edison Company
CONE	Cost of new entry
CP	Pulverized coal-fired generator
CPI	Consumer Price Index
CPL	Carolina Power & Light Company
CPS	Control performance standard
CRC	Central Repository for Curtailments
CSP	Curtailment service provider
CT	Combustion turbine
CTR	Capacity transfer right
DASR	Day-Ahead Scheduling Reserve
DAY	Dayton Power & Light Company
DC	Direct current
DCS	Disturbance control standard
DEC	Decrement bid
DFAX	Distribution factor
DL	Diesel
DLCO	Duquesne Light Company
DPL	Delmarva Power & Light Company
DPLN	Delmarva Peninsula north
DPLS	Delmarva Peninsula south
DR	Demand response
DSR	Demand-side response

DUK	Duke Energy Corporation
EAF	Equivalent availability factor
ECAR	East Central Area Reliability Council
EDC	Electricity distribution company
EDT	Eastern Daylight Time
EE	Energy Efficiency
EEA	Emergency energy alert
EES	Enhanced Energy Scheduler
EFOF	Equivalent forced outage factor
EFORd	Equivalent demand forced outage rate
EFORp	Equivalent forced outage rate during peak hours
EHV	Extra-high-voltage
EKPC	East Kentucky Power Cooperative, Inc.
EMAAC	Eastern Mid-Atlantic Area Council
EMOF	Equivalent maintenance outage factor
EMS	Energy management system
EPA	Environmental Protection Agency
EPOF	Equivalent planned outage factor
EPT	Eastern Prevailing Time
EST	Eastern Standard Time
ExGen	Exelon Generation Company, L.L.C.
FE	FirstEnergy Corp.
FERC	The United States Federal Energy Regulatory Commission
FFE	Firm flow entitlement

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FGD	Flue-gas desulfurization
FMU	Frequently mitigated unit
FPA	Federal Power Act
FPR	Forecast pool requirement
FRR	Fixed resource requirement
FTR	Financial Transmission Right
GACT	Generally Available Control Technology
GCA	Generation control area
GE	General Electric Company
GHG	Greenhouse Gas
GW	Gigawatt
GWh	Gigawatt-hour
HAP	Hazardous Air Pollutants
HHI	Herfindahl-Hirschman Index
HRSG	Heat recovery steam generator
HVDC	High-voltage direct current
Hz	Hertz
IA	RPM Incremental Auction
ICAP	Installed capacity
ICCP	Inter-Control Center Protocol
IDC	Interchange distribution calculator
IESO	Ontario Independent Electricity System Operator
ILR	Interruptible load for reliability
INC	Increment offer

IP	Illinois Power Company
IPL	Indianapolis Power & Light Company
IPP	Independent power producer
IRM	Installed reserve margin
IRR	Internal rate of return
ISA	Interconnection service agreement
ISO	Independent system operator
JCPL	Jersey Central Power & Light Company
JOA	Joint operating agreement
JOU	Jointly owned units
JRCA	Joint Reliability Coordination Agreement
LAS	PJM Load Analysis Subcommittee
LCA	Load control area
LDA	Locational deliverability area
LGEE	LG&E Energy, L.L.C.
LIND	Linden Variable Frequency Transformer (VFT)
LM	Load management
LMP	Locational marginal price
LOC	Lost opportunity cost
LSE	Load-serving entity
MAAC	Mid-Atlantic Area Council
MAAC+APS	Mid-Atlantic Area Council plus the Allegheny Power System
MACRS	Modified accelerated cost recovery schedule
MACT	Maximum Achievable Control Technology

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MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MCP	Market-clearing price
MDS	Maximum daily starts
MDT	Minimum down time
MEC	MidAmerican Energy Company
MECS	Michigan Electric Coordinated System
Met-Ed	Metropolitan Edison Company
MIC	Market Implementation Committee
MICHFE	The pricing point for the Michigan Electric Coordinated System and FirstEnergy control areas
MIL	Mandatory interruptible load
MIS	Market information system
MISO	Midwest Independent Transmission System Operator, Inc.
MMU	PJM Market Monitoring Unit
Mon Power	Monongahela Power
MP	Market participant
MRC	Markets and reliability committee
MRT	Minimum run time
MUI	Market user interface
MW	Megawatt
MWh	Megawatt-hour
MWS	Maximum weekly starts
NAESB	North American Energy Standards Board

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NCMPA	North Carolina Municipal Power Agency
NEPT	Neptune DC line
NERC	North American Electric Reliability Council
NESHAP	National Emission Standards for Hazardous Air Pollutants
NICA	Northern Illinois Control Area
NIPSCO	Northern Indiana Public Service Company
NNL	Network and native load
NO_x	Nitrogen oxides
NUG	Non-utility generator
NYISO	New York Independent System Operator
OA	Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.
OASIS	Open Access Same-Time Information System
OATI	Open Access Technology International, Inc.
OATT	PJM Open Access Transmission Tariff
ODEC	Old Dominion Electric Cooperative
OEM	Original equipment manufacturer
OI	PJM Office of the Interconnection
Ontario IESO	Ontario Independent Electricity System Operator
OMC	Outside Management Control
OVEC	Ohio Valley Electric Corporation
ORS	NERC Operating Reliability Subcommittee
PAR	Phase angle regulator
PE	PECO zone
PEC	Progress Energy Carolinas, Inc.

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PECO	PECO Energy Company
PENELEC	Pennsylvania Electric Company
Pepco	Formerly Potomac Electric Power Company or PEPCO
PJM	PJM Interconnection, L.L.C.
PJM/AEPNI	The interface between the American Electric Power Control Zone and Northern Illinois
PJM/AEPPJM	The interface between the American Electric Power Control Zone and PJM
PJM/AEPVP	The single interface pricing point formed in March 2003 from the combination of two previous interface pricing points: PJM/American Electric Power Company, Inc. and PJM/Dominion Resources, Inc.
PJM/AEPVPEXP	The export direction of the PJM/AEPVP interface pricing point
PJM/AEPVPIMP	The import direction of the PJM/AEPVP interface pricing point
PJM/ALTE	The interface between PJM and the eastern portion of the Alliant Energy Corporation's control area
PJM/ALTW	The interface between PJM and the western portion of the Alliant Energy Corporation's control area
PJM/AMRN	The interface between PJM and the Ameren Corporation's control area
PJM/CILC	The interface between PJM and the Central Illinois Light Company's control area
PJM/CIN	The interface between PJM and the Cinergy Corporation's control area
PJM/CPLE	The interface between PJM and the eastern portion of the Carolina Power & Light Company's control area
PJM/CPLW	The interface between PJM and the western portion of the Carolina Power & Light Company's control area
PJM/CWPL	The interface between PJM and the City Water, Light & Power's (City of Springfield, IL) control area

PJM/DLCO	The interface between PJM and the Duquesne Light Company's control area
PJM/DUK	The interface between PJM and the Duke Energy Corp.'s control area
PJM/EKPC	The interface between PJM and the Eastern Kentucky Power Corporation's control area
PJM/FE	The interface between PJM and the FirstEnergy Corp.'s control area
PJMICC	PJM Industrial Customer Coalition
PJM/IP	The interface between PJM and the Illinois Power Company's control area
PJM/IPL	The interface between PJM and the Indianapolis Power & Light Company's control area
PJM/LGEE	The interface between PJM and the Louisville Gas and Electric Company's control area
PJM/LIND	The interface between PJM and the New York System Operator over the Linden VFT line
PJM/MEC	The interface between PJM and MidAmerican Energy Company's control area
PJM/MECS	The interface between PJM and the Michigan Electric Coordinated System's control area
PJM/MISO	The interface between PJM and the Midwest Independent System Operator
PJM/NEPT	The interface between PJM and the New York Independent System Operator over the Neptune DC line
PJM/NIPS	The interface between PJM and the Northern Indiana Public Service Company's control area
PJM/NYIS	The interface between PJM and the New York Independent System Operator
PJM/Ontario IESO	PJM/Ontario IESO pricing point
PJM/OVEC	The interface between PJM and the Ohio Valley Electric Corporation's control area

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PJM/TVA	The interface between PJM and the Tennessee Valley Authority's control area
PJM/VAP	The interface between PJM and the Dominion Virginia Power's control area
PJM/WEC	The interface between PJM and the Wisconsin Energy Corporation's control area
PLS	Parameter limited schedule
PMSS	Preliminary market structure screen
PNNE	PENELEC's northeastern subarea
PNNW	PENELEC's northwestern subarea
POD	Point of delivery
POR	Point of receipt
PPL	PPL Electric Utilities Corporation
PSE&G	Public Service Electric and Gas Company (a wholly owned subsidiary of PSEG)
PSEG	Public Service Enterprise Group
PSN	PSEG north
PSNC	PSEG northcentral
RAA	Reliability Assurance Agreement among Load-Serving Entities
RCIS	Reliability Coordinator Information System
REC	Renewable Energy Credit
RECO	Rockland Electric Company zone
RFC	Reliability*First* Corporation
RGGI	Regional Greenhouse Gas Initiative
RLD (MW)	Ramp-limited desired (Megawatts)
RLR	Retail load responsibility

RMCP	Regulation market-clearing price
RMR	Reliability Must Run
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standard
RSI	Residual supply index
RSI_x	Residual supply index, using “x” pivotal suppliers
RTC	Real-time commitment
RTEP	Regional Transmission Expansion Plan
RTO	Regional transmission organization
SCE&G	South Carolina Energy and Gas
SCED	Security Constrained Economic Dispatch
SCPA	Southcentral Pennsylvania subarea
SCR	Selective catalytic reduction
SEPA	Southeast Power Administration
SEPJM	Southeastern PJM subarea
SERC	Southeastern Electric Reliability Council
SFT	Simultaneous feasibility test
SMECO	Southern Maryland Electric Cooperative
SMP	System marginal price
SNJ	Southern New Jersey
SO_2	Sulfur dioxide
SOUTHEXP	South Export pricing point
SOUTHIMP	South Import pricing point
SPP	Southwest Power Pool, Inc.

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SPREGO	Synchronized reserve and regulation optimizer (market-clearing software)
SRMCP	Synchronized reserve market-clearing price
STD	Standard deviation
SVC	Static Var compensator
SWMAAC	Southwestern Mid-Atlantic Area Council
TARA	Transmission adequacy and reliability assessment
TDR	Turn down ratio
TEAC	Transmission Expansion Advisory Committee
THI	Temperature-humidity index
TISTF	Transactions Issues Senior Task Force
TLR	Transmission loading relief
TPS	Three pivotal supplier
TPSTF	Three Pivotal Supplier Task Force
TPY	Tons Per Year
TSIN	NERC Transmission System Information Network
TVA	Tennessee Valley Authority
UCAP	Unforced capacity
UDS	Unit dispatch system
UGI	UGI Utilities, Inc.
UPF	Unit participation factor
VACAR	Virginia and Carolinas Area
VAP	Dominion Virginia Power
VFT	Variable frequency transformer
VOM	Variable operation and maintenance expense

VRR	Variable resource requirement
WEC	Wisconsin Energy Corporation
WLR	Wholesale load responsibility
WPC	Willing to pay congestion
WWP	Winter Weather Parameter
XEFORd	EFORd modified to exclude OMC outages

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