2009 Quarterly State of the Market Report for PJM:
January through June

Monitoring Analytics, LLC
Independent Market Monitor for PJM

August 14, 2009

PREFACE

PJM has filed to amend Attachment M (PJM Market Monitoring Plan) to the PJM Open Access Transmission Tariff in order to provide, consistent with Order No. 719,[1] a requirement that the Market Monitoring Unit (MMU) "report on aggregate market performance on no less than a quarterly basis to Commission staff, to staff of interested state commissions, and to the management and board of directors of the RTOs or ISOs." Upon acceptance by the Commission, Section VI.A of Attachment M would read:[2]

> 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. The annual reports shall, and the quarterly reports may include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required.

Although the tariff language is not yet approved, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit defined in Attachment M, has determined to meet the requirement for a quarterly report on the basis of the requirement established in Order No. 719. Accordingly, the MMU submits this *2009 Quarterly State of the Market Report for PJM: January through June*.

1 125 FERC ¶61,071 at PP 395, 413–19 (2008), *order on reh'g*, 128 FERC ¶61,059.
2 PJM OATT, "Attachment M: PJM Market Monitoring Plan," Sixth Revised Sheet No. 452–452A (proposed to become effective June 29, 2009).

TABLE OF CONTENTS

TABLES

SECTION 3 – ENERGY MARKET, PART 2 41

FIGURES

SECTION 2 – ENERGY MARKET, PART 1 3

SECTION 3 – ENERGY MARKET, PART 2 41

SECTION 4 – INTERCHANGE TRANSACTIONS 71

SECTION 5 – CAPACITY MARKET 93

SECTION 6 – ANCILLARY SERVICE MARKETS 119

SECTION 1 – INTRODUCTION

The PJM Interconnection, L.L.C. operates a centrally dispatched, competitive wholesale electric power market that, as of June 1, 2009 had installed generating capacity of 167,454 megawatts (MW) and more than 500 market buyers, sellers and traders of electricity in a region including more than 51 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.[1] 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.

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]

1 See the *2008 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution.
2 See also the *2008 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones."
3 Analysis of 2008 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 *2008 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

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 includes the price of energy, capacity, ancillary services, transmission service, administrative fees, regulatory support fees and uplift charges. This total price is an average price and actual prices vary by location.

Table 1-1 Total price per MWh: January through June 2009 (New Table)

Category	$/MWh	Percent
Load Weighted Energy	$42.48	73.1%
Capacity	$9.76	16.8%
Transmission Service	$3.88	6.7%
Operating Reserves (Uplift)	$0.51	0.9%
Regulation	$0.38	0.6%
Reactive	$0.36	0.6%
PJM Adminstrative	$0.33	0.6%
Transmission Cost Recovery	$0.18	0.3%
Transmission Owner (Schedule 1A)	$0.08	0.1%
Synchronized Reserves	$0.04	0.1%
Supporting Facility	$0.03	0.0%
Black Start Services	$0.02	0.0%
RTO Startup and Expansion	$0.01	0.0%
NERC/RFC	$0.01	0.0%
Load Response	$0.01	0.0%
Total	$58.09	100.0%

Conclusions

This report assesses the competitiveness of the markets managed by PJM during the first six months of 2009, 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.

The MMU concludes that in the first six months of 2009:

- The Energy Market results were competitive;
- The Capacity Market results were competitive;
- The Regulation Market results were competitive;
- The Synchronized Reserve Market results were competitive;
- The Day Ahead Scheduling Reserve Market results were competitive; and
- The FTR Auction Market results were competitive.

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 the first six months of 2009, including market size, concentration, residual supply index, price-cost markup, net revenue and price.[1] The MMU concludes that the PJM Energy Market results were competitive in the first six months of 2009.

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] PJM's market power mitigation goals have 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.

Overview

Market Structure

- **Supply.** During the April through June 2009 quarter, the PJM Energy Market received an hourly average of 153,310 MW in supply offers including hydroelectric generation.[3] The second quarter 2009 average supply offers were 2,149 MW lower than the second quarter 2008 average supply of 155,459 MW.

- **Demand.** The PJM system peak load in the second quarter 2009 was 116,732 MW in the hour ended 1700 EPT on June 25, 2009, while the PJM peak load in the second quarter 2008 was 130,100 in the hour ended 1700 on June 9, 2008.[4] The 2009 second quarter peak load was 13,368 MW, or 11.5 percent, lower than the second quarter 2008 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 base load segment, but high concentration in the intermediate and peaking segments.

1 Analysis of the first six months of 2009 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 *2008 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

2 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment M: Market Monitoring Plan," First Revised Sheet No. 448.05 (Effective August 1, 2008).

3 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.

4 For the purpose of *2009 Quarterly State of the Market Report for PJM: January through June*, all hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See *2008 State of the Market Report for PJM,* Appendix M, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

- **Local Market Structure and Offer Capping.** Noncompetitive local market structure is the trigger for offer capping. PJM applied a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in January through June 2009. 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 were 0.2 percent of all hours in the first six months of 2009, the same level as 2008. In the Real-Time Energy Market offer-capped unit hours fell from 1.0 percent in 2008 to 0.5 percent of all hours in the first six months of 2009.

- **Local Market Structure.** A summary of the results of PJM's application of the three pivotal supplier test is presented for all constraints which occurred for 50 or more hours during the first two quarters of calendar year 2009. During the first two quarters of 2009 (January 1, 2009 through June 30, 2009), the PSEG, AP, AEP, PENELEC, Dominion, AECO, DLCO, ComEd, PECO and BGE Control Zones experienced congestion resulting from one or more constraints binding for 50 or more hours. The analysis of the application of the three pivotal supplier test to local markets demonstrates that it is working successfully to ensure that owners are not subject to offer capping when the market structure is competitive and to offer cap only pivotal owners when the market structure is noncompetitive.

Market Conduct

- **Price-Cost Markup.** The price-cost markup index is a measure of conduct or behavior by the owners of generating units and not a measure of market impact. For marginal units, the markup index is a measure of market power. A positive markup by marginal units will result in a difference between the observed market price and the competitive market price. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[5] 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.[6] In the real time market, the average markup index from January to June 2009 was -0.07 with a monthly average maximum of -0.04 in January and a monthly average minimum of -0.1 in April. In the day ahead market, the average markup index from January to June 2009 was 0.0036 with a monthly average maximum of 0.02 in February and a minimum of -0.02 in April. 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.

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 was $-3.10 per MWh, or -7.3 percent. The markup was

5 A marginal unit's offer price does not always correspond to the LMP at the unit's bus. As a general matter the LMP at a bus is equal to the unit's offer. However in practice, actual, security-constrained dispatch can create conditions where the LMP at a marginal unit bus does not correspond to the unit's offer. The marginal unit's offer price and associated cost are used when calculating measures of participant behavior or conduct, like markup.

6 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00), the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost.

$-2.49 per MWh during peak hours and $-3.74 per MWh during off-peak hours.

The markup component of the overall PJM day-ahead, load-weighted, average LMP was -$0.05 per MWh, or -0.1 percent. The markup was $0.84 per MWh during peak hours and -$1.01 per MWh during off-peak hours.

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

- **Load.** On average, PJM real-time load decreased in the first six months of 2009 by 3.4 percent from the first six months of 2008, falling from 78,684 MW to 75,993 MW. PJM day-ahead load decreased in the first six months of 2009 by 7.1 percent from the first six months of 2008, falling from 95,485 MW to 88,688 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. For example, overall average prices subsume congestion (price differences at a point in time) and price differences over time.

  PJM Real-Time Energy Market prices decreased in the first six months of 2009 compared to the first six months of 2008. The system simple average LMP was 42.9 percent lower in the first six months of 2009 than in the first six months of 2008, $40.12 per MWh versus $70.19 per MWh. The load-weighted LMP was 43.2 percent lower in the first six months of 2009 than in the first six months of 2008, $42.48 per MWh versus $74.77 per MWh. The fuel-cost-adjusted, load-weighted, average LMP was 6.4 percent lower in the first six months of 2009 than the load-weighted, average LMP in the first six months of 2008, $70.00 per MWh compared to $74.77 per MWh. Fuel costs and lower loads in the first half of 2009 contributed to downward pressure on LMP.

  PJM Day-Ahead Energy Market prices decreased in the first six months of 2009 compared to the first six months of 2008. The system simple average LMP was 42.9 percent lower in the first six months of 2009 than in the first six months of 2008, $40.01 per MWh versus $70.12 per MWh. The load-weighted LMP was 42.7 percent lower in the first six months of 2009 than in the first six months of 2008, $42.21 per MWh versus $73.71 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 single PJM parent company that serves load, its load can be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In the first six months of 2009, 13.4 percent of real-time load was supplied by bilateral contracts, 16.4 percent by spot market purchases and 70.2 percent by self-supply. Compared with 2008, reliance on bilateral contracts decreased by 1.3 percentage points; reliance on spot supply decreased by 3.7 percentage points; and reliance on self-supply increased by 5.0 percentage points in January through June 2009.

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. There are significant issues with the current approach to measuring demand-side response MW, which is the basis on which program participants are paid. The current approach can and has resulted in payments when the customer has taken no action to respond to market prices. 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.

  Total demand-side response resources available in PJM on January 16, 2009 (the peak day in January through June 2009), were 4,498.2 MW eligible for capacity credits and 1,957.8 MW eligible for energy payments from the Emergency Load-Response Program and 3,311.0 MW from the Economic Load-Response Program.

Participation in the Economic Load-Response Program, in terms of settlement days submitted and active customers, has decreased significantly in the first six months of 2009 compared to the same period in 2008, resulting from a combination of program verification improvements implemented in 2008, and lower price levels across PJM in 2009. Participation in the Load Management (LM) Program has increased significantly, both in Demand Response offering into RPM Auctions and ILR available in delivery year 2009/2010.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance for the first six months of 2009, including aggregate supply and demand, concentration ratios, local market concentration ratios, 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.

Aggregate supply decreased by about 2,149 MW when comparing the second quarter of 2009 to the second quarter of 2008 while aggregate peak load decreased by 13,368 MW, modifying the general supply demand balance from 2008 with a corresponding impact on peak Energy Market prices. Overall load was also lower than in second quarter 2008. Market concentration levels remained moderate and average markup was negative. 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 scarcity conditions. 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, as implemented, is consistent with the United States Federal Energy Regulatory Commission's (FERC's) market power tests, encompassed under the delivered price test. The three pivotal supplier test is an application of the delivered price test to both the Real-Time Market and hourly Day-Ahead Market. 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.

Energy Market results for the first six months of 2009 generally reflected supply-demand fundamentals. Lower prices in the Energy Market were the result of lower fuel costs and of lower demand. PJM Real-Time, load-weighted, average LMP for the first six months of 2009 was 43.2 percent lower than the load-weighted, average LMP for the first six months of 2008. The real-time, fuel-cost-adjusted, load-weighted, average LMP in the first six months of 2009 was only 6.4 percent lower than the load-weighted LMP in the first six months of 2008. In other words, if fuel costs for the first six months of 2009 had been the same as for the first six months of 2008, the 2009 load-weighted LMP would have been higher, $70.00 per MWh and 6.4 percent lower than the first half of 2008, instead of the observed $42.48 per

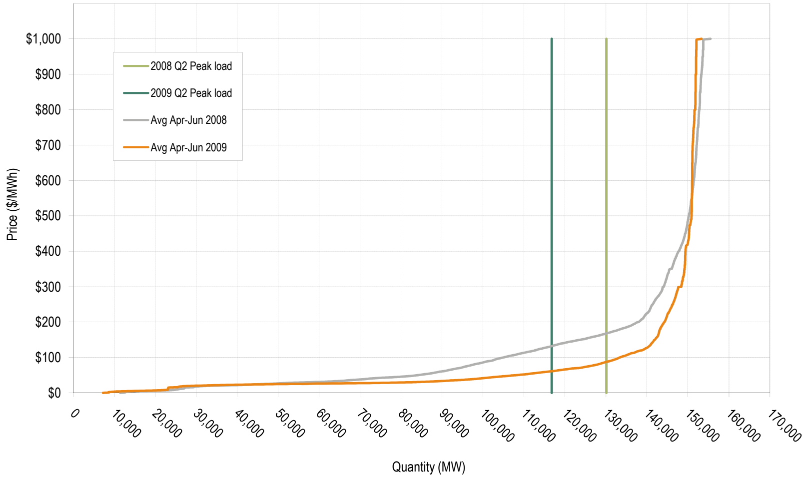
MWh. Lower fuel prices in 2009 resulted in lower prices in 2009 than would have occurred if fuel prices had remained at 2008 levels.

The overall market results support the conclusion that prices in PJM are set, on average, by marginal units operating at, or close to, their marginal costs. This is evidence of competitive behavior and competitive market outcomes. Given the structure of the Energy Market, tighter markets or a change in participant behavior remain potential sources of concern in the Energy Market. The MMU concludes that the PJM Energy Market results were competitive in the first six months of 2009.

Market Structure

Supply

Figure 2-1 Average PJM aggregate supply curves: April through June 2008 and 2009 (See 2008 SOM, Figure 2-1)

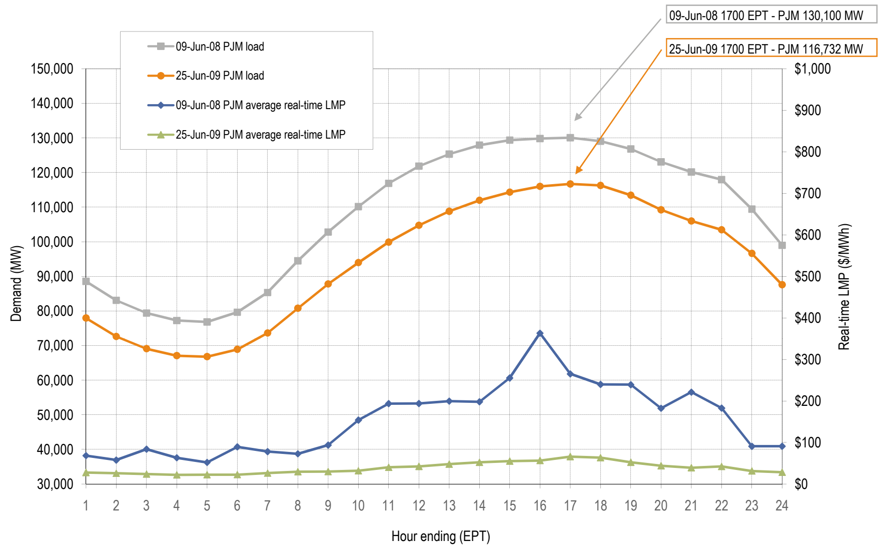


Demand

Table 2-1 Actual PJM footprint quarter 2 peak loads: 2005 to 2009 (See 2008 SOM, Table 2-2)

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Difference (MW)
2005	28-Jun-05	1600	124,052	NA
2006	30-May-06	1700	121,165	(2,887)
2007	27-Jun-07	1600	130,971	9,806
2008	9-Jun-08	1700	130,100	(871)
2009	25-Jun-09	1700	116,732	(13,368)

Figure 2-2 PJM quarter 2 peak-load comparison: Thursday, June 25, 2009, and Monday, June 9, 2008 (See 2008 SOM, Figure 2-2)



Market Concentration

PJM HHI Results

Table 2-2 PJM hourly Energy Market HHI: January through June 2009 (See 2008 SOM, Table 2-3)

	Hourly Market HHI
Average	1260
Minimum	1044
Maximum	1628
Highest market share (One hour)	32%
Highest market share (All hours)	23%
# Hours	4343
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

Local Market Structure and Offer Capping

Table 2-3 Annual offer-capping statistics: Calendar years 2005 through June 2009 (See 2008 SOM, Table 2-5)

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2005	1.8%	0.4%	0.2%	0.1%
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	0.5%	0.2%	0.2%	0.1%

Table 2-4 Offer-capped unit statistics: January through June 2009 (See 2008 SOM, Table 2-6)

	2009 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	0	3	25
80% and < 90%	0	0	0	0	0	7
75% and < 80%	0	0	0	0	0	12
70% and < 75%	0	0	0	0	0	10
60% and < 70%	0	0	0	0	1	17
50% and < 60%	0	0	0	0	0	13
25% and < 50%	0	0	0	0	0	31
10% and < 25%	0	0	0	1	1	29

Local Market Structure

Table 2-5 Three pivotal supplier results summary for regional constraints: January 1, 2009, through June 30, 2009[7] (See 2008 SOM, Table 2-7)

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	581	561	97%	44	8%
	Off Peak	133	127	95%	16	12%
AP South	Peak	856	492	57%	538	63%
	Off Peak	495	279	56%	325	66%
Bedington - Black Oak	Peak	243	216	89%	117	48%
	Off Peak	110	84	76%	41	37%
Kammer	Peak	1,974	1,843	93%	307	16%
	Off Peak	2,339	2,062	88%	545	23%
West	Peak	231	225	97%	22	10%
	Off Peak	59	59	100%	0	0%

7 The number of tests with one or more failing owners plus the number of tests with one or more passing owners can exceed the total number of tests applied. A single test can result in one or more owners passing and one or more owners failing. In such a case, the interval would be counted as including one or more passing owners and one or more failing owners.

Table 2-6 Three pivotal supplier test details for regional constraints: January 1, 2009, through June 30, 2009[8] (See 2008 SOM, Table 2-8)

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	61	346	19	18	1
	Off Peak	57	307	17	16	1
AP South	Peak	94	286	12	6	6
	Off Peak	103	309	11	5	6
Bedington - Black Oak	Peak	67	193	12	9	3
	Off Peak	57	214	13	9	4
Kammer	Peak	49	247	20	18	2
	Off Peak	51	234	16	14	2
West	Peak	132	592	20	20	1
	Off Peak	121	738	18	18	0

Table 2-7 Three pivotal supplier results summary for the East and Central interfaces: January 1, 2009, through June 30, 2009[9] (See 2008 SOM, Table 2-13)

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
Central	Peak	17	17	100%	0	0%
	Off Peak	9	9	100%	0	0%
East	Peak	0	NA	NA	NA	NA
	Off Peak	0	NA	NA	NA	NA

Table 2-8 Three pivotal supplier test details for the East and Central interfaces: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-15)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Central	Peak	61	565	19	19	0
	Off Peak	84	884	19	19	0
East	Peak	NA	NA	NA	NA	NA
	Off Peak	NA	NA	NA	NA	NA

Table 2-9 Three pivotal supplier results summary for constraints located in the PSEG Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-17)

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	292	8	3%	288	99%
	Off Peak	122	5	4%	121	99%
Brunswick - Edison	Peak	226	6	3%	226	100%
	Off Peak	84	0	0%	84	100%
Cedar Grove - Roseland	Peak	216	33	15%	199	92%
	Off Peak	12	0	0%	12	100%
Plainsboro - Trenton	Peak	592	0	0%	592	100%
	Off Peak	13	0	0%	13	100%

8 The average number of owners passing and the average number of owners failing are rounded to the nearest whole number and may not sum to the average number of owners, also rounded to the nearest whole number.

9 The East Interface constraint did not occur from January 1, 2009 through June 30, 2009. The Central Interface constraint occurred for eight hours from January 1, 2009 through June 30, 2009.

Table 2-10 Three pivotal supplier test details for constraints located in the PSEG Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-18)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Athenia - Saddle-brook	Peak	13	36	3	0	3
	Off Peak	10	40	3	0	3
Brunswick - Edison	Peak	8	89	1	0	1
	Off Peak	6	65	1	0	1
Cedar Grove - Roseland	Peak	40	156	8	1	7
	Off Peak	27	182	8	0	8
Plainsboro - Trenton	Peak	9	122	1	0	1
	Off Peak	7	141	1	0	1

Table 2-11 Three pivotal supplier results summary for constraints located in the AP Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-19)

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
Bedington	Peak	569	125	22%	569	100%
	Off Peak	333	11	3%	333	100%
Sammis - Wylie Ridge	Peak	128	86	67%	53	41%
	Off Peak	441	324	73%	204	46%
Tiltonsville - Windsor	Peak	918	1	0%	917	100%
	Off Peak	217	0	0%	217	100%
Wylie Ridge	Peak	695	577	83%	182	26%
	Off Peak	945	653	69%	378	40%

Table 2-12 Three pivotal supplier test details for constraints located in the AP Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-20)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Bedington	Peak	40	4	3	0	2
	Off Peak	38	4	3	0	3
Sammis - Wylie Ridge	Peak	48	116	17	11	6
	Off Peak	54	130	17	11	6
Tiltonsville - Windsor	Peak	12	6	2	0	2
	Off Peak	7	7	2	0	2
Wylie Ridge	Peak	36	147	17	15	2
	Off Peak	37	141	14	12	2

Table 2-13 Three pivotal supplier results summary for constraints located in the AEP Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-21)

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
Cloverdale - Lexington	Peak	264	146	55%	178	67%
	Off Peak	930	528	57%	602	65%
Kammer - Ormet	Peak	1,439	28	2%	1,411	98%
	Off Peak	1,965	0	0%	1,965	100%
Kanawha River - Kincaid	Peak	318	0	0%	318	100%
	Off Peak	240	0	0%	240	100%
Poston - Postel Tap	Peak	211	0	0%	211	100%
	Off Peak	0	NA	NA	NA	NA
Ruth - Turner	Peak	1,263	0	0%	1,263	100%
	Off Peak	1,470	0	0%	1,470	100%

Table 2-14 Three pivotal supplier test details for constraints located in the AEP Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-22)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Cloverdale - Lexington	Peak	75	223	16	8	8
	Off Peak	69	201	14	7	7
Kammer - Ormet	Peak	18	21	1	0	1
	Off Peak	22	31	1	0	1
Kanawha River - Kincaid	Peak	12	4	1	0	1
	Off Peak	9	5	1	0	1
Poston - Postel Tap	Peak	6	14	1	0	1
	Off Peak	NA	NA	NA	NA	NA
Ruth - Turner	Peak	19	3	1	0	1
	Off Peak	20	3	1	0	1

Table 2-15 Three pivotal supplier results summary for constraints located in the PENELEC Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-25)

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
Homer City - Shelocta	Peak	302	20	7%	293	97%
	Off Peak	82	0	0%	82	100%

Table 2-16 Three pivotal supplier test details for constraints located in the PENELEC Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-26)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Homer City - Shelocta	Peak	29	67	5	0	5
	Off Peak	47	57	6	0	6

Table 2-17 Three pivotal supplier results summary for constraints located in the Dominion Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-27)

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	540	0	0%	540	100%
	Off Peak	117	0	0%	117	100%

Table 2-18 Three pivotal supplier test details for constraints located in the Dominion Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-28)

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	4	4	1	0	1
	Off Peak	4	2	1	0	1

Table 2-19 Three pivotal supplier results summary for constraints located in the AECO Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-31)

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
Absecon - Lewis	Peak	61	0	0%	61	100%
	Off Peak	16	0	0%	16	100%

Table 2-20 Three pivotal supplier test details for constraints located in the AECO Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-32)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Absecon - Lewis	Peak	8	19	1	0	1
	Off Peak	7	27	1	0	1

Table 2-21 Three pivotal supplier results summary for constraints located in the DLCO Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-33)

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
Logans Ferry - Universal	Peak	963	0	0%	963	100%
	Off Peak	197	0	0%	197	100%

Table 2-22 Three pivotal supplier test details for constraints located in the DLCO Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-34)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Logans Ferry - Universal	Peak	7	42	1	0	1
	Off Peak	6	37	1	0	1

Table 2-23 Three pivotal supplier results summary for constraints located in the ComEd Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-35)

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
Crete - East Frankfurt	Peak	62	16	26%	59	95%
	Off Peak	897	68	8%	876	98%
Electric Jct - Nelson	Peak	175	5	3%	174	99%
	Off Peak	267	1	0%	267	100%
Electric Junction - Aurora	Peak	27	0	0%	27	100%
	Off Peak	4	0	0%	4	100%
Pleasant Valley - Belvidere	Peak	334	0	0%	334	100%
	Off Peak	671	0	0%	671	100%

Table 2-24 Three pivotal supplier test details for constraints located in the ComEd Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-36)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Crete - East Frankfurt	Peak	34	89	5	1	4
	Off Peak	37	49	4	0	4
Electric Jct - Nelson	Peak	28	16	3	0	3
	Off Peak	37	9	2	0	2
Electric Junction - Aurora	Peak	8	15	2	0	2
	Off Peak	14	2	1	0	1
Pleasant Valley - Belvidere	Peak	12	1	1	0	1
	Off Peak	13	0	1	0	1

Table 2-25 Three pivotal supplier results summary for constraints located in the PECO Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-37)

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
Buckingham - Pleasant Valley	Peak	200	81	41%	147	74%
	Off Peak	41	28	68%	19	46%

Table 2-26 Three pivotal supplier test details for constraints located in the PECO Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-38)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Buckingham - Pleasant Valley	Peak	12	41	7	3	4
	Off Peak	8	47	10	6	4

Table 2-27 Three pivotal supplier results summary for constraints located in the BGE Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-39)

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
Graceton - Raphael Road	Peak	331	307	93%	44	13%
	Off Peak	105	86	82%	36	34%

Table 2-28 Three pivotal supplier test details for constraints located in the BGE Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-40)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Graceton - Raphael Road	Peak	30	123	19	18	1
	Off Peak	39	114	19	15	4

Market Performance: Markup

Real-Time Markup

Table 2-29 Marginal unit contribution to PJM real-time, annual, load-weighted LMP (By parent company): January through June 2009 (See 2007 SOM, Table 2-31)

Company	Percent of Price
1	16%
2	14%
3	9%
4	8%
5	8%
6	7%
7	6%
8	4%
9	3%
Other (46 companies)	25%

Table 2-30 Type of fuel used (By real-time marginal units): January through June 2009 (See 2007 SOM, Table 2-32)

Fuel Type	2009
Coal	75%
Natural Gas	20%
Petroleum	3%
Landfill Gas	1%
Interface	1%
Misc	0%

Figure 2-3 Real-time, LMP contribution and load-weighted, unit markup index: January through June 2009 (See 2007 SOM, Figure 2-4)

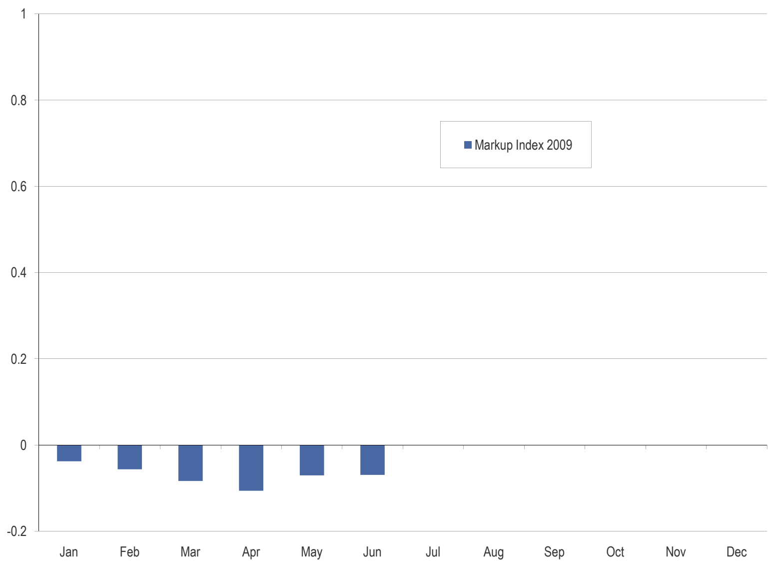


Table 2-31 Average, real-time marginal unit markup index (By price category): January through June 2009 (See 2007 SOM, Table 2-34)

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.11)	($3.65)
$25 to $50	(0.11)	($5.50)
$50 to $75	(0.03)	($2.87)
$75 to $100	0.03	$2.10
$100 to $125	0.07	$6.08
$125 to $150	0.07	$6.82
> $150	0.05	$9.94

Table 2-32 Monthly markup components of load-weighted LMP: January through June 2009 (See 2007 SOM, Table 2-35)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($1.53)	($0.48)	($2.52)
Feb	($1.97)	($1.65)	($2.31)
Mar	($4.24)	($4.73)	($3.73)
Apr	($4.78)	($3.78)	($5.96)
May	($3.23)	($2.75)	($3.68)
Jun	($3.33)	($1.99)	($4.98)
2009 (Jan - Jun)	($3.10)	($2.49)	($3.74)

Table 2-33 Average real-time zonal markup component: January through June 2009 (See 2007 SOM, Table 2-36)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($3.09)	($2.77)	($3.42)
AEP	($3.62)	($2.80)	($4.46)
AP	($2.65)	($1.89)	($3.45)
BGE	($2.47)	($1.78)	($3.18)
ComEd	($3.90)	($3.18)	($4.69)
DAY	($4.01)	($3.15)	($4.94)
DLCO	($4.10)	($3.17)	($5.10)
Dominion	($2.24)	($1.66)	($2.84)
DPL	($2.66)	($2.27)	($3.06)
JCPL	($2.90)	($2.54)	($3.30)
Met-Ed	($2.78)	($2.47)	($3.12)
PECO	($3.01)	($2.76)	($3.28)
PENELEC	($3.21)	($2.75)	($3.71)
Pepco	($2.41)	($1.84)	($3.02)
PPL	($2.87)	($2.60)	($3.15)
PSEG	($2.98)	($2.52)	($3.49)
RECO	($2.86)	($2.41)	($3.38)

Table 2-34 Average real-time markup component (By price category): January through June 2009 (See 2008 SOM, Table 2-41)

	Average Markup Component	Frequency
Below $20	($2.62)	3.6%
$20 to $40	($5.66)	61.0%
$40 to $60	($2.74)	24.5%
$60 to $80	$1.21	6.5%
$80 to $100	$8.23	2.6%
$100 to $120	$11.50	0.8%
$120 to $140	$40.38	0.5%
$140 to $160	$12.72	0.2%
Above $160	$52.56	0.2%

Day-Ahead Markup

Table 2-35 Marginal unit contribution to PJM day-ahead, annual, load-weighted LMP (By parent company): January through June 2009 (See 2007 SOM, Table 2-31)

Company	Percent of Price
1	35%
2	8%
3	5%
4	5%
5	5%
6	4%
7	3%
8	3%
9	3%
Other (111 companies)	30%

Table 2-36 Day-ahead marginal resources by type/fuel: January through June 2009 (See 2007 SOM, Table 2-32)

Fuel Type	2009
Transaction	36%
DEC	29%
INC	17%
Coal	13%
Natural gas	3%
Price sensitive demand	1%
Petroleum	0%
Wind	0%
Misc	0%
Landfill gas	0%

Figure 2-4 Day-ahead, LMP contribution and load-weighted unit markup index: January through June 2009 (See 2007 SOM, Figure 2-4)

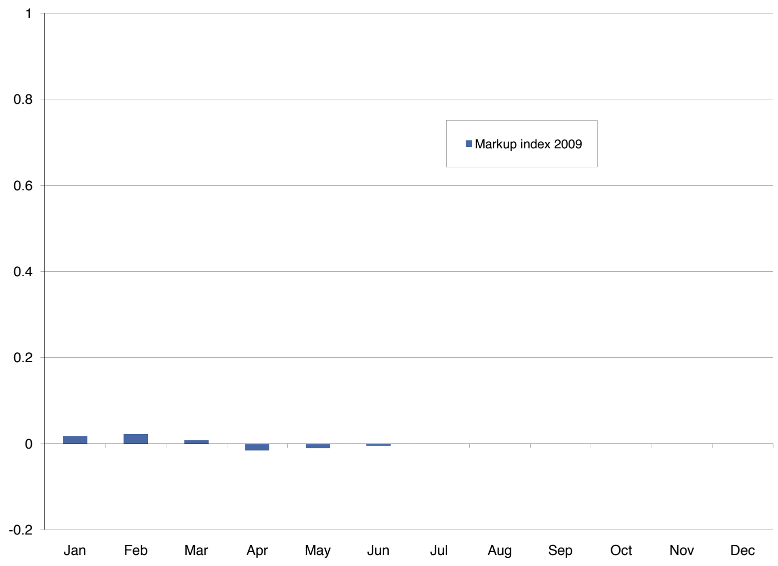


Table 2-37 Average, day-ahead marginal unit markup index (By price category): January through June 2009 (See 2007 SOM, Table 2-34)

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.05)	($2.25)
$25 to $50	0.05	$1.12
$50 to $75	0.08	$4.79
$75 to $100	0.09	$7.98
$100 to $125	0.28	$31.16
$125 to $150	(0.04)	($8.16)
> $150	0.00	$0.00

Table 2-38 Monthly markup components of day-ahead, load-weighted LMP: January through June 2009 (See 2007 SOM, Table 2-35)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	$0.89	$1.62	$0.20
Feb	$0.76	$2.18	($0.75)
Mar	$0.16	$0.91	($0.65)
Apr	($0.97)	($0.33)	($1.72)
May	($0.62)	$0.07	($1.28)
Jun	($0.83)	$0.39	($2.37)
2009 (Jan - Jun)	($0.05)	$0.84	($1.01)

Table 2-39 Day-ahead, average, zonal markup component: January through June 2009 (See 2007 SOM, Table 2-36)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	$0.20	$0.98	($0.66)
AEP	($0.50)	$0.67	($1.72)
AP	$0.79	$1.68	($0.13)
BGE	$0.13	$1.12	($0.93)
ComEd	($0.08)	$0.75	($0.94)
DAY	($0.60)	$0.59	($1.92)
DLCO	($0.56)	$0.62	($1.83)
Dominion	($0.45)	$0.38	($1.29)
DPL	$0.24	$0.99	($0.53)
JCPL	$0.34	$1.13	($0.58)
Met-Ed	$0.30	$1.07	($0.54)
PECO	$0.21	$1.02	($0.65)
PENELEC	$0.41	$1.18	($0.49)
Pepco	($0.19)	$0.69	($1.18)
PPL	$0.26	$0.93	($0.47)
PSEG	$0.12	$0.82	($0.68)
RECO	$0.20	$0.89	($0.64)

Table 2-40 Average, day-ahead markup (By price category): January through June 2009 (See 2007 SOM, Table 2-37)

	Average Markup Component	Frequency
Below $20	($0.51)	4%
$20 to $40	($1.41)	56%
$40 to $60	$1.16	30%
$60 to $80	$1.50	7%
$80 to $100	$2.75	2%
$100 to $120	$4.26	1%
$120 to $140	$1.43	0%
Above $160	$0.00	0%

Frequently Mitigated Unit and Associated Unit Adders – Component of Price

Table 2-41 Frequently mitigated units and associated units (By month): January through June 2009 (See 2008 SOM, Table 2-42)

	FMUs and AUs			Total Eligible
	Tier 1	Tier 2	Tier 3	for Any Adder
January	26	56	55	137
February	46	46	36	128
March	31	48	54	133
April	33	41	63	137
May	32	43	61	136
June	40	42	62	144

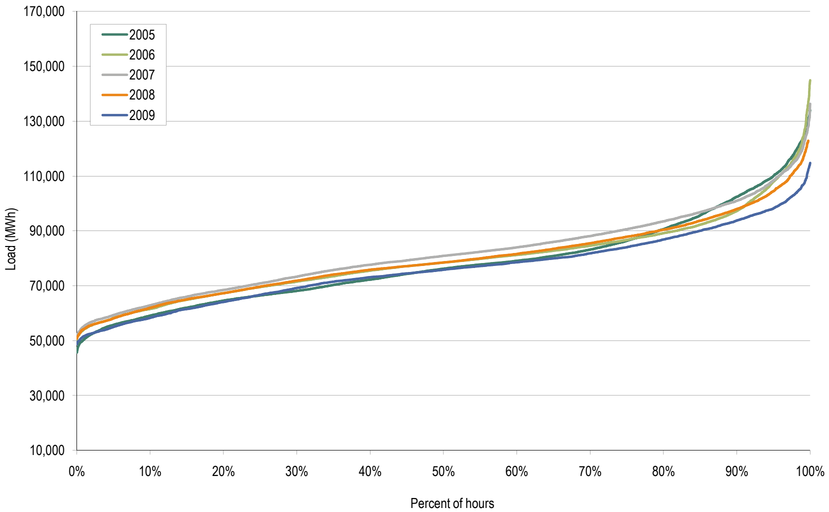
Market Performance: Load and LMP

Load

Real-Time Load

PJM Real-Time Load Duration

Figure 2-5 PJM real-time load duration curves: Calendar years 2005 through June 2009 (See 2008 SOM, Figure 2-4)



PJM Real-Time, Annual Average Load

Table 2-42 PJM real-time average load: Calendar years 2000 through June 2009 (See 2008 SOM, Table 2-44)

	PJM Real-Time Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	30,113	30,170	5,529	NA	NA	NA
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	75,993	75,847	12,898	(4.4%)	(3.4%)	(6.2%)

PJM Real-Time, Monthly Average Load

Figure 2-6 PJM real-time average load: Calendar years 2008 through June 2009 (See 2008 SOM, Figure 2-5)

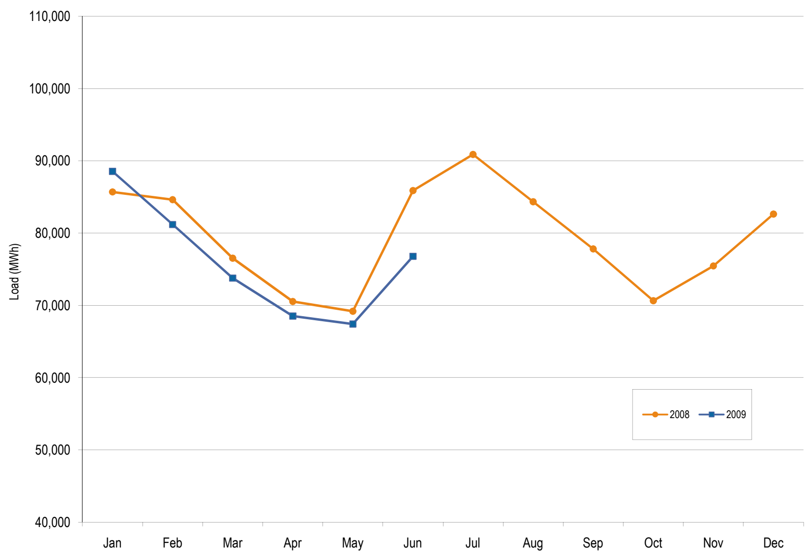


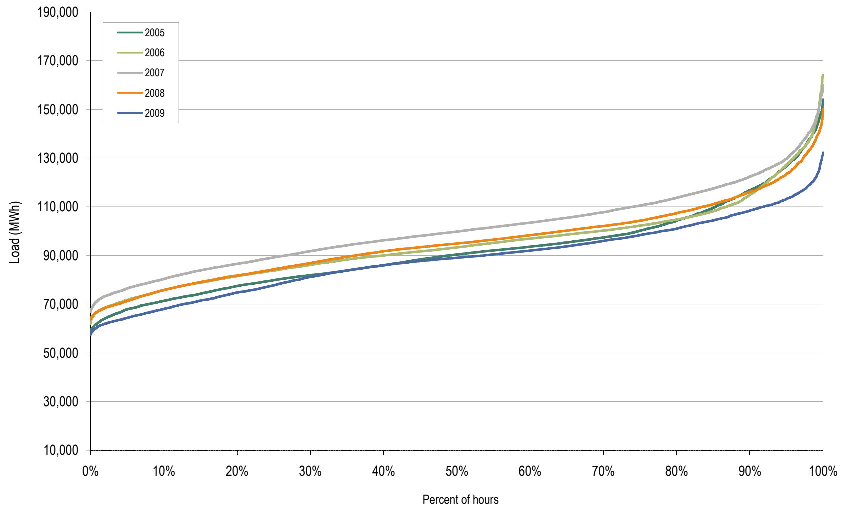
Table 2-43 Monthly minimum, average and maximum of PJM hourly THI: Cooling periods of 2008 and 2009 (See 2008 SOM, Table 2-45)

	2008			2009			Difference		
	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max
Jun	54.94	70.16	81.30	52.53	67.86	77.88	(4.4%)	(3.3%)	(4.2%)
Jul	62.00	72.25	80.34						
Aug	59.89	69.70	78.62						

Day-Ahead Load

PJM Day-Ahead Load Duration

Figure 2-7 PJM day-ahead load duration curves: Calendar years 2005 through June 2009 (See 2008 SOM, Figure 2-6)



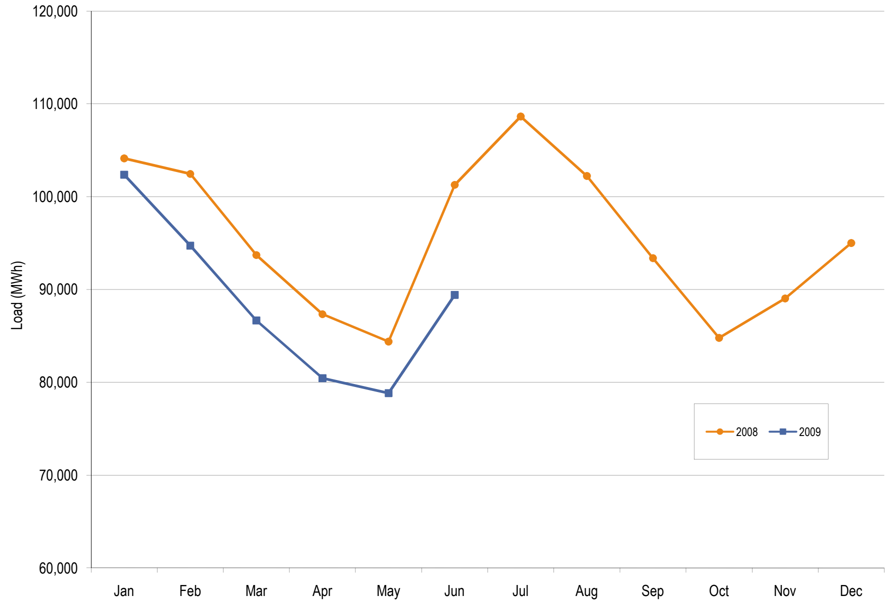
PJM Day-Ahead, Annual Average Load

Table 2-44 PJM day-ahead average load: Calendar years 2005 through June 2009 (See 2008 SOM, Table 2-46)

	PJM Day-Ahead Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2005	92,002	90,424	17,381	NA	NA	NA
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	88,688	89,066	14,650	(7.2%)	(6.1%)	(5.1%)

PJM Day-Ahead, Monthly Average Load

Figure 2-8 PJM day-ahead average load: Calendar years 2008 through June 2009 (See 2008 SOM, Figure 2-7)

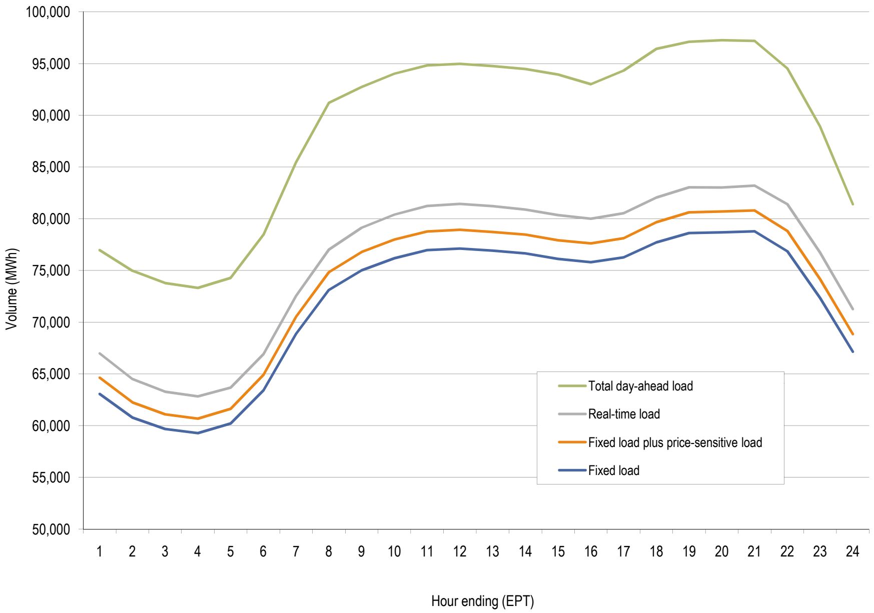


Real-Time and Day-Ahead Load

Table 2-45 Cleared day-ahead and real-time load (MWh): January through June 2009 (See 2008 SOM, Table 2-47)

	Day Ahead				Real Time	Average Difference	
	Cleared Fixed Demand	Cleared Price Sensitive	Cleared DEC Bid	Total Load	Total Load	Total Load	Total Load Minus DEC Bid
Average	71,903	1,742	15,043	88,688	75,993	12,695	(2,348)
Median	71,635	1,739	15,310	89,066	75,847	13,219	(2,091)
Standard deviation	12,110	435	2,554	14,650	12,898	1,752	(802)

Figure 2-9 Day-ahead and real-time loads (Average hourly volumes): January through June 2009 (See 2008 SOM, Figure 2-8)

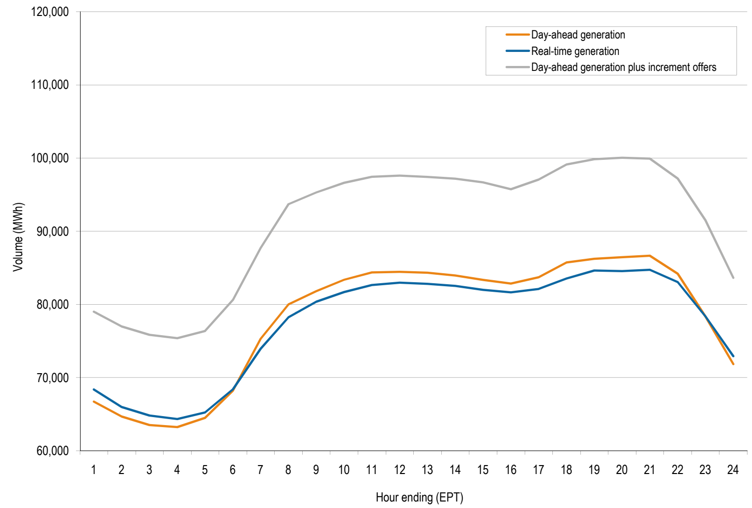


Real-Time and Day-Ahead Generation

Table 2-46 Day-ahead and real-time generation (MWh): January through June 2009 (See 2008 SOM, Table 2-48)

	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	78,259	12,907	91,166	77,508	751	13,658
Median	78,909	12,781	91,595	77,626	1,283	13,970
Standard deviation	14,195	1,673	15,055	12,961	1,233	2,093

Figure 2-10 Day-ahead and real-time generation (Average hourly volumes): January through June 2009 (See 2008 SOM, Figure 2-9)



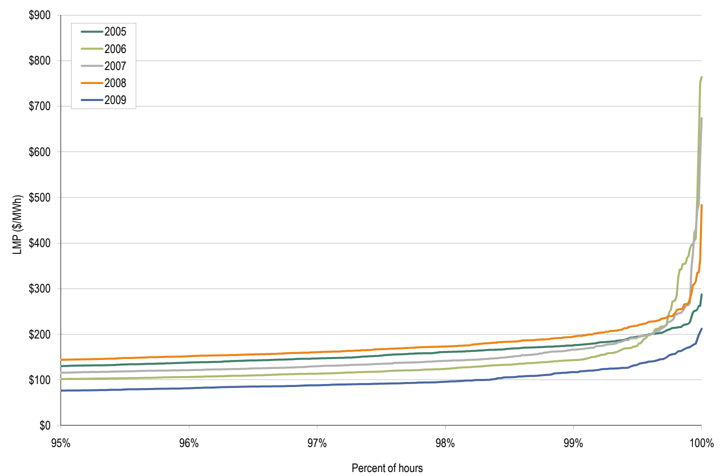
Locational Marginal Price (LMP)

Real-Time LMP

Real-Time Average LMP

PJM Real-Time LMP Duration

Figure 2-11 Price duration curves for the PJM Real-Time Energy Market during hours above the 95th percentile: Calendar years 2005 through June 2009 (See 2008 SOM, Figure 2-10)



PJM Real-Time, Annual Average LMP

Table 2-47 PJM real-time, simple average LMP (Dollars per MWh): Calendar years 2000 through June 2009 (See 2008 SOM, Table 2-49)

	Real-Time LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$28.14	$19.11	$25.69	NA	NA	NA
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	$40.12	$35.42	$19.30	(39.6%)	(36.2%)	(50.0%)

Zonal Real-Time, Annual Average LMP

Table 2-48 Zonal real-time, simple average LMP (Dollars per MWh): January through June 2008 and 2009 (See 2008 SOM, Table 2-50)

	2008 (Jan - Jun)	2009 (Jan - Jun)	Difference	Difference as Percent of 2008
AECO	$84.92	$44.59	($40.33)	(47.5%)
AEP	$56.20	$36.37	($19.83)	(35.3%)
AP	$69.61	$41.77	($27.84)	(40.0%)
BGE	$84.14	$45.22	($38.92)	(46.3%)
ComEd	$52.81	$30.28	($22.53)	(42.7%)
DAY	$56.66	$35.90	($20.76)	(36.6%)
DLCO	$52.57	$34.49	($18.08)	(34.4%)
Dominion	$78.58	$43.53	($35.05)	(44.6%)
DPL	$81.59	$45.20	($36.39)	(44.6%)
JCPL	$86.58	$44.92	($41.66)	(48.1%)
Met-Ed	$79.58	$43.73	($35.85)	(45.0%)
PECO	$78.86	$43.63	($35.23)	(44.7%)
PENELEC	$67.94	$40.06	($27.88)	(41.0%)
Pepco	$84.33	$44.77	($39.56)	(46.9%)
PPL	$78.47	$43.14	($35.34)	(45.0%)
PSEG	$85.48	$45.44	($40.04)	(46.8%)
RECO	$84.33	$44.22	($40.11)	(47.6%)

Real-Time, Annual Average LMP by Jurisdiction

Table 2-49 Jurisdiction real-time, simple average LMP (Dollars per MWh): January through June 2008 and 2009 (See 2008 SOM, Table 2-51)

	2008 (Jan - Jun)	2009 (Jan - Jun)	Difference	Difference as Percent of 2008
Delaware	$80.69	$44.87	($35.83)	(44.4%)
Illinois	$52.81	$30.28	($22.53)	(42.7%)
Indiana	$56.03	$35.71	($20.33)	(36.3%)
Kentucky	$56.50	$36.25	($20.25)	(35.8%)
Maryland	$83.80	$45.20	($38.61)	(46.1%)
Michigan	$56.95	$37.07	($19.88)	(34.9%)
New Jersey	$85.75	$45.16	($40.59)	(47.3%)
North Carolina	$73.52	$42.45	($31.08)	(42.3%)
Ohio	$55.67	$35.69	($19.98)	(35.9%)
Pennsylvania	$73.14	$41.88	($31.27)	(42.7%)
Tennessee	$56.75	$36.34	($20.41)	(36.0%)
Virginia	$76.00	$42.77	($33.23)	(43.7%)
West Virginia	$57.92	$37.62	($20.30)	(35.0%)
District of Columbia	$84.32	$44.92	($39.40)	(46.7%)

Hub Real-Time, Annual Average LMP

Table 2-50 Hub real-time, simple average LMP (Dollars per MWh): January through June 2008 and 2009 (See 2008 SOM, Table 2-52)

	2008 (Jan - Jun)	2009 (Jan - Jun)	Difference	Difference as Percent of 2008
AEP Gen Hub	$53.04	$34.21	($18.83)	(35.5%)
AEP-DAY Hub	$55.92	$35.87	($20.04)	(35.8%)
Chicago Gen Hub	$52.10	$29.44	($22.66)	(43.5%)
Chicago Hub	$52.86	$30.49	($22.37)	(42.3%)
Dominion Hub	$76.02	$42.82	($33.19)	(43.7%)
Eastern Hub	$81.31	$45.06	($36.24)	(44.6%)
N Illinois Hub	$52.37	$30.07	($22.30)	(42.6%)
New Jersey Hub	$85.45	$45.11	($40.34)	(47.2%)
Ohio Hub	$56.03	$35.84	($20.19)	(36.0%)
West Interface Hub	$61.55	$37.20	($24.35)	(39.6%)
Western Hub	$72.09	$41.40	($30.69)	(42.6%)

Real-Time, Load-Weighted, Average LMP

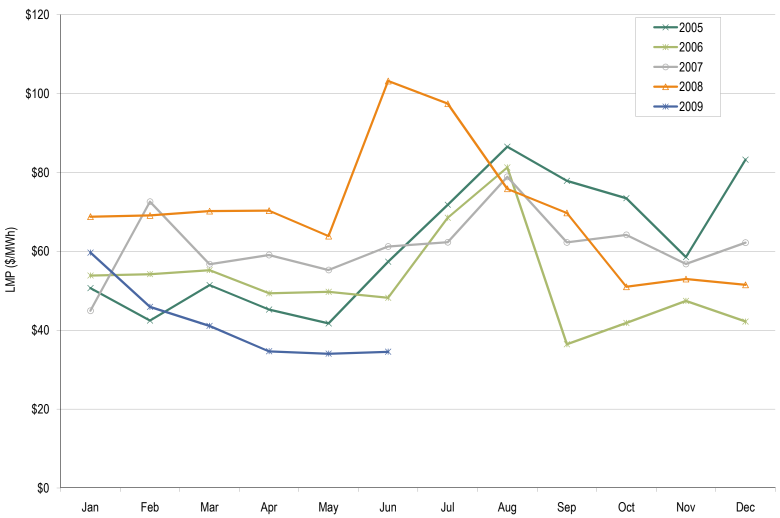
PJM Real-Time, Annual, Load-Weighted, Average LMP

Table 2-51 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 2000 through June 2009 (See 2008 SOM, Table 2-53)

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$30.72	$20.51	$28.38	NA	NA	NA
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	$42.48	$36.95	$20.61	(40.3%)	(37.9%)	(49.7%)

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

Figure 2-12 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2005 through June 2009 (See 2008 SOM, Figure 2-11)



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

Table 2-52 Zonal real-time, annual, load-weighted, average LMP (Dollars per MWh): January through June 2008 and 2009 (See 2008 SOM, Table 2-54)

	2008 (Jan - Jun)	2009 (Jan - Jun)	Difference	Difference as Percent of 2008
AECO	$93.41	$46.77	($46.64)	(49.9%)
AEP	$59.26	$38.30	($20.96)	(35.4%)
AP	$73.85	$44.59	($29.26)	(39.6%)
BGE	$91.31	$48.39	($42.92)	(47.0%)
ComEd	$56.35	$32.25	($24.10)	(42.8%)
DAY	$60.47	$37.77	($22.70)	(37.5%)
DLCO	$55.68	$35.62	($20.06)	(36.0%)
Dominion	$85.94	$46.89	($39.04)	(45.4%)
DPL	$87.98	$48.77	($39.21)	(44.6%)
JCPL	$94.12	$47.50	($46.62)	(49.5%)
Met-Ed	$84.70	$46.64	($38.06)	(44.9%)
PECO	$84.40	$46.05	($38.35)	(45.4%)
PENELEC	$71.14	$42.08	($29.06)	(40.8%)
Pepco	$92.13	$47.69	($44.43)	(48.2%)
PPL	$83.20	$46.39	($36.81)	(44.2%)
PSEG	$91.71	$47.42	($44.29)	(48.3%)
RECO	$92.02	$46.29	($45.73)	(49.7%)

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

Table 2-53 Jurisdiction real-time, annual, load-weighted, average LMP (Dollars per MWh): January through June 2008 and 2009 (See 2008 SOM, Table 2-55)

	2008 (Jan - Jun)	2009 (Jan - Jun)	Difference	Difference as Percent of 2008
Delaware	$86.35	$47.92	($38.43)	(44.5%)
Illinois	$56.35	$32.25	($24.10)	(42.8%)
Indiana	$58.65	$37.00	($21.65)	(36.9%)
Kentucky	$60.42	$39.03	($21.39)	(35.4%)
Maryland	$91.33	$48.71	($42.62)	(46.7%)
Michigan	$60.58	$38.50	($22.08)	(36.4%)
New Jersey	$92.65	$47.34	($45.31)	(48.9%)
North Carolina	$82.09	$45.76	($36.33)	(44.3%)
Ohio	$58.74	$37.35	($21.39)	(36.4%)
Pennsylvania	$77.42	$44.33	($33.10)	(42.7%)
Tennessee	$58.81	$38.96	($19.85)	(33.7%)
Virginia	$82.83	$46.18	($36.65)	(44.2%)
West Virginia	$60.97	$40.12	($20.85)	(34.2%)
District of Columbia	$90.78	$46.88	($43.90)	(48.4%)

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

Fuel Cost

Figure 2-13 Spot average fuel price comparison: Calendar years 2008 through June 2009 (See 2008 SOM, Figure 2-12)

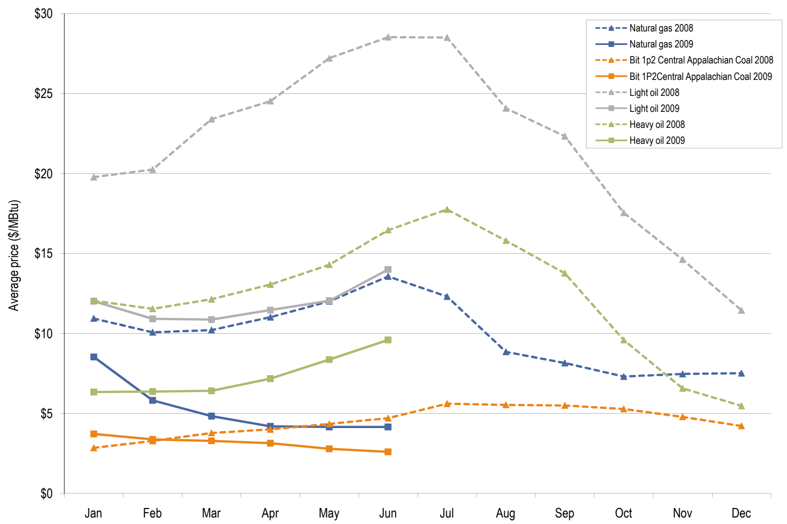


Figure 2-14 Spot average emission price comparison: Calendar years 2008 through June 2009 (See 2008 SOM, Figure 2-13)

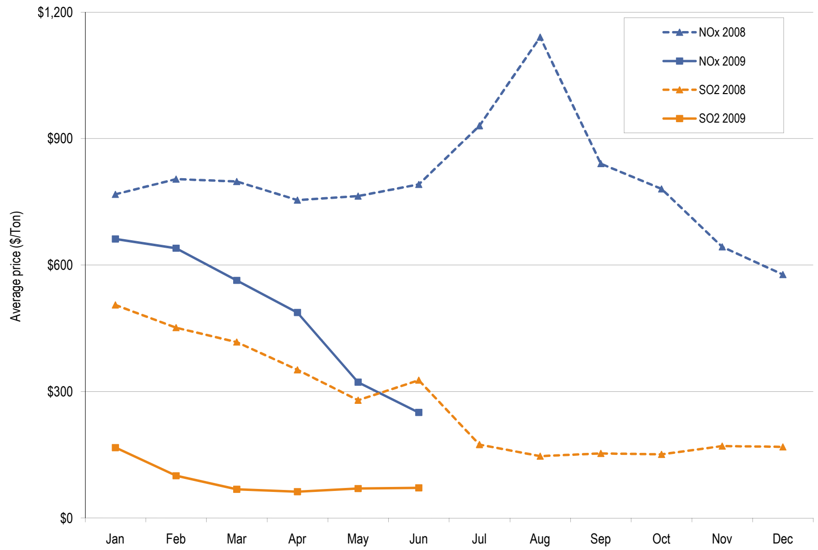


Table 2-54 PJM real-time, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): January through June 2009, year-over-year method (See 2008 SOM, Table 2-56)

	2008 (Jan - Jun) Load-Weighted LMP	2009 (Jan - Jun) Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$74.77	$70.00	(6.4%)

Components of Real-Time, Load-Weighted LMP

Table 2-55 Components of PJM annual, load-weighted, average LMP: January through June 2009 (See 2008 SOM, Table 2-57)

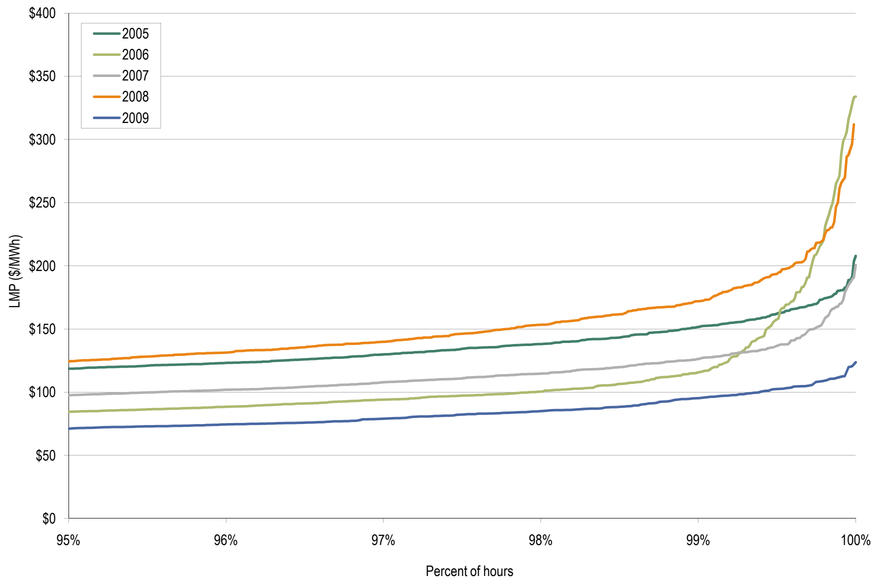
Element	Contribution to LMP	Percent
Coal	$25.49	60.0%
Gas	$14.92	35.1%
Oil	$1.34	3.2%
Uranium	$0.00	0.0%
Municipal Waste	$0.02	0.0%
FMU Adder	$0.23	0.5%
SO2	$0.94	2.2%
NOX	$0.22	0.5%
VOM	$2.96	7.0%
Markup	($3.10)	(7.3%)
Offline CT Adder	$0.07	0.2%
UDS Override Differential	($0.24)	(0.6%)
Dispatch Differential	($0.10)	(0.2%)
M2M Adder	($0.29)	(0.7%)
Flow violation Adjustment	($0.02)	(0.0%)
Unit LMP Differential	($0.00)	(0.0%)
NA	$0.04	0.1%
LMP	$42.48	100.0%

Day-Ahead LMP

Day-Ahead Average LMP

PJM Day-Ahead LMP Duration

Figure 2-15 Price duration curves for the PJM Day-Ahead Energy Market during hours above the 95th percentile: Calendar years 2005 through June 2009 (See 2008 SOM, Figure 2-14)



PJM Day-Ahead, Annual Average LMP

Table 2-56 PJM day-ahead, simple average LMP (Dollars per MWh): Calendar years 2005 through June 2009 (See 2008 SOM, Table 2-61)

	Day-Ahead LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2005	$57.89	$50.08	$30.04	NA	NA	NA
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	$40.01	$37.46	$15.38	(39.5%)	(36.4%)	(50.2%)

Zonal Day-Ahead, Annual Average LMP

Table 2-57 Zonal day-ahead, simple average LMP (Dollars per MWh): January through June 2008 and 2009 (See 2008 SOM, Table 2-62)

	2008 (Jan - Jun)	2009 (Jan - Jun)	Difference	Difference as Percent of 2008
AECO	$83.43	$45.38	($38.05)	(45.6%)
AEP	$56.26	$36.19	($20.07)	(35.7%)
AP	$69.57	$41.11	($28.46)	(40.9%)
BGE	$85.34	$46.01	($39.32)	(46.1%)
ComEd	$53.80	$30.42	($23.38)	(43.4%)
DAY	$56.33	$35.34	($20.99)	(37.3%)
DLCO	$54.78	$34.04	($20.73)	(37.9%)
Dominion	$79.34	$44.17	($35.17)	(44.3%)
DPL	$82.19	$45.80	($36.39)	(44.3%)
JCPL	$87.60	$45.58	($42.02)	(48.0%)
Met-Ed	$80.83	$44.24	($36.58)	(45.3%)
PECO	$80.54	$44.67	($35.87)	(44.5%)
PENELEC	$70.22	$40.30	($29.92)	(42.6%)
Pepco	$86.25	$45.60	($40.64)	(47.1%)
PPL	$79.68	$43.82	($35.86)	(45.0%)
PSEG	$86.08	$46.27	($39.82)	(46.3%)
RECO	$84.51	$45.06	($39.45)	(46.7%)

Day-Ahead, Annual Average LMP by Jurisdiction

Table 2-58 Day-ahead, simple average LMP (Dollars per MWh) by jurisdiction: January through June 2008 and 2009 (See 2008 SOM, Table 2-63)

	2008 (Jan - Jun)	2009 (Jan - Jun)	Difference	Difference as Percent of 2008
Delaware	$81.25	$45.21	($36.04)	(44.4%)
Illinois	$53.80	$30.42	($23.38)	(43.4%)
Indiana	$56.39	$35.47	($20.92)	(37.1%)
Kentucky	$55.71	$35.95	($19.76)	(35.5%)
Maryland	$84.73	$45.89	($38.84)	(45.8%)
Michigan	$57.13	$36.78	($20.34)	(35.6%)
New Jersey	$86.24	$45.94	($40.30)	(46.7%)
North Carolina	$74.53	$43.03	($31.50)	(42.3%)
Ohio	$55.75	$35.29	($20.47)	(36.7%)
Pennsylvania	$74.70	$42.33	($32.37)	(43.3%)
Tennessee	$56.34	$36.51	($19.83)	(35.2%)
Virginia	$76.57	$43.40	($33.17)	(43.3%)
West Virginia	$57.46	$37.35	($20.11)	(35.0%)
District of Columbia	$85.92	$45.68	($40.24)	(46.8%)

Day-Ahead, Load-Weighted, Average LMP

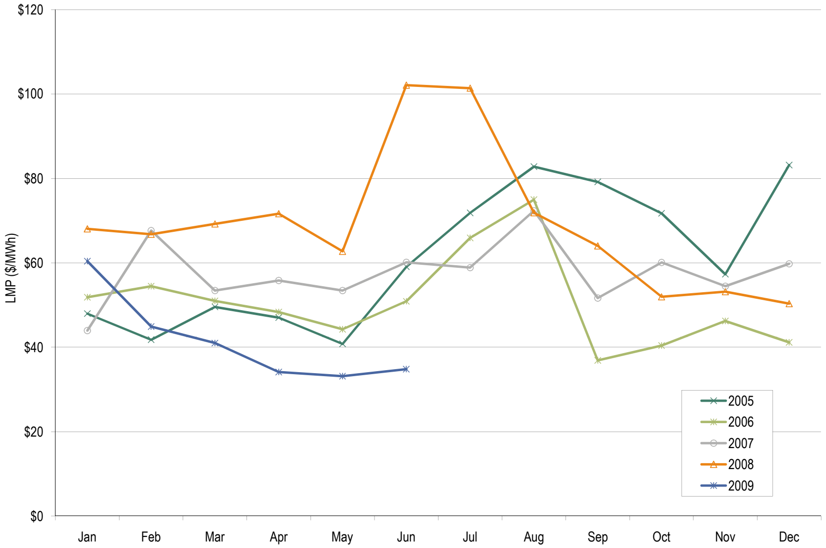
PJM Day-Ahead, Annual, Load-Weighted, Average LMP

Table 2-59 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2005 through June 2009 (See 2008 SOM, Table 2-64)

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2005	$62.50	$54.74	$31.72	NA	NA	NA
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	$42.21	$38.83	$16.16	(39.9%)	(38.3%)	(51.2%)

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

Figure 2-16 Day-ahead, monthly, load-weighted, average LMP: Calendar years 2005 through June 2009 (See 2008 SOM, Figure 2-15)



Zonal Day-Ahead, Annual, Load-Weighted LMP

Table 2-60 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): January through June 2008 and 2009 (See 2008 SOM, Table 2-65)

	2008 (Jan - Jun)	2009 (Jan - Jun)	Difference	Difference as Percent of 2008
AECO	$90.78	$48.09	($42.69)	(47.0%)
AEP	$58.75	$37.95	($20.79)	(35.4%)
AP	$71.72	$43.83	($27.89)	(38.9%)
BGE	$91.96	$49.12	($42.84)	(46.6%)
ComEd	$56.09	$31.72	($24.37)	(43.4%)
DAY	$59.19	$36.99	($22.20)	(37.5%)
DLCO	$57.72	$35.10	($22.63)	(39.2%)
Dominion	$85.99	$47.39	($38.60)	(44.9%)
DPL	$88.22	$48.86	($39.36)	(44.6%)
JCPL	$94.29	$47.94	($46.35)	(49.2%)
Met-Ed	$84.63	$47.29	($37.34)	(44.1%)
PECO	$85.89	$47.08	($38.81)	(45.2%)
PENELEC	$72.09	$42.35	($29.75)	(41.3%)
Pepco	$90.58	$48.20	($42.38)	(46.8%)
PPL	$83.57	$46.72	($36.85)	(44.1%)
PSEG	$91.65	$48.45	($43.20)	(47.1%)
RECO	$91.10	$47.59	($43.52)	(47.8%)

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

Table 2-61 Jurisdiction day-ahead, load weighted LMP (Dollars per MWh): January through June 2008 and 2009 (See 2008 SOM, Table 2-66)

	2008 (Jan - Jun)	2009 (Jan - Jun)	Difference	Difference as Percent of 2008
Delaware	$87.13	$48.05	($39.08)	(44.9%)
Illinois	$56.09	$31.72	($24.37)	(43.4%)
Indiana	$58.86	$36.72	($22.14)	(37.6%)
Kentucky	$58.04	$38.34	($19.71)	(34.0%)
Maryland	$90.14	$49.12	($41.01)	(45.5%)
Michigan	$59.41	$37.93	($21.48)	(36.2%)
New Jersey	$92.31	$48.22	($44.09)	(47.8%)
North Carolina	$81.31	$46.44	($34.86)	(42.9%)
Ohio	$58.27	$36.89	($21.38)	(36.7%)
Pennsylvania	$77.92	$44.69	($33.23)	(42.6%)
Tennessee	$58.49	$38.72	($19.76)	(33.8%)
Virginia	$82.34	$46.52	($35.82)	(43.5%)
West Virginia	$59.94	$39.60	($20.34)	(33.9%)
District of Columbia	$89.84	$47.70	($42.14)	(46.9%)

Components of Day-Ahead, Load-Weighted LMP

Table 2-62 Components of PJM day-ahead, annual, load-weighted, average LMP: January through June 2009 (See 2008 SOM, Table 2-57)

Element	Contribution to LMP	Percent
DEC	$13.69	32.4%
INC	$11.76	27.9%
Coal	$9.54	22.6%
Gas	$3.13	7.4%
Price sensitive demand	$1.62	3.8%
Transaction	$1.06	2.5%
VOM	$0.89	2.1%
SO2	$0.30	0.7%
Oil	$0.27	0.6%
NOx	$0.07	0.2%
Misc	$0.00	0.0%
FMU adder	$0.00	0.0%
Constrained off	($0.00)	(0.0%)
Markup	($0.05)	(0.1%)
NA	($0.07)	(0.2%)
LMP	$42.21	100.0%

Marginal Losses

Table 2-63 PJM real-time, simple average LMP components (Dollars per MWh): Calendar years 2006 through June 2009 (See 2008 SOM, Table 2-67)

	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	$66.29	$0.06	$0.04
2009	$40.12	$40.04	$0.05	$0.03

Table 2-64 Zonal real-time, simple average LMP components (Dollars per MWh): January through June 2008 and 2009 (See 2008 SOM, Table 2-68)

	2008 (Jan - Jun)				2009 (Jan - Jun)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$84.92	$70.09	$10.85	$3.98	$44.59	$40.04	$2.60	$1.95
AEP	$56.20	$70.09	($11.32)	($2.57)	$36.37	$40.04	($2.38)	($1.28)
AP	$69.61	$70.09	$0.30	($0.78)	$41.77	$40.04	$1.79	($0.05)
BGE	$84.14	$70.09	$11.44	$2.61	$45.22	$40.04	$3.49	$1.69
ComEd	$52.81	$70.09	($13.81)	($3.47)	$30.28	$40.04	($7.26)	($2.50)
DAY	$56.66	$70.09	($11.86)	($1.57)	$35.90	$40.04	($3.22)	($0.92)
DLCO	$52.57	$70.09	($14.31)	($3.21)	$34.49	$40.04	($4.12)	($1.43)
Dominion	$78.58	$70.09	$7.78	$0.70	$43.53	$40.04	$2.90	$0.59
DPL	$81.59	$70.09	$8.29	$3.21	$45.20	$40.04	$3.02	$2.14
JCPL	$86.58	$70.09	$12.25	$4.24	$44.92	$40.04	$2.72	$2.17
Met-Ed	$79.58	$70.09	$7.25	$2.25	$43.73	$40.04	$2.70	$1.00
PECO	$78.86	$70.09	$5.92	$2.86	$43.63	$40.04	$2.19	$1.41
PENELEC	$67.94	$70.09	($1.69)	($0.46)	$40.06	$40.04	$0.09	($0.07)
Pepco	$84.33	$70.09	$12.51	$1.73	$44.77	$40.04	$3.60	$1.13
PPL	$78.47	$70.09	$6.56	$1.82	$43.14	$40.04	$2.29	$0.81
PSEG	$85.48	$70.09	$11.13	$4.26	$45.44	$40.04	$3.17	$2.23
RECO	$84.33	$70.09	$10.36	$3.87	$44.22	$40.04	$2.21	$1.98

Table 2-65 Hub real-time, simple average LMP components (Dollars per MWh): January through June 2009 (See 2008 SOM, Table 2-69)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$34.21	$40.04	($3.29)	($2.54)
AEP-DAY Hub	$35.87	$40.04	($2.70)	($1.46)
Chicago Gen Hub	$29.44	$40.04	($7.56)	($3.03)
Chicago Hub	$30.49	$40.04	($7.07)	($2.48)
Dominion Hub	$42.82	$40.04	$2.58	$0.20
Eastern Hub	$45.06	$40.04	$2.71	$2.32
N Illinois Hub	$30.07	$40.04	($7.27)	($2.70)
New Jersey Hub	$45.11	$40.04	$2.94	$2.14
Ohio Hub	$35.84	$40.04	($2.76)	($1.43)
West Interface Hub	$37.20	$40.04	($1.54)	($1.30)
Western Hub	$41.40	$40.04	$1.50	($0.14)

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

Table 2-66 Zonal and PJM real-time, annual, load-weighted, average LMP components (Dollars per MWh): January through June 2009 (See 2008 SOM, Table 2-70)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$46.77	$41.88	$2.83	$2.06
AEP	$38.30	$42.58	($2.90)	($1.37)
AP	$44.59	$42.73	$1.94	($0.08)
BGE	$48.39	$42.56	$4.01	$1.83
ComEd	$32.25	$41.84	($7.04)	($2.55)
DAY	$37.77	$42.42	($3.74)	($0.92)
DLCO	$35.62	$41.82	($4.68)	($1.52)
Dominion	$46.89	$42.83	$3.43	$0.64
DPL	$48.77	$42.88	$3.54	$2.35
JCPL	$47.50	$42.25	$2.94	$2.31
Met-Ed	$46.64	$42.51	$3.04	$1.09
PECO	$46.05	$42.15	$2.40	$1.50
PENELEC	$42.08	$42.23	($0.06)	($0.09)
Pepco	$47.69	$42.40	$4.10	$1.20
PPL	$46.39	$42.78	$2.69	$0.92
PSEG	$47.42	$41.74	$3.35	$2.33
RECO	$46.29	$41.89	$2.34	$2.07
PJM	$42.48	$42.40	$0.05	$0.03

Table 2-67 PJM day-ahead, simple average LMP components (Dollars per MWh): 2006 through June 2009 (See 2008 SOM, Table 2-71)

	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	$40.01	$40.27	($0.14)	($0.12)

Table 2-68 Zonal day-ahead, simple average LMP components (Dollars per MWh): January through June 2008 and 2009. (See 2008 SOM, Table 2-72)

	2008 (Jan - Jun)				2009 (Jan - Jun)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$83.43	$70.51	$8.01	$4.90	$45.38	$40.27	$2.61	$2.49
AEP	$56.26	$70.51	($10.69)	($3.56)	$36.19	$40.27	($2.41)	($1.67)
AP	$69.57	$70.51	($0.02)	($0.92)	$41.11	$40.27	$0.75	$0.08
BGE	$85.34	$70.51	$11.68	$3.15	$46.01	$40.27	$3.72	$2.02
ComEd	$53.80	$70.51	($12.30)	($4.41)	$30.42	$40.27	($6.40)	($3.45)
DAY	$56.33	$70.51	($11.10)	($3.09)	$35.34	$40.27	($3.37)	($1.57)
DLCO	$54.78	$70.51	($11.83)	($3.91)	$34.04	$40.27	($4.56)	($1.68)
Dominion	$79.34	$70.51	$7.96	$0.87	$44.17	$40.27	$2.93	$0.96
DPL	$82.19	$70.51	$7.83	$3.85	$45.80	$40.27	$2.92	$2.61
JCPL	$87.60	$70.51	$11.02	$6.07	$45.58	$40.27	$2.51	$2.80
Met-Ed	$80.83	$70.51	$7.46	$2.86	$44.24	$40.27	$2.69	$1.28
PECO	$80.54	$70.51	$5.95	$4.08	$44.67	$40.27	$2.43	$1.97
PENELEC	$70.22	$70.51	($0.21)	($0.09)	$40.30	$40.27	($0.01)	$0.04
Pepco	$86.25	$70.51	$13.25	$2.49	$45.60	$40.27	$3.67	$1.66
PPL	$79.68	$70.51	$6.61	$2.56	$43.82	$40.27	$2.46	$1.09
PSEG	$86.08	$70.51	$9.45	$6.12	$46.27	$40.27	$2.99	$3.00
RECO	$84.51	$70.51	$8.50	$5.50	$45.06	$40.27	$2.06	$2.72

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

Table 2-69 Zonal and PJM day-ahead, load-weighted, average LMP components (Dollars per MWh): January through June 2009 (See 2008 SOM, Table 2-73)

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$48.09	$42.51	$2.90	$2.68
AEP	$37.95	$42.75	($2.99)	($1.81)
AP	$43.83	$43.12	$0.62	$0.08
BGE	$49.12	$42.68	$4.27	$2.17
ComEd	$31.72	$41.65	($6.39)	($3.54)
DAY	$36.99	$42.59	($3.95)	($1.64)
DLCO	$35.10	$41.95	($5.07)	($1.79)
Dominion	$47.39	$42.88	$3.47	$1.04
DPL	$48.86	$42.70	$3.35	$2.81
JCPL	$47.94	$42.27	$2.71	$2.96
Met-Ed	$47.29	$42.79	$3.10	$1.40
PECO	$47.08	$42.32	$2.66	$2.10
PENELEC	$42.35	$42.42	($0.14)	$0.06
Pepco	$48.20	$42.35	$4.07	$1.78
PPL	$46.72	$42.68	$2.83	$1.21
PSEG	$48.45	$42.11	$3.19	$3.16
RECO	$47.59	$42.47	$2.21	$2.91
PJM	$42.21	$42.47	($0.14)	($0.12)

Marginal Loss Accounting

Monthly Marginal Loss Costs

Table 2-70 Marginal loss costs by type (Dollars (Millions)): 2009 (See 2008 SOM, Table 2-74)

	Marginal Loss Costs (Millions)								
	Day Ahead				Balancing				
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
Jan	$52.4	($143.8)	$14.2	$210.5	$1.0	($2.6)	($6.8)	($3.2)	$207.3
Feb	$35.9	($88.8)	$8.2	$132.9	($0.3)	($1.2)	($4.2)	($3.2)	$129.7
Mar	$34.9	($78.6)	$8.5	$122.0	($0.8)	($1.3)	($5.3)	($4.8)	$117.2
Apr	$22.2	($59.5)	$5.9	$87.6	($1.3)	($0.1)	($3.7)	($4.9)	$82.6
May	$20.3	($53.6)	$4.6	$78.5	($0.5)	($0.4)	($2.5)	($2.5)	$76.0
Jun	$18.6	($71.2)	$3.1	$92.9	($0.5)	($1.5)	($1.5)	($0.6)	$92.3
Jul	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Aug	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Sep	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Oct	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Nov	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Dec	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total	$184.2	($495.5)	$44.6	$724.4	($2.4)	($7.1)	($23.9)	($19.2)	$705.2

Zonal Marginal Loss Costs

Table 2-71 Marginal loss costs by control zone and type (Dollars (Millions)): January through June 2009 (See 2008 SOM, Table 2-75)

	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	$13.4	$2.7	$0.2	$10.8	$0.3	($0.1)	$0.1	$0.4	$11.3
AEP	($26.4)	($133.1)	$10.0	$116.8	$0.2	($0.3)	($0.9)	($0.3)	$116.5
AP	$2.9	($47.3)	$5.9	$56.1	$1.1	$2.0	($3.1)	($4.0)	$52.1
BGE	$26.9	$5.3	$0.5	$22.1	$1.8	($1.0)	($0.4)	$2.4	$24.5
ComEd	($78.0)	($221.6)	$0.3	$143.9	($0.3)	($1.7)	($0.2)	$1.2	$145.1
DAY	($2.3)	($29.3)	$0.7	$27.6	($0.2)	$1.5	$0.1	($1.5)	$26.1
DLCO	($11.7)	($24.0)	$0.1	$12.5	($1.3)	$0.1	($0.0)	($1.5)	$11.0
Dominion	$42.3	($24.7)	$2.6	$69.6	$1.1	($0.7)	($1.4)	$0.4	$70.0
DPL	$28.2	$4.4	$0.3	$24.1	($1.7)	($0.4)	($0.2)	($1.5)	$22.6
JCPL	$35.2	$12.6	$0.2	$22.9	($0.1)	($1.3)	($0.1)	$1.0	$23.9
Met-Ed	$10.7	$2.8	$0.2	$8.0	($0.1)	($0.3)	($0.1)	$0.1	$8.1
PECO	$31.9	$6.9	$0.0	$25.0	($0.2)	($0.5)	$0.0	$0.3	$25.4
PENELEC	($6.3)	($44.6)	$0.4	$38.8	($0.9)	$1.0	($0.2)	($2.1)	$36.7
Pepco	$40.8	$18.3	$1.4	$23.8	($0.8)	($1.4)	($1.0)	($0.4)	$23.5
PJM	($2.7)	($23.8)	$17.3	$38.4	($0.2)	($6.8)	($13.6)	($7.1)	$31.3
PPL	$23.7	($9.4)	$0.9	$34.0	($0.3)	$0.4	$0.1	($0.6)	$33.3
PSEG	$53.7	$9.4	$3.5	$47.8	($0.6)	$2.4	($2.8)	($5.9)	$41.9
RECO	$2.0	$0.0	$0.1	$2.1	($0.1)	($0.0)	($0.1)	($0.1)	$2.0
Total	$184.2	($495.5)	$44.6	$724.4	($2.4)	($7.1)	($23.9)	($19.2)	$705.2

Table 2-72 Monthly marginal loss costs by control zone (Dollars (Millions)): 2009 (See 2008 SOM, Table 2-76)

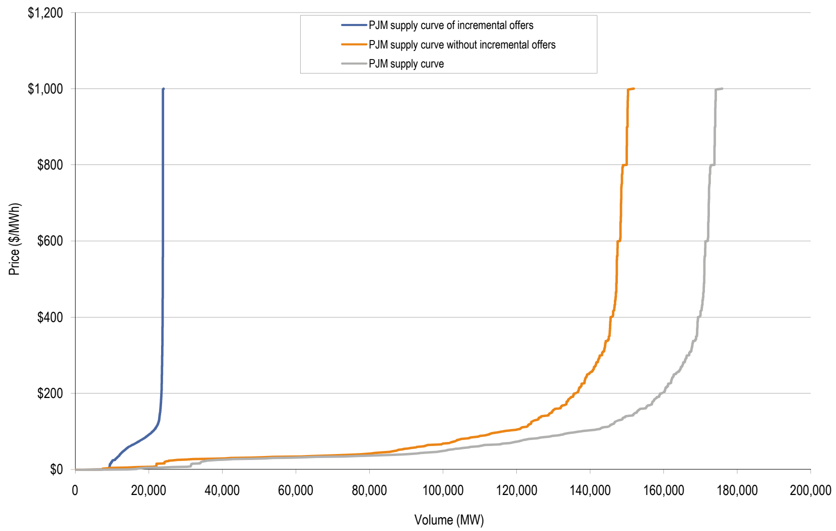
	Marginal Loss Costs by Control Zone (Millions)												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
AECO	$3.4	$2.0	$1.7	$1.7	$1.2	$1.3	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$11.3
AEP	$32.6	$22.9	$18.6	$13.1	$11.7	$17.5	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$116.5
AP	$18.0	$9.4	$8.4	$6.2	$4.8	$5.4	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$52.1
BGE	$7.0	$4.4	$4.2	$2.6	$2.8	$3.4	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$24.5
ComEd	$36.3	$26.1	$28.0	$19.4	$16.9	$18.4	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$145.1
DAY	$7.8	$4.6	$4.5	$3.3	$2.2	$3.7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$26.1
DLCO	$3.5	$1.9	$2.1	$1.2	$0.7	$1.6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$11.0
Dominion	$20.2	$11.8	$11.1	$7.0	$8.2	$11.5	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$70.0
DPL	$6.8	$4.3	$4.0	$2.9	$2.4	$2.2	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$22.6
JCPL	$8.3	$5.6	$3.7	$2.4	$2.1	$1.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$23.9
Met-Ed	$2.4	$1.4	$1.2	$0.9	$0.8	$1.4	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$8.1
PECO	$8.0	$4.3	$3.5	$2.6	$2.9	$4.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$25.4
PENELEC	$12.1	$5.6	$4.3	$4.1	$5.0	$5.6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$36.7
Pepco	$6.0	$3.6	$4.3	$3.1	$2.8	$3.7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$23.5
PJM	$14.1	$6.0	$4.8	$2.0	$3.2	$1.3	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$31.3
PPL	$10.1	$6.5	$5.5	$3.8	$3.0	$4.5	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$33.3
PSEG	$10.1	$8.8	$7.1	$6.0	$5.1	$4.9	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$41.9
RECO	$0.6	$0.4	$0.3	$0.3	$0.2	$0.2	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$2.0
Total	$207.3	$129.7	$117.2	$82.6	$76.0	$92.3	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$705.2

Virtual Offers and Bids

Table 2-73 Type of day-ahead marginal units: January through June 2009 (See 2008 SOM, Table 2-77)

	Generation	Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	20.6%	32.2%	33.3%	13.0%	1.0%
Feb	17.4%	38.8%	28.5%	14.6%	0.8%
Mar	14.9%	39.8%	27.6%	17.0%	0.7%
Apr	16.2%	38.7%	28.6%	16.0%	0.5%
May	12.2%	38.5%	29.1%	19.0%	1.2%
Jun	17.3%	30.7%	27.2%	24.0%	0.8%
Annual	16.4%	36.4%	29.1%	17.3%	0.8%

Figure 2-17 PJM day-ahead aggregate supply curves: 2009 example day (See 2008 SOM, Figure 2-16)



Price Convergence

Table 2-74 Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): January through June 2009 (See 2008 SOM, Table 2-78)

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
Average	$40.01	$40.12	$0.11	0.3%
Median	$37.46	$35.42	($2.04)	(5.8%)
Standard deviation	$15.38	$19.30	$3.92	20.3%

Table 2-75 Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): Calendar years 2000 through June 2009 (See 2008 SOM, Table 2-79)

Year	Day Ahead	Real Time	Difference	Difference as Percent Real Time
2000	$31.97	$30.36	($1.61)	(5.3%)
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	5.0%
2008	$66.12	$66.40	$0.28	0.4%
2009	$40.01	$40.12	$0.11	0.3%

Table 2-76 Frequency distribution by hours of PJM real-time and day-ahead LMP difference (Dollars per MWh): 2005 through June 2009 (See 2008 SOM, Table 2-80)

	2005		2006		2007		2008		2009	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($150)	0	0.00%	1	0.01%	0	0.00%	0	0.00%	0	0.00%
($150) to ($100)	1	0.01%	1	0.02%	0	0.00%	1	0.01%	0	0.00%
($100) to ($50)	64	0.74%	9	0.13%	33	0.38%	88	1.01%	3	0.07%
($50) to $0	5,015	57.99%	5,205	59.54%	4,600	52.89%	5,120	59.30%	2,541	58.58%
$0 to $50	3,471	97.61%	3,372	98.04%	3,827	96.58%	3,247	96.27%	1,772	99.38%
$50 to $100	190	99.78%	152	99.77%	255	99.49%	284	99.50%	25	99.95%
$100 to $150	17	99.98%	9	99.87%	31	99.84%	37	99.92%	2	100.00%
$150 to $200	2	100.00%	4	99.92%	5	99.90%	4	99.97%	0	100.00%
$200 to $250	0	100.00%	1	99.93%	1	99.91%	2	99.99%	0	100.00%
$250 to $300	0	100.00%	3	99.97%	3	99.94%	0	99.99%	0	100.00%
$300 to $350	0	100.00%	0	99.97%	2	99.97%	1	100.00%	0	100.00%
$350 to $400	0	100.00%	1	99.98%	1	99.98%	0	100.00%	0	100.00%
$400 to $450	0	100.00%	0	99.98%	1	99.99%	0	100.00%	0	100.00%
$450 to $500	0	100.00%	1	99.99%	1	100.00%	0	100.00%	0	100.00%
>= $500	0	100.00%	1	100.00%	0	100.00%	0	100.00%	0	100.00%

Figure 2-18 Hourly real-time minus hourly day-ahead LMP: January through June 2009 (See 2008 SOM, Figure 2-17)

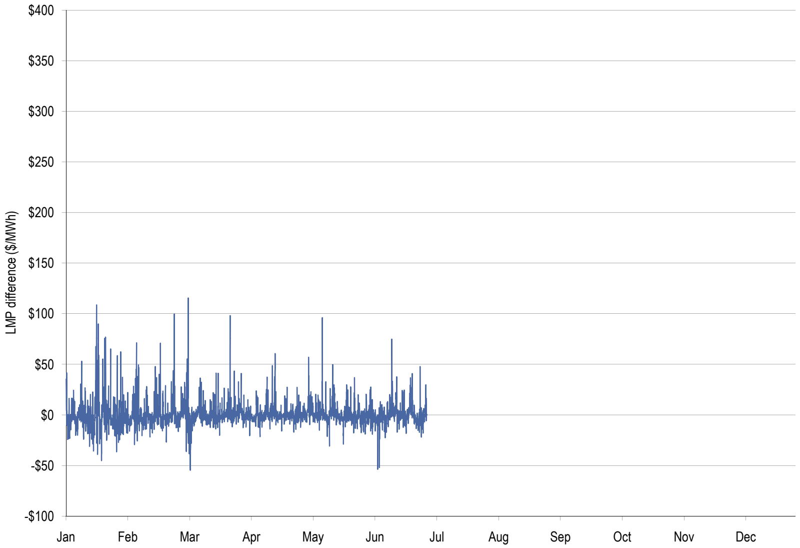


Figure 2-19 Monthly average of real-time minus day-ahead LMP: January through June 2009 (See 2008 SOM, Figure 2-18)

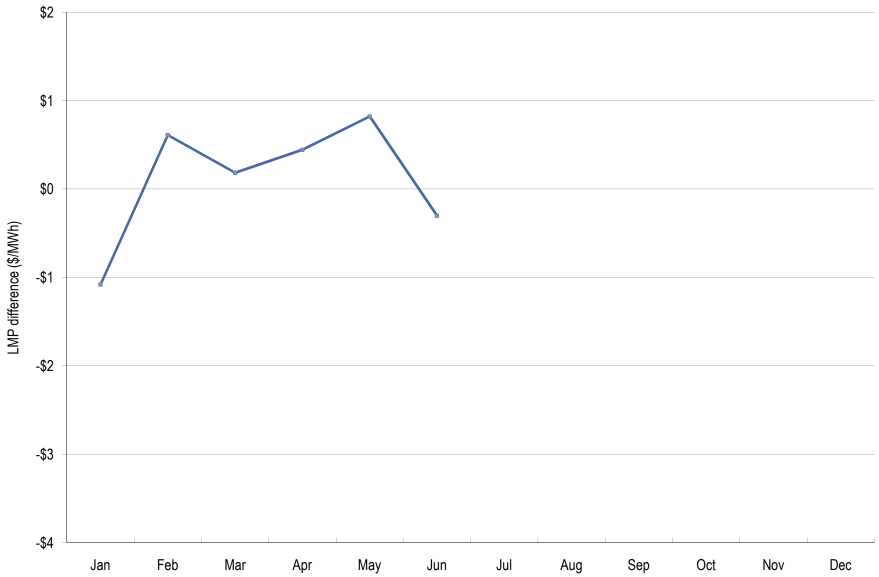
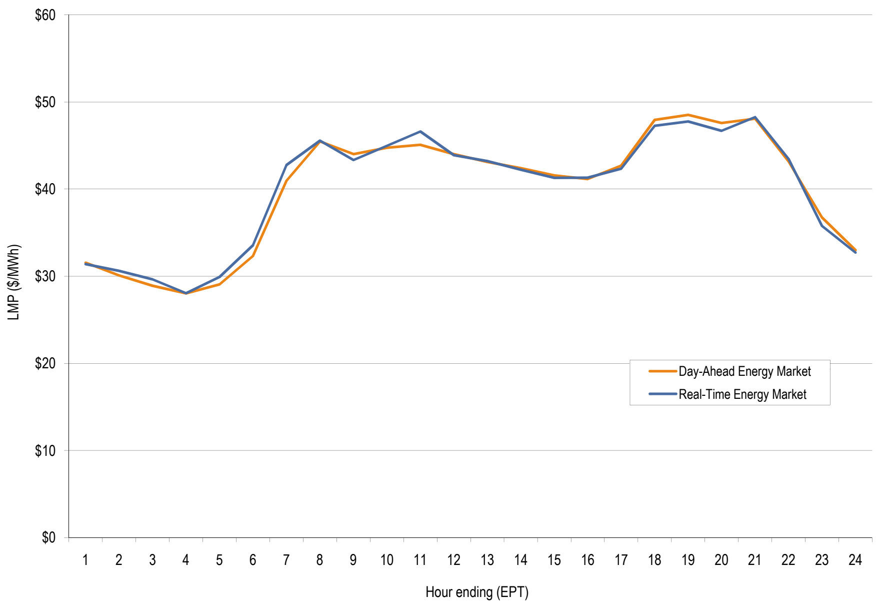


Figure 2-20 PJM system hourly average LMP: January through June 2009 (See 2008 SOM, Figure 2-19)



Zonal Price Convergence

Table 2-77 Zonal Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): January through June 2009 (See 2008 SOM, Table 2-81)

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$45.38	$44.59	($0.78)	(1.8%)
AEP	$36.19	$36.37	$0.18	0.5%
AP	$41.11	$41.77	$0.66	1.6%
BGE	$46.01	$45.22	($0.79)	(1.8%)
ComEd	$30.42	$30.28	($0.14)	(0.5%)
DAY	$35.34	$35.90	$0.56	1.6%
DLCO	$34.04	$34.49	$0.45	1.3%
Dominion	$44.17	$43.53	($0.64)	(1.5%)
DPL	$45.80	$45.20	($0.61)	(1.3%)
JCPL	$45.58	$44.92	($0.66)	(1.5%)
Met-Ed	$44.24	$43.73	($0.51)	(1.2%)
PECO	$44.67	$43.63	($1.04)	(2.4%)
PENELEC	$40.30	$40.06	($0.24)	(0.6%)
Pepco	$45.60	$44.77	($0.83)	(1.9%)
PPL	$43.82	$43.14	($0.68)	(1.6%)
PSEG	$46.27	$45.44	($0.83)	(1.8%)
RECO	$45.06	$44.22	($0.84)	(1.9%)

Price Convergence by Jurisdiction

Table 2-78 Jurisdiction Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): January through June 2009 (See 2008 SOM, Table 2-82)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Delaware	$45.21	$44.87	($0.34)	(0.8%)
Illinois	$30.42	$30.28	($0.14)	(0.5%)
Indiana	$35.47	$35.71	$0.24	0.7%
Kentucky	$35.95	$36.25	$0.30	0.8%
Maryland	$45.89	$45.20	($0.69)	(1.5%)
Michigan	$36.78	$37.07	$0.29	0.8%
New Jersey	$45.94	$45.16	($0.78)	(1.7%)
North Carolina	$43.03	$42.45	($0.58)	(1.4%)
Ohio	$35.29	$35.69	$0.40	1.1%
Pennsylvania	$42.33	$41.88	($0.45)	(1.1%)
Tennessee	$36.51	$36.34	($0.17)	(0.5%)
Virginia	$43.40	$42.77	($0.63)	(1.5%)
West Virginia	$37.35	$37.62	$0.27	0.7%
District of Columbia	$45.68	$44.92	($0.76)	(1.7%)

Load and Spot Market

Real-Time Load and Spot Market

Table 2-79 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: 2008 through June 2009 (See 2008 SOM, Table 2-83)

	2008			2009			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	14.3%	17.3%	68.4%	12.6%	15.4%	72.0%	(1.7%)	(1.9%)	3.6%
Feb	15.2%	17.3%	67.5%	13.4%	14.5%	72.1%	(1.7%)	(2.9%)	4.6%
Mar	16.0%	17.1%	66.9%	13.8%	16.7%	69.5%	(2.3%)	(0.4%)	2.6%
Apr	16.6%	18.0%	65.4%	13.5%	17.2%	69.3%	(3.1%)	(0.8%)	3.9%
May	16.0%	18.8%	65.3%	14.6%	18.8%	66.7%	(1.4%)	(0.0%)	1.4%
Jun	13.1%	21.0%	65.9%	12.5%	16.5%	71.0%	(0.6%)	(4.5%)	5.1%
Jul	13.7%	20.6%	65.7%						
Aug	14.9%	22.6%	62.4%						
Sep	14.7%	23.0%	62.2%						
Oct	15.1%	22.7%	62.2%						
Nov	14.8%	22.9%	62.3%						
Dec	12.1%	20.5%	67.4%						
Annual	14.6%	20.1%	65.2%	13.4%	16.4%	70.2%	(1.3%)	(3.7%)	5.0%

Day-Ahead Load and Spot Market

Table 2-80 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: 2008 through June 2009 (See 2008 SOM, Table 2-84)

	2008			2009			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	4.2%	15.6%	80.2%	4.4%	13.9%	81.7%	0.2%	(1.7%)	1.5%
Feb	4.5%	16.0%	79.5%	4.5%	12.7%	82.9%	(0.1%)	(3.3%)	3.4%
Mar	4.7%	16.0%	79.3%	4.3%	13.2%	82.5%	(0.4%)	(2.8%)	3.2%
Apr	5.0%	16.8%	78.2%	4.4%	14.1%	81.5%	(0.5%)	(2.7%)	3.3%
May	5.0%	18.2%	76.8%	4.6%	15.9%	79.5%	(0.4%)	(2.3%)	2.7%
Jun	5.5%	20.2%	74.3%	4.7%	14.2%	81.2%	(0.8%)	(6.1%)	6.9%
Jul	5.6%	20.4%	74.0%						
Aug	4.9%	20.2%	75.0%						
Sep	5.4%	19.3%	75.3%						
Oct	5.4%	20.3%	74.3%						
Nov	5.6%	18.9%	75.5%						
Dec	4.6%	19.1%	76.3%						
Annual	5.0%	18.4%	76.5%	4.5%	13.9%	81.6%	(0.5%)	(4.5%)	5.0%

Virtual Markets

Increment Offers and Decrement Bids

Table 2-81 Monthly volume of cleared and submitted INCs, DECs: January through June 2009 (See 2008 SOM, Table 2-85)

	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	13,986	21,401	423	621	16,879	26,080	487	670
Feb	13,487	22,228	484	739	15,557	24,967	420	624
Mar	13,364	22,639	552	820	15,186	23,243	459	651
Apr	11,363	19,935	380	645	13,900	21,173	428	607
May	12,853	16,863	388	750	13,973	19,274	529	805
Jun	12,375	15,369	315	750	14,777	18,402	482	802
Jul								
Aug								
Sep								
Oct								
Nov								
Dec								
Annual	12,906	19,719	423	721	15,043	22,169	468	693

Demand-Side Response (DSR)

Emergency Program

Table 2-82 Zonal capability in the Emergency Program for the 2009 peak day through June (By option): January 16, 2009 (See 2008 SOM, Table 2-86)

	Energy Only		Full		Capacity Only	
	Sites	MW	Sites	MW	Sites	MW
AECO	0	0.0	70	20.0	7	8.6
AEP	0	0.0	137	512.5	54	698.5
AP	0	0.0	100	138.9	39	133.7
BGE	0	0.0	196	428.4	46	32.8
ComEd	0	0.0	69	95.6	877	820.9
DAY	0	0.0	23	8.4	8	50.0
DLCO	0	0.0	13	27.0	21	45.6
Dominion	0	0.0	59	5.5	74	81.1
DPL	0	0.0	60	79.3	29	46.0
JCPL	0	0.0	80	97.6	33	14.5
Met-Ed	0	0.0	70	150.7	24	40.8
PECO	0	0.0	146	60.7	154	216.9
PENELEC	0	0.0	38	50.5	35	30.0
Pepco	0	0.0	109	46.8	35	21.3
PPL	0	0.0	114	59.6	97	278.7
PSEG	0	0.0	236	175.3	63	19.9
RECO	0	0.0	3	1.0	21	1.1
Total	0	0.0	1,523	1,957.8	1,617	2,540.4

Table 2-83 Zonal monthly capacity credits: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-87)

Zone	January	February	March	April	May	June
AECO	$154,551	$139,595	$154,551	$149,566	$154,551	$375,086
AEP	$2,578,133	$2,328,636	$2,578,133	$2,494,967	$2,578,133	$3,746,728
APS	$966,835	$873,270	$966,835	$935,647	$966,835	$2,982,596
BGE	$2,882,161	$2,603,243	$2,882,161	$2,789,189	$2,882,161	$4,464,694
ComEd	$3,294,602	$2,975,769	$3,294,602	$3,188,324	$3,294,602	$4,217,299
DAY	$258,904	$233,849	$258,904	$250,552	$258,904	$646,419
DLCO	$258,489	$233,474	$258,489	$250,151	$258,489	$375,138
Dominion	$296,319	$267,643	$296,319	$286,760	$296,319	$1,602,407
DPL	$665,561	$601,152	$665,561	$644,091	$665,561	$971,656
JCPL	$554,279	$500,639	$554,279	$536,399	$554,279	$868,932
Met-Ed	$681,734	$615,760	$681,734	$659,743	$681,734	$1,313,605
PECO	$1,375,581	$1,242,460	$1,375,581	$1,331,207	$1,375,581	$2,052,483
PENELEC	$283,241	$255,831	$283,241	$274,105	$283,241	$1,282,941
Pepco	$572,160	$516,789	$572,160	$553,703	$572,160	$788,433
PPL	$1,200,552	$1,084,370	$1,200,552	$1,161,825	$1,200,552	$3,500,850
PSEG	$922,290	$833,036	$922,290	$892,538	$922,290	$1,720,276
RECO	$10,219	$9,230	$10,219	$9,890	$10,219	$17,897
Total	$16,955,611	$15,314,746	$16,955,611	$16,408,656	$16,955,611	$30,927,439

Economic Program

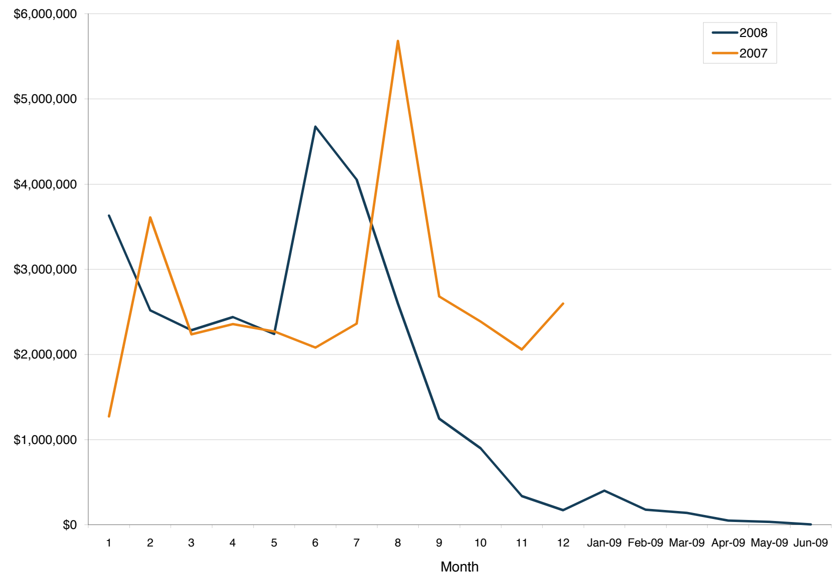
Table 2-84 Economic Program registration on the last day of the month: January 2007 through June 2009[10] (New table)

	2007		2008		2009	
Month	Registered Sites	Registered MW	Registered Sites	Registered MW	Registered Sites	Registered MW
Jan	508	1,530	4,906	2,959	4,862	3,303
Feb	953	1,567	4,902	2,961	4,869	3,219
Mar	959	1,578	4,972	3,012	4,867	3,227
Apr	980	1,648	5,016	3,197	2,582	3,242
May	996	3,674	5,069	3,588	1,250	2,860
Jun	2,490	2,168	3,112	3,014	1,261	2,455
Jul	2,872	2,459	4,542	3,165		
Aug	2,911	2,582	4,815	3,232		
Sep	4,868	2,915	4,836	3,263		
Oct	4,873	2,880	4,846	3,266		
Nov	4,897	2,948	4,851	3,271		
Dec	4,898	2,944	4,851	3,290		
Avg.	2,684	2,408	4,727	3,185	3,282	3,051

Table 2-85 Zonal capability in the Economic Program: January 16, 2009 (See 2008 SOM, Table 2-89)

	Sites	MW
AECO	32	11.4
AEP	13	251.1
AP	33	228.2
BGE	143	608.1
ComEd	3,849	969.5
DAY	9	10.0
DLCO	27	95.6
Dominion	63	208.9
DPL	114	127.3
JCPL	77	120.3
Met-Ed	41	99.3
PECO	192	222.3
PENELEC	12	23.3
Pepco	16	16.4
PPL	91	225.3
PSEG	148	93.2
RECO	3	0.9
Total	4,863	3,311.0

Figure 2-21 Economic Program Payments: Calendar years 2007 (without incentive payments), 2008 and January through June of 2009[11] (See 2008 SOM, Figure 2-20)



10 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.

11 All May and June settlement, reduction and credit data are subject to change. Settlements may be submitted up to 60 days following an event day. EDC/LSEs have up to 10 business days to approve which could result in a maximum lag of approximately 74 calendar days. In addition, June data submitted after July 1, 2009 is not reflected due to changes to the PJM DSR settlement collection system and database structure. All MWh reductions and CSP credits have been provided by PJM as the best data available as of July 27, 2009.

Table 2-86 PJM Economic Program by zonal reduction: January through June 2009 (See 2008 SOM, Table 2-92)

	Real Time			Day Ahead			Dispatched in Real Time			Totals		
	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours
AECO	35	$1,123	89	0	$0	0	4	$117	15	40	$1,241	104
AEP	3,895	$53,692	247	0	$25,038	44	0	$0	0	3,895	$78,730	291
AP	121	$8,079	81	0	$0	0	10	$562	11	131	$8,641	92
BGE	45	$2,193	246	0	$0	0	0	$0	0	45	$2,193	246
ComEd	21	$316	72	0	$0	0	647	$4,351	771	669	$4,667	843
DAY	0	$0	0	0	$0	0	0	$0	0	0	$0	0
DLCO	0	$0	0	0	$0	0	0	$0	0	0	$0	0
Dominion	3,365	$200,005	690	42	$442	76	130	$4,953	109	3,537	$205,400	875
DPL	10	$414	244	0	$0	0	0	$0	0	10	$414	244
JCPL	0	$0	0	0	$0	0	9	$248	30	9	$248	30
Met-Ed	64	$3,218	90	0	$0	0	4	$254	14	68	$3,472	104
PECO	5,125	$122,640	9,968	0	$0	0	204	$13,496	1,053	5,329	$136,136	11,021
PENELEC	154	$6,661	26	0	$0	0	2	$47	6	156	$6,708	32
Pepco	126	$4,224	63	0	$0	0	39	$1,753	71	164	$5,977	134
PPL	6,582	$260,617	2,933	1,895	$65,199	730	172	$14,954	336	8,649	$340,770	3,999
PSEG	62	$1,809	90	0	$0	0	5	$177	32	68	$1,987	122
RECO	1	$12	24	0	$0	0	0	$0	0	1	$12	24
Total	19,606	$665,003	14,863	1,937	$90,679	850	1,227	$40,914	2,448	22,769	$796,596	18,161
Max	6,582	$260,617	9,968	1,895	$65,199	730	647	$14,954	1,053	8,649	$340,770	11,021
Avg	1,153	$39,118	874	114	$5,334	50	72	$2,407	144	1,339	$46,859	1,068

Table 2-87 Settlement days submitted by month in the Economic Program: 2007, 2008 and January through June 2009 (New table)

Month	2007	2008	2009
Jan	887	2,894	1,224
Feb	1,099	2,785	630
Mar	1,185	2,802	542
Apr	1,468	3,386	318
May	1,609	3,309	260
Jun	1,731	3,072	30
Jul	2,421	3,209	
Aug	3,783	3,732	
Sep	3,320	3,179	
Oct	3,446	1,947	
Nov	2,819	1,068	
Dec	2,655	933	
Total	26,423	32,316	2,396

Table 2-88 Distinct customers and CSPs submitting settlements in the Economic Program by month: Calendar years 2007, 2008 and January through June 2009 (New table)

	2007		2008		2009	
Month	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers
Jan	10	68	11	260	13	234
Feb	8	83	10	241	11	128
Mar	8	82	10	216	9	143
Apr	9	92	11	204	5	67
May	10	103	9	227	4	79
Jun	10	163	14	276	1	13
Jul	13	227	14	255		
Aug	15	285	15	270		
Sep	13	280	14	276		
Oct	9	240	10	222		
Nov	8	202	11	205		
Dec	9	241	10	192		
Total Distinct Active	17	384	20	494	13	271

Table 2-89 Hourly frequency distribution of Economic Program MWh reductions and credits: January through June 2009 (See 2008 SOM, Table 2-93)

	MWh Reductions				Program Credits			
Hour	MWh Reductions	Percent	Cumulative Frequency	Cumulative Percent	Credits	Percent	Cumulative Frequency	Cumulative Percent
1	338	1.48%	338	1.48%	$5,752	0.72%	$5,752	0.72%
2	350	1.54%	689	3.02%	$5,909	0.74%	$11,660	1.46%
3	376	1.65%	1,065	4.68%	$7,064	0.89%	$18,724	2.35%
4	398	1.75%	1,462	6.42%	$7,454	0.94%	$26,178	3.29%
5	404	1.77%	1,866	8.20%	$8,087	1.02%	$34,265	4.30%
6	432	1.90%	2,298	10.09%	$11,313	1.42%	$45,578	5.72%
7	1,408	6.19%	3,707	16.28%	$85,289	10.71%	$130,867	16.43%
8	1,772	7.78%	5,479	24.06%	$102,739	12.90%	$233,606	29.33%
9	1,639	7.20%	7,118	31.26%	$65,834	8.26%	$299,441	37.59%
10	1,227	5.39%	8,345	36.65%	$51,673	6.49%	$351,113	44.08%
11	1,055	4.63%	9,400	41.28%	$45,952	5.77%	$397,065	49.85%
12	980	4.30%	10,379	45.58%	$28,932	3.63%	$425,998	53.48%
13	967	4.25%	11,347	49.83%	$25,788	3.24%	$451,785	56.71%
14	989	4.34%	12,336	54.18%	$25,913	3.25%	$477,699	59.97%
15	950	4.17%	13,286	58.35%	$21,354	2.68%	$499,053	62.65%
16	940	4.13%	14,226	62.48%	$17,649	2.22%	$516,702	64.86%
17	1,055	4.63%	15,282	67.11%	$25,788	3.24%	$542,490	68.10%
18	1,238	5.44%	16,519	72.55%	$46,513	5.84%	$589,003	73.94%
19	1,470	6.46%	17,989	79.01%	$54,571	6.85%	$643,574	80.79%
20	1,502	6.59%	19,491	85.60%	$52,930	6.64%	$696,504	87.43%
21	1,316	5.78%	20,807	91.38%	$58,154	7.30%	$754,658	94.74%
22	848	3.72%	21,655	95.10%	$23,813	2.99%	$778,470	97.72%
23	612	2.69%	22,266	97.79%	$11,193	1.41%	$789,663	99.13%
24	503	2.21%	22,769	100.00%	$6,933	0.87%	$796,596	100.00%

Table 2-90 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): January through June 2009 (See 2008 SOM, Table 2-94)

	MWh Reductions				Program Credits			
LMP	MWh Reductions	Percent	Cumulative Frequency	Cumulative Percent	Credits	Percent	Cumulative Frequency	Cumulative Percent
$0 to $25	122	0.53%	122	0.53%	$5,406	0.68%	$5,406	0.68%
$25 to $50	10,460	45.94%	10,581	46.47%	$146,563	18.40%	$151,969	19.08%
$50 to $75	4,892	21.48%	15,473	67.96%	$125,629	15.77%	$277,597	34.85%
$75 to $100	3,327	14.61%	18,800	82.57%	$152,876	19.19%	$430,474	54.04%
$100 to $125	1,698	7.46%	20,498	90.03%	$108,344	13.60%	$538,817	67.64%
$125 to $150	1,082	4.75%	21,581	94.78%	$92,569	11.62%	$631,386	79.26%
$150 to $200	804	3.53%	22,385	98.31%	$94,528	11.87%	$725,914	91.13%
$200 to $250	318	1.40%	22,702	99.71%	$51,662	6.49%	$777,576	97.61%
$250 to $300	9	0.04%	22,712	99.75%	$2,175	0.27%	$779,751	97.89%
> $300	58	0.25%	22,769	100.00%	$16,845	2.11%	$796,596	100.00%

Load Management (LM)

Table 2-91 Available LM MW by program type: Delivery years 2007 through 2009 (New table)

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	1,021.1	6,273.8	7,294.9

Table 2-92 Demand Response (DR) offered and cleared in RPM Base Residual Auction: Delivery years 2007 through 2012 (New table)

Planning Year	DR Offered in BRA	DR Cleared in BRA
2007/2008	123.5	123.5
2008/2009	691.9	536.2
2009/2010	906.9	856.2
2010/2011	935.6	908.1
2011/2012	1,597.3	1,319.5
2012/2013	9,535.4	6,824.1

SECTION 3 – ENERGY MARKET, PART 2

The Market Monitoring Unit (MMU) analyzed measures of PJM Energy Market structure, participant conduct and market performance for 2009. 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.

Overview

Net Revenue

- **Net Revenue Adequacy.** 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 cost 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 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.

  Overall, through the first six months of 2009, net revenue results were mixed compared to the same period in 2008. For the new entrant combustion turbine (CT), nine zones had lower net revenue and eight zones had higher net revenue compared to 2008. (Table 3-8.) All zones had lower energy net revenue compared to 2008 for the new entrant CT, however, for zones that cleared in the RTO Locational Delivery Area (LDA) for the 2007/2008 and the 2008/2009 BRA, this decrease in energy net revenue was more than offset by higher capacity revenues in the 2008/2009 delivery year. For the new entrant combined cycle (CC), eleven zones had lower net revenue and six zones had higher net revenue compared to 2008, which reflects a decrease in energy and capacity market revenue in most eastern zones, an increase in capacity revenues in western zones and an increase in both capacity and energy revenues in AEP, ComEd, DAY and DLCO. For the new entrant coal plant (CP), all zones had a significant decrease in net revenue compared to 2008, which is driven by lower energy revenues.

  The levels of net revenue through June of 2009 for new peaking, midmerit and baseload power plants vary significantly by location. Energy market prices and delivered fuel prices are down from the same period in 2008, although the spread between fuel costs and energy market prices varies by location. In western zones, energy market prices decreased less than in eastern zones, and, in some cases, average on peak energy prices decreased by less than natural gas prices. As a result, several western zones had an increase in net revenue for the CT and the CC technology. The decrease in net revenues for the CP technology in all zones reflects the fact that energy prices decreased more than the price of delivered coal compared to the same period in 2008. Capacity market revenues also show mixed results for the first six months of 2009 compared to the same period in 2008. Zones in the RTO LDA show an increase in capacity revenues from the same period in 2008 as the RTO cleared significantly higher in 2008/2009 and 2009/2010 compared to the 2007/2008 BRA. Some zones in the east show a decrease in capacity revenues from the same period in 2008 as the 2007/2008 auction cleared at a higher price for eastern zones than the 2008/2009 auction. When capacity market revenues for the full year 2009 are reflected, all control zones will show an increase in capacity revenue compared to calendar year 2008. The results from January through June of 2009 illustrate that the profitability of, and thus the incentive to invest in power generation technologies is closely tied to changes in the spread between electricity market prices and input fuel market prices in specific locations. In addition, 2009 results highlight the importance of revenues from the capacity market when energy market net revenues are insufficient to recover fixed costs.

  Zonal net revenue reflects differences in locational energy prices and differences in locational capacity prices. The zonal variation in net revenue illustrates the substantial impact of location on economic incentives. While the 2009 net revenue using PJM real-time average locational marginal prices was $23,845 per MW-year for a CT, the zonal maximum net revenue was $42,549 in the Pepco Control Zone and the minimum was $20,762 in the ComEd Control Zone.[1] While the PJM

1 Calculated values shown in Section 3, "Energy Market, Part 2," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

average net revenue in 2009 was $39,673 per MW-year for a CC, the zonal maximum net revenue was $67,829 in the Pepco Control Zone and the minimum was $34,516 in the ComEd Control Zone. While the PJM average net revenue in 2008 was $53,477 per MW-year for a CP, the zonal maximum net revenue was $105,845 in the Pepco Control Zone and the minimum was $50,938 in the DAY Control Zone.

Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1, through July 1, 2009, PJM installed capacity resources rose slightly from 164,899 MW on January 1 to 167,454 MW on June 1.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at June 1, 2009, 40.7 percent was coal; 29.2 percent was natural gas; 18.3 percent was nuclear; 6.4 percent was oil; 4.7 percent was hydroelectric; 0.4 percent was solid waste, and 0.2 percent was wind.

- **Generation Fuel Mix.** During January through June 2009, coal provided 51.3 percent, nuclear 36.1 percent, gas 8.6 percent, oil 0.2 percent, hydroelectric 2.0 percent, solid waste 0.8 percent and wind 0.8 percent of total generation.

- **Planned Generation.** If current trends continue, it is expected that older steam units in the east will be replaced by units burning natural gas and the result has potentially significant implications for future congestion, the role of firm and interruptible gas supply and natural gas supply infrastructure.

Scarcity

- **Scarcity Pricing Events in 2009.** PJM did not declare a scarcity event in the first two quarters of 2009.

- **Scarcity.** 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 capacity market 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. 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 have a scarcity pricing mechanism in the energy market because it provides direct, market-based incentives to load and generation, as long as the market rules are designed to ensure that scarcity revenues directly offset RPM revenues to prevent double collection of scarcity revenues.

  A hybrid market design can provide scarcity revenues both via scarcity pricing in the energy market and via the capacity market. However, if scarcity revenues are provided in the energy market, there must be an explicit mechanism to remove those revenues from capacity market revenues. This offset must reflect the actual scarcity revenues and not those reflected in forward curves or forecast by analysts from any organization. The absence of such a mechanism is likely to result in an over collection of scarcity revenues as such revenues are episodic and unlikely to be fully reflected in forward curves, even if such curves were based on a liquid market three years forward and reflected locational results, which they do not. The most straightforward way to ensure that such over collection 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 resources and eliminate the need for a complex, uncertain, after the fact procedure for offsetting scarcity revenues in the capacity market.

- **Modifications to Scarcity Pricing.** While PJM's triggers for administrative scarcity pricing are reasonable measures of scarcity conditions, PJM's scarcity pricing rules need refinement. In addition, PJM should consider creating a mechanism for defining new scarcity pricing regions in real time if system conditions warrant.

The current single scarcity price signal should be replaced by locational signals. Locational scarcity signals could be implemented via reserve requirements modeled as constraints for scarcity regions, with administrative scarcity penalty factors, in the security constrained dispatch. The level of the penalty factor and the reserve target would be determined by the severity level of the scarcity event. This would provide a means to signal scarcity that is consistent with economic dispatch, consistent with locational pricing and consistent with competitive market outcomes.

Administrative scarcity pricing should include stages, based on system conditions, with progressive impacts on prices. The trigger for each stage should be based on the level of available operating reserve using a dynamically determined and relevant operating reserve requirement and the progressive use of emergency measures. Implemented as scarcity region specific operating reserve constraints in the security constrained dispatch, the severity of scarcity event should be reflected in a set of increasing, administrative penalty factors.

If implemented using reserve requirement constraints with escalating penalty factors, the scarcity pricing mechanism would eliminate the need to lift offer capping during a scarcity pricing event. Properly set, the penalty factors would increase prices on the system to provide a locational pricing signal reflecting the severity of the shortage. This approach also eliminates the incentive for participants to make non-competitive energy offers in anticipation of scarcity events. Keeping offers consistent during the event would have the added benefit of avoiding the operational issues involved with sudden changes in the economic dispatch order before, during and after a scarcity event.

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, operating reserve 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. 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.

- **Operating Reserve Charges in 2009.** The level of operating reserve credits and corresponding charges decreased in the months of January through June by 26.2 percent compared to the months of January through June 2008. This was the result of a large decrease in the amount of balancing operating reserve credits. Day-ahead credits increased significantly from the first six months of 2008, while synchronous condensing credits were slightly higher.

- **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.

- **Parameter Limited Schedule rules.** On March 19, 2009, the Commission issued an order rejecting PJM's proposed revisions to Section 6.6(c) of Schedule 1 of the PJM Operating Agreement that would have altered the application of the rules for evaluating requests for exceptions to the values included in or derived on a formulaic basis from the Parameter Limited Schedule Matrix.[2] As a consequence, the business rules approved by the Members Committee on November 15, 2007, were reinstated. PJM and the Market Monitor jointly administered these rules for the spring cycle.

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

2 126 FERC ¶61,251 (2009).

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 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 in well-defined stages 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. With a capacity market design that appropriately reflects a direct and explicit offset for scarcity rents in the energy market, 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.

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.

While net revenue in PJM has been almost sufficient to cover the costs of new peaking units in some years and was sufficient to cover the costs of a new coal plant in 2005 and close to covering those costs in 2006 in some eastern zones, net revenue prior to the RPM construct was generally below the level required to cover the full costs of new generation investment for several years and below that level on average for all unit types for the entire market period. The fact that investors' expectations have not been realized in every year could be taken as a reflection of cyclical supply-demand fundamentals in PJM markets. However, it is also the case that there have been some units in PJM, needed for reliability, with revenues less than annual going-forward costs, which, if it persists, is a signal to retire. This suggests that market price signals and reliability needs have not been fully synchronized.

The historical level of net revenues in PJM markets is 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 value the resources needed to provide for reliability, although the contribution of the Energy Market will be more consistent with reliability signals if the Energy Market appropriately provides for scarcity pricing when scarcity does occur.

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 combination of locational Energy Market and locational Capacity Market signals in 2007 represented a significant change from market performance over prior years. The combined locational prices clearly signaled a need for and an incentive for investment in eastern zones where there is a demonstrated need for new capacity, although the results vary by technology. In 2007, net revenues exceeded the costs of all technologies in the BGE and Pepco Control Zones and net revenues exceeded the costs of CC technology in seven eastern control zones.

In January through June of 2009, energy market revenues were lower as a result of lower energy prices in all zones compared to the same period in 2008. However, the cost of input fuels was also down significantly from the prior period, resulting in lower marginal costs for all technologies. The change in energy market net revenue is a function of the change in locational price levels and fuel costs. As a result, the change in energy market net revenue from the first six months of 2009 compared to the first six months of 2008 varies significantly by fuel type, technology and location.

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 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 the first half of 2009. Scarcity revenues in the energy market 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, when the actual fixed costs of capacity increase rapidly, or, when energy net revenues available for new entrants decreases rapidly, there is a corresponding lag in Capacity Market prices which will tend to lead to an under recovery of the fixed costs of CTs.

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 CTs set price based on gas costs. In January through June of 2009, with generally lower load levels, CTs ran less often, which reduced the net revenue received by coal plants.

Net Revenue

Capacity Market Net Revenue

Table 3-1 2008 PJM RPM auction-clearing capacity price and capacity revenue by LDA and zone: Effective for January 1, through June 30, 2009 (See 2008 SOM, Table 3-3)

	Delivery Year 2008/2009			Delivery Year 2009/2010			
Zone	LDA	$/MW-Day	$/MW in 2009	LDA	$/MW-Day	$/MW in 2009	RPM Revenue 2009 (Jan-Jun)
AECO	EMAAC	$148.80	$22,469	MAAC+APS	$191.32	$5,740	$28,208
AEP	RTO	$111.92	$16,900	RTO	$102.04	$3,061	$19,961
AP	RTO	$111.92	$16,900	MAAC+APS	$191.32	$5,740	$22,640
BGE	SWMAAC	$210.11	$31,727	SWMAAC	$237.33	$7,120	$38,847
ComEd	RTO	$111.92	$16,900	RTO	$102.04	$3,061	$19,961
DAY	RTO	$111.92	$16,900	RTO	$102.04	$3,061	$19,961
DLCO	RTO	$111.92	$16,900	RTO	$102.04	$3,061	$19,961
Dominion	RTO	$111.92	$16,900	RTO	$102.04	$3,061	$19,961
DPL	EMAAC	$148.80	$22,469	MAAC+APS	$191.32	$5,740	$28,208
JCPL	EMAAC	$148.80	$22,469	MAAC+APS	$191.32	$5,740	$28,208
Met-Ed	RTO	$111.92	$16,900	MAAC+APS	$191.32	$5,740	$22,640
PECO	EMAAC	$148.80	$22,469	MAAC+APS	$191.32	$5,740	$28,208
PENELEC	RTO	$111.92	$16,900	MAAC+APS	$191.32	$5,740	$22,640
Pepco	SWMAAC	$210.11	$31,727	SWMAAC	$237.33	$7,120	$38,847
PPL	RTO	$111.92	$16,900	MAAC+APS	$191.32	$5,740	$22,640
PSEG	EMAAC	$148.80	$22,469	MAAC+APS	$191.32	$5,740	$28,208
RECO	EMAAC	$148.80	$22,469	MAAC+APS	$191.32	$5,740	$28,208
PJM	N/A	$124.58	$18,812	N/A	$138.46	$4,154	$22,965

Table 3-2 Capacity revenue by PJM zones (Dollars per MW-year): January through June 2009 (See 2008 SOM, Table 3-4)

Zone	2008 (Jan- Jun)	2009 (Jan-Jun)	Percent Change
AECO	$34,510	$28,208	(18%)
AEP	$9,559	$19,961	109%
AP	$9,559	$22,640	137%
BGE	$34,961	$38,847	11%
ComEd	$9,559	$19,961	109%
DAY	$9,559	$19,961	109%
DLCO	$9,559	$19,961	109%
Dominion	$9,559	$19,961	109%
DPL	$34,510	$28,208	(18%)
JCPL	$34,510	$28,208	(18%)
Met-Ed	$9,559	$22,640	137%
PECO	$34,510	$28,208	(18%)
PENELEC	$9,559	$22,640	137%
Pepco	$34,961	$38,847	11%
PPL	$9,559	$22,640	137%
PSEG	$34,510	$28,208	(18%)
RECO	$34,510	$28,208	(18%)
PJM	$17,127	$22,965	34%

New Entrant Net Revenues

Table 3-3 Average delivered fuel price in PJM (Dollars per MBtu): January through June 2008 and 2009 (See 2008 SOM, Table 3-6)

	2008 (Jan-Jun)	2009 (Jan-Jun)	Percent Change
Natural Gas	$11.31	$5.28	(53%)
Low Sulfur Coal	$4.18	$3.38	(19%)

Table 3-4 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): Net revenue for January through June 2008 and 2009 (See 2008 SOM, Table 3-7)

Zone	2008 (Jan - Jun)	2009 (Jan - Jun)	Percent Change
AECO	$29,200	$4,953	(83%)
AEP	$2,685	$2,537	(6%)
AP	$13,072	$8,495	(35%)
BGE	$22,578	$7,102	(69%)
ComEd	$1,812	$1,774	(2%)
DAY	$2,891	$2,042	(29%)
DLCO	$2,156	$1,904	(12%)
Dominion	$17,205	$7,247	(58%)
DPL	$15,969	$6,055	(62%)
JCPL	$20,048	$5,639	(72%)
Met-Ed	$11,875	$4,829	(59%)
PECO	$11,750	$4,211	(64%)
PENELEC	$2,868	$1,519	(47%)
Pepco	$23,816	$6,731	(72%)
PPL	$10,326	$4,063	(61%)
PSEG	$14,290	$5,043	(65%)
RECO	$11,203	$3,382	(70%)
PJM	$5,288	$2,180	(59%)

Table 3-5 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): Net revenue for January through June 2008 and 2009 (See 2008 SOM, Table 3-7)

Zone	2008 (Jan - Jun)	2009 (Jan - Jun)	Percent Change
AECO	$70,898	$26,600	(62%)
AEP	$13,976	$16,343	17%
AP	$37,100	$33,170	(11%)
BGE	$61,579	$28,702	(53%)
ComEd	$12,325	$13,633	11%
DAY	$15,397	$16,129	5%
DLCO	$12,514	$14,622	17%
Dominion	$50,067	$31,057	(38%)
DPL	$52,847	$28,171	(47%)
JCPL	$68,255	$27,791	(59%)
Met-Ed	$46,588	$24,008	(48%)
PECO	$46,320	$23,066	(50%)
PENELEC	$21,162	$14,611	(31%)
Pepco	$61,553	$27,220	(56%)
PPL	$44,132	$22,312	(49%)
PSEG	$59,692	$29,654	(50%)
RECO	$50,745	$24,012	(53%)
PJM	$25,775	$15,888	(38%)

Table 3-6 PJM Real-Time Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): Net revenue for January through June 2008 and 2009 (See 2008 SOM, Table 3-7)

Zone	2008 (Jan - Jun)	2009 (Jan - Jun)	Percent Change
AECO	$202,796	$67,460	(67%)
AEP	$100,331	$42,122	(58%)
AP	$159,616	$69,765	(56%)
BGE	$188,046	$61,089	(68%)
ComEd	$126,266	$58,761	(53%)
DAY	$90,399	$31,359	(65%)
DLCO	$91,276	$45,033	(51%)
Dominion	$168,317	$62,911	(63%)
DPL	$192,769	$55,603	(71%)
JCPL	$206,426	$66,538	(68%)
Met-Ed	$177,570	$64,039	(64%)
PECO	$177,333	$62,327	(65%)
PENELEC	$154,631	$66,369	(57%)
Pepco	$197,381	$69,239	(65%)
PPL	$180,403	$67,043	(63%)
PSEG	$165,925	$55,348	(67%)
RECO	$201,345	$64,013	(68%)
PJM	$119,207	$31,711	(73%)

New Entrant Combustion Turbine

Table 3-7 Real-time PJM-wide net revenue for a CT under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through June 2008 and 2009 (See 2008 SOM, Table 3-10)

	2008 (Jan - Jun)	2009 (Jan - Jun)	Percent Change
Energy	$5,288	$2,180	(59%)
Capacity	$15,263	$20,466	34%
Synchronized	$0	$0	0%
Regulation	$0	$0	0%
Reactive	$1,199	$1,199	0%
Total	$21,750	$23,845	10%

Table 3-8 Real-time zonal combined net revenue from all markets for a CT under peak-hour, economic dispatch (Dollars per installed MW-year): January through June 2008 and 2009 (See 2008 SOM, Table 3-11)

Zone	2008 (Jan - Jun)	2009 (Jan - Jun)	Percent Change
AECO	$61,153	$31,291	(49%)
AEP	$12,403	$21,525	74%
AP	$22,790	$29,870	31%
BGE	$54,934	$42,919	(22%)
ComEd	$11,530	$20,762	80%
DAY	$12,609	$21,029	67%
DLCO	$11,874	$20,892	76%
Dominion	$26,923	$26,235	(3%)
DPL	$47,922	$32,392	(32%)
JCPL	$52,002	$31,977	(39%)
Met-Ed	$21,593	$26,204	21%
PECO	$43,704	$30,549	(30%)
PENELEC	$12,586	$22,894	82%
Pepco	$56,172	$42,549	(24%)
PPL	$20,044	$25,438	27%
PSEG	$46,243	$31,380	(32%)
RECO	$43,156	$29,720	(31%)
PJM	$21,750	$23,845	10%

New Entrant Combined Cycle

Table 3-9 Real-time PJM-wide net revenue for a CC under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through June 2008 and 2009 (See 2008 SOM, Table 3-12)

	2008 (Jan - Jun)	2009 (Jan - Jun)	Percent Change
Energy	$25,775	$15,888	(38%)
Capacity	$16,546	$22,186	34%
Synchronized	$0	$0	0%
Regulation	$0	$0	0%
Reactive	$1,599	$1,599	0%
Total	$43,920	$39,673	(10%)

Table 3-10 Real-time zonal combined net revenue from all markets for a CC under peak-hour, economic dispatch (Dollars per installed MW-year): January through June 2008 and 2009 (See 2008 SOM, Table 3-13)

Zone	2008 (Jan - Jun)	2009 (Jan - Jun)	Percent Change
AECO	$105,836	$55,451	(48%)
AEP	$24,810	$37,226	50%
AP	$47,933	$56,641	18%
BGE	$96,953	$67,829	(30%)
ComEd	$23,159	$34,516	49%
DAY	$26,231	$37,012	41%
DLCO	$23,348	$35,505	52%
Dominion	$60,901	$51,940	(15%)
DPL	$87,785	$57,021	(35%)
JCPL	$103,193	$56,641	(45%)
Met-Ed	$57,422	$47,478	(17%)
PECO	$81,258	$51,917	(36%)
PENELEC	$31,996	$38,081	19%
Pepco	$96,927	$66,347	(32%)
PPL	$54,966	$45,782	(17%)
PSEG	$94,630	$58,504	(38%)
RECO	$85,683	$52,862	(38%)
PJM	$43,920	$39,673	(10%)

New Entrant Coal Plant

Table 3-11 Real-time PJM-wide net revenue for a CP under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through June 2008 and 2009 (See 2008 SOM, Table 3-14)

	2008 (Jan - Jun)	2009 (Jan - Jun)	Percent Change
Energy	$119,207	$31,711	(73%)
Capacity	$15,441	$20,705	34%
Synchronized	$0	$0	0%
Regulation	$352	$170	(52%)
Reactive	$892	$892	0%
Total	$135,891	$53,477	(61%)

Table 3-12 Real-time zonal combined net revenue from all markets for a CP under peak-hour, economic dispatch (Dollars per installed MW-year): January through June 2008 and 2009 (See 2008 SOM, Table 3-15)

Zone	2008 (Jan - Jun)	2009 (Jan - Jun)	Percent Change
AECO	$235,299	$94,506	(60%)
AEP	$110,315	$61,750	(44%)
AP	$169,716	$91,846	(46%)
BGE	$220,952	$97,301	(56%)
ComEd	$136,532	$78,327	(43%)
DAY	$100,312	$50,930	(49%)
DLCO	$101,420	$64,726	(36%)
Dominion	$178,372	$82,447	(54%)
DPL	$225,296	$82,106	(64%)
JCPL	$238,863	$93,273	(61%)
Met-Ed	$187,554	$86,012	(54%)
PECO	$209,834	$89,349	(57%)
PENELEC	$164,723	$88,455	(46%)
Pepco	$230,335	$105,845	(54%)
PPL	$190,393	$89,089	(53%)
PSEG	$198,378	$81,853	(59%)
RECO	$233,873	$90,697	(61%)
PJM	$135,891	$53,477	(61%)

New Entrant Day-Ahead Net Revenues

Table 3-13 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): January through June 2008 and 2009 (See 2008 SOM, Table 3-16)

Zone	2008 (Jan - Jun)	2009 (Jan - Jun)	Percent Change
AECO	$8,172	$1,578	(81%)
AEP	$599	$880	47%
AP	$5,416	$3,765	(30%)
BGE	$12,230	$2,840	(77%)
ComEd	$184	$343	87%
DAY	$366	$392	7%
DLCO	$345	$389	13%
Dominion	$8,017	$4,000	(50%)
DPL	$7,259	$1,924	(73%)
JCPL	$6,068	$1,380	(77%)
Met-Ed	$5,013	$1,185	(76%)
PECO	$5,199	$1,251	(76%)
PENELEC	$1,923	$511	(73%)
Pepco	$14,070	$2,680	(81%)
PPL	$4,207	$1,069	(75%)
PSEG	$5,513	$1,289	(77%)
RECO	$136,356	$836	(99%)
PJM	$2,661	$508	(81%)

Table 3-14 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): January through June 2008 and 2009 (See 2008 SOM, Table 3-17)

Zone	2008 (Jan - Jun)	2009 (Jan - Jun)	Percent Change
AECO	$45,811	$27,935	(39%)
AEP	$9,589	$15,384	60%
AP	$29,254	$30,339	4%
BGE	$51,634	$29,531	(43%)
ComEd	$8,838	$10,207	15%
DAY	$9,533	$13,450	41%
DLCO	$6,524	$11,897	82%
Dominion	$41,456	$32,751	(21%)
DPL	$39,396	$29,055	(26%)
JCPL	$57,161	$28,666	(50%)
Met-Ed	$36,345	$24,096	(34%)
PECO	$34,301	$25,170	(27%)
PENELEC	$17,660	$13,509	(24%)
Pepco	$54,854	$28,008	(49%)
PPL	$33,424	$22,812	(32%)
PSEG	$50,130	$30,979	(38%)
RECO	$239,769	$26,865	(89%)
PJM	$17,662	$13,598	(23%)

Table 3-15 PJM Day-Ahead Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): January through June 2008 and 2009 (See 2008 SOM, Table 3-18)

Zone	2008 (Jan - Jun)	2009 (Jan - Jun)	Percent Change
AECO	$196,782	$70,556	(64%)
AEP	$98,742	$40,801	(59%)
AP	$158,653	$67,078	(58%)
BGE	$192,227	$63,445	(67%)
ComEd	$129,447	$58,235	(55%)
DAY	$86,515	$28,208	(67%)
DLCO	$96,995	$41,808	(57%)
Dominion	$170,613	$65,272	(62%)
DPL	$194,963	$56,656	(71%)
JCPL	$209,636	$68,608	(67%)
Met-Ed	$182,130	$66,001	(64%)
PECO	$183,801	$66,439	(64%)
PENELEC	$162,675	$67,319	(59%)
Pepco	$204,536	$72,532	(65%)
PPL	$184,864	$69,761	(62%)
PSEG	$167,942	$56,705	(66%)
RECO	$117,596	$66,248	(44%)
PJM	$70,556	$30,389	(57%)

Table 3-16 Real-Time and Day-Ahead Energy Market net revenues for a CT under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2008 and January through June 2009 (See 2008 SOM, Table 3-19)

	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 (Jan - Jun)	$2,180	$508	$1,673	77%

Table 3-17 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 2008 and January through June 2009 (See 2008 SOM, Table 3-20)

	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 (Jan - Jun)	$15,888	$13,598	$2,290	14%

Table 3-18 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 2008 and January through June 2009 (See 2008 SOM, Table 3-21)

	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 (Jan - Jun)	$31,711	$30,389	$1,321	4%

Net Revenue Adequacy

Table 3-19 New entrant 20-year levelized fixed costs (By plant type (Dollars per installed MW-year)) (See 2008 SOM, Table 3-22)

	2005 20-Year Levelized Fixed Cost	2006 20-Year Levelized Fixed Cost	2007 20-Year Levelized Fixed Cost	2008 20-Year Levelized Fixed Cost
CT	$72,207	$80,315	$90,656	$123,640
CC	$93,549	$99,230	$143,600	$171,361
CP	$208,247	$267,792	$359,750	$492,780

Table 3-20 CT 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through June 2008 and 2009 (See 2008 SOM, Table 3-24)

Zone	2008 (Jan - Jun)	2009 (Jan - Jun)	20-Year Levelized Fixed Cost	2008 Percent Recovery	2009 Percent Recovery
AECO	$61,153	$31,291	$123,640	49%	25%
AEP	$12,403	$21,525	$123,640	10%	17%
AP	$22,790	$29,870	$123,640	18%	24%
BGE	$54,934	$42,919	$123,640	44%	35%
ComEd	$11,530	$20,762	$123,640	9%	17%
DAY	$12,609	$21,029	$123,640	10%	17%
DLCO	$11,874	$20,892	$123,640	10%	17%
Dominion	$26,923	$26,235	$123,640	22%	21%
DPL	$47,922	$32,392	$123,640	39%	26%
JCPL	$52,002	$31,977	$123,640	42%	26%
Met-Ed	$21,593	$26,204	$123,640	17%	21%
PECO	$43,704	$30,549	$123,640	35%	25%
PENELEC	$12,586	$22,894	$123,640	10%	19%
Pepco	$56,172	$42,549	$123,640	45%	34%
PPL	$20,044	$25,438	$123,640	16%	21%
PSEG	$46,243	$31,380	$123,640	37%	25%
RECO	$43,156	$29,720	$123,640	35%	24%
PJM	$21,750	$23,845	$123,640	18%	19%

Table 3-21 CC 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through June 2008 and 2009 (See 2008 SOM, Table 3-26)

Zone	2008 (Jan - Jun)	2009 (Jan - Jun)	20-Year Levelized Fixed Cost	2008 Percent Recovery	2009 Percent Recovery
AECO	$105,836	$55,451	$171,361	62%	32%
AEP	$24,810	$37,226	$171,361	14%	22%
AP	$47,933	$56,641	$171,361	28%	33%
BGE	$96,953	$67,829	$171,361	57%	40%
ComEd	$23,159	$34,516	$171,361	14%	20%
DAY	$26,231	$37,012	$171,361	15%	22%
DLCO	$23,348	$35,505	$171,361	14%	21%
Dominion	$60,901	$51,940	$171,361	36%	30%
DPL	$87,785	$57,021	$171,361	51%	33%
JCPL	$103,193	$56,641	$171,361	60%	33%
Met-Ed	$57,422	$47,478	$171,361	34%	28%
PECO	$81,258	$51,917	$171,361	47%	30%
PENELEC	$31,996	$38,081	$171,361	19%	22%
Pepco	$96,927	$66,347	$171,361	57%	39%
PPL	$54,966	$45,782	$171,361	32%	27%
PSEG	$94,630	$58,504	$171,361	55%	34%
RECO	$85,683	$52,862	$171,361	50%	31%
PJM	$43,920	$39,673	$171,361	26%	23%

Figure 3-1 New entrant CT zonal net revenue for January through June 2008 and 2009 with 20-year levelized fixed cost as of 2008 (Dollars per installed MW-year): January through June 2008 and 2009 (See 2008 SOM, Figure 3-3)

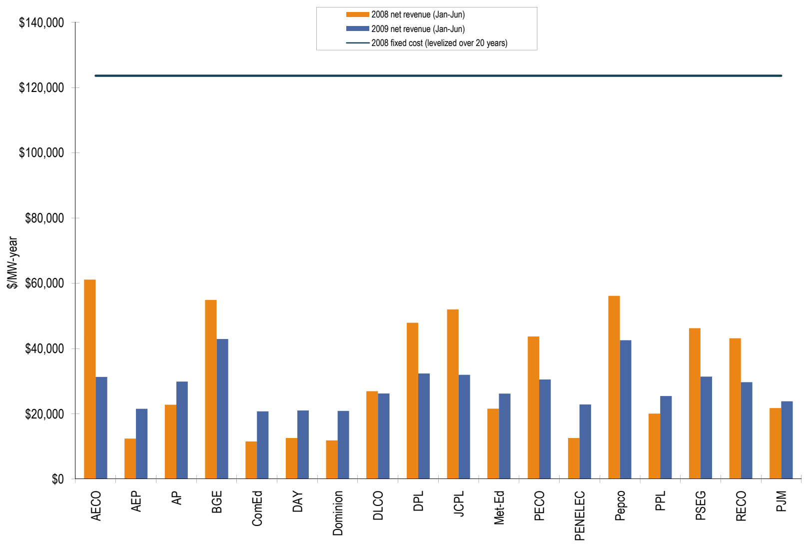


Figure 3-2 New entrant CC zonal net revenue for January through June 2008 and 2009 with 20-year levelized fixed cost as of 2008 (Dollars per installed MW-year): January through June 2008 and 2009 (See 2008 SOM, Figure 3-5)

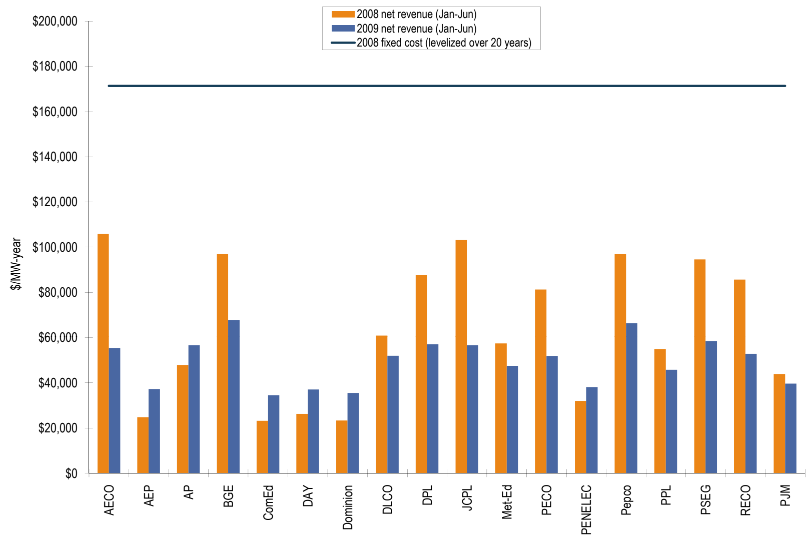
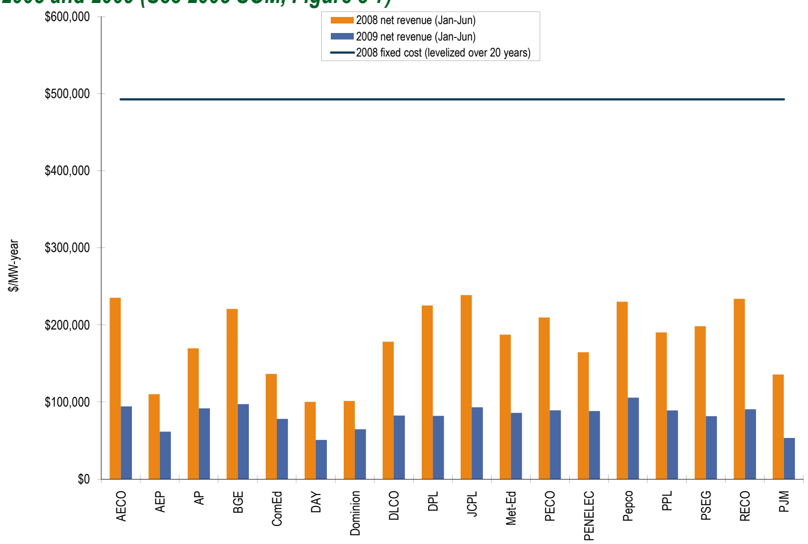


Table 3-22 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through June 2008 and 2009 (See 2008 SOM, Table 3-28)

Zone	2008 (Jan - Jun)	2009 (Jan - Jun)	20-Year Levelized Fixed Cost	2008 Percent Recovery	2009 Percent Recovery
AECO	$235,299	$94,506	$492,780	48%	19%
AEP	$110,315	$61,750	$492,780	22%	13%
AP	$169,716	$91,846	$492,780	34%	19%
BGE	$220,952	$97,301	$492,780	45%	20%
ComEd	$136,532	$78,327	$492,780	28%	16%
DAY	$100,312	$50,930	$492,780	20%	10%
DLCO	$101,420	$64,726	$492,780	21%	13%
Dominion	$178,372	$82,447	$492,780	36%	17%
DPL	$225,296	$82,106	$492,780	46%	17%
JCPL	$238,863	$93,273	$492,780	48%	19%
Met-Ed	$187,554	$86,012	$492,780	38%	17%
PECO	$209,834	$89,349	$492,780	43%	18%
PENELEC	$164,723	$88,455	$492,780	33%	18%
Pepco	$230,335	$105,845	$492,780	47%	21%
PPL	$190,393	$89,089	$492,780	39%	18%
PSEG	$198,378	$81,853	$492,780	40%	17%
RECO	$233,873	$90,697	$492,780	47%	18%
PJM	$135,891	$53,477	$492,780	28%	11%

Figure 3-3 New entrant CP zonal net revenue for January through June 2008 and 2009 with 20-year levelized fixed cost as of 2008 (Dollars per installed MW-year): January through June 2008 and 2009 (See 2008 SOM, Figure 3-7)



Existing and Planned Generation

Installed Capacity and Fuel Mix

Installed Capacity

Table 3-23 PJM installed capacity (By fuel source): January 1, May 31, June 1, 2009 (See 2008 SOM, Table 3-30)[3, 4]

	1-Jan-09		31-May-09		1-Jun-09	
	MW	Percent	MW	Percent	MW	Percent
Coal	67,064.7	40.7%	67,025.3	40.6%	68,159.0	40.7%
Oil	10,714.9	6.5%	10,674.3	6.5%	10,704.3	6.4%
Gas	48,333.9	29.3%	48,506.9	29.4%	48,979.3	29.2%
Nuclear	30,478.0	18.5%	30,542.5	18.5%	30,701.5	18.3%
Solid waste	664.7	0.4%	664.7	0.4%	672.1	0.4%
Hydroelectric	7,476.3	4.5%	7,550.1	4.6%	7,939.9	4.7%
Wind	166.4	0.1%	182.9	0.1%	297.8	0.2%
Total	164,898.9	100.0%	165,146.7	100.0%	167,453.9	100.0%

Energy Production by Fuel Source

Table 3-24 PJM generation (By fuel source (GWh)): January through June 2009 (See 2008 SOM, Table 3-31)

	GWh	Percent
Coal	175,095.0	51.3%
Gas	29,493.0	8.6%
Hydroelectric	6,991.8	2.0%
Nuclear	123,217.3	36.1%
Oil	844.6	0.2%
Solar	1.8	0.0%
Solid Waste	2,895.3	0.8%
Wind	2,712.0	0.8%
Total	341,250.9	100.0%

3 The capacity described in this section is the capability of all PJM capacity resources, as entered into the eRPM system, regardless of whether the capacity cleared in the RPM auctions.

4 Wind-based resources accounted for 297.8 MW of installed capacity in PJM on June 1, 2009. 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 13 percent factor. 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.

Planned Generation Additions

Table 3-25 Year-to-year capacity additions: Calendar years 2000 through June 2009 (See 2008 SOM, Table 3-32)

	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	410

PJM Generation Queues

Table 3-26 Queue comparison (MW): Calendar years 2009 vs. 2008 (See 2008 SOM, Table 3-33)

	MW in the Queue 2008	MW in the Queue 2009	Year-to-Year Change (MW)	Year-to-Year Change
2009	9,023	12,701	3,679	41%
2010	18,052	16,162	(1,889)	(10%)
2011	17,253	16,282	(972)	(6%)
2012	15,527	12,794	(2,734)	(18%)
2013	7,920	9,588	1,668	21%
2014	11,965	12,450	485	4%
2015	2,436	2,437	1	0%
2016	0	1,000	1,000	NA
2018	1,594	1,594	0	0%
Total	83,770	85,008	1,238	1%

Table 3-27 Capacity in PJM queues (MW): At June 30, 2009[5, 6] (See 2008 SOM, Table 3-34)

Queue	Active	In-Service	Under Construction	Withdrawn	Total
A Expired 31-Jan-98	0	8,121	0	17,347	25,468
B Expired 31-Jan-99	0	4,671	0	15,833	20,503
C Expired 31-Jul-99	0	531	0	4,151	4,682
D Expired 31-Jan-00	0	851	0	7,603	8,454
E Expired 31-Jul-00	0	795	0	16,887	17,682
F Expired 31-Jan-01	0	52	0	3,093	3,145
G Expired 31-Jul-01	0	486	630	21,986	23,102
H Expired 31-Jan-02	0	603	0	8,522	9,124
I Expired 31-Jul-02	0	103	0	3,738	3,841
J Expired 31-Jan-03	0	40	0	846	886
K Expired 31-Jul-03	0	128	0	2,516	2,643
L Expired 31-Jan-04	20	257	0	4,014	4,290
M Expired 31-Jul-04	0	319	186	3,978	4,482
N Expired 31-Jan-05	1,462	2,263	88	6,714	10,527
O Expired 31-Jul-05	2,708	748	487	3,831	7,774
P Expired 31-Jan-06	2,611	816	1,840	3,450	8,717
Q Expired 31-Jul-06	5,216	675	2,491	6,383	14,765
R Expired 31-Jan-07	8,689	297	566	13,289	22,840
S Expired 31-Jul-07	9,515	590	1,381	9,407	20,892
T Expired 31-Jan-08	22,909	158	193	5,227	28,486
U Expired 31-Jan-09	20,142	29	90	14,581	34,841
V Expires 31-Jan-10	3,786	0	0	0	3,786
Total	77,057	22,530	7,951	173,393	280,931

5 The *2009 Quarterly State of the Market Report for PJM: January through June* contains all projects in the queue including reratings of existing generating units and energy only resources.
6 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.

Distribution of Units in the Queues

Table 3-28 Capacity additions in active or under-construction queues by control zone (MW): At June 30, 2009 (See 2008 SOM, Table 3-36)

	Battery	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Unknown	Total
AECO	0	0	939	4	0	0	4	665	1,416	0	3,028
AEP	0	1,035	594	7	112	84	5	3,813	8,071	53	13,774
AP	0	930	604	0	165	0	0	1,304	1,751	0	4,755
BGE	0	220	376	0	0	0	0	0	0	132	728
ComEd	0	1,680	1,044	94	0	392	0	1,326	27,157	44	31,737
DAY	0	0	10	2	0	0	0	12	597	0	621
DLCO	0	0	0	0	87	75	0	0	0	0	162
DPL	20	0	280	0	0	0	0	23	1,050	20	1,393
Dominion	0	3,923	1,011	29	30	1,944	0	326	230	166	7,660
JCPL	0	2,750	27	30	1	0	46	0	0	0	2,854
Met-Ed	0	1,745	122	86	0	24	0	0	0	0	1,977
PECO	1	2,460	595	2	0	180	1	18	0	0	3,257
PENELEC	0	0	161	16	32	0	0	50	1,792	0	2,051
Pepco	0	1,195	245	5	0	1,640	0	0	0	20	3,105
PPL	0	1,400	137	2	143	1,600	21	120	352	153	3,926
PSEG	0	1,875	1,047	0	1,000	0	60	0	0	0	3,982
Total	21	19,213	7,192	277	1,569	5,939	137	7,657	42,415	588	85,008

Table 3-29 Existing PJM capacity on June 30, 2009 (By zone and unit type (MW)) (See 2008 SOM, Table 3-37)

	Battery	CC	CT	Diesel	Hydroelectric	Nuclear	Steam	Solar	Wind	Total
AECO	0	0	641	23	0	0	1,257	0	8	1,928
AEP	0	4,355	3,581	57	1,001	2,106	21,255	0	400	32,756
AP	0	1,129	1,140	36	108	0	7,974	0	245	10,632
BGE	0	0	849	3	0	1,735	2,965	0	0	5,552
ComEd	0	1,836	7,217	108	0	10,336	7,094	0	1,003	27,594
DAY	0	0	1,377	52	0	0	3,551	0	0	4,980
DLCO	0	0	0	0	6	1,741	1,259	0	0	3,006
DPL	0	364	2,473	95	0	0	2,016	0	0	4,948
Dominion	0	3,216	3,786	156	2,955	3,425	8,456	0	0	21,993
External	0	974	1,890	0	0	439	9,314	0	185	12,802
JCPL	0	856	1,430	25	400	615	540	0	0	3,865
Met-Ed	0	2,000	407	24	20	786	860	0	0	4,097
PECO	1	2,540	833	7	1,642	4,488	2,129	3	0	11,643
PENELEC	0	0	287	47	521	0	6,830	0	294	7,979
Pepco	0	0	1,440	9	0	0	4,829	0	0	6,278
PPL	0	1,662	729	63	571	2,275	5,830	0	217	11,347
PSEG	0	2,921	2,852	0	5	3,493	1,656	0	0	10,927
Total	1	21,853	30,931	706	7,229	31,439	87,813	3	2,352	182,326

Table 3-30 PJM capacity age (MW) (See 2008 SOM, Table 3-38)

Age (years)	Battery	CC	CT	Diesel	Hydro	Nuclear	Steam	Solar	Wind	Total
Less than 10	1	18,568	19,150	400	52	0	1,327	3	2,352	41,852
10 to 20	0	3,037	4,073	121	37	1,134	7,982	0	0	16,383
20 to 30	0	158	20	20	2,807	14,787	9,043	0	0	26,834
30 to 40	0	90	5,917	47	451	15,518	35,515	0	0	57,538
40 to 50	0	0	1,771	115	2,470	0	21,074	0	0	25,430
50 to 60	0	0	0	4	348	0	12,234	0	0	12,586
60 to 70	0	0	0	0	107	0	491	0	0	598
70 to 80	0	0	0	0	239	0	149	0	0	388
80 to 90	0	0	0	0	492	0	0	0	0	492
90 to 100	0	0	0	0	194	0	0	0	0	194
100 and over	0	0	0	0	32	0	0	0	0	32
Total	1	21,853	30,931	706	7,229	31,439	87,813	3	2,352	182,326

Table 3-31 Capacity additions in active or under-construction queues by LDA (MW): At June 30, 2009 (See 2008 SOM, Table 3-39)

	Battery	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Unknown	Total
EMAAC	21	7,085	2,888	36	1,001	180	112	726	2,466	0	14,514
Non-MAAC	0	7,568	3,263	132	394	2,495	5	6,781	37,805	263	58,707
SWMAAC	0	1,415	621	5	0	1,640	0	0	0	152	3,833
WMAAC	0	3,145	420	104	175	1,624	21	173	2,144	150	7,954
Total	21	19,213	7,192	277	1,569	5,939	137	7,680	42,415	565	85,008

Table 3-32 Comparison of generators 40 years and older with planned capacity additions (MW): Through 2018[7] (See 2008 SOM, Table 3-40)

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%	21	22	0.1%
	Combined Cycle	0	0.0%	6,681	20.1%	7,085	13,766	31.5%
	Combustion Turbine	627	10.3%	8,228	24.7%	2,888	10,489	24.0%
	Diesel	49	0.8%	150	0.5%	36	137	0.3%
	Hydroelectric	2,042	33.5%	2,047	6.1%	1,001	3,048	7.0%
	Nuclear	0	0.0%	8,596	25.8%	180	8,776	20.1%
	Solar	0	0.0%	3	0.0%	112	115	0.3%
	Steam	3,384	55.5%	7,598	22.8%	726	4,939	11.3%
	Wind	0	0.0%	8	0.0%	2,466	2,474	5.7%
	Unknown	0	0.0%	0	0.0%	0	0	0.0%
	EMAAC Total	6,102	100.0%	33,311	100.0%	14,514	43,765	100.0%
Non-MAAC	Combined Cycle	0	0.0%	11,510	10.1%	7,568	19,078	12.8%
	Combustion Turbine	631	2.5%	18,991	16.7%	3,263	21,623	14.5%
	Diesel	34	0.1%	409	0.4%	132	507	0.3%
	Hydroelectric	1,396	5.6%	4,070	3.6%	394	4,464	3.0%
	Nuclear	0	0.0%	18,047	15.9%	2,495	20,542	13.8%
	Solar	0	0.0%	0	0.0%	5	5	0.0%
	Steam	23,002	91.8%	58,903	51.8%	6,781	42,682	28.7%
	Wind	0	0.0%	1,833	1.6%	37,805	39,639	26.6%
	Unknown	0	0.0%	0	0.0%	263	263	0.2%
	Non-MAAC Total	25,063	100.0%	113,763	100.0%	58,707	148,803	100.0%
SWMAAC	Combined Cycle	0	0.0%	0	0.0%	1,415	1,415	11.6%
	Combustion Turbine	315	9.0%	2,289	19.4%	621	2,595	21.3%
	Diesel	0	0.0%	12	0.1%	5	17	0.1%
	Nuclear	0	0.0%	1,735	14.7%	1,640	3,375	27.8%
	Steam	3,192	91.0%	7,793	65.9%	0	4,602	37.9%
	Unknown	0	0.0%	0	0.0%	152	152	1.3%
	SWMAAC Total	3,507	100.0%	11,830	100.0%	3,833	12,156	100.0%
WMAAC	Combined Cycle	0	0.0%	3,662	15.6%	3,145	6,807	25.4%
	Combustion Turbine	198	3.9%	1,423	6.1%	420	1,645	6.1%
	Diesel	35	0.7%	135	0.6%	104	204	0.8%
	Hydroelectric	444	8.8%	1,112	4.7%	175	1,286	4.8%
	Nuclear	0	0.0%	3,061	13.1%	1,624	4,685	17.5%
	Solar	0	0.0%	0	0.0%	21	21	0.1%
	Steam	4,370	86.6%	13,519	57.7%	173	9,322	34.8%
	Wind	0	0.0%	511	2.2%	2,144	2,655	9.9%
	Unknown	0	0.0%	0	0.0%	150	150	0.6%
	WMAAC Total	5,047	100.0%	23,422	100.0%	7,954	26,773	100.0%
All Areas	Total	39,719		182,326		85,008	231,497	

Characteristic of Wind Units

Table 3-33 Capacity factor of wind units in PJM, January through June 2009 (New Table)

Type of Resource	Capacity Factor	Total Hours	Installed Capacity
Energy-Only Resource	30.1%	81,940	613
Capacity Resource	32.2%	46,133	1,739
All Units	30.7%	128,073	2,352

Table 3-34 Wind resources in Real-Time offering at a negative price in PJM, June 2009[8] (New Table)

	Average MW Offered Daily	Intervals Marginal	Percent of All Intervals
At Negative Price	115.0	5	0.06%
All Wind	1,104.9	6	0.07%

7 Percents shown in Table 3-32 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

8 Units were permitted to submit negative price offers beginning June 1, 2009.

Figure 3-4 Average hourly real-time generation of wind units in PJM, January through June 2009 (New Figure)

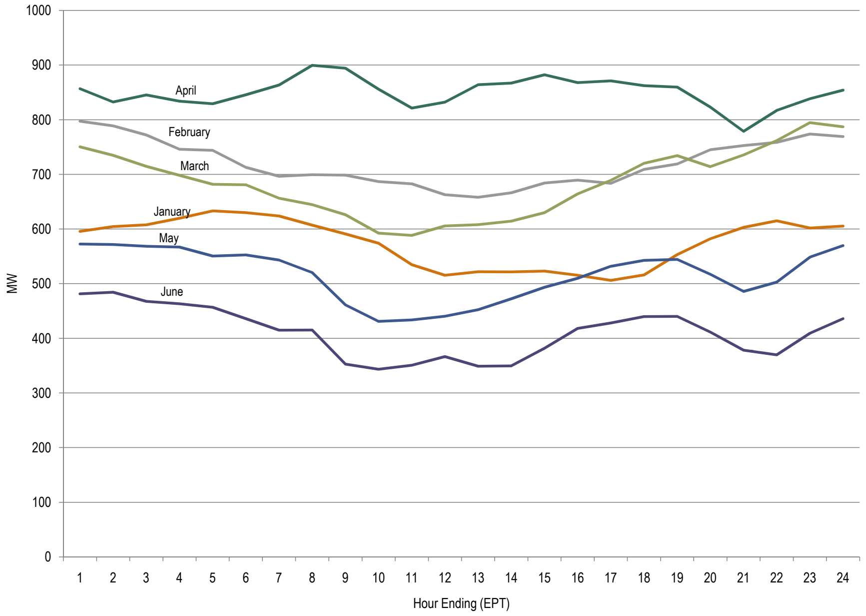


Figure 3-5 Average hourly day-ahead generation of wind units in PJM, January through June 2009 (New Figure)

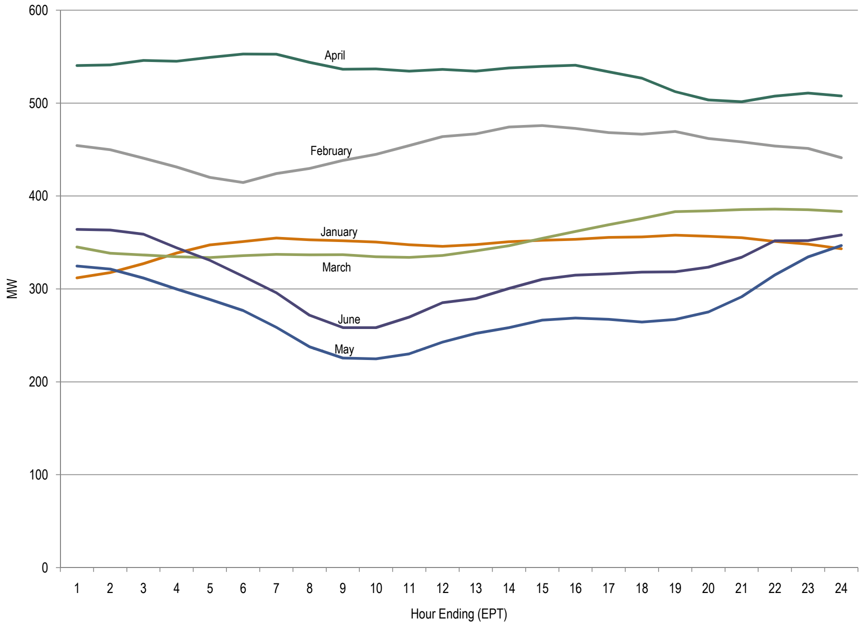
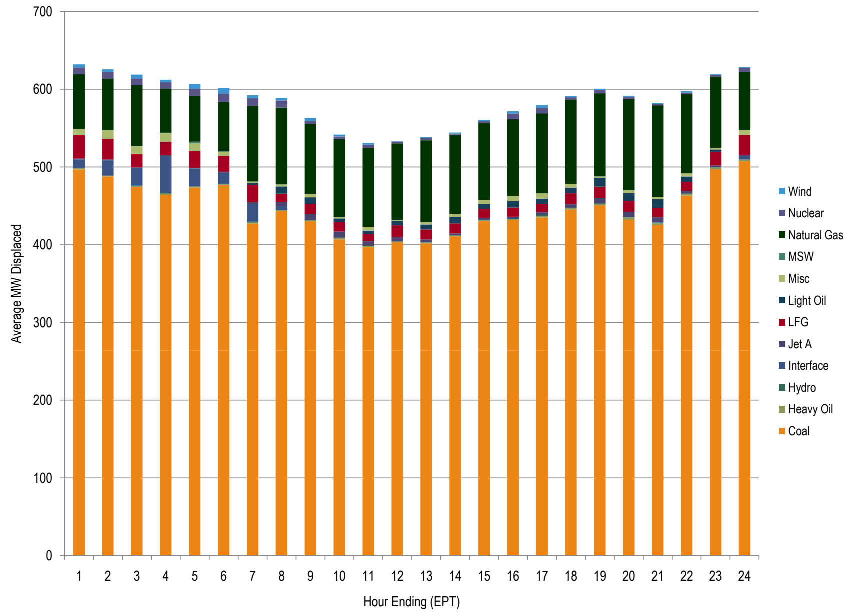


Figure 3-6 Marginal fuel displacement by wind generation in PJM, January through June 2009 (New Figure)



Operating Reserve

Overall Results

Table 3-35 Monthly operating reserve charges: January through June 2008 and 2009[9] (See 2008 SOM, Table 3-45)

	2008 (Jan - Jun) Charges				2009 (Jan - Jun) Charges			
	Day-Ahead	Synchronous Condensing	Balancing	Total	Day-Ahead	Synchronous Condensing	Balancing	Total
Jan	$4,126,221	$456,972	$39,935,491	$44,518,684	$9,260,150	$1,328,814	$29,991,144	$40,580,108
Feb	$3,731,017	$200,456	$23,165,838	$27,097,312	$7,434,068	$839,679	$16,500,510	$24,774,257
Mar	$2,904,498	$249,900	$18,916,241	$22,070,639	$9,549,963	$108,664	$25,889,938	$35,548,565
Apr	$4,213,578	$209,366	$22,559,577	$26,982,522	$6,998,364	$19,929	$13,227,874	$20,246,168
May	$10,873,205	$202,397	$22,970,363	$34,045,964	$6,024,108	$5,543	$15,197,148	$21,226,799
Jun	$7,064,877	$575,927	$65,597,311	$73,238,115	$6,722,329	$0	$19,077,096	$25,799,425
Total	$32,913,397	$1,895,019	$193,144,820	$227,953,236	$45,988,983	$2,302,629	$119,883,710	$168,175,322
Share of Annual Charges	14.4%	0.8%	84.7%	100.0%	27.3%	1.4%	71.3%	100.0%

Table 3-36 Regional balancing charges allocation: January through June 2008 and 2009 (New Table)

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	$2,749,936	$108,748	$2,858,684	$34,212,966	$20,980,028	$10,893,912	$66,086,906	$68,945,590
RTO	3.0%	0.1%	3.1%	36.8%	22.6%	11.7%	71.1%	74.2%
East	$324,661	$11,529	$336,190	$3,382,299	$1,927,684	$989,854	$6,299,837	$6,636,027
East	0.3%	0.0%	0.4%	3.6%	2.1%	1.1%	6.8%	7.1%
West	$14,474,332	$667,966	$15,142,298	$1,111,579	$755,649	$369,206	$2,236,433	$17,378,731
West	15.6%	0.7%	16.3%	1.2%	0.8%	0.4%	2.4%	18.7%
Total	$17,548,928	$788,243	$18,337,172	$38,706,844	$23,663,360	$12,252,972	$74,623,176	$92,960,347
Total	18.9%	0.8%	19.7%	41.6%	25.5%	13.2%	80.3%	100.0%

9 The balancing charges shown in Table 3-35 are higher than total credits for the months of January through June, 2009 due to credits to units that were overstated in initial market settlements, and required manual charge refunds to the transmission owner. These make whole payments will be allocated as generator local charge credits.

Deviations

Table 3-37 Monthly balancing operating reserve deviations (MWh): January through June 2008 and 2009 (See 2008 SOM, Table 3-46)

	2008 (Jan - Jun) Deviations				2009 (Jan - Jun) Deviations			
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)
Jan	8,172,164	3,297,121	2,572,113	14,041,398	9,136,874	5,677,781	2,637,940	17,452,595
Feb	6,728,062	3,046,290	2,546,510	12,320,861	7,044,678	4,232,679	2,107,229	13,384,585
Mar	6,392,821	2,520,387	2,405,061	11,318,269	7,214,090	4,426,764	2,410,544	14,051,398
Apr	5,951,654	3,127,726	2,224,157	11,303,537	6,873,427	3,872,032	2,275,152	13,020,611
May	6,624,696	3,787,650	2,699,616	13,111,962	6,958,699	5,184,983	2,386,124	14,529,806
Jun	8,117,669	3,179,999	2,644,016	13,941,684	8,569,879	4,603,052	2,637,411	15,810,343
Total	41,987,065	18,959,174	15,091,472	76,037,711	45,797,648	27,997,291	14,454,399	88,249,338
Share of Annual Deviations	55.2%	24.9%	19.8%	100.0%	51.9%	31.7%	16.4%	100.0%

Table 3-38 Regional charges determinants (MWh): January through June 2009 (New Table)

	Reliability Charges			Deviation Charges				
	Real-Time Load (MWh)	Real-Time Exports (MWh)	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total	Total
RTO	330,039,231	13,612,493	343,651,724	45,797,648	27,997,291	14,454,399	88,249,338	431,901,062
East	179,822,112	6,499,599	186,321,711	27,204,634	15,061,498	7,623,685	49,889,818	236,211,529
West	150,217,119	7,112,894	157,330,013	18,451,023	12,878,283	6,830,714	38,160,020	195,490,033

Figure 3-7 Daily RTO reliability and deviation rates: January through June 2009 (New Figure)

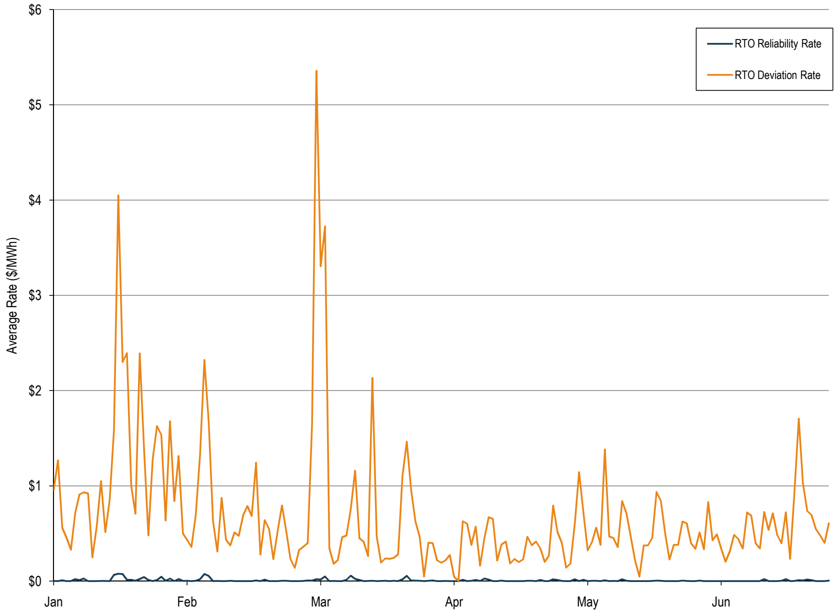
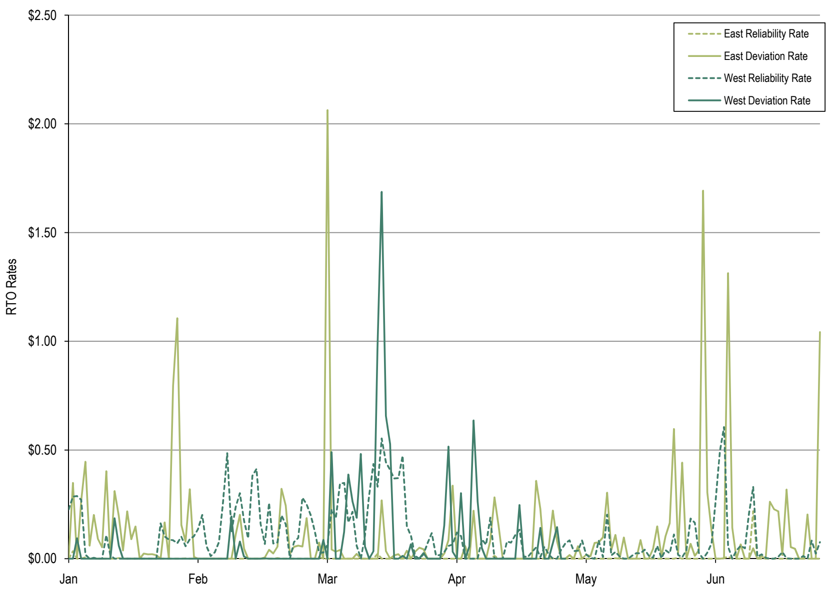


Figure 3-8 Daily regional reliability and deviation rates: January through June 2009 (New Figure)



Balancing Operating Reserve Charge Rate

Table 3-39 Average regional balancing operating reserve rates: January through June 2009 (See 2008 SOM, Table 3-48)

	Reliability	Deviations
RTO	0.007	0.702
East	0.002	0.114
West	0.101	0.057

Operating Reserve Credits by Category

Figure 3-9 Operating reserve credits: January through June 2009 (See 2008 SOM, Figure 3-11)

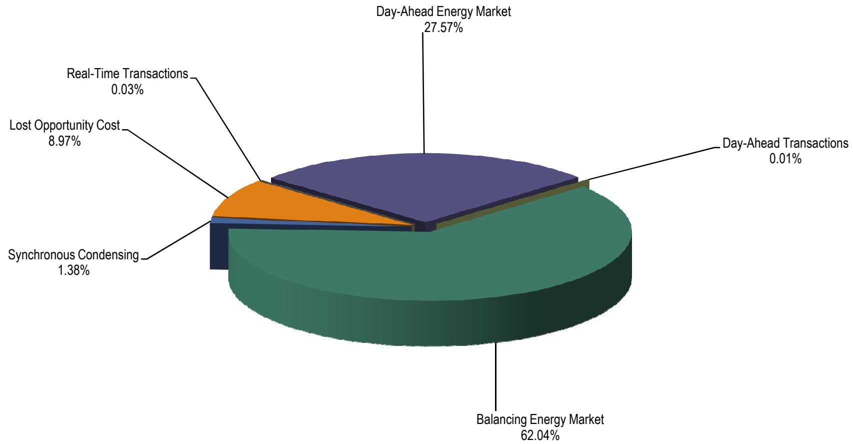


Table 3-40 Credits by month (By operating reserve market): January through June 2009 (See 2008 SOM, Table 3-49)

	Day-Ahead Generator	Day-Ahead Transactions	Synchronous Condensing	Balancing Generator	Balancing Transactions	Lost Opportunity Cost	Total
Jan	$9,260,150	$0	$1,328,814	$26,443,459	$0	$3,547,685	$40,580,108
Feb	$7,434,068	$0	$839,679	$14,406,379	$31,258	$2,062,873	$24,774,257
Mar	$9,542,383	$7,580	$108,664	$22,220,993	$13,249	$3,508,074	$35,400,943
Apr	$6,998,364	$0	$19,929	$10,731,331	$6,942	$1,830,088	$19,586,655
May	$6,024,108	$0	$5,543	$13,714,645	$0	$1,488,712	$21,233,008
Jun	$6,711,471	$10,858	$0	$15,940,386	$0	$2,510,286	$25,173,000
Total	$45,970,544	$18,438	$2,302,629	$103,457,193	$51,449	$14,947,718	$166,747,970

Characteristics of Credits and Charges

Types of Units

Table 3-41 Credits by unit types (By operating reserve market): January through June 2009 (See 2008 SOM, Table 3-50)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Total
Combined Cycle	39.3%	0.0%	60.0%	0.7%	$53,604,989
Combustion Turbine	1.3%	5.2%	77.6%	15.9%	$44,697,492
Diesel	0.2%	0.0%	2.9%	96.9%	$2,629,272
Hydro	0.0%	0.3%	99.7%	0.0%	$166,159
Nuclear	0.0%	0.0%	0.0%	100.0%	$150,645
Steam	37.1%	0.0%	55.6%	7.3%	$65,429,277
Wind Farm	0.0%	0.0%	0.0%	100.0%	$250

Table 3-42 Credits by operating reserve market (By unit type): January through June 2009 (See 2008 SOM, Table 3-51)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost
Combined Cycle	45.9%	0.0%	31.1%	2.4%
Combustion Turbine	1.3%	100.0%	33.5%	47.7%
Diesel	0.0%	0.0%	0.1%	17.1%
Hydro	0.0%	0.0%	0.2%	0.0%
Nuclear	0.0%	0.0%	0.0%	1.0%
Steam	52.9%	0.0%	35.2%	31.8%
Wind Farm	0.0%	0.0%	0.0%	0.0%
Total	$45,970,544	$2,302,629	$103,457,193	$14,947,718

Economic and Noneconomic Generation

Table 3-43 PJM self-scheduled, economic, noneconomic and regulation generation receiving operating reserve payments: January through June 2009 (See 2008 SOM, Table 3-52)

	All Hours	On Peak	Off Peak
Self-scheduled generation	24.8%	23.5%	27.7%
Economic generation	64.2%	68.7%	53.9%
Noneconomic generation	10.0%	7.3%	16.4%
Regulation generation	1.0%	0.5%	2.0%
Total	100%	100%	100%

Table 3-44 PJM generation (By unit type receiving operating reserve payments): January through June 2009 (See 2008 SOM, Table 3-53)

	Self-Scheduled Generation	Economic Generation	Noneconomic Generation	Regulation Generation
Combined cycle	2.2%	7.8%	26.1%	16.2%
Combustion turbine	0.2%	0.2%	1.9%	0.0%
Diesel	0.2%	0.0%	0.0%	0.0%
Hydroelectric	2.4%	0.7%	0.0%	0.0%
Steam	93.9%	91.3%	72.0%	83.7%
Wind	1.2%	0.0%	0.0%	0.0%
Total	100%	100%	100%	100%

Table 3-45 PJM unit type generation distribution (By unit type receiving operating reserve payments): January through June 2009 (See 2008 SOM, Table 3-54)

	Self-Scheduled Generation	Economic Generation	Noneconomic Generation	Regulation Generation	Total
Combined cycle	6.5%	60.1%	31.5%	1.9%	100%
Combustion turbine	14.3%	31.3%	54.3%	0.1%	100%
Diesel	73.4%	19.4%	7.2%	0.0%	100%
Hydroelectric	56.8%	43.2%	0.0%	0.0%	100%
Steam	25.8%	65.3%	8.0%	0.9%	100%
Wind	99.1%	0.9%	0.0%	0.0%	100%

Geography of Balancing Credits and Charges

Table 3-46 Monthly balancing operating reserve charges and credits to generators (By location): January through June 2009 (See 2008 SOM, Table 3-55)

	Eastern Region						Western Region							
	Unit Deviation Charges	Unit Deviation LOC Charges	Total Unit Deviation Charges	Balancing Generator Credit	LOC Credit	Total Balancing Credit	Unit Deviation Charges	Unit Deviation LOC Charges	Total Unit Deviation Charges	Balancing Generator Credit	LOC Credit	Total Balancing Credit	Total Unit Deviation Charges Percent of Total Operating Reserve Charges	Total Unit Deviation Credits Percent of Total Operating Reserve Credits
Jan	$2,139,517	$312,053	$2,451,569	$21,038,966	$2,607,437	$23,646,403	$1,508,492	$250,222	$1,758,714	$5,404,493	$940,247	$6,344,741	10.4%	66.5%
Feb	$838,506	$168,497	$1,007,003	$7,814,120	$1,685,163	$9,499,283	$669,918	$153,709	$823,627	$6,592,259	$377,710	$6,969,970	7.4%	59.5%
Mar	$1,572,526	$349,336	$1,921,862	$13,125,363	$2,280,516	$15,405,879	$1,251,529	$257,801	$1,509,330	$9,095,630	$1,227,558	$10,323,188	9.6%	64.5%
Apr	$522,037	$164,054	$686,091	$3,978,840	$1,094,655	$5,073,494	$501,154	$149,107	$650,262	$6,752,492	$735,433	$7,487,925	6.6%	56.4%
May	$729,050	$119,822	$848,872	$6,750,078	$1,288,656	$8,038,734	$628,669	$120,320	$748,990	$6,964,567	$200,056	$7,164,623	7.5%	65.7%
Jun	$1,090,103	$212,220	$1,302,323	$8,647,384	$1,996,522	$10,643,906	$801,470	$199,890	$1,001,361	$7,293,001	$513,764	$7,806,765	8.9%	65.0%
Average	56.2%	54.0%	55.9%	59.3%	73.3%	61.1%	43.8%	46.0%	44.1%	40.7%	26.7%	38.9%	8.4%	62.9%

Market Power Issues

Top 10 Units

Table 3-47 Top 10 units and organizations receiving total operating reserve credits: January through June 2009 (See 2008 SOM, Table 3-57)

	Units			Organizations		
Rank	Total Credit	Total Credit Share	Total Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$18,989,859	11.4%	11.4%	$53,037,032	31.8%	31.8%
2	$12,992,666	7.8%	19.2%	$36,819,954	22.1%	53.9%
3	$6,713,051	4.0%	23.2%	$11,610,012	7.0%	60.9%
4	$5,818,956	3.5%	26.7%	$10,438,977	6.3%	67.1%
5	$5,519,629	3.3%	30.0%	$9,194,798	5.5%	72.7%
6	$5,326,982	3.2%	33.2%	$7,145,293	4.3%	76.9%
7	$3,029,911	1.8%	35.0%	$5,791,157	3.5%	80.4%
8	$2,356,878	1.4%	36.4%	$3,238,158	1.9%	82.4%
9	$2,217,461	1.3%	37.8%	$3,118,188	1.9%	84.2%
10	$2,024,680	1.2%	39.0%	$2,743,466	1.6%	85.9%

Table 3-48 Top 10 units and organizations receiving day-ahead generator credits: January through June 2009 (See 2008 SOM, Table 3-58)

	Units			Organizations		
Rank	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cumulative Distribution	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cumulative Distribution
1	$9,819,249	21.4%	21.4%	$23,449,745	51.0%	51.0%
2	$6,844,101	14.9%	36.2%	$5,707,317	12.4%	63.4%
3	$5,374,231	11.7%	47.9%	$4,058,995	8.8%	72.3%
4	$1,200,962	2.6%	50.6%	$2,187,062	4.8%	77.0%
5	$941,815	2.0%	52.6%	$1,913,941	4.2%	81.2%
6	$677,532	1.5%	54.1%	$1,382,409	3.0%	84.2%
7	$616,766	1.3%	55.4%	$1,197,322	2.6%	86.8%
8	$584,464	1.3%	56.7%	$982,520	2.1%	88.9%
9	$581,877	1.3%	58.0%	$869,382	1.9%	90.8%
10	$576,741	1.3%	59.2%	$819,262	1.8%	92.6%

Table 3-49 Top 10 units and organizations receiving synchronous condensing credits: January through June 2009 (See 2008 SOM, Table 3-59)

	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	$199,676	8.7%	8.7%	$2,051,535	89.1%	89.1%
2	$197,058	8.6%	17.2%	$165,168	7.2%	96.3%
3	$192,296	8.4%	25.6%	$75,847	3.3%	99.6%
4	$189,164	8.2%	33.8%	$5,133	0.2%	99.8%
5	$187,366	8.1%	41.9%			
6	$186,694	8.1%	50.0%			
7	$181,954	7.9%	57.9%			
8	$89,051	3.9%	61.8%			
9	$84,254	3.7%	65.5%			
10	$77,903	3.4%	68.9%			

Table 3-50 Top 10 units and organizations receiving balancing generator credits: January through June 2009 (See 2008 SOM, Table 3-60)

	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	$12,143,407	11.7%	11.7%	$30,123,095	29.1%	29.1%
2	$6,377,229	6.2%	17.9%	$27,378,907	26.5%	55.6%
3	$5,106,545	4.9%	22.8%	$8,890,830	8.6%	64.2%
4	$4,782,758	4.6%	27.5%	$8,589,384	8.3%	72.5%
5	$3,064,712	3.0%	30.4%	$4,935,610	4.8%	77.2%
6	$2,734,557	2.6%	33.1%	$3,604,057	3.5%	80.7%
7	$2,062,962	2.0%	35.1%	$2,100,525	2.0%	82.8%
8	$1,822,126	1.8%	36.8%	$2,036,396	2.0%	84.7%
9	$1,740,959	1.7%	38.5%	$1,793,683	1.7%	86.5%
10	$1,678,473	1.6%	40.1%	$1,369,006	1.3%	87.8%

Table 3-51 Top 10 units and organizations receiving lost opportunity cost credits: January through June 2009 (See 2008 SOM, Table 3-61)

	Units			Organizations		
Rank	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution
1	$1,172,459	7.8%	7.8%	$7,144,333	47.8%	47.8%
2	$1,003,375	6.7%	14.6%	$2,037,592	13.6%	61.4%
3	$978,634	6.5%	21.1%	$989,542	6.6%	68.0%
4	$869,881	5.8%	26.9%	$931,002	6.2%	74.3%
5	$862,761	5.8%	32.7%	$689,762	4.6%	78.9%
6	$831,725	5.6%	38.3%	$665,671	4.5%	83.3%
7	$689,762	4.6%	42.9%	$457,096	3.1%	86.4%
8	$463,631	3.1%	46.0%	$398,245	2.7%	89.1%
9	$433,445	2.9%	48.9%	$268,250	1.8%	90.9%
10	$388,048	2.6%	51.5%	$156,846	1.0%	91.9%

Figure 3-10 Cumulative distribution of units receiving credits (By operating reserve category): January through June 2009 (See 2008 SOM, Figure 3-12)

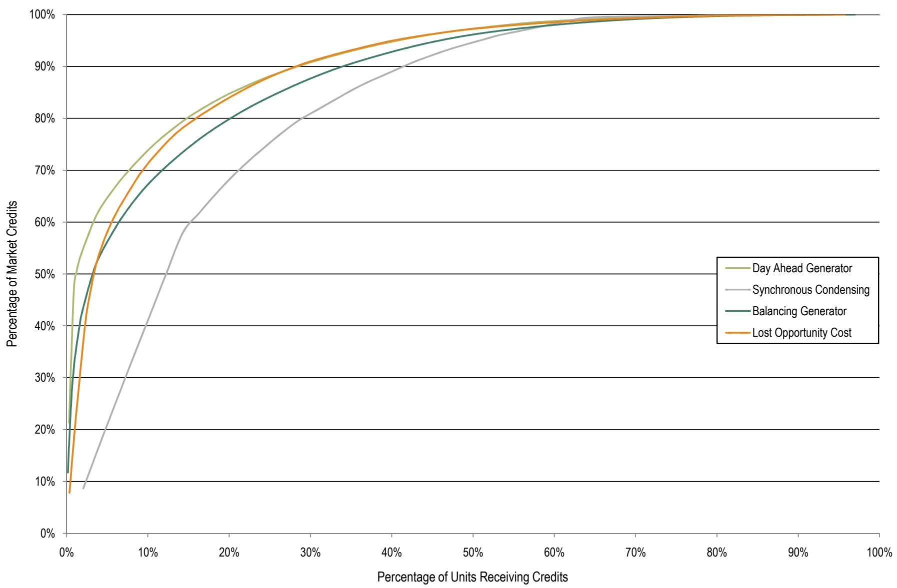
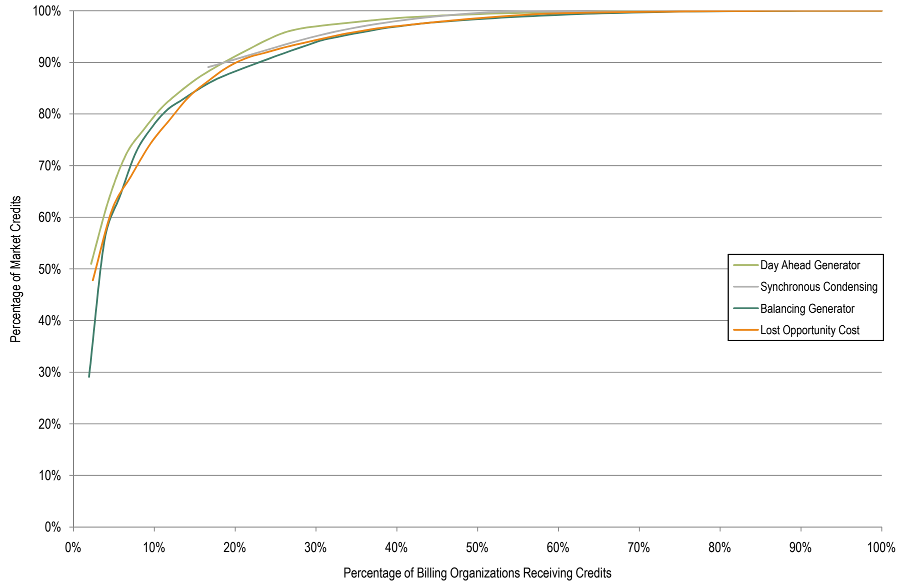


Figure 3-11 Cumulative distribution of billing organizations receiving credits (By operating reserve market): January through June 2009 (See 2008 SOM, Figure 3-13)



Markup

Unit Markup - Top 10 Units

Table 3-52 Top 10 operating reserve revenue units markup: January through June 2009 (See 2008 SOM, Table 3-62)

	Top 10 Units' Weighted Markup	Steam Share of Top 10 Units' Credits	Steam Units' in Top 10 Weighted Markup	Combined Cycle Share of Top 10 Units' Credits	Combined Cycle Units' in Top 10 Weighted Markup	Combustion Turbine Share of Top 10 Units' Credits	Combustion Turbine Units' in Top 10 Weighted Markup
2009 (Jan -Jun)	(1.9%)	42.7%	(7.1%)	57.3%	.8%	0.0%	NA

Unit Markup - All Units

Table 3-53 Average real-time weighted markup by unit type receiving balancing credits: January through June 2009 (New Table)

Unit Type	Number of Units	Weighted Markup
Combustion Turbine	361	(1.9%)
Steam	230	(7.2%)
Combined Cycle	46	(11.7%)
Diesel	20	(62.9%)
Hydro	8	284.6%
Nuclear	2	(30.0%)
Wind Farm	1	0.0%

March 3, 2009

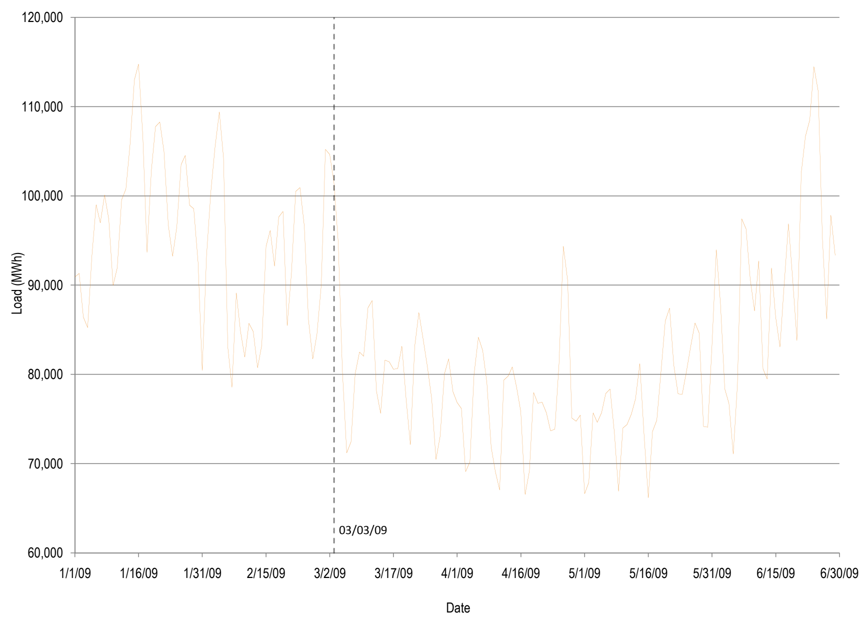
A Spike in Operating Reserves Charges

A spike in the RTO balancing deviation rate occurred on Tuesday, March 3, 2009. On March 3, $2,836,708 was paid to generators in RTO deviation credits. The RTO deviation rate on March 3 was $5.3568/MWh ($2,836,708/529,545 MWh). (See Table 3-55.) The deviation rate was 6.68 standard deviations higher than the average RTO deviation rate of .7023 for the period of January 1, 2009 through June 30, 2009.

There appear to be several reasons for the large increase in operating reserve charges on March 3. The increase in load from March 1 to March 2, of 15,233 MW, was the third largest single day increase of the year, while the peak load on March 3 was 572 MW lower than that on March 2. The actual load for March 3 was substantially lower than the forecast load and real-time prices were lower than day-ahead prices. Some zonal LMPs increased sharply during the early morning load pickup hours which prompted extra units to be called on. In particular, one plant received operating reserve credits for start costs of six units that were called on, while only three of those units actually started. The payments to those units were about 24 percent of the total balancing operating reserves credits for the day.

While actual load was less than forecast, March 3, 2009 was still a relatively high PJM load day for the time of year. At HE 8, the PJM load reached 104,647 MWh, one of the highest hourly peaks in the six month period between January 1 and June 30. Figure 3-12 shows the daily PJM peak load for those six months.

Figure 3-12 Daily PJM Peak Load: January 1, 2009 through June 30, 2009 (New Figure)



Five minute zonal LMPs were just below $100 during the peak hours of March 3, but zonal prices increased substantially during the morning load pick up (Figure 3-13). Figure 3-14 shows the hourly zonal and PJM loads for the day.

Figure 3-13 Five Minute Zonal LMPs: March 3, 2009 (New Figure)

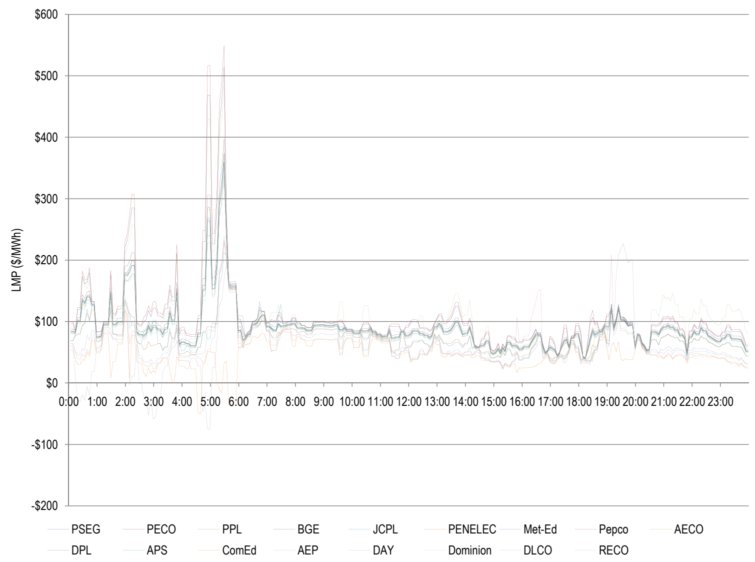
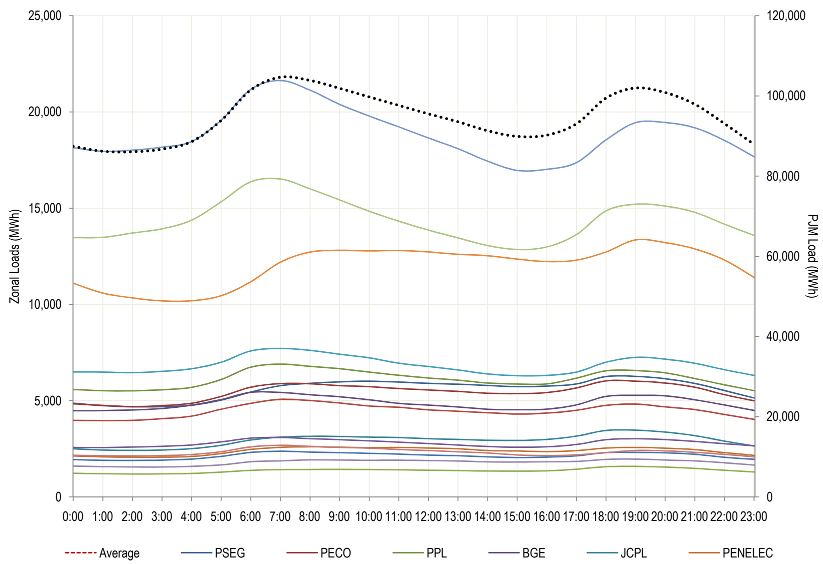


Figure 3-14 Hourly Zonal Loads: March 3, 2009 (New Figure)



The original day-ahead load forecast was greater than the actual real-time load for March 3 by an hourly average of 3,253 MW. The real-time forecasted load was greater than the actual real-time load by an hourly average of 2,579 MW. The two forecasts and actual real-time load are shown in Figure 3-15.

Figure 3-15 Hourly PJM load forecast and actual real-time PJM load: March 3, 2009 (New Figure)

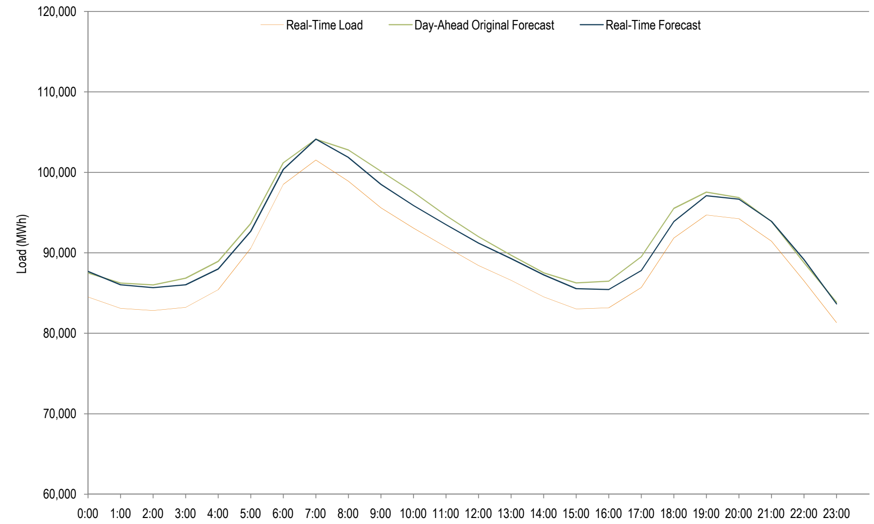


Figure 3-16 shows that the hourly integrated PJM real-time LMP was lower than the day-ahead LMP for 17 hours of the day on March 3, including all but one peak hour.

Figure 3-16 Hourly integrated PJM LMP: March 3, 2009 (New Figure)

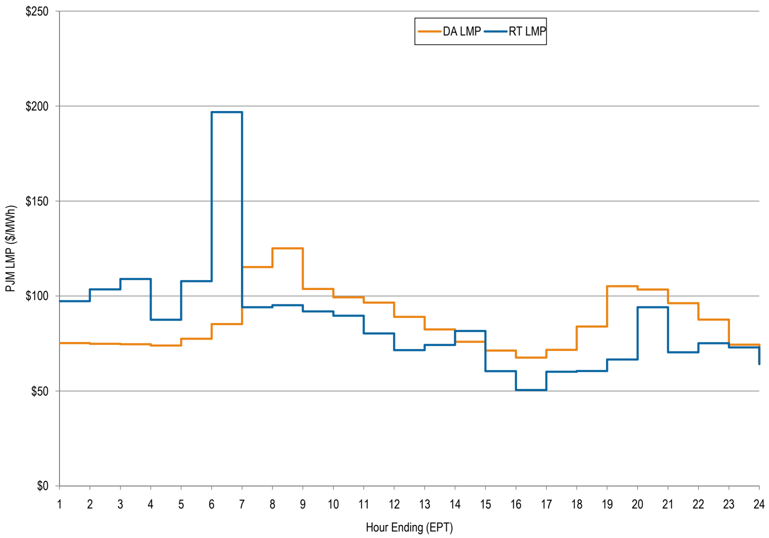


Table 3-54 shows a summary of outages by zone for March 3. The MW reduction is the sum of the MW on an outage, MW loss is the sum of each unit's reduction times the duration, and the zone EAF (Equivalent Availability Factor) is calculated as (1 – (MW loss / (zone capacity * 24 hours)).

Table 3-54 Zonal Outage Summary: Tuesday, March 3, 2009 (New Table)

Zone	MW Reduction	MW Loss	Zone EAF
AECO	609	14,372	68.2%
PENELEC	1,478	34,835	79.9%
Dominion	3,231	75,670	81.2%
BGE	977	23,448	83.0%
AEP	5,747	108,036	85.8%
PPL	1,805	36,120	86.5%
DPL	656	10,921	88.2%
PSEG	1,534	28,005	89.2%
DAY	633	16,099	89.4%
PECO	1,474	30,871	89.5%
JCPL	312	7,488	90.2%
ComEd	2,591	59,699	90.7%
APS	971	23,304	92.4%
External (XIC)	584	9,900	92.7%
Pepco	553	12,176	94.1%
DLCO	150	2,760	96.0%
Met-Ed	40	890	99.3%

Table 3-55 shows the RTO, East, and West charges, credits, and MWh for March 3. RTO deviation credits were $2,836,708, or 96.7 percent, of the total credits for the day. Charges paid by demand deviations were 48.8 percent of the total charges for the day, while charges paid by supply deviations were 30.7 percent, and generator deviations 17.3 percent.

Table 3-55 Regional Credits, Charges, and Deviations Breakdown: March 3, 2009 (New Table)

	Reliability			Deviations				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO (MWh)	2,272,810	68,024	2,340,834	267,172	167,854	94,518	529,545	2,870,378
RTO (Charges / Credits)	$46,803	$1,401	$48,204	$1,431,209	$899,176	$506,323	$2,836,708	$2,884,912
RTO (% of Total Charges)	1.6%	0.0%	1.6%	48.8%	30.7%	17.3%	96.7%	98.3%
East (MWh)	1,265,989	31,282	1,297,271	144,841	97,216	61,408	303,465	1,600,736
East (Charges / Credits)	$0	$0	$0	$0	$0	$0	$0	$0
East (% of Total Charges)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
West (MWh)	1,006,820	36,742	1,043,562	119,466	70,360	28,849	218,675	1,262,237
West (Charges / Credits)	$28,708	$1,048	$29,756	$10,308	$6,071	$2,489	$18,868	$48,624
West (% of Total Charges)	1.0%	0.0%	1.0%	0.4%	0.2%	0.1%	0.6%	1.7%
Sum of Charges	$75,511	$2,448	$77,960	$1,441,516	$905,247	$508,812	$2,855,575	$2,933,535

Table 3-56 shows that 61.9 percent of the balancing generator credits were paid to combustion turbines, 35.7 to combined cycles, and 2.3 percent to steam units for a total of $2,934,195. Cancellation and local constraint credits are not included in Table 3-55, but are included in balancing generator credits in Table 3-56, which accounts for the $660 difference.

Table 3-56 Credits by operating reserve market (By unit type): March 3, 2009 (See 2008 SOM, Table 3-51)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost
Combined Cycle	78.0%	0.0%	35.7%	0.8%
Combustion Turbine	5.1%	0.0%	61.9%	59.5%
Diesel	0.0%	0.0%	0.1%	0.0%
Hydro	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%
Steam	17.0%	0.0%	2.3%	39.7%
Wind Farm	0.0%	0.0%	0.0%	0.0%
Total	$264,780	$0	$2,934,195	$836,396

Table 3-57 shows the top 10 units in each category that received operating reserve credits. The amount of balancing generator credits paid to the top 10 units receiving balancing generator credits made up for about 50 percent of the total balancing generator credits, for a total of $1,483,757.

Table 3-57 Top 10 units receiving operating reserve credits: March 3, 2009 (See 2008 SOM, Table 3-57 through Table 3-61)

Unit Rank	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cummulative Distribution	Day Ahead Generator Markup	Synchronous Condensing Credit	Synchronous Condensing Credit Share	Synchronous Condensing Credit Cummulative Distribution	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cummulative Distribution	Balancing Generator Markup	LOC Credit	LOC Credit Share	LOC Credit Cummulative Distribution	LOC Markup	Total Credit	Total Credit Share	Total Credit Cummulative Distribution
1	$96,024	36.3%	36.3%	0.0%	$0	0.0%	0.0%	$312,038	10.6%	10.6%	0.0%	$102,598	10.8%	10.8%	116.6%	$312,038	3.8%	3.8%
2	$60,916	23.0%	59.3%	0.0%	$0	0.0%	0.0%	$219,750	7.5%	18.1%	36.0%	$97,522	10.3%	21.1%	0.0%	$312,038	3.8%	7.5%
3	$23,165	8.7%	68.0%	0.0%	$0	0.0%	0.0%	$131,652	4.5%	22.6%	50.3%	$81,865	8.6%	29.8%	0.0%	$219,750	2.7%	10.2%
4	$21,460	8.1%	76.1%	27.3%	$0	0.0%	0.0%	$118,331	4.0%	26.6%	324.3%	$59,937	6.3%	36.1%	0.0%	$219,750	2.7%	12.8%
5	$15,229	5.8%	81.9%	0.0%	$0	0.0%	0.0%	$118,283	4.0%	30.7%	324.3%	$57,024	6.0%	42.1%	0.0%	$162,514	2.0%	14.8%
6	$12,841	4.8%	86.7%	0.0%	$0	0.0%	0.0%	$118,275	4.0%	34.7%	324.3%	$53,430	5.6%	47.8%	8.8%	$162,514	2.0%	16.8%
7	$8,510	3.2%	89.9%	0.0%	$0	0.0%	0.0%	$118,233	4.0%	38.7%	324.3%	$50,503	5.3%	53.1%	8.4%	$131,652	1.6%	18.3%
8	$5,472	2.1%	92.0%	0.0%	$0	0.0%	0.0%	$118,134	4.0%	42.8%	324.3%	$38,999	4.1%	57.2%	0.0%	$131,652	1.6%	19.9%
9	$4,704	1.8%	93.8%	0.0%	$0	0.0%	0.0%	$118,066	4.0%	46.8%	324.3%	$37,492	4.0%	61.2%	8.8%	$118,331	1.4%	21.4%
10	$4,453	1.7%	95.5%	0.0%	$0	0.0%	0.0%	$110,995	3.8%	50.6%	38.0%	$37,492	4.0%	65.2%	8.8%	$118,331	1.4%	22.8%

Review of Impact on Regional Balancing Operating Reserve Charges

Total regional balancing generator credits for both reliability and deviation purposes for March 3, 2009 totaled $2,933,535.

Table 3-58 Regional balancing operating reserve credits: March 3, 2009 (New Table)

	Reliability Credits	Deviation Credits	Total Credits
RTO	$48,204	$2,836,708	$2,884,912
East	$0	$0	$0
West	$29,756	$18,868	$48,624
Total	$77,960	$2,855,575	$2,933,535

Table 3-59 Total deviations: March 3, 2009 (New Table)

	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total
Total (MWh)	267,172	167,854	94,518	529,545

Under the old operating reserve construct, total credits (see Table 3-58) for the day would have been allocated to demand, supply, and generator deviations (see Table 3-59), resulting in the balancing rate of $2,933,535 / 529,545 MWh = 5.5397 $/MWh. This balancing rate would then have been applied to the sum of demand, supply, and generator deviations, summed across the entire RTO.

Table 3-60 Charge allocation under old operating reserve construct: March 3, 2009 (New Table)

	Demand Deviations	Supply Deviations	Generator Deviations	Total
Total (MWh)	267,172	167,854	94,518	529,545
Balancing Rate ($/MWh)	5.540	5.540	5.540	5.540
Charges ($)	$1,480,060	$929,867	$523,605	$2,933,532

Under the new operating reserve construct, rates are applied separately to credits for reliability or deviation purposes in the Eastern, Western, and RTO regions, resulting in six balancing rates. Reliability credits are allocated by Real-Time load MWh plus Real-Time export MWh in the Eastern and Western regions, and the sum of those MWh for the RTO rate. Regional deviation credits are allocated to the sum of demand, supply, and generator deviations for each region in which they occur (deviations at aggregates that span both regions apply to RTO deviations). Total RTO deviations are the sum of the Eastern deviations, Western deviations, and the deviations that were directly applied to the RTO.

For March 3, 2009, charges were actually allocated as shown in Table 3-61.

Table 3-61 Actual regional credits, charges, rates and charge allocation MWh: March 3, 2009 (New Table)

	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	$48,204	2,340,834	0.021	$48,204	$2,836,708	529,545	5.357	$2,836,708	$2,884,912
East	$0	1,297,271	0.000	$0	$0	303,465	0.000	$0	$0
West	$29,756	1,043,562	0.029	$29,756	$18,868	119,466	0.158	$18,868	$48,624
Total	$77,960	2,340,834	NA	$77,960	$2,855,575	529,545	NA	$2,855,575	$2,933,535

The difference between the charges based on the old operating reserve construct (see Table 3-60) and the actual charges allocated under the current rules is shown in Table 3-62, 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.

Table 3-62 Difference in total charges between old rules and new rules: March 3, 2009 (New Table)

	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	$1,480,060	$929,867	$523,605	$2,933,532
Charges (Current)	$75,511	$2,448	$77,960	$1,441,516	$905,247	$508,812	$2,855,575
Difference	$75,511	$2,448	$77,960	($38,543)	($24,621)	($14,793)	($77,960)

A breakdown of the reallocation of charges for the period January 2009 through June 2009 is shown in Table 3-63.

Table 3-63 Difference in total charges between old rules and new rules: January through June 2009 (New Table)

	Reliability Charges			Deviation Charges			
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Injection Deviations	Generator Deviations	Deviations Total
Difference	$17,548,928	$788,243	$18,337,172	($9,518,775)	($5,902,678)	($2,915,720)	($18,337,172)

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.

Overview

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Market.** In contrast to the period from 2004 through late 2008, PJM was a net importer of energy in the Real-Time Market during January, February, March and May of 2009, and a net exporter of energy during April and June. In the Real-Time Market, monthly net interchange averaged 253 GWh.[1] Gross monthly import volumes averaged 3,924 GWh while gross monthly exports averaged 3,671 GWh.

- **Aggregate Imports and Exports in the Day-Ahead Market.** During the first six months of 2009, PJM was a net exporter of energy in the Day-Ahead Market in all months. The Day-Ahead monthly net interchange averaged -772 GWh. Gross monthly import volumes averaged 3,945 GWh while gross monthly exports averaged 4,717 GWh.

- **Aggregate Imports and Exports in the Day-Ahead Market versus the Real-Time Market.** During the first six months of 2009, gross imports in the Day-Ahead Energy Market were 99 percent of the Real-Time Market's gross imports (90 percent for the calendar year 2008) while gross exports in the Day-Ahead Market were 128 percent of the Real-Time Market's gross exports (106 percent for the calendar year 2008).

- **Interface Imports and Exports in the Real-Time Market.** In the Real-Time Market, during the first six months of 2009, there were net exports at 12 of PJM's 20 interfaces. The top four net exporting interfaces in the Real-Time Market accounted for 69 percent of the total net exports: PJM/Neptune (NEPT) with 26 percent, PJM/New York Independent System Operator, Inc. (NYIS) with 19 percent, PJM/Carolina Power and Light-East (CPLE) with 12 percent and PJM/First Energy (FE) with 12 percent of the net export volume. Eight PJM interfaces had net imports, with two importing interfaces accounting for 77 percent of the net import volume: PJM/Ohio Valley Electric Corporation (OVEC) with 57 percent and PJM/Michigan Electric Coordinated System (MECS) with 20 percent.

- **Interface Imports and Exports in the Day-Ahead Market.** In the Day-Ahead Market, there were net exports at 12 of PJM's 20 interfaces. The top three net exporting interfaces accounted for 62 percent of the total net exports, PJM/western Alliant Energy Corporation (ALTW) with 26 percent, PJM/eastern Alliant Energy Corporation (ALTE) with 19 percent and PJM/NEPTUNE (NEPT) with 17 percent. There were net imports in the Day-Ahead Market at eight of PJM's 20 interfaces. The top three importing interfaces accounted for 76 percent of the total net imports, PJM/OVEC with 49 percent, PJM/Michigan Electric Coordinated System (MECS) with 16 percent and PJM/Tennessee Valley Authority (TVA) with 11 percent.

- **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, including undersea and underground cable, was placed in service. This is a merchant 230 kV transmission line with a capacity of 660 MW. The line is bi-directional, but in the first six months of 2009, power flows were only from PJM to New York. The average hourly flow during the first six months of 2009 was -549 MW.

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.

Interactions with Bordering Areas

- **PJM Interface Pricing with Organized Markets.**
  - **PJM and Midwest ISO Interface Pricing.** During the first six months of 2009, the relationship between prices at the PJM/MISO Interface and at the MISO/PJM Interface reflected economic fundamentals as did the relationship between interface price differentials and power flows between PJM and the Midwest ISO.
  - **PJM and New York ISO Interface Pricing.** During the first six months of 2009, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus reflected economic fundamentals, as did the relationship between interface price differentials and power flows between PJM and NYISO. Both continued to be affected by differences in institutional and operating practices between PJM and NYISO.
  - **PJM TLRs.** During the first six months of 2009, PJM issued 90 transmission loading relief procedures (TLRs). This represents an increase of 48 percent from the same time period in 2008 (61 during the first six months of 2008). The increase in TLR activity in 2009 was primarily attributed to a single low load pocket in northern Illinois, where excess generation in that area, during the off-peak hours, created excessive flows on nearby low voltage transmission lines. The need to continue to call TLRs for this overload was alleviated by the development of a new PJM dispatcher operating procedure that was implemented in early May of 2009.
- **Operating Agreements with Bordering Areas.**
  - **PJM and New York Independent System Operator, Inc. Joint Operating Agreement (JOA).**[2] 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. While the JOA does not include provisions for market-based congestion management or other market-to-market activity, at the request of PJM, PJM and the NYISO began discussion of a market-based congestion management protocol.
  - **PJM and Midwest ISO Joint Operating Agreement.** The Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C., executed on December 31, 2003, continued during the first six months of 2009. The market-based congestion management process is reviewed and modified as necessary through the Congestion Management Process (CMP) protocols.[3]

    In 2009, the Midwest ISO requested that PJM review the components of the CMP to verify data accuracy. During this review, it was found that some data inputs to the market flow calculator were incorrect. The result of the errors in input data created inaccuracies in the market flow calculation, which resulted in smaller net settlements from PJM to the Midwest ISO as determined in the JOA. 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 extent of any miscalculations.
  - **PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.**[4] 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 the first six months of 2009.
  - **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**[5] On September 9, 2005, the United States Federal Energy Regulatory Commission (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 the first six months of 2009. As part of this agreement, both parties

2 See PJM. "Joint Operating Agreement Among And Between New York Independent System Operator Inc. And PJM Interconnection, L.L.C." (May 22, 2007) (Accessed July 6, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20071102-nyiso-pjm.ashx> (208 KB).

3 See PJM. "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (November 1, 2007) (Accessed July 6, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (1,534 KB).

4 See PJM. "Congestion Management Process (CMP) Master" (May 1, 2007) (Accessed July 6, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20080502-miso-pjm-tva-baseline-cmp.ashx> (432 KB).

5 See PJM. "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (July 29, 2005) (Accessed July 6, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20081114-progress-pjm-joa.ashx> (2.98 MB).

agreed to develop a formal CMP. During the first six months of 2009, PEC and PJM continued discussions on more granular interface pricing as well as the development of the CMP.

- **PJM and Virginia and Carolinas Area (VACAR) South Reliability Coordination Agreement.**[6] On May 23, 2007, PJM and VACAR South (VACAR is a subregion within the NERC Southeastern Electric Reliability Council (SERC) Region) entered into a reliability coordination agreement. It provides for system and outage coordination, emergency procedures and the exchange of data. Provisions are also made for regional studies and recommendations to improve the reliability of interconnected bulk power systems.

- **Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts.** During the first six months of 2009, PJM continued to operate under the terms of the operating protocol developed in 2005.[7]

Interchange Transaction Issues

- **Up-To Congestion.** 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 Market and real-time transactions.[8] In 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. Increasing the offer cap, and allowing negative offers, could potentially increase the cleared volume of up-to congestion transactions, and aggravate the issue.

  On February 21, 2008, the MRC approved PJM's proposed resolution to the request for implementation on March 1, 2008.[9] The proposal allowed for an increased offer cap from $25 to ± $50, and explicitly allowed for negative offers. PJM also eliminated certain available sources and sinks in an effort to address the mismatches between the Day-Ahead and Real-Time Markets.

  The Market Monitoring Unit (MMU) recommends that PJM consider eliminating all internal PJM buses for use in up-to congestion bidding. In effect, the use of specific buses is equivalent to creating a scheduled transaction which will not equal the actual corresponding power flow.

- **Loop Flows.** Loop flows are measured as the difference between actual and scheduled flows at one or more specific interfaces. Loop flows 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 that the energy takes. Although PJM's total scheduled and actual flows differed by 3.1 percent in the first six months of 2009, greater differences existed at individual interfaces. 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 2008, the PJM/Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows (-7,563 GWh during the first six months of 2009 and -14,014 GWh during the calendar year 2008), particularly during the overnight hours. The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows (1,827 GWh during the first six months of 2009 and 4,065 GWh during the calendar year 2008), although these mismatches have declined since the consolidation of the former PJM southeast and southwest pricing points in October 2006. 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.

6 See PJM. "Adjacent Reliability Coordinator Coordination Agreement" (May 23, 2007) (Accessed July 6, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx> (528 KB).

7 111 FERC ¶ 61,228 (2005).

8 See PJM. "Up-to Congestion Transactions. Proposed Interim Changes Pending Development of a Spread Product" (February 21, 2008) (Accessed July 6, 2009) <http://www.pjm.com/~/media/committees-groups/committees/mrc/20080221-item-03-up-to-congestion-transactions.ashx> (38KB).

9 See PJM. "20080221-minutes.pdf" (February 21, 2008) (Accessed July 6, 2009) <http://www.pjm.com/Media/committees-groups/committees/mrc/20080221-minutes.pdf > (61KB).

- **Loop Flows at PJM's Southern Interfaces.** The improvement in the difference between scheduled and actual power flows at PJM's southern interfaces (PJM/TVA and PJM/Eastern Kentucky Power Corporation (EKPC) to the west and PJM/eastern portion of Carolina Power & Light Company (CPLE), PJM/western portion of Carolina Power & Light Company (CPLW) and PJM/DUK to the east) observed in late 2006, 2007 and during 2008 was sustained during the first six months of 2009. These improvements followed the changes from the Southeast and Southwest interface pricing points to the SOUTHIMP and SOUTHEXP interface pricing points that occurred on October 1, 2006.

- **Loop Flows at PJM's Northern Interfaces.** In 2008, new loop flows were created when pricing rules gave participants an incentive to schedule power flows in a manner inconsistent with the associated actual power flows. Market participants scheduled transactions on a path from the NYISO to PJM through Ontario's Independent Electricity System Operator (IESO) and Midwest ISO systems, rather than reflecting the actual power flows which were primarily directly from NYISO to PJM. The participants faced a price incentive to engage in this behavior. When export transactions were scheduled from NYISO to Ontario, participants paid the lower export price at NYISO's Ontario interface rather than the higher export price at NYISO's PJM interface. The export price differences were more than enough to cover the cost of transmission through Ontario and MISO into PJM. When the export transactions were approved in the NYISO hourly market, the NYISO committed additional generation to support the transactions. The actual flow of energy that resulted was primarily directly from NYISO to PJM across the PJM/NYISO Interface. PJM's interface pricing calculations correctly reflected the actual power flows, but 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.

- **Data Required for Full Loop Flow Analysis.** A complete analysis of loop flow across the Eastern Interconnection could enhance overall market efficiency and shed light on the interactions among market and non market areas. This is important because loop flows have negative impacts on the efficiency of market prices in markets with explicit locational pricing and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. More broadly, a complete analysis of loop flow could advance the overall transparency of electricity transactions. The term non market area is a misnomer in the sense that all electricity transactions are part of the broad energy market in the Eastern Interconnection. There are areas with transparent markets, and there are areas with less transparent markets, 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 flow.

  The MMU recommends that PJM and the Midwest ISO reiterate their initial recommendation to create an energy schedule tag archive, as this would provide the transparency necessary for a complete loop flow analysis. The data required for a meaningful loop flow analysis include tag data, market flow impact data, actual flowgate flow data and balancing authority ACE data for the Eastern Interconnection. The MMU recommends that the RTOs request action, and that both NERC and FERC consider taking the action required to make these data available to the RTOs and market monitors to make a full market analysis possible.

Additional Interchange Transaction Analysis

- **Net Interchange Fluctuation.** Figure 4-3 shows that PJM had been a net exporter of energy in the Real-Time Market during the period from 2004 through 2008. During this period, maximum exports occurred during the third quarter of the year (July, August and September) and minimum exports occurred during the first half of the year. As shown in Figure 4-1, PJM's net interchange during the first six months of 2009 fluctuated between net imports and net exports. In January, February and March, PJM was a net importer of energy. In April, PJM became a net exporter of energy, but a net importer in May and a net exporter in June. This fluctuation can be partially attributed to seasonal variations, generation availability and interface pricing mechanisms.

  Historically, PJM has exported more energy in the summer months than in the winter months. The seasonal decrease in exports during

January, February and March contributed to PJM being a net importer in those months.

In addition to the seasonal variability, interface pricing mechanisms also had an effect on the overall net interchange. Figure 4-17 and Figure 4-18 show the real-time interchange volume and the corresponding average hourly LMP available for Duke Energy Carolinas and Progress Energy Carolinas. In January, when the interface price was the highest, both Duke and Progress had the largest amount of imports into PJM. Imports appear clearly related to the interface price while the relationship is less clear for exports. The interface pricing method for Duke and Progress was modified in 2009.

- **Interface Pricing Agreements with Individual Companies.** PJM entered into confidential locational interface pricing agreements with Duke Energy Carolinas, Progress Energy Carolinas and North Carolina Municipal Power Agency (NCMPA) in 2007 that provided more advantageous pricing to these companies than the applicable interface pricing rules. Each of these agreements established a locational price for purchases and sales between PJM and the individual company that applied under specified conditions. 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 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. The first option is to continue using the SouthImp and SouthExp pricing points. While the SouthImp and SouthExp pricing points reflect the physical flows into and out of PJM, the interface encompasses a large geographic area, and individual neighboring balancing authorities may benefit from providing additional data to take advantage of a more granular pricing mechanism. The second option is the "high/low" option. To utilize the "high/low" option, PJM must be able to verify the source for import transactions and the sink for export transactions. Under this option, PJM uses the highest generator bus LMP for exports from PJM and the lowest generator bus LMP for imports into PJM. In addition, unit level telemetry can be provided that shows the real-time unit status. When a generator is not running, the "high/low" method eliminates that bus LMP from the determination of the import or export price. The third option is the "marginal cost proxy method". 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 marginal generator of the external supplier. The marginal generator is based on 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 for any such units. The "marginal cost proxy method" falls short of a full congestion management agreement.

  The proposed tariff revisions were filed with FERC on December 2, 2008[10], and approved on May 1, 2009.[11] 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 "high/low" and "marginal cost proxy" pricing beyond January 31, 2010), and to file such agreements unexecuted, if requested, after 90 days.[12] As of July 1, 2009, each of Duke Energy Carolinas, Progress Energy Carolinas and the North Carolina Municipal Power Agency was in the process of negotiating a congestion management agreement with PJM.

  As of July 1, 2009, due to the required software modifications to support the proposed tariff revisions, neither the "high/low" nor the "marginal cost proxy method" options were implemented. Figure 4-17 through Figure 4-20 show the real-time and day-ahead prices for imports and exports

10 PJM Interconnection, L.L.C., Transmittal Letter, Docket No. ER09-369-000 (December 2, 2008).
11 PJM Interconnection, L.L.C., Letter Order, Docket No. ER09-369-000 (May 1, 2009).
12 127 FERC ¶ 61,101.

applicable for the interface pricing under the various agreements. During the period from February 1 through May 3, 2009, the interface pricing is based on the SouthIMP and SouthEXP LMPs as there were no agreements in place.

- **Spot Import.** Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. However, PJM interpreted its Joint Operating Agreement (JOA) with 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.[13] The rule caused the availability of spot import service to be limited by ATC on the transmission path. As a result of the rule, requests for service sometimes exceeded the amount of service available to customers. Unlike non-firm point-to-point WPC service, spot import (a network service) is provided at no charge to the market participant offering into the PJM spot market.

  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 any 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 at 5:00 EPT when queued the day prior. On June 23, PJM implemented the new business rules. Since the implementation of the rule changes, the spot import service usage has been 100 percent, compared to 70 percent prior to the modification. (See Figure 4-21). The MMU will continue to monitor participant use of spot import service.

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 nontransparent.

The MMU analyzed the transactions between PJM and neighboring balancing authorities for the first six months of 2009, including evolving transaction patterns, economics and issues. During the first six months of 2009, PJM was a net importer of energy and a large share of both import and export activity occurred at a small number of interfaces. Four interfaces accounted for 69 percent of the total real-time net exports and two interfaces accounted for 77 percent of the real-time net import volume. Three interfaces accounted for 62 percent of the total day-ahead net exports and three interfaces accounted for 76 percent of the day-ahead net import volume.

In order to manage interactions with other market areas, PJM has entered into formal agreements with a number of balancing authorities. The redispatch agreement between PJM and the Midwest ISO is a model for such agreements and is being continuously improved. As interactions with external areas are increasingly governed by economic fundamentals, interface prices and volumes reflect supply and demand conditions. However, more needs to be done to assure that market signals are used to manage constraints affecting interarea transactions. PJM and NYISO, as neighboring market areas, should develop market-based congestion management protocols as soon as practicable. In addition, PJM should continue its efforts to gain access to the data required to understand loop flows in real-time and to ensure that responsible parties pay their appropriate share of the costs of redispatch.

In order to manage interactions with non market areas, PJM has entered into coordination agreements with other balancing authorities as a first step. In addition, PJM has attempted to address loop flows by creating and modifying interface prices that reflect actual power flows, regardless of contract path. Loop flows are also managed through the use of redispatch and TLR procedures. PJM has entered into dynamic scheduling agreements with generation owners for specific units to permit transparent, market-based signals and responses. PJM has modified the rules governing the use of limited transaction ramp capability between PJM and contiguous balancing authorities to help ensure that transactions are free to respond to

13 See "WPC White Paper" (April 20, 2007) (Accessed July 6, 2008) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx> (97 KB).

market signals and to reduce the ability to game or hoard ramp. PJM also entered into agreements with specific balancing authorities for separate interface pricing that have been questioned with respect to transparency and equal access. PJM needs to ensure that such pricing is transparent and that all participants have access to the defined pricing when in the same position.

Loop flows are measured as the difference between actual and scheduled (contract path) flows at one or more specific interfaces. Loop flows do not exist within markets because power flows are explicitly priced under locational marginal pricing, but markets can create loop flows in external balancing authorities. PJM attempts to manage loop flows by creating interface prices that reflect the actual power flows, regardless of contract path. But this approach cannot be completely successful as long as it is possible to schedule a transaction and be paid based on that schedule, regardless of how the power flows.

PJM continues to face significant loop flows for reasons that continue not to be fully understood as a result of inadequate access to the required data. A complete analysis of loop flow across the Eastern Interconnection could improve overall market efficiency, shed light on the interactions among market and non market areas and permit market based congestion management across the Eastern Interconnection. Loop flows have negative impacts on the efficiency of market prices in markets with explicit locational pricing and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. The MMU recommends that the RTOs request action, and that both NERC and FERC consider taking the action required to make these data available to the RTOs and market monitors to make a full market analysis possible.

PJM needs to continue to pay careful attention to all the mechanisms used to manage flows at the interfaces between PJM and surrounding areas. PJM manages its interface with external areas, in part, through limitations on the amount of change in net interchange within 15-minute intervals. The change in net interchange is referred to as ramp. Changes in net interchange affect PJM operations and markets as they require increases or decreases in generation to meet load. As a result of the fact that ramp is free but is a valuable resource, there are strong incentives to game the ramp rules. The same is true of spot import service. Up-to congestion service is a market option used to import power to or export power from PJM which can create mismatches between transactions in the Day-Ahead Energy Market and the Real-Time Energy Market that result in inaccurate pricing and can provide a gaming opportunity.

Interchange Transaction Activity

Aggregate Imports and Exports

Figure 4-1 PJM real-time scheduled imports and exports: January through June 2009 (See 2008 SOM, Figure 4-1)

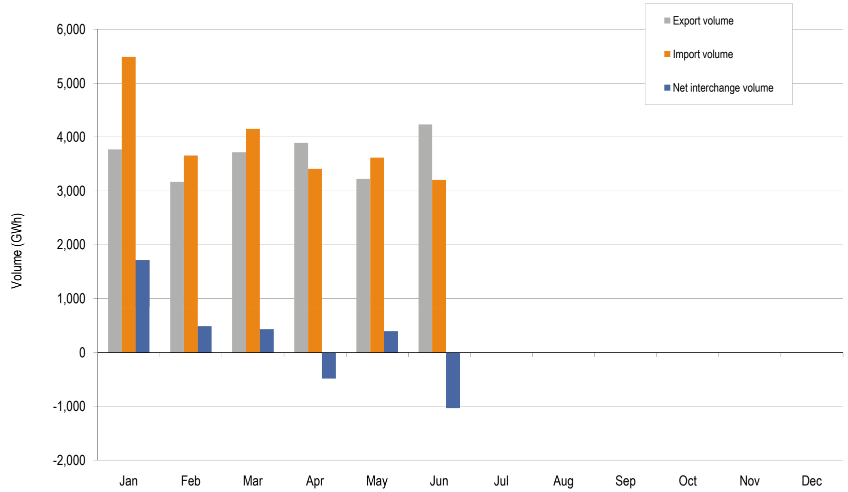


Figure 4-2 PJM day-ahead scheduled imports and exports: January through June 2009 (See 2008 SOM, Figure 4-2)

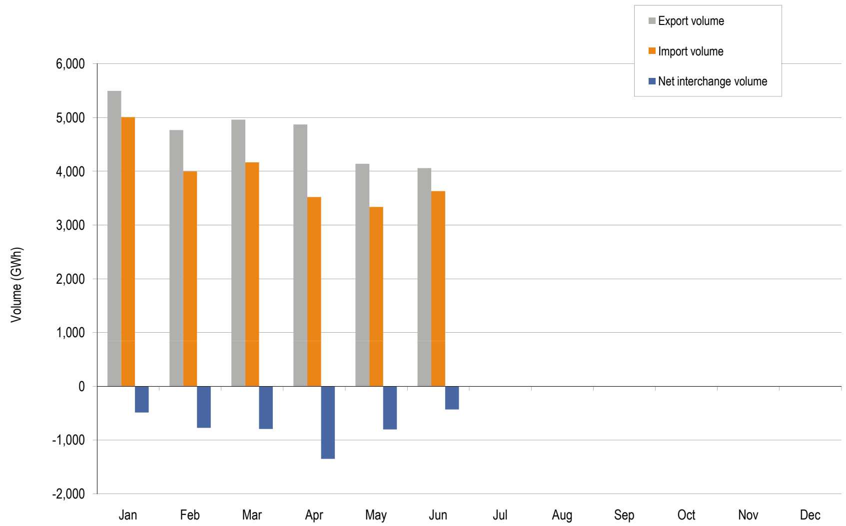
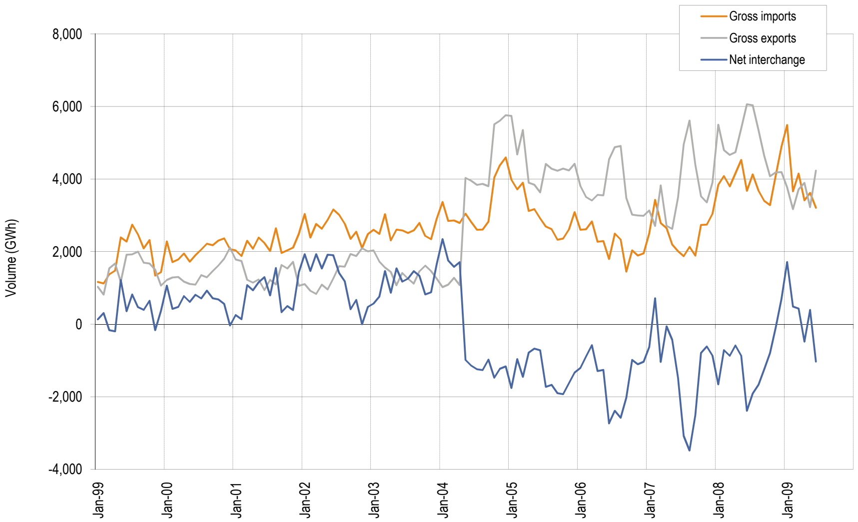


Figure 4-3 PJM scheduled import and export transaction volume history: 1999 through June 2009 (See 2008 SOM, Figure 4-3)



Interface Imports and Exports

Table 4-1 Real-time scheduled net interchange volume by interface (GWh): January through June 2009 (See 2008 SOM, Table 4-1)

	Jan	Feb	Mar	Apr	May	Jun	Total
ALTE	44.4	(41.8)	(86.5)	(147.3)	(117.6)	(143.6)	(492.4)
ALTW	(65.6)	(69.6)	(74.3)	(97.5)	(66.4)	(175.3)	(548.7)
AMIL	126.2	23.7	8.7	(14.9)	28.0	(24.0)	147.7
CIN	102.6	(96.1)	(179.7)	(216.6)	14.7	(91.8)	(466.9)
CPLE	(62.7)	(161.8)	(208.1)	(281.1)	(113.8)	(293.2)	(1,120.7)
CPLW	(71.4)	(67.4)	(74.3)	(72.0)	(60.3)	(69.8)	(415.2)
CWLP	0.0	0.0	0.7	0.0	0.0	0.0	0.7
DUK	622.7	67.8	89.9	10.6	60.9	(86.0)	765.9
EKPC	(173.5)	(78.8)	(88.6)	(57.4)	67.3	(9.7)	(340.7)
FE	(215.6)	(221.5)	(166.6)	(204.3)	(178.6)	(93.1)	(1,079.7)
IPL	47.1	(17.5)	(88.6)	(79.8)	101.5	(23.9)	(61.2)
LGEE	137.4	90.7	176.3	101.4	169.8	32.6	708.2
MEC	150.4	302.1	146.1	155.1	(148.4)	(239.8)	365.5
MECS	421.7	361.8	552.3	60.9	341.6	398.7	2,137.0
NEPT	(294.8)	(402.5)	(445.1)	(400.9)	(434.5)	(456.9)	(2,434.7)
NIPS	(8.2)	(51.5)	(35.5)	(60.0)	(3.9)	(38.1)	(197.2)
NYIS	(396.1)	(231.7)	(253.3)	(180.8)	(265.5)	(466.0)	(1,793.4)
OVEC	1,171.3	994.2	1,018.4	1,012.5	970.4	995.2	6,162.0
TVA	244.0	128.7	167.6	35.2	69.3	(160.0)	484.8
WEC	(64.6)	(41.0)	(26.5)	(44.9)	(38.3)	(86.3)	(301.6)
Total	1,715.3	487.8	432.9	(481.8)	396.2	(1,031.0)	1,519.4

Table 4-2 Real-time scheduled gross import volume by interface (GWh): January through June 2009 (See 2008 SOM, Table 4-2)

	Jan	Feb	Mar	Apr	May	Jun	Total
ALTE	170.4	65.4	18.2	1.7	0.1	0.1	255.9
ALTW	45.7	22.2	1.7	0.0	1.9	3.5	75.0
AMIL	147.3	44.9	38.3	26.8	62.2	48.6	368.1
CIN	382.9	265.0	335.2	209.3	256.2	335.3	1,783.9
CPLE	223.9	69.4	66.8	39.9	115.1	16.8	531.9
CPLW	2.1	0.0	0.0	0.0	0.0	0.0	2.1
CWLP	0.0	0.0	0.7	0.0	0.0	0.0	0.7
DUK	737.8	277.9	209.5	154.1	239.2	151.2	1,769.7
EKPC	2.7	6.1	12.9	2.5	90.3	33.2	147.7
FE	60.5	32.6	101.6	60.8	73.0	160.0	488.5
IPL	107.5	43.8	51.9	63.5	148.6	65.7	481.0
LGEE	187.4	125.2	183.6	125.8	172.0	55.7	849.7
MEC	337.6	428.2	371.7	361.2	77.8	26.5	1,603.0
MECS	573.5	500.4	679.7	264.3	458.0	486.8	2,962.7
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NIPS	32.5	8.1	0.5	0.0	11.0	0.0	52.1
NYIS	1,004.4	589.8	829.7	982.3	795.2	791.0	4,992.4
OVEC	1,171.3	994.2	1,018.4	1,012.5	970.4	995.2	6,162.0
TVA	292.8	185.1	214.2	107.1	146.2	31.4	976.8
WEC	8.7	1.2	17.8	0.6	4.4	5.8	38.5
Total	5,489.0	3,659.5	4,152.4	3,412.4	3,621.6	3,206.8	23,541.7

Table 4-3 Real-time scheduled gross export volume by interface (GWh): January through June 2009 (See 2008 SOM, Table 4-3)

	Jan	Feb	Mar	Apr	May	Jun	Total
ALTE	126.0	107.2	104.7	149.0	117.7	143.7	748.3
ALTW	111.3	91.8	76.0	97.5	68.3	178.8	623.7
AMIL	21.1	21.2	29.6	41.7	34.2	72.6	220.4
CIN	280.3	361.1	514.9	425.9	241.5	427.1	2,250.8
CPLE	286.6	231.2	274.9	321.0	228.9	310.0	1,652.6
CPLW	73.5	67.4	74.3	72.0	60.3	69.8	417.3
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	115.1	210.1	119.6	143.5	178.3	237.2	1,003.8
EKPC	176.2	84.9	101.5	59.9	23.0	42.9	488.4
FE	276.1	254.1	268.2	265.1	251.6	253.1	1,568.2
IPL	60.4	61.3	140.5	143.3	47.1	89.6	542.2
LGEE	50.0	34.5	7.3	24.4	2.2	23.1	141.5
MEC	187.2	126.1	225.6	206.1	226.2	266.3	1,237.5
MECS	151.8	138.6	127.4	203.4	116.4	88.1	825.7
NEPT	294.8	402.5	445.1	400.9	434.5	456.9	2,434.7
NIPS	40.7	59.6	36.0	60.0	14.9	38.1	249.3
NYIS	1,400.5	821.5	1,083.0	1,163.1	1,060.7	1,257.0	6,785.8
OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TVA	48.8	56.4	46.6	71.9	76.9	191.4	492.0
WEC	73.3	42.2	44.3	45.5	42.7	92.1	340.1
Total	3,773.7	3,171.7	3,719.5	3,894.2	3,225.4	4,237.8	22,022.3

Table 4-4 Day-ahead net interchange volume by interface (GWh): January through June 2009 (See 2008 SOM, Table 4-4)

	Jan	Feb	Mar	Apr	May	Jun	Total
ALTE	(142.2)	(61.4)	(518.5)	(673.0)	(779.1)	(521.6)	(2,695.8)
ALTW	(722.6)	(756.0)	(604.5)	(746.7)	(389.5)	(497.7)	(3,717.0)
AMIL	52.8	72.3	42.2	86.6	102.4	261.6	617.9
CIN	(225.4)	(96.3)	(47.8)	57.5	(36.7)	55.7	(293.0)
CPLE	49.1	(23.0)	(86.0)	(81.0)	(88.1)	(157.1)	(386.1)
CPLW	(176.6)	(166.0)	(184.5)	(180.0)	(155.9)	(176.2)	(1,039.2)
CWLP	(0.7)	(0.1)	0.0	0.0	0.0	0.0	(0.8)
DUK	255.9	26.4	1.1	22.3	120.9	58.7	485.4
EKPC	(31.1)	(22.8)	(1.1)	0.0	0.0	0.0	(55.0)
FE	(206.7)	(233.8)	(241.4)	(197.3)	(206.0)	(116.4)	(1,201.6)
IPL	(316.7)	(191.0)	(157.2)	(67.1)	85.2	143.0	(503.8)
LGEE	(16.5)	(8.9)	23.5	6.9	9.7	39.9	54.6
MEC	27.3	(90.0)	(173.4)	(185.3)	(209.3)	(252.9)	(883.6)
MECS	101.9	172.9	250.4	261.1	370.6	433.8	1,590.7
NEPT	(326.4)	(403.8)	(446.4)	(402.1)	(436.6)	(472.3)	(2,487.6)
NIPS	(233.7)	(320.9)	(71.3)	(194.6)	(286.2)	(62.2)	(1,168.9)
NYIS	158.7	146.5	130.8	7.5	(1.8)	(8.2)	433.4
OVEC	835.6	743.5	786.0	738.6	824.2	857.3	4,785.2
TVA	482.5	384.6	151.7	81.8	5.4	(42.8)	1,063.2
WEC	(52.5)	57.0	352.4	117.2	269.0	28.7	771.8
Total	(487.2)	(770.8)	(794.0)	(1,347.6)	(801.8)	(428.7)	(4,630.1)

Table 4-5 Day-ahead gross import volume by interface (GWh): January through June 2009 (See 2008 SOM, Table 4-5)

	Jan	Feb	Mar	Apr	May	Jun	Total
ALTE	675.2	674.4	470.1	173.7	52.2	106.5	2,152.1
ALTW	190.8	183.6	33.2	2.3	0.0	12.5	422.4
AMIL	59.4	75.0	44.5	91.5	105.0	261.6	637.0
CIN	103.2	159.2	178.5	247.6	190.5	320.2	1,199.2
CPLE	187.6	75.8	14.4	21.0	24.0	7.8	330.6
CPLW	9.5	2.1	0.6	0.0	2.8	0.0	15.0
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	291.9	102.7	55.9	71.4	138.8	90.0	750.7
EKPC	0.8	0.0	0.0	0.0	0.0	0.0	0.8
FE	15.2	44.9	60.0	23.0	10.3	100.7	254.1
IPL	246.5	159.9	153.2	254.2	258.7	250.0	1,322.5
LGEE	2.9	0.2	24.9	8.1	11.4	41.0	88.5
MEC	173.2	0.0	0.0	0.0	0.0	0.0	173.2
MECS	504.9	400.1	488.5	606.8	631.9	626.5	3,258.7
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NIPS	284.5	248.4	490.5	208.0	135.6	151.4	1,518.4
NYIS	890.3	584.5	776.0	776.4	612.0	675.0	4,314.2
OVEC	866.7	766.6	810.5	763.1	828.4	858.2	4,893.5
TVA	496.4	407.2	172.8	104.0	20.2	12.0	1,212.6
WEC	11.2	113.8	393.7	172.7	316.2	118.3	1,125.9
Total	5,010.2	3,998.4	4,167.3	3,524.0	3,338.0	3,631.7	23,669.6

Table 4-6 Day-ahead gross export volume by interface (GWh): January through June 2009 (See 2008 SOM, Table 4-6)

	Jan	Feb	Mar	Apr	May	Jun	Total
ALTE	817.4	735.8	988.6	846.7	831.3	628.1	4,847.9
ALTW	913.4	939.6	637.7	749.0	389.5	510.2	4,139.4
AMIL	6.6	2.7	2.3	4.9	2.6	0.0	19.1
CIN	328.6	255.5	226.3	190.1	227.2	264.5	1,492.2
CPLE	138.5	98.8	100.4	102.0	112.1	164.9	716.7
CPLW	186.1	168.1	185.1	180.0	158.7	176.2	1,054.2
CWLP	0.7	0.1	0.0	0.0	0.0	0.0	0.8
DUK	36.0	76.3	54.8	49.1	17.9	31.3	265.3
EKPC	31.9	22.8	1.1	0.0	0.0	0.0	55.8
FE	221.9	278.7	301.4	220.3	216.3	217.1	1,455.8
IPL	563.2	350.9	310.4	321.3	173.5	107.0	1,826.3
LGEE	19.4	9.1	1.4	1.2	1.7	1.1	33.9
MEC	145.9	90.0	173.4	185.3	209.3	252.9	1,056.8
MECS	403.0	227.2	238.1	345.8	261.3	192.7	1,668.0
NEPT	326.4	403.8	446.4	402.1	436.6	472.3	2,487.6
NIPS	518.2	569.3	561.8	402.6	421.8	213.6	2,687.3
NYIS	731.6	438.0	645.2	768.9	613.8	683.2	3,880.8
OVEC	31.1	23.1	24.5	24.5	4.2	0.9	108.3
TVA	13.9	22.6	21.1	22.2	14.8	54.8	149.4
WEC	63.7	56.8	41.3	55.5	47.2	89.6	354.1
Total	5,497.4	4,769.2	4,961.3	4,871.6	4,139.8	4,060.4	28,299.7

Interface Pricing

Table 4-7 Active interfaces: January through June 2009 (See 2008 SOM, Table 4-7)

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

Figure 4-4 PJM's footprint and its external interfaces (See 2008 SOM, Figure 4-4)

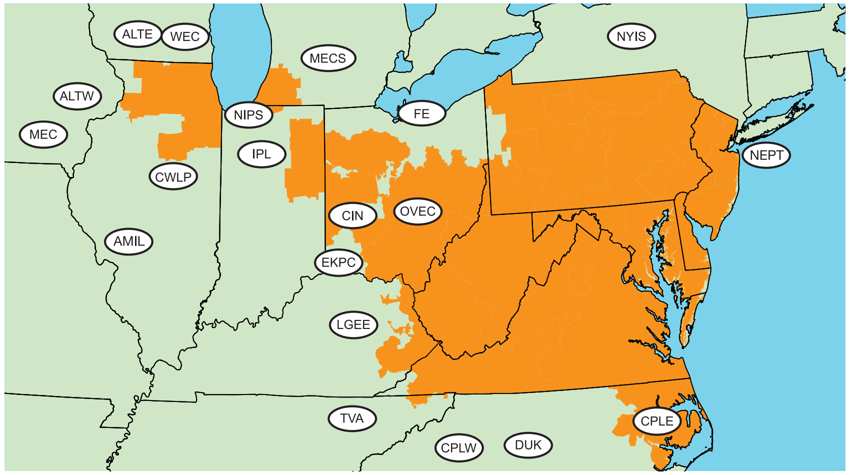


Table 4-8 Active pricing points: January through June 2009 (See 2008 SOM, Table 4-8)

PJM 2009 (Jan - Jun) Pricing Points				
MICHFE	MISO	NEPT	NIPSCO	Northwest
NYIS	Ontario IESO	OVEC	SOUTHEXP	SOUTHIMP

Interactions with Bordering Areas

PJM and Midwest ISO Interface Prices

Figure 4-5 Real-time daily hourly average price difference (Midwest ISO Interface minus PJM/MISO): January through June 2009 (See 2008 SOM, Figure 4-5)

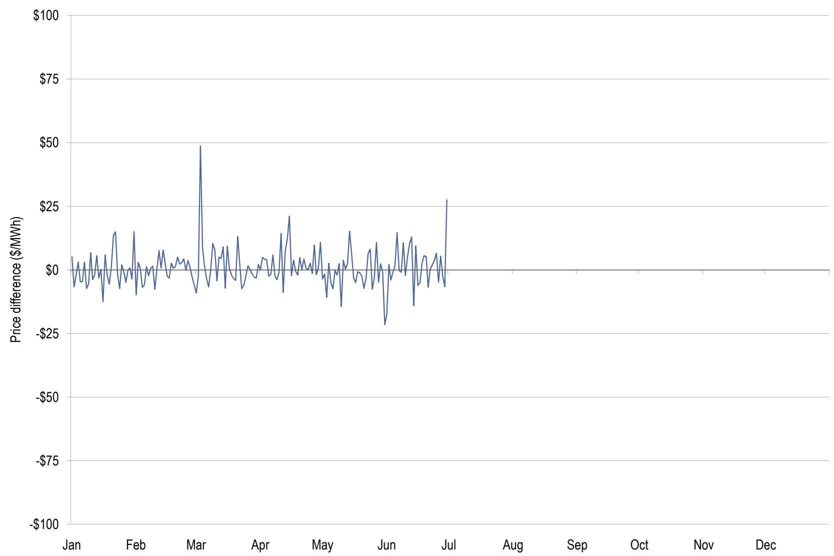


Figure 4-6 Real-time monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 through June 2009 (See 2008 SOM, Figure 4-6)

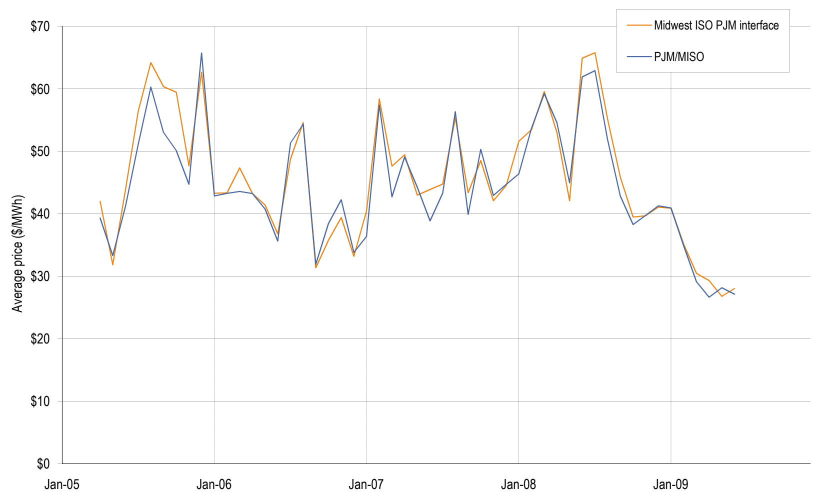


Table 4-9 Average real-time LMP difference (PJM minus Midwest ISO): January 1, 2006, through June 30, 2009 (See 2008 SOM, Table 4-9)

	2006	2007 (Pre-Marginal Losses)	2007 (Post-Marginal Losses)	2008	2009 (Jan - Jun)
Kincaid (PJM) & Coffeen (MISO)	$5.87	$4.31	$5.76	$8.26	$6.22
Beaver Valley (PJM) & Mansfield (MISO)	$2.28	($2.64)	$0.55	$0.89	$3.67
Miami Fort (PJM) & (MISO)	$1.95	($1.30)	($0.95)	$1.25	$2.60
Stuart (PJM) & (MISO)	$2.09	($0.81)	($0.64)	$0.85	$2.23
PJM/MISO Interface	($0.23)	($1.83)	($0.85)	($0.76)	($0.61)

Figure 4-7 Day-ahead daily hourly average price difference (Midwest ISO interface minus PJM/MISO): January through June 2009 (New Figure)

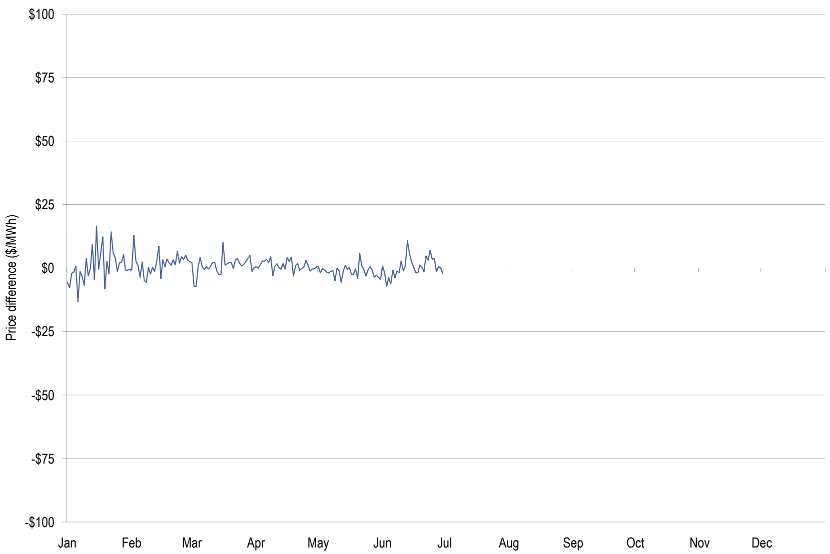


Figure 4-8 Day-ahead monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 through June 2009 (New Figure)

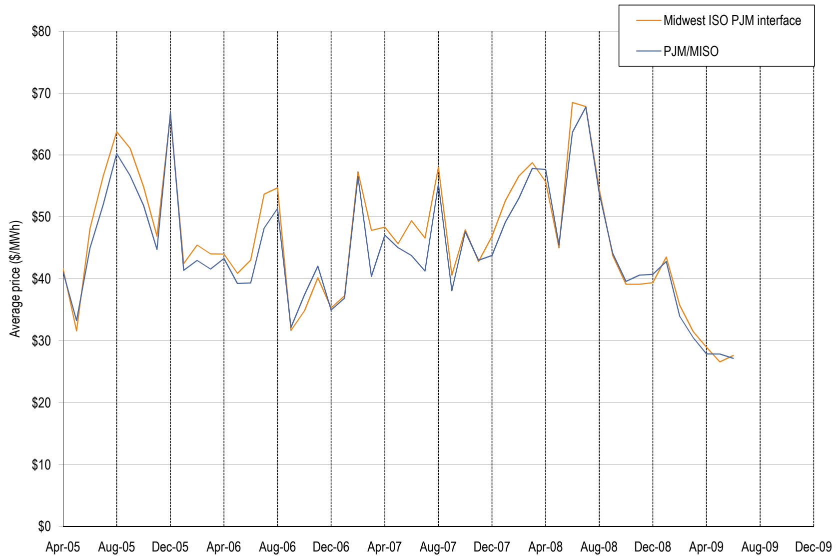


Table 4-10 Average day-ahead LMP difference (PJM minus Midwest ISO): January through June 2009 (New Table)

	2009 (Jan - Jun)
Kincaid (PJM) & Coffeen (MISO)	$5.59
Beaver Valley (PJM) & Mansfield (MISO)	$2.48
Miami Fort (PJM) & (MISO)	$2.36
Stuart (PJM) & (MISO)	$1.93
PJM/MISO Interface	($0.60)

PJM and NYISO Interface Prices

Figure 4-9 Real-time daily hourly average price difference (NY proxy - PJM/NYIS): January through June 2009 (See 2008 SOM, Figure 4-7)

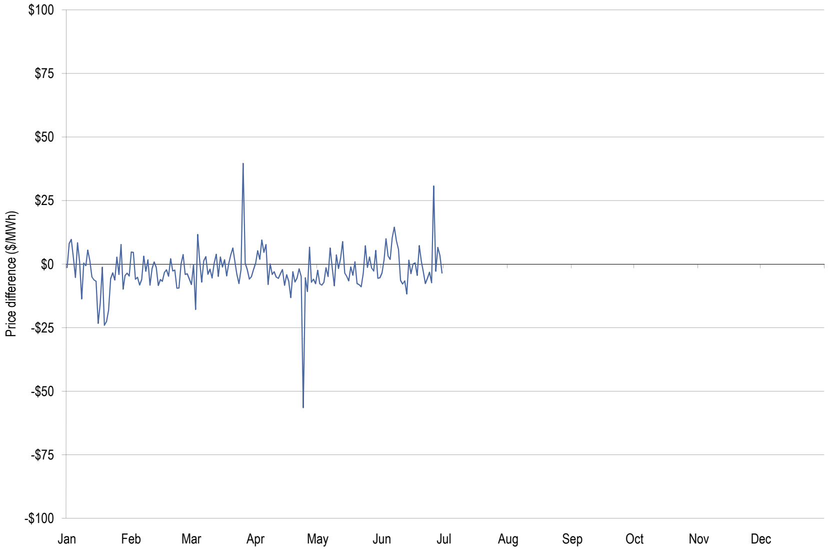


Figure 4-10 Real-time monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: January 2002 through June 2009 (See 2008 SOM, Figure 4-8)

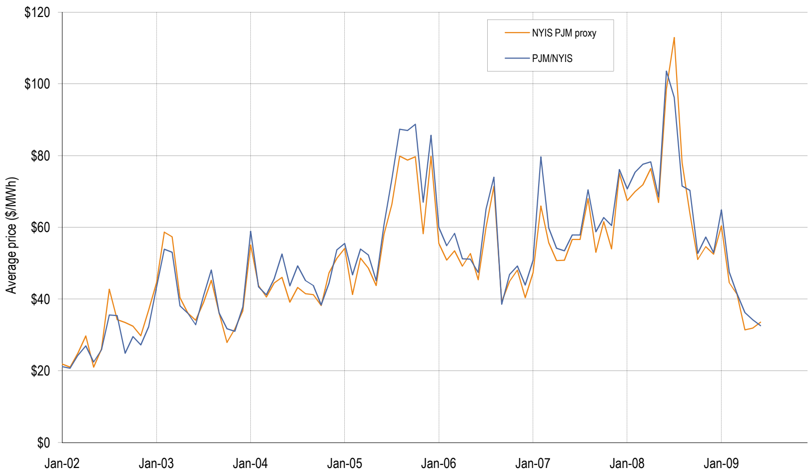
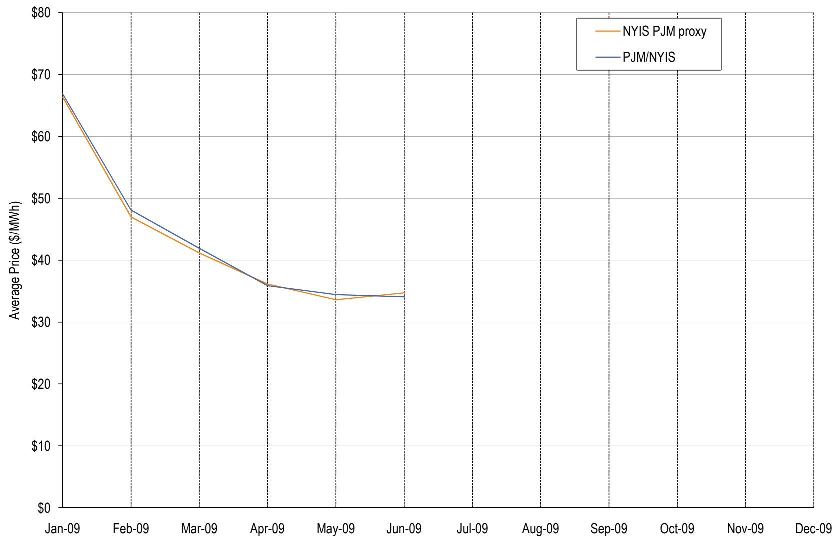


Figure 4-11 Day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): January through June 2009 (New Figure)

Figure 4-12 Day-ahead monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: January through June 2009 (New Figure)



Summary of Interface Prices between PJM and Organized Markets

Figure 4-13 PJM, NYISO and Midwest ISO real-time border price averages: January through June 2009 (See 2008 SOM, Figure 4-9)

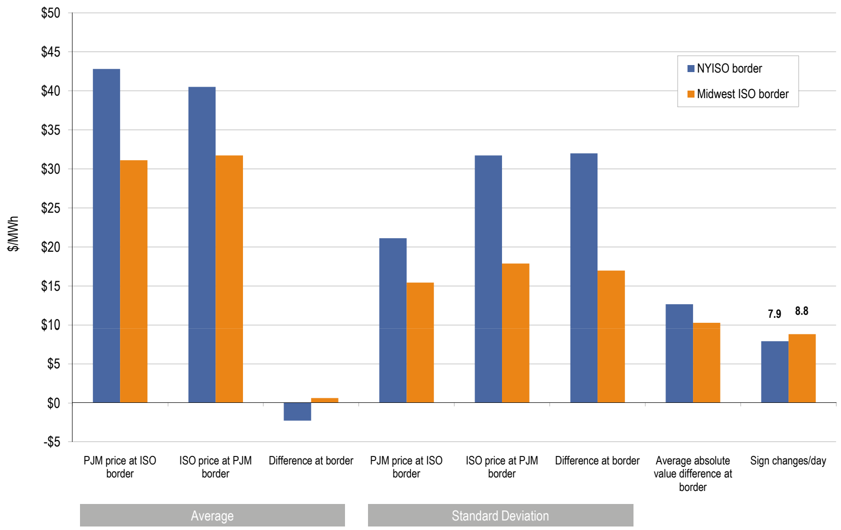
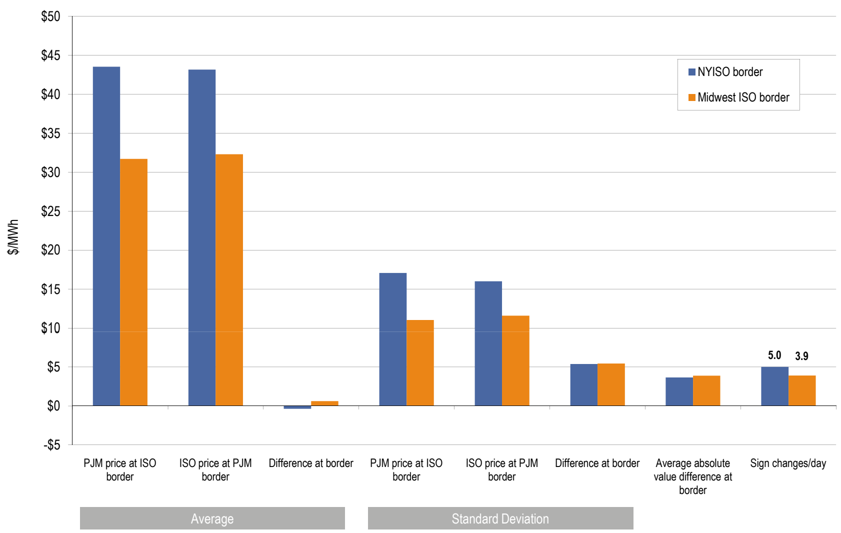


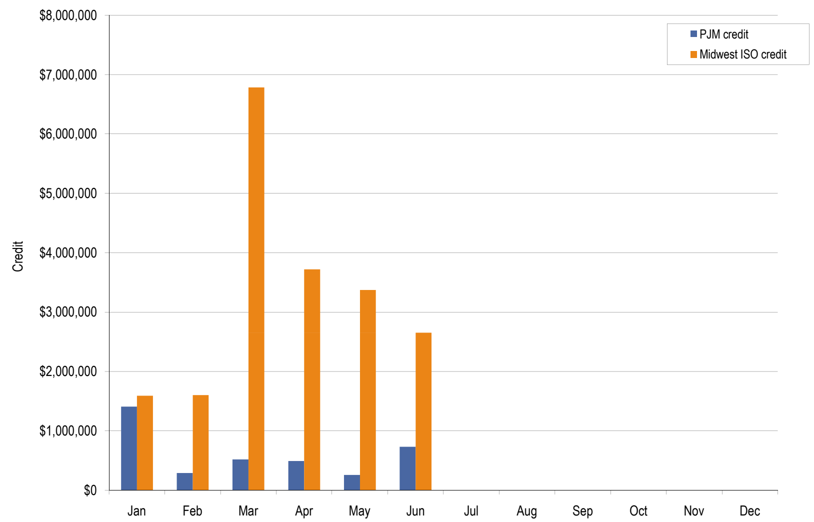
Figure 4-14 PJM, NYISO and Midwest ISO day-ahead border price averages: January through June 2009 (New Figure)



Operating Agreements with Bordering Areas

PJM and Midwest ISO Joint Operating Agreement (JOA)

Figure 4-15 Credits for coordinated congestion management: January through June 2009 (See 2008 SOM, Figure 4-10)



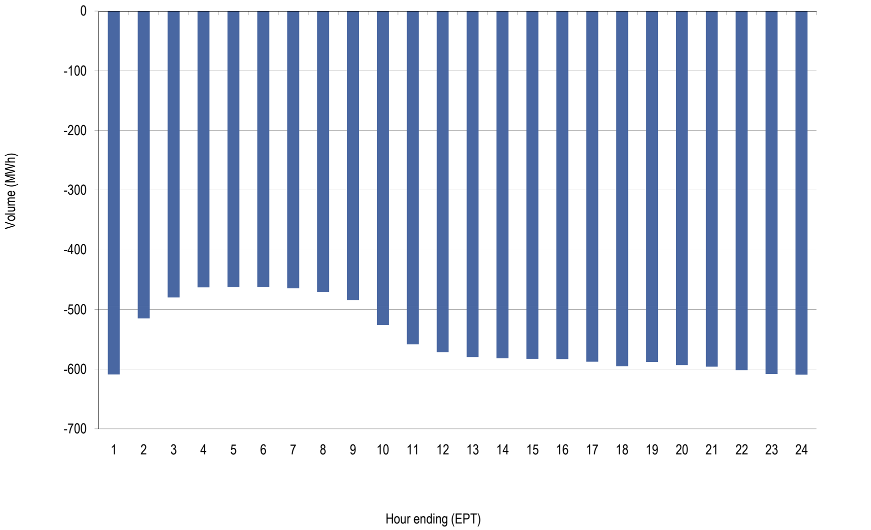
Con Edison and PSE&G Wheeling Contracts

Table 4-11 Con Edison and PSE&G wheeling settlement data: January through June 2009 (See 2008 SOM, Table 4-10)

	Con Edison			PSE&G		
	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Total Congestion Credit	$919,769	$1,900	$921,669	$2,962,871	$0	$2,962,871
Congestion Credit			$864,388			$2,978,822
Adjustments			$484,182			$11,879
Net Charge			($426,901)			($27,830)

Neptune Underwater Transmission Line to Long Island, New York

Figure 4-16 Neptune hourly average flow: January through June 2009 (See 2008 SOM, Figure 4-11)



Interface Pricing Agreements with Individual Companies

Table 4-12 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January 2009 (See 2008 SOM, Table 4-11)

	LMP	SOUTHIMP	SOUTHEXP	Difference LMP - SOUTHIMP	Difference LMP - SOUTHEXP
Duke	$50.58	$47.29	$47.29	$3.29	$3.29
PEC	$52.21	$47.29	$47.29	$4.93	$4.93
NCMPA	$50.66	$47.29	$47.29	$3.37	$3.37

Table 4-13 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: May 3, 2009 through June 2009 (See 2008 SOM, Table 4-11)

	IMPORT LMP	EXPORT LMP	SOUTH-IMP	SOUTH-EXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$31.58	$31.98	$30.92	$30.92	$0.66	$1.06
PEC	$31.94	$33.12	$30.92	$30.92	$1.02	$2.20
NCMPA	$31.79	$31.85	$30.92	$30.92	$0.87	$0.93

Figure 4-17 Real-time interchange volume vs. average hourly LMP available for Duke and PEC imports: January through June 2009 (New Figure)

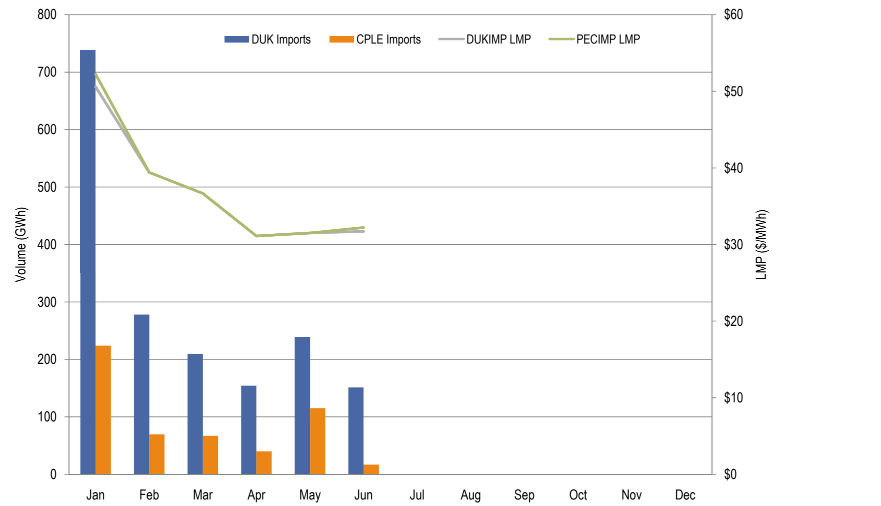


Figure 4-18 Real-time interchange volume vs. average hourly LMP available for Duke and PEC exports: January through June 2009 (New Figure)

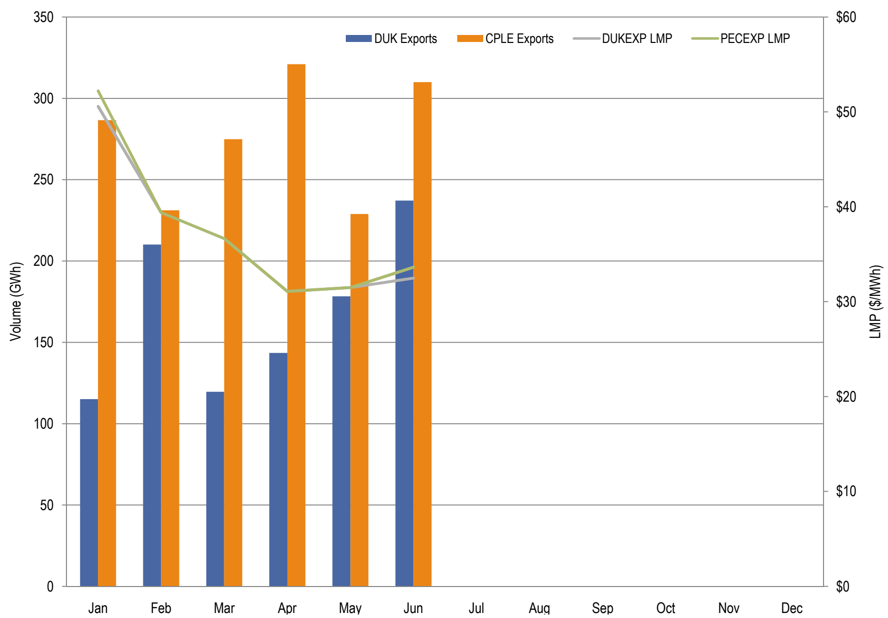


Table 4-14 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January 2009 (New Table)

	LMP	SOUTHIMP	SOUTHEXP	Difference LMP - SOUTHIMP	Difference LMP - SOUTHEXP
Duke	$52.01	$48.59	$48.59	$3.42	$3.42
PEC	$54.41	$48.59	$48.59	$5.82	$5.82
NCMPA	$52.10	$48.59	$48.59	$3.51	$3.51

Table 4-15 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: May 3, 2009 through June 2009 (New Table)

	IMPORT LMP	EXPORT LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$31.69	$32.49	$31.37	$31.37	$0.32	$1.12
PEC	$32.19	$33.64	$31.37	$31.37	$0.82	$2.27
NCMPA	$32.06	$32.13	$31.37	$31.37	$0.69	$0.76

Figure 4-19 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC imports: January through June 2009 (New Figure)

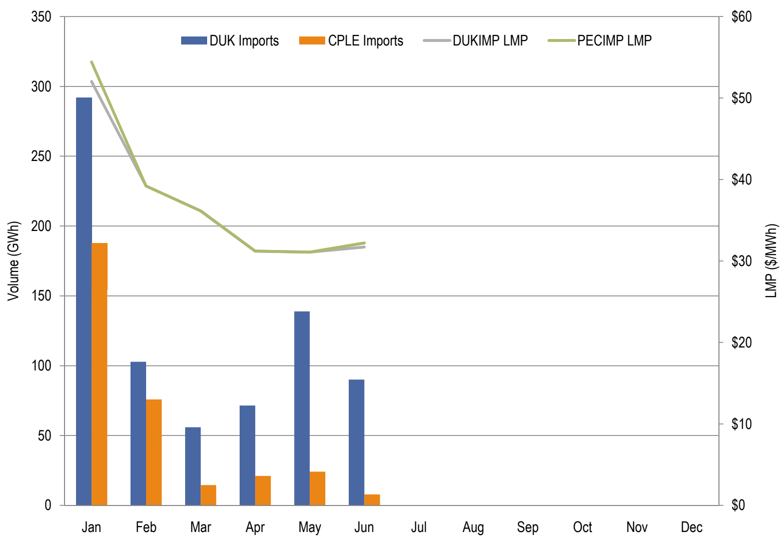
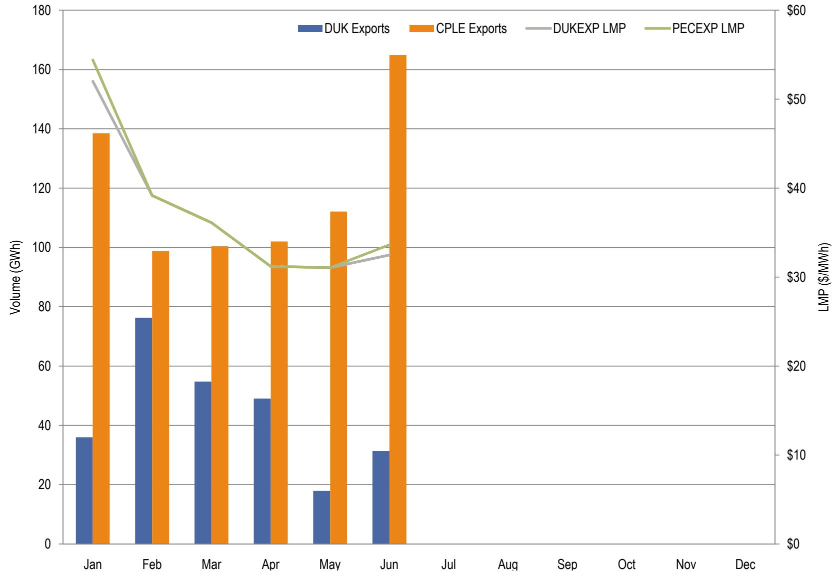


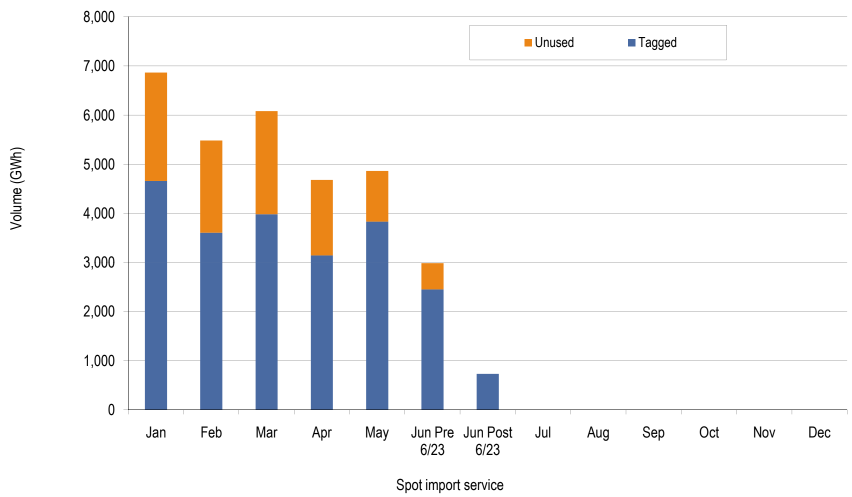
Figure 4-20 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC exports: January through June 2009 (New Figure)



Interchange Transaction Issues

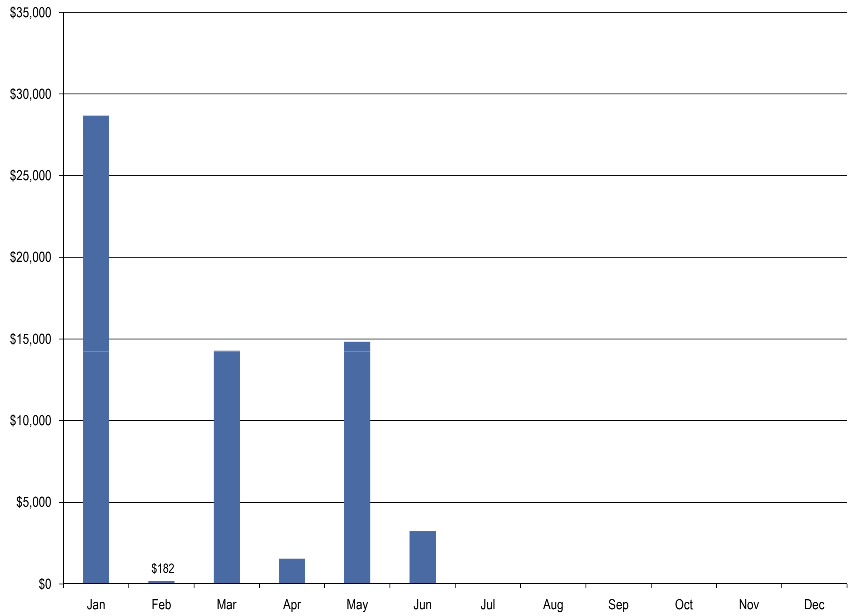
Spot Import

Figure 4-21 Spot import service utilization: January through June 2009 (See 2008 SOM, Figure 4-12)



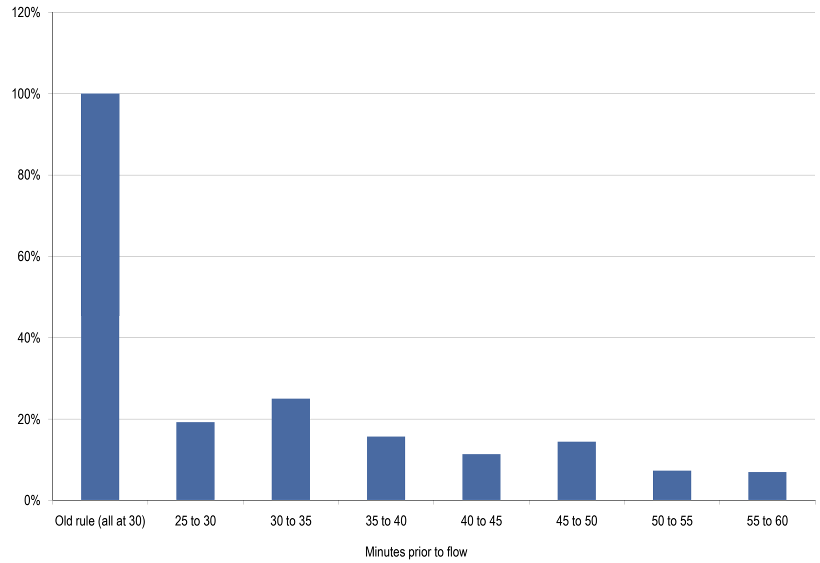
Willing to Pay Congestion and Not Willing to Pay Congestion

Figure 4-22 Monthly uncollected congestion charges: January through June 2009 (See 2008 SOM, Figure 4-13)



Ramp Availability

Figure 4-23 Distribution of expired ramp reservations in the hour prior to flow (Old rules (Theoretical) and new rules (Actual)) October 2006 through June 2009 (See 2008 SOM, Figure 4-14)



Curtailment of Transactions

TLRs

Figure 4-24 PJM and Midwest ISO TLR procedures: Calendar year 2008 and January through June 2009 (See 2008 SOM, Figure 4-15)

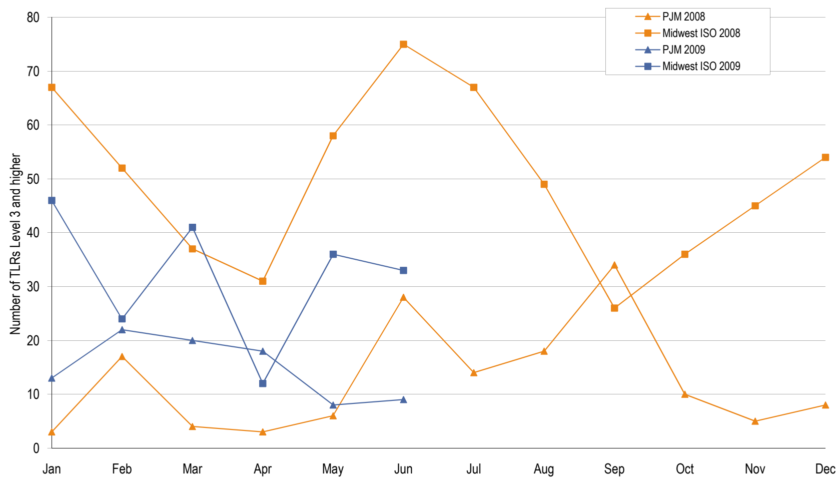


Figure 4-25 Number of different PJM flowgates that experienced TLRs: Calendar year 2008 and January through June 2009 (See 2008 SOM, Figure 4-16)

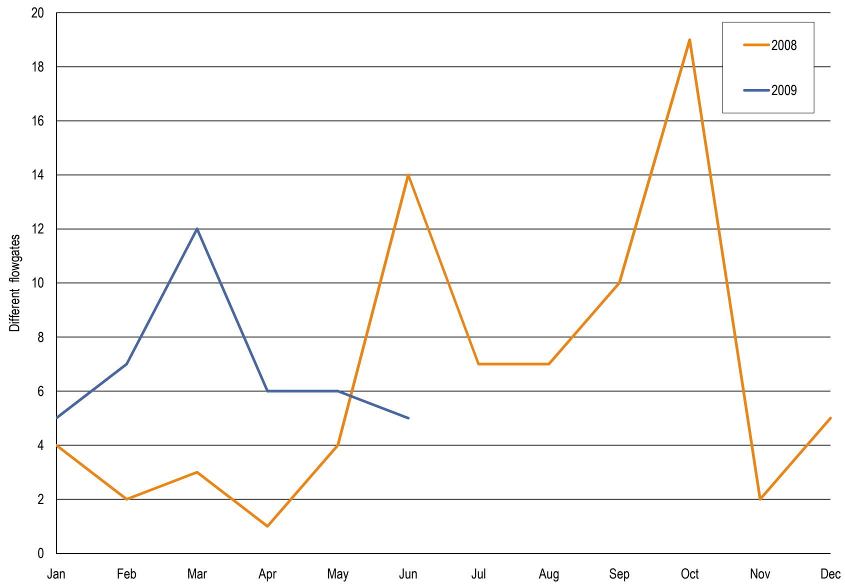
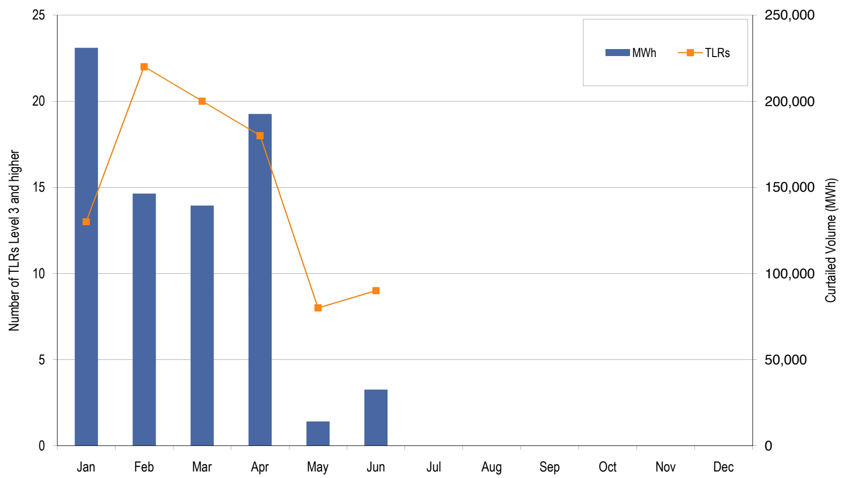
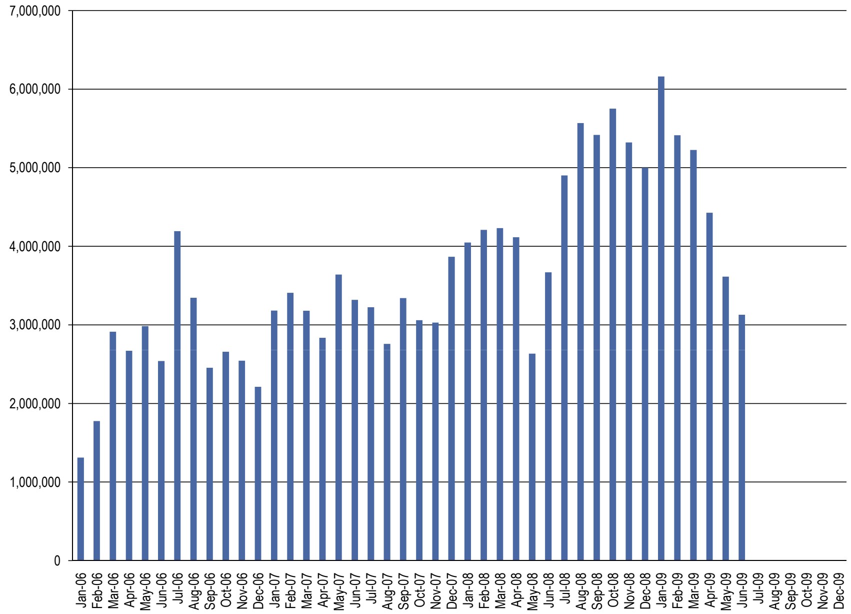


Figure 4-26 Number of PJM TLRs and curtailed volume: January through June 2009 (See 2008 SOM, Figure 4-17)



Up-To Congestion

Figure 4-27 Monthly up-to congestion bids in MWh: January 2006 through June 2009[14] (See 2008 SOM, Figure 4-18)



14 Prior MMU presentations to the Members Committee overstated the volume of up-to congestion bids.

Loop Flows

Table 4-16 Net scheduled and actual PJM interface flows (GWh): January through June 2009 (See 2008 SOM, Table 4-12)

Net scheduled and actual PJM interface flows: JAN - JUN 2009	Actual	Net Scheduled	Difference (GMh)	Difference (percent of net scheduled)
ALTE	(3,184)	(492)	(2,692)	547%
ALTW	(1,025)	(549)	(476)	87%
AMIL	4,830	106	4,724	4457%
CIN	1,027	(374)	1,401	(375%)
CPLE	3,882	(559)	4,441	(794%)
CPLW	(813)	(414)	(399)	96%
CWLP	(339)	-	(339)	0%
DUK	(994)	766	(1,760)	(230%)
EKPC	411	(341)	752	(221%)
FE	(999)	(1,463)	464	(32%)
IPL	1,165	(61)	1,226	(2010%)
LGEE	708	708	-	0%
MEC	(910)	369	(1,279)	(347%)
MECS	(5,426)	2,137	(7,563)	(354%)
NEPT	(2,385)	(2,385)	-	0%
NIPS	(1,332)	(197)	(1,135)	576%
NYIS	(1,000)	(1,904)	904	(47%)
OVEC	4,109	6,162	(2,053)	(33%)
TVA	2,312	485	1,827	377%
WEC	1,603	(302)	1,905	(631%)
YTD Total	1,640	1,692	(52)	(3.1%)

Loop Flows at the PJM/MECS and PJM/TVA Interfaces

Figure 4-28 PJM/MECS Interface average actual minus scheduled volume: January through June 2009 (See 2008 SOM, Figure 4-19)

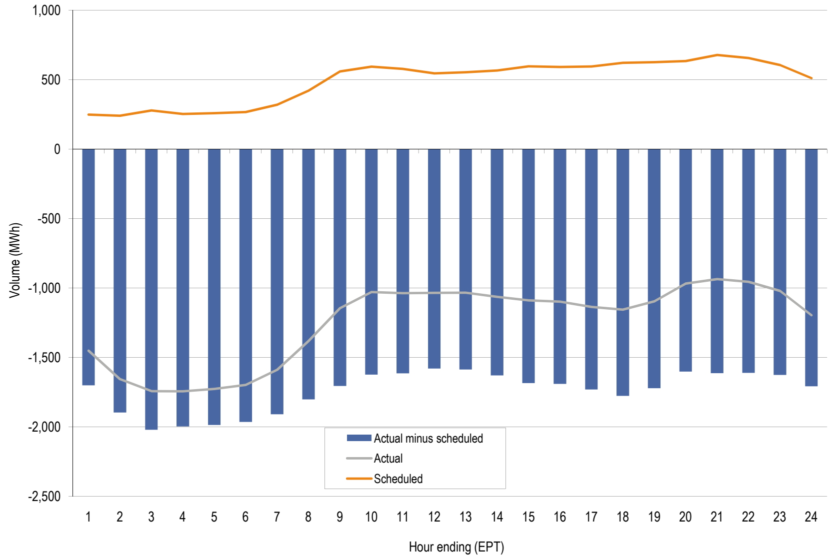


Figure 4-29 PJM/TVA average flows: January 1, through September 30, 2006, pre-consolidation (See 2008 SOM, Figure 4-20)

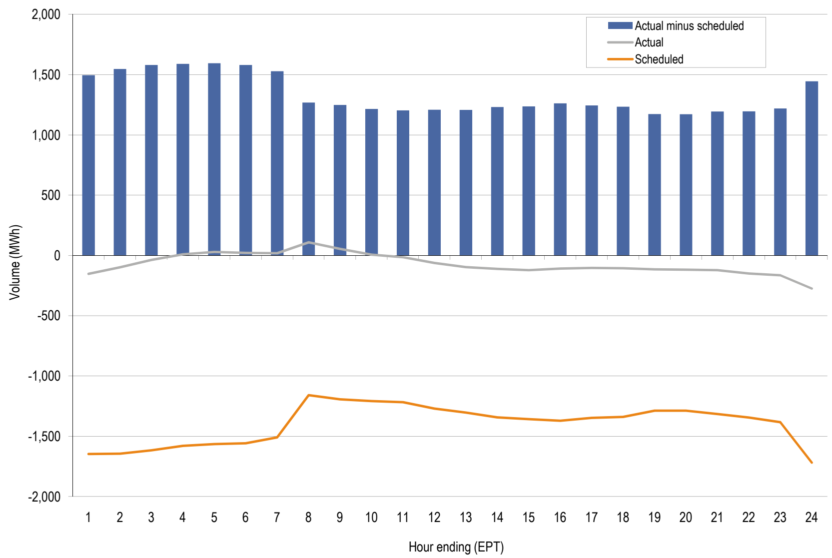


Figure 4-30 PJM/TVA average flows: January through June 2009 (See 2008 SOM, Figure 4-21)

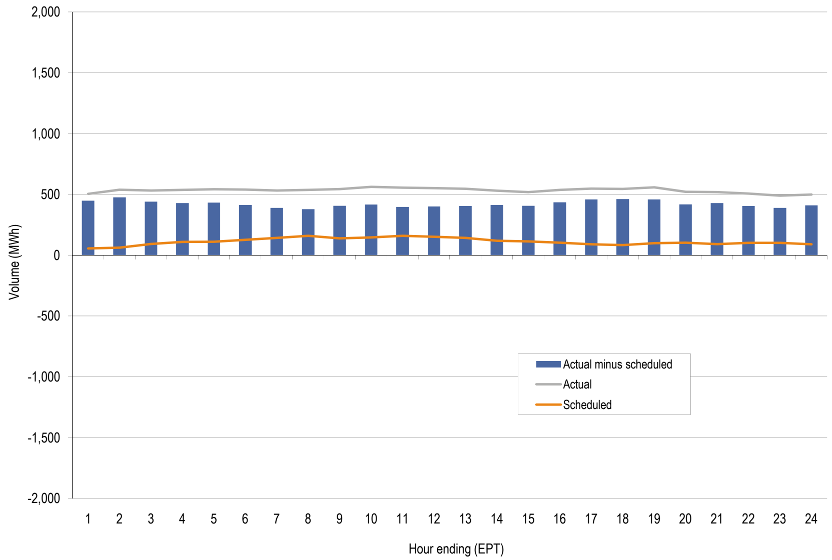
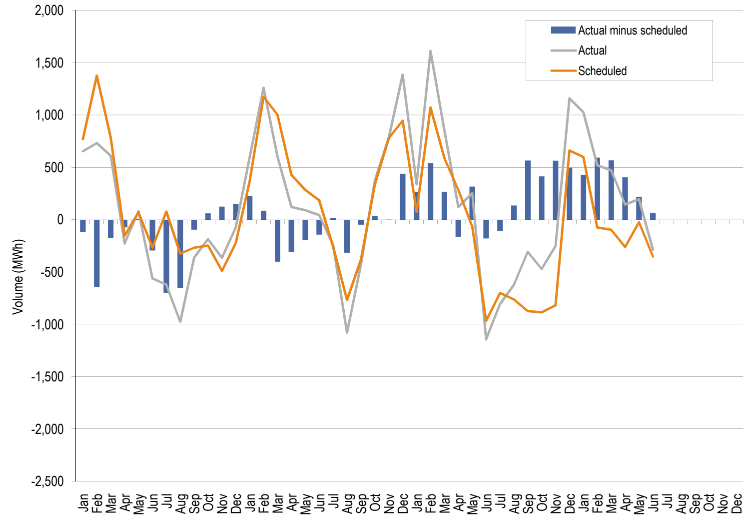
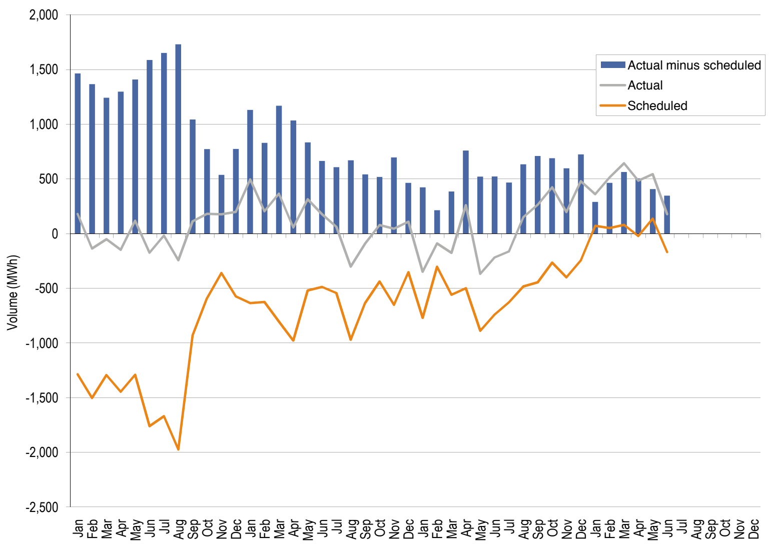


Figure 4-32 Southeast actual and scheduled flows: January 2006 through June 2009 (See 2008 SOM, Figure 4-23)



Loop Flows at PJM's Southern Interfaces

Figure 4-31 Southwest actual and scheduled flows: January 2006 through June 2009 (See 2008 SOM, Figure 4-22)



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 developing demand-side resources and offering them into the capacity market, or constructing transmission upgrades and offering them into the capacity market.

Overview

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market for the first six months of 2009, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.

RPM Capacity Market

Market Design

On June 1, 2007, the RPM Capacity Market design was implemented in the PJM region, replacing the CCM Capacity Market design that had been in place since 1999.[1] The RPM design represents a significant change in the structure of the Capacity Market in PJM. 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 the 2012/2013 delivery year, First, Second and Third Incremental RPM Auctions are held for each delivery year, occurring 23, 13 and four months, respectively, prior to the delivery year.[2] Prior to the 2012/2013 delivery year, the second incremental auction is conducted when there is an increase in the region's unforced capacity obligations as a result of a load forecast increase. Also effective for the 2012/2013 delivery year, a conditional incremental auction may be held to address significant unexpected changes that occur after the BRA, such as a delay in planned large transmission upgrades that results in the need for procurement of additional capacity. RPM prices are locational and may vary depending on transmission constraints.[3] Existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for the fixed resource requirement (FRR) option. Under RPM, participation by LSEs is mandatory, except for 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. Under RPM there are performance incentives for generation. 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 do not limit prices offered by new entrants. Demand-side resources may be offered directly into RPM auctions and receive the clearing price.

Market Structure

- **Supply.** Total internal capacity increased 350.2 MW from 156,968.0 MW on June 1, 2008, to 157,318.2 MW on June 1, 2009.[4] This increase was the result of 439.2 MW of new generation, 74.1 MW from generation uprates, 220.6 MW from demand resource (DR) mods, offset in part by 383.7 MW from higher EFORds.

  In the 2010/2011, 2011/2012, and 2012/2013 auctions, new generation increased 3,271.9 MW; 651.9 MW came out of retirement and net generation deratings were 2,994.9 MW, for a total of 928.9 MW. DR and Energy Efficiency (EE) offers increased 9,409.3 MW through June 1, 2012 offset in part by 890.3 MW from higher EFORds. The reclassification of the Duquesne resources as internal added 3,817.2 MW to total internal capacity. The net effect from June 1, 2009, through June 1, 2012, was an increase in total internal capacity of 12,635.1 MW (8.0 percent) from 157,318.2 MW to 169,953.3 MW.

1 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2009 Quarterly State of the Market Report for PJM: January through June*, Section 5, "Capacity Market" and include all capacity within the PJM footprint.
2 126 FERC ¶ 61,275 (2009).
3 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.
4 Unless otherwise specified, all volumes are in terms of UCAP.

In the 2009/2010 auction, 17 more generating resources made offers than in the 2008/2009 RPM Auction. The increase included eight new combustion turbine (CT) resources (380.2 MW), two new diesel resources (9.2 MW) and one new steam resource (49.8 MW) while the remaining six resources included more resources imported, fewer resources exported, a decrease in resources excused from offering into the auction and fewer resources removed from the auction under the fixed resource requirement (FRR) option.

In the 2010/2011 auction, 11 more generating resources made offers than in the 2009/2010 RPM auction. The net increase of 11 resources consisted of 15 new resources, four reactivated resources and three resources from the FRR participant, offset by three retired resources, four deactivated resources, three resources exported from PJM and one resource excused from offering. There were seven new CT resources (270.5 MW), three new diesel resources (16.4 MW), five new wind resources (120.0 MW) and four reactivated resources (165.0 MW) for a total of 19 resources. There were three resources that retired (358.3 MW), four resources that were deactivated (52.9 MW) and an additional three resources exported out of PJM (521.5 MW) for a total of 10 resources.

In the 2011/2012 auction, 21 more generating resources made offers than in the 2010/2011 RPM auction. The net increase of 21 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 FRR resources (64.2 MW) and two retired resources (85.8 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).

In the 2012/2013 auction, eight more generating 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).[5] 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 units 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).

- **Demand.** There was a 2,545.5 MW increase in the RPM reliability requirement from 150,934.6 MW on June 1, 2008 to 153,480.1 MW on June 1, 2009. On June 1, 2009, PJM EDCs and their affiliates maintained a 79.3 percent market share of load obligations under RPM, down from 80.1 percent on June 1, 2008.

- **Market Concentration.** For the 2009/2010, 2010/2011, 2011/2012, and 2012/2013 RPM Auctions, all defined markets failed the preliminary market structure screen (PMSS). In the 2009/2010 BRA, 2009/2010 Third IA, 2010/2011 BRA, 2011/2012 BRA, and 2011/2012 First IA 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 test. The result was that offer caps were applied to all sell offers that did not pass the test.

- **Imports and Exports.** Net exchange increased 1,688.3 MW from June 1, 2008 to June 1, 2009. Net exchange, which is imports less exports, increased due to an increase in imports of 45.1 MW and a decrease in exports of 1,643.2 MW.

- **Demand-Side Resources.** Under RPM, demand-side resources in the Capacity Market increased by 3,206.9 MW from 4,167.5 MW on June 1, 2008 to 7,374.4 MW on June 1, 2009. Prior to the 2012/2013 delivery year, demand-side resources included DR cleared in the RPM Auctions and certified/forecast interruptible load for reliability (ILR). For delivery years 2012/2013 and beyond, ILR was eliminated and demand-side resources include DR and Energy Efficiency (EE) resources.

5 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.

- **Net Excess.** Net excess increased 3,254.4 MW from 5,011.1 MW on June 1, 2008 to 8,265.5 MW on June 1, 2009.

Market Conduct

- **2009/2010 RPM Base Residual Auction.** Of the 1,093 generating resources which submitted offers, unit-specific offer caps were calculated for 151 resources (13.8 percent). Offer caps of all kinds were calculated for 550 resources (50.3 percent), of which 377 were based on the technology specific default (proxy) ACR posted by the MMU.

- **2009/2010 Third Incremental Auction.** Of the 267 generating resources which submitted offers, 255 resources chose the offer cap option of 1.1 times the BRA clearing price (95.5 percent).[6] Unit-specific offer caps were calculated for two resources (0.7 percent). Offer caps of all kinds were calculated for five resources (1.9 percent), of which one was based on the technology specific default (proxy) ACR posted by the MMU.

- **2010/2011 RPM Base Residual Auction.** Of the 1,104 generating 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 posted by the MMU.

- **2011/2012 RPM Base Residual Auction.** Of the 1,125 generating resources which submitted offers, unit-specific offer caps were calculated for 145 resources (12.9 percent). Offer caps of all kinds were calculated for 472 resources (42.0 percent), of which 303 were based on the technology specific default (proxy) ACR posted by the MMU.

- **2011/2012 RPM First Incremental Auction.** Of the 129 generating resources which submitted offers, unit-specific offer caps were calculated for 19 resources (14.8 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 posted by the MMU.

6 124 FERC ¶ 61,140 (2008).

- **2012/2013 RPM Base Residual Auction.**[7] Of the 1,133 generating 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 posted by the MMU.

Market Performance

2009/2010 RPM Base Residual Auction

- **RTO.** Total internal RTO unforced capacity of 157,318.2 MW includes all generating units and DR that qualified as a PJM capacity resource for the 2009/2010 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 136,300.4 MW. The 132,231.8 MW of cleared resources for the entire RTO represented a reserve margin of 17.8 percent, which was 1,784.0 MW greater than the reliability requirement of 130,447.8 MW (installed reserve margin (IRM) of 15.0 percent) and resulted in a clearing price of $102.04 per MW-day.

  Total cleared resources in the RTO were 132,231.8 MW which resulted in a net excess of 8,265.5 MW, an increase of 3,254.4 MW from the net excess of 5,011.1 MW in the 2008/2009 RPM Base Residual Auction. Certified interruptible load for reliability (ILR) was 6,481.5 MW.

  Cleared resources across the entire RTO will receive a total of $7.5 billion based on the unforced MW cleared and the prices in the 2009/2010 RPM BRA, an increase of approximately $1.4 billion from the 2008/2009 planning year.

- **MAAC+APS.**[8] Total internal MAAC+APS unforced capacity of 73,021.9 MW includes all generating units and DR that qualified as a PJM capacity resource, excludes external units and reflects owners' modifications to ICAP ratings. Including imports into MAAC+APS, RPM unforced capacity was 73,102.2 MW.[9] Of the 5,764.9 MW of incremental supply, 5,314.7 MW cleared, which resulted in a resource-clearing price of $191.32 per MW-day.

7 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>

8 EMAAC was an acronym for Eastern Mid-Atlantic Area Council and SWMAAC was an acronym for Southwestern Mid-Atlantic Area Council. MAAC no longer exists as its role was taken on by Reliabilty*First* Corporation. EMAAC and SWMAAC are now regions of PJM.

9 Rules for RPM auctions state that imports are modeled in the unconstrained region of the RTO. See PJM. "Manual 18: PJM Capacity Market," Revision 6 (Effective June 18, 2009), p. 31, <http://www.pjm.com/documents/~/media/documents/manuals/m18.ashx> (1.25 MB). The import MW into MAAC+APS consist of MW under a grandfathered agreement related to Rural Electric Cooperatives (RECs) generation.

Total resources in MAAC+APS were 77,488.7 MW, which when combined with certified ILR of 3,081.0 MW resulted in a net excess of 2,666.8 MW (3.4 percent) greater than the reliability requirement of 77,902.9 MW.

- **SWMAAC.** Total internal SWMAAC unforced capacity of 10,345.2 MW includes all generating units and DR that qualified as a PJM capacity resource, excludes external units and reflects owners' modifications to ICAP ratings. There were no imports from outside PJM into SWMAAC. Of the 2,413.7 MW of incremental supply, 2,016.6 cleared, which resulted in a resource-clearing price of $237.33 per MW-day.

  Total resources in SWMAAC were 16,305.6 MW, which when combined with certified ILR of 519.3 MW resulted in a net excess of 506.1 MW (3.1 percent) greater than the reliability requirement of 16,318.8 MW.

2009/2010 RPM Third Incremental Auction

- **RTO.** There were 3,255.8 MW offered into the Third Incremental Auction while buy bids totaled 2,697.6 MW. Cleared volumes in the RTO were 1,798.4 MW, resulting in an RTO clearing price of $40.00 per MW-day. The 1,457.4 MW of uncleared volumes can be used as replacement capacity or traded bilaterally.

  Cleared resources across the entire RTO will receive a total of $47.7 million based on the unforced MW cleared and the prices in the 2009/2010 RPM Third Incremental Auction.

- **MAAC+APS.** In MAAC+APS, 2,142.3 MW were offered into the auction while buy bids in MAAC+APS totaled 1,953.2 MW. Cleared volumes in MAAC+APS were 1,275.3 MW, resulting in a MAAC+APS clearing price of $86.00 per MW-day. The 867.0 MW of uncleared volumes can be used as replacement capacity or traded bilaterally.

- **SWMAAC.** Although SWMAAC was a constrained LDA in the 2009/2010 BRA, supply and demand curves resulted in a price less than the MAAC+APS clearing price. Supply offers in the incremental auction in SWMAAC (985.1 MW) exceeded SWMAAC demand bids (135.5 MW). The result was that all of SWMAAC supply which cleared received the MAAC+APS clearing price.

Generator Performance

- **Forced Outage Rates.** PJM EFORd increased from 7.4 percent in 2008 to 8.2 percent in 2009 (January through May). The increase in EFORd from 2008 to 2009 was the result of increased forced outage rates for combustion turbine, combined cycle, and nuclear units. PJM EFORp decreased slightly from 4.9 percent in 2008 to 4.8 percent in 2009 (January through May).[10] The forced outage rates are for the entire PJM footprint.

- **Outages Outside of Management Control (OMC).** PJM permits units to use a forced outage rate (XEFORd) for purposes of selling unforced capacity in the Capacity Market, calculated excluding outages that are designated outside management control. Use of different forced outage metrics for defining reliability targets and for determining available capacity to meet those reliability targets introduces an inconsistency. For example, the EFORd for CTs is 12.6 percent, while the XEFORd for CTs is 10.5 percent. Using artificially reduced outage rates for determining unforced capacity that can be sold in RPM auctions will result in the sale of capacity that is not actually available. A forced outage is a forced outage, from the perspective of system reliability, regardless of the cause.

Conclusion

Market Design

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.

10 2008 data are for the 12 months ended December 31, 2008, as downloaded from the PJM GADS database on January 23, 2009. 2009 data are for the 5 months ending May 31, 2009, as downloaded from the PJM GADS database on July 14, 2009. 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.

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.

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, 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.

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 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; and the obligation that the energy output from the resource be deliverable to load in PJM.

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 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.

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 hours defined as critical, it will receive no energy revenues for those hours. If a unit defined as a capacity resource does not produce energy 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 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 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. 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 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.

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.

The MMU found serious market structure issues, but no exercise of market power in the PJM Capacity Market during the first six months of 2009. 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 during the first six months of 2009.

RPM Capacity Market

Table 5-1 Internal capacity: June 1, 2008, through May 31, 2012[11, 12] (See 2008 SOM, Table 5-1)

	UCAP (MW)						
	RTO	MAAC+APS	MAAC	EMAAC	SWMAAC	DPL-South	PSEG-North
Total internal capacity @ 01-Jun-08	156,968.0	72,889.5			10,777.1		
New generation	439.2	109.9			0.0		
Units out of retirement	0.0	0.0			0.0		
Generation capmods	74.1	(149.7)			(298.2)		
DR mods	220.6	163.2			42.3		
Net EFORd effect	(383.7)	0.0			(176.0)		
Total internal capacity @ 01-Jun-09	157,318.2	73,012.9			10,345.2	1,587.0	
New generation	406.9					0.0	
Units out of retirement	165.0					0.0	
Generation capmods	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	
New generation	2,203.7						
Units out of retirement	486.9						
Generation capmods	(2,567.6)						
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	3,187.2		0.0	0.0		0.0	0.0
Adjusted internal capacity @ 01-Jun-11	163,069.9		66,329.7	32,733.0		1,460.3	4,167.5
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 capmods	(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

11 The RTO includes all LDAs. MAAC+APS and MAAC include EMAAC and SWMAAC. EMAAC includes DPL-South and PSEG-North. Maps of the LDAs can be found in the *2008 State of the Market Report for PJM*, Appendix A, "PJM Geography."
12 The UCAP MW value attributed to the reclassification of Duquesne units differs from the value reported in the *2008 State of the Market Report for PJM* as a result of generation cap mods, DR and EE mods, and EFORd changes.

Demand

Table 5-2 PJM Capacity Market load obligation served: June 1, 2009 (See 2008 SOM, Table 5-2)

	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	68,626.9	11,774.2	25,831.0	1,033.8	10,416.7	509.1	15,695.3	133,887.0
Percent of total obligation	51.2%	8.8%	19.3%	0.8%	7.8%	0.4%	11.7%	100.0%

Market Concentration

Preliminary Market Structure Screen

Table 5-3 Preliminary market structure screen results: 2008/2009 through 2012/2013 RPM Auctions (See 2008 SOM, Table 5-3)

RPM Markets	Highest Market Share	HHI	Pivotal Suppliers	Pass/Fail
2008/2009				
RTO	18.5%	879	1	Fail
EMAAC	33.1%	2180	1	Fail
SWMAAC	47.5%	4290	1	Fail
2009/2010				
RTO	18.4%	853	1	Fail
SWMAAC	51.1%	4229	1	Fail
MAAC+APS	26.9%	1627	1	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

Auction Market Structure

Table 5-4 RSI results: 2008/2009 through 2012/2013 RPM Auctions (See 2008 SOM, Table 5-4)

RPM Markets	RSI_3	Total Participants	Failed RSI_3 Participants
2008/2009 BRA			
RTO	0.61	65	65
EMAAC	0.25	10	10
SWMAAC	0.00	3	3
2008/2009 Third IA			
RTO/EMAAC	0.87	40	22
SWMAAC	0.00	3	3
2009/2010 BRA			
RTO	0.60	66	66
MAAC+APS	0.37	21	21
SWMAAC	0.00	3	3
2009/2010 Third IA			
RTO	0.64	40	40
MAAC+APS	0.14	8	8
2010/2011 BRA			
RTO	0.60	68	68
DPL-South	0.00	2	2
2011/2012 BRA			
RTO	0.63	76	76
2011/2012 First IA			
RTO	0.62	30	30
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

Imports and Exports

Table 5-5 PJM capacity summary (MW): June 1, 2008, through May 31, 2012[13, 14] (See 2008 SOM, Table 5-5)

	01-Jun-08	01-Jun-09	01-Jun-10	01-Jun-11	01-Jun-12
Installed capacity (ICAP)	164,444.1	166,916.0	168,061.5	172,666.6	181,159.7
Unforced capacity	155,590.2	157,628.7	158,634.2	163,144.3	171,147.8
Cleared capacity	129,597.6	132,231.8	132,190.4	132,221.5	136,143.5
RPM reliability requirement (pre-FRR)	150,934.6	153,480.1	156,636.8	154,251.1	157,488.5
RPM reliability requirement (less FRR)	128,194.6	130,447.8	132,698.8	130,658.7	133,732.4
RPM net excess	5,011.1	8,265.5	1,149.2	3,156.6	5,754.4
Imports	2,460.3	2,505.4	2,750.7	6,420.0	3,831.6
Exports	(3,838.1)	(2,194.9)	(3,147.4)	(3,158.4)	(2,637.1)
Net exchange	(1,377.8)	310.5	(396.7)	3,261.6	1,194.5
DR cleared	536.2	892.9	939.0	1,364.9	7,047.2
EE cleared					568.9
ILR	3,608.1	6,481.5	2,110.5	1,593.8	
FRR DR	452.8	423.6	452.9	452.9	488.1
Short-Term Resource Procurement Target					3,343.3

13 FRR DR values have been revised since the *2008 State of the Market Report for PJM* was posted.

14 Prior to the 2012/2013 delivery year, net excess under RPM was calculated as cleared capacity less the reliability requirement plus ILR. For 2008/2009 and 2009/2010, certified ILR was used in the calculation. For 2010/2011, forecast ILR less FRR DR is used in the calculation because PJM forecast ILR including FRR DR for the first four base residual auctions. FRR DR is not subtracted in the calculation for the 2011/2012 auction, because PJM forecast ILR excluding FRR DR for the 2011/2012 BRA. 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.

Demand-Side Resources

Table 5-6 RPM load management statistics: June 1, 2008 through May 31, 2012[15] (See 2008 SOM, Table 5-6)

	UCAP (MW)						
	RTO	MAAC+APS	MAAC	EMAAC	SWMAAC	DPL-South	PSEG-North
DR cleared	559.4			169.0	309.2		
ILR certified	3,608.1			622.6	219.7		
RPM load management @ 01-June-2008	4,167.5			791.6	528.9		
DR cleared	892.9	813.9			356.3		
ILR certified	6,481.5	1,055.7			345.7		
RPM load management @ 01-June-2009	7,374.4	1,869.6			702.0		
DR cleared	939.0					14.9	
ILR forecast - FRR DR	1,657.6					22.2	
RPM load management @ 01-June-2010	2,596.6					37.1	
DR cleared	1,364.9						
ILR forecast	1,593.8						
RPM load management @ 01-June-2011	2,958.7						
DR cleared	7,047.2		4,723.7	1,638.4		64.6	67.6
EE cleared	568.9		179.9	20.0		0.0	0.9
RPM load management @ 01-June-2012	7,616.1		4,903.6			64.6	68.5

15 PJM used forecast ILR, including FRR DR, for the first four base residual auctions. For 2008/2009 and 2009/2010, certified ILR data were used in the calculation here because the certified ILR data are now available. For 2010/2011, forecast ILR less FRR DR is used and will continue to be used until certified ILR data are available. PJM used forecast ILR, excluding FRR DR, for the 2011/2012 BRA. Therefore, FRR DR is not subtracted in the calculation here for the 2011/2012 auction. Effective the 2012/2013 delivery year, ILR was eliminated and the Energy Efficiency (EE) resource type was eligible to be offered in RPM auctions.

Market Conduct

Offer Caps

Table 5-7 ACR statistics: 2008/2009 and 2009/2010 RPM Auctions[16] (See 2008 SOM, Table 5-7)

	2008/2009 BRA		2008/2009 Third IA		2009/2010 BRA		2009/2010 Third IA	
Calculation Type	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered
Default ACR selected	399	37.1%	121	37.5%	377	34.5%	1	0.4%
ACR data input (non-APIR)	37	3.4%	8	2.5%	22	2.0%	0	0.0%
ACR data input (APIR)	80	7.4%	16	5.0%	129	11.8%	2	0.7%
Opportunity cost input	8	0.7%	5	1.5%	10	0.9%	2	0.7%
Transition adder only	43	4.0%	19	5.9%	12	1.1%	0	0.0%
Offer caps calculated	567	52.6%	169	52.4%	550	50.3%	5	1.9%
Uncapped new units	0	0.0%	2	0.6%	3	0.3%	6	2.2%
Generators capped at 1.1 times BRA clearing price	NA		NA		NA		255	95.5%
Generator price takers	509	0.474	152	47.0%	540	49.4%	1	0.4%
Generating units offered	1,076	100.0%	323	100.0%	1,093	100.0%	267	100.0%
Demand resources offered	23		13		38		13	
Total capacity resources offered	1,099		336		1,131		280	

16 The 2008/2009 Third IA data has been updated since the MMU report was posted.

Table 5-8 ACR statistics: 2010/2011 through 2012/2013 RPM Auctions (See 2008 SOM, Table 5-8)

	2010/2011 BRA		2011/2012 BRA		2011/2012 First IA		2012/2013 BRA	
Calculation Type	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered
Default ACR selected	370	33.5%	301	26.8%	47	36.4%	476	42.0%
ACR data input (non-APIR)	20	1.8%	12	1.1%	18	14.0%	118	10.4%
ACR data input (APIR)	134	12.1%	133	11.8%	1	0.8%	2	0.2%
Opportunity cost input	8	0.7%	24	2.1%	2	1.6%	8	0.7%
Default ACR and opportunity cost input	0	0.0%	2	0.2%	0	0.0%	3	0.3%
Offer caps calculated	532	48.1%	472	42.0%	68	52.8%	607	53.6%
Uncapped new units	15	1.4%	20	1.8%	1	0.8%	11	1.0%
Generator price takers	557	50.5%	633	56.2%	60	46.4%	515	45.4%
Generating units offered	1,104	100.0%	1,125	100.0%	129	100.0%	1,133	100.0%
Demand resources offered	23		37		0		233	
Energy efficiency resources offered	0		0		0		53	
Total capacity resources offered	1,127		1,162		129		1,419	

Table 5-9 APIR statistics: 2008/2009 through 2012/2013 RPM Auctions[17, 18, 19] (See 2008 SOM, Table 5-9)

		Weighted-Average ($ per MW-day UCAP)						
		Combined Cycle	Combustion Turbine	Oil or Gas Steam	SubCritical/ SuperCritical Coal	Other	Opportunity Costs	Total
2008/2009 BRA								
Non-APIR units	ACR	$38.81	$24.59	$70.24	$151.50	$76.66		$86.25
	Net revenues	$61.58	$21.17	$25.62	$362.48	$496.75		$184.49
	Offer caps	$17.14	$13.33	$45.63	$9.14	$4.30	$106.44	$20.45
APIR units	ACR	$40.64	$18.08	$121.39	$297.81	$27.61		$129.96
	Net revenues	$99.11	$19.60	$20.19	$202.87	$15.76		$89.95
	Offer caps	$4.70	$4.60	$101.20	$109.96	$21.85		$58.46
	APIR	$0.80	$4.92	$28.47	$131.38	$15.54		$49.29
	Maximum APIR effect							$211.28
2008/2009 Third IA								
Non-APIR units	ACR	$25.17	$24.46	$75.38	$155.14	$23.56		$68.29
	Net revenues	$40.23	$16.75	$31.25	$307.06	$53.07		$105.35
	Offer caps	$12.08	$14.75	$46.66	$24.31	$8.86	$149.90	$39.73
APIR units	ACR	$112.16	$11.96	$781.65	$348.73	NA		$350.53
	Net revenues	$256.98	$18.33	$1.53	$141.61	NA		$140.94
	Offer caps	$0.00	$1.29	$780.12	$207.12	NA		$209.74
	APIR	$0.56	$2.61	$199.31	$126.64	NA		$126.82
	Maximum APIR effect							$209.26
2009/2010 BRA								
Non-APIR units	ACR	$37.74	$26.07	$80.09	$159.26	$84.07		$82.66
	Net revenues	$61.97	$23.08	$31.92	$321.88	$516.72		$162.48
	Offer caps	$14.76	$13.51	$49.81	$11.44	$1.36	$123.60	$26.32
APIR units	ACR	$58.12	$43.83	$129.59	$525.98	$30.71		$285.17
	Net revenues	$97.94	$16.10	$19.71	$322.91	$15.75		$172.57
	Offer caps	$17.93	$30.45	$109.88	$164.31	$22.45		$102.07
	APIR	$0.24	$22.86	$43.79	$386.13	$18.96		$195.85
	Maximum APIR effect							$383.79

17 The weighted-average offer cap can still be positive even when the weighted-average net revenues are higher than the weighted-average ACR due to the offer-cap minimum being zero. On a unit basis, if net revenues are greater than ACR, net revenues in an amount equal to the ACR are used in the calculation and the offer cap is zero.
18 This table has been updated since the MMU RPM Auction reports were posted.
19 Statistics for the 2009/2010 Third IA are not included as 95.5 percent of the resources chose the offer cap option of 1.1 times the BRA clearing price.

Table 5-9 Cont.		Weighted-Average ($ per MW-day UCAP)						
		Combined Cycle	Combustion Turbine	Oil or Gas Steam	SubCritical/ SuperCritical Coal	Other	Opportunity Costs	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	$124.60	$20.98
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		$75.86
	Net revenues	$69.04	$20.16	$17.27	$466.41	$322.78		$173.54
	Offer caps	$11.76	$16.42	$62.13	$7.88	$11.50	$182.41	$45.80
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	$71.79	$284.63	$30.04		$169.77
	Net revenues	$220.31	$44.98	$10.25	$298.96	$0.07		$195.83
	Offer caps	$2.66	$2.64	$61.54	$150.63	$29.97	$136.01	$78.56
APIR units	ACR	$220.20	$152.28	$194.25	$583.59			$326.57
	Net revenues	$81.72	$6.94	$23.64	$328.71			$128.90
	Offer caps	$138.48	$145.34	$170.62	$254.88			$197.67
	APIR	$220.19	$120.84	$82.87	$324.31			$170.61
	Maximum APIR effect							$468.26

Table 5-9 Cont.		Weighted-Average ($ per MW-day UCAP)						
		Combined Cycle	Combustion Turbine	Oil or Gas Steam	SubCritical/ SuperCritical Coal	Other	Opportunity Costs	Total
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	$136.48	$21.55
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

Market Performance

Table 5-10 Capacity prices: 2007/2008 through 2012/2013 RPM Auctions (See 2008 SOM, Table 5-10)

	RPM Clearing Price ($ per MW-day)						
	RTO	MAAC+APS	MAAC	EMAAC	SWMAAC	DPL-South	PSEG North
2007/2008 BRA	$40.80			$197.67	$188.54		
2008/2009 BRA	$111.92			$148.80	$210.11		
2008/2009 Third IA	$10.00				$223.85		
2009/2010 BRA	$102.04	$191.32			$237.33		
2009/2010 Third IA	$40.00	$86.00					
2010/2011 BRA	$174.29					$178.27	
2011/2012 BRA	$110.00						
2011/2012 First IA	$55.00						
2012/2013 BRA	$16.46		$133.37	$139.73		$222.30	$185.00

Figure 5-1 History of capacity prices: Calendar year 1999 through 2012[20, 21] (See 2008 SOM, Figure 5-1)

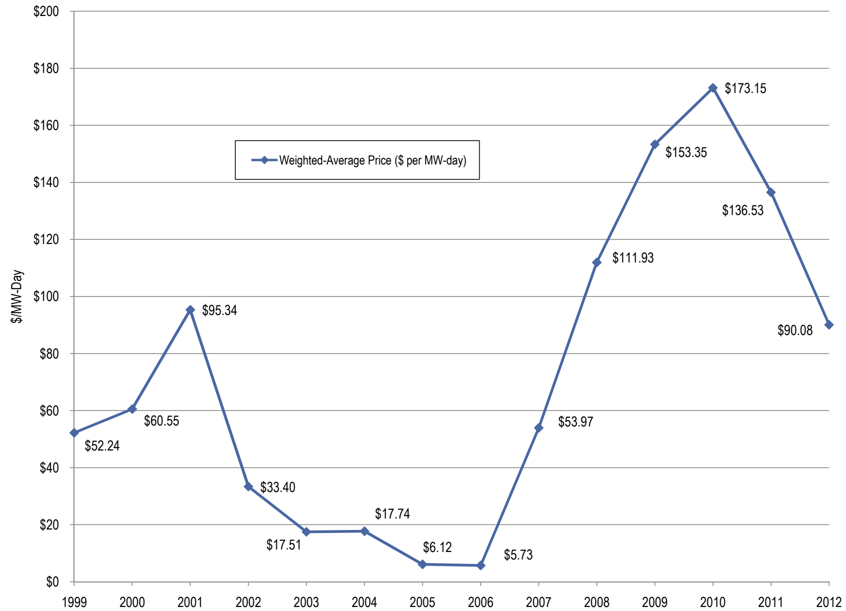


Table 5-11 RPM cost to load: 2008/2009 through 2012/2013 RPM Auctions[22, 23, 24] (See 2008 SOM, Table 5-11)

	Net Load Price ($/MW-Day)	UCAP Obligation (MW)	Annual Charges
2008/2009 BRA			
RTO	$113.22	79,814.6	$3,298,362,289
EMAAC	$145.24	35,755.4	$1,895,486,718
SWMAAC	$183.03	15,684.6	$1,047,824,603
2009/2010 BRA			
RTO	$104.82	57,520.9	$2,200,709,369
MAAC+APS	$193.77	60,399.9	$4,271,846,347
SWMAAC	$224.59	15,966.1	$1,308,826,636
2010/2011 BRA			
RTO	$174.29	129,253.2	$8,222,552,183
DPL	$178.27	4,595.0	$298,989,987
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

20 1999-2006 capacity prices are CCM combined market, weighted average prices. The 2007 capacity price is a combined CCM/RPM weighted average price. The 2008-2012 capacity prices are RPM weighted average prices.

21 The 2011 weighted average price has been revised since the *2008 State of the Market Report for PJM* was posted to reflect the 2011/2012 First IA clearing.

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

23 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.

24 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 2010/2011, 2011/2012, and 2012/2013 Net Load Prices and Obligation MW are not finalized.

2009/2010 RPM Base Residual Auction

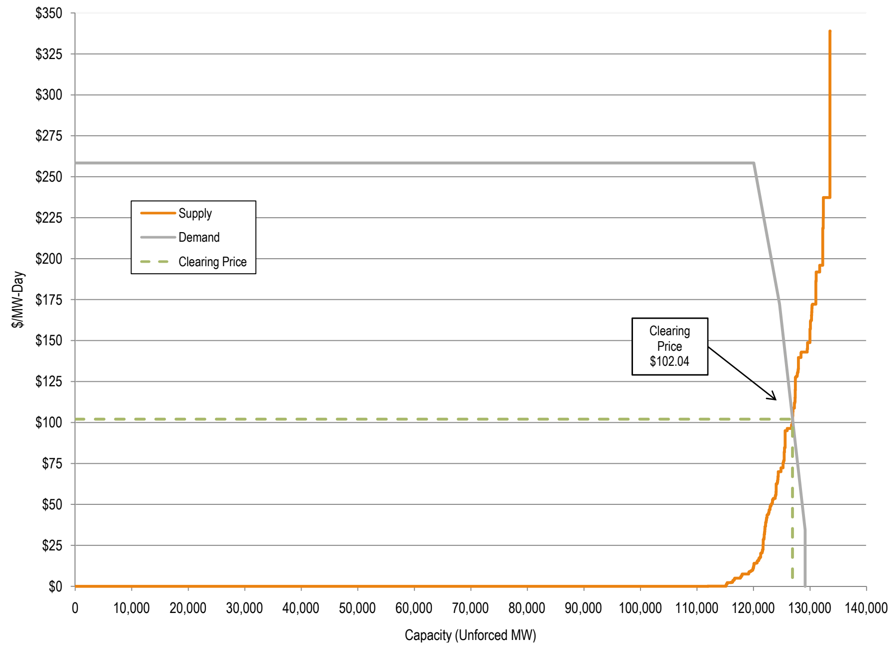
RTO

Table 5-12 RTO offer statistics: 2009/2010 RPM Base Residual Auction[25] (See 2008 SOM, Table 5-12)

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total Internal RTO Capacity (Gen and DR)	166,639.7	157,318.2		
FRR	(25,316.2)	(23,523.2)		
Imports	2,652.5	2,505.4		
RPM Capacity	143,976.0	136,300.4		
Exports	(2,376.2)	(2,194.9)		
FRR Optional	(552.5)	(450.2)		
Excused	(136.8)	(104.3)		
Available	140,910.5	133,551.0	100.0%	100.0%
Generation Offered	140,003.6	132,614.2	99.4%	99.3%
DR Offered	906.9	936.8	0.6%	0.7%
Total Offered	140,910.5	133,551.0	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	133,859.0	126,917.1	95.0%	95.0%
Cleared in LDAs	5,594.4	5,314.7	4.0%	4.0%
Total Cleared	139,453.4	132,231.8	99.0%	99.0%
Uncleared in RTO	895.5	869.0	0.6%	0.7%
Uncleared in LDAs	561.6	450.2	0.4%	0.3%
Total Uncleared	1,457.1	1,319.2	1.0%	1.0%
Reliability Requirement		130,447.8		
Total Cleared		132,231.8		
ILR Certified		6,481.5		
RPM Net Excess/(Deficit)		8,265.5		
Resource Clearing Price ($ per MW-day)		$102.04	A	
Final Zonal Capacity Price ($ per MW-day)		$104.82	B	
Final Zonal CTR Credit Rate ($ per MW-day)		$0.00	C	
Final Zonal ILR Price ($ per MW-day)		$102.04	A-C	
Net Load Price ($ per MW-day)		$104.82	B-C	

25 Prices are only for those generating units outside of MAAC+APS and SWMAAC.

Figure 5-2 RTO market supply/demand curves: 2009/2010 RPM Base Residual Auction[26] (See 2008 SOM, Figure 5-2)



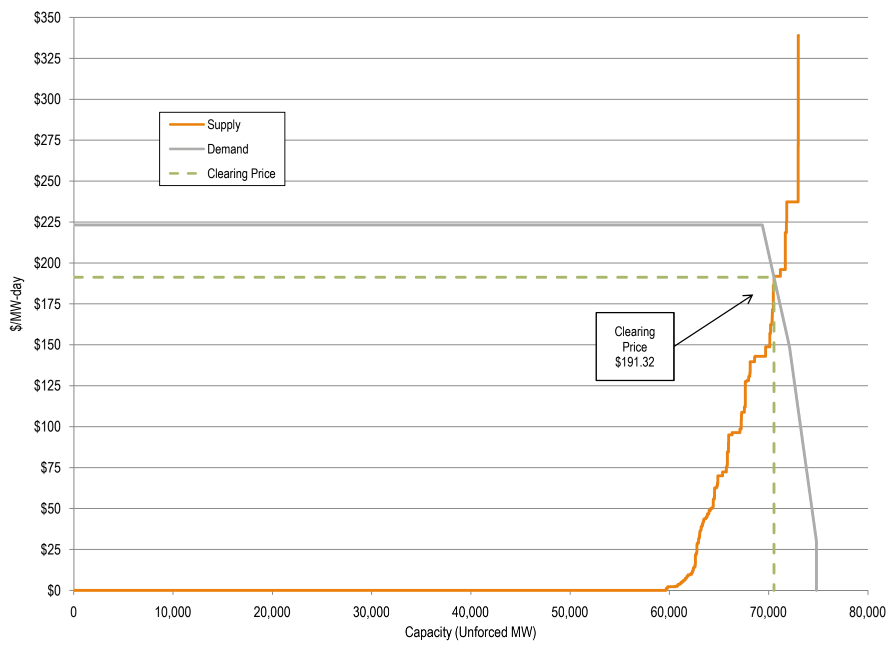
26 The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve excludes incremental demand which cleared in MAAC+APS and SWMAAC.

MAAC+APS

Table 5-13 MAAC+APS offer statistics: 2009/2010 RPM Base Residual Auction[27] (New Table)

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total Internal MAAC+APS Capacity (Gen and DR)	77,870.6	73,012.9		
Imports	89.3	89.3		
RPM Capacity	77,959.9	73,102.2		
Exports	0.0	0.0		
Excused	(136.8)	(104.3)		
Available	77,823.1	72,997.9	100.0%	100.0%
Generation Offered	77,028.6	72,177.3	99.0%	98.9%
DR Offered	794.5	820.6	1.0%	1.1%
Total Offered	77,823.1	72,997.9	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	71,667.1	67,233.0	92.1%	92.1%
Cleared in LDAs	5,594.4	5,314.7	7.2%	7.3%
Total Cleared	77,261.5	72,547.7	99.3%	99.4%
Uncleared	561.6	450.2	0.7%	0.6%
Reliability Requirement		77,902.9		
Total Cleared		72,547.7		
CETL		4,941.0		
Total Resources		77,488.7		
ILR Certified		3,081.0		
RPM Net Excess/(Deficit)		2,666.8		
Resource Clearing Price ($ per MW-day)		$191.32	A	
Final Zonal Capacity Price ($ per MW-day)		$196.54	B	
Final Zonal CTR Credit Rate ($ per MW-day)		$2.77	C	
Final Zonal ILR Price ($ per MW-day)		$188.55	A-C	
Net Load Price ($ per MW-day)		$193.77	B-C	

Figure 5-3 MAAC+APS supply/demand curves: 2009/2010 RPM Base Residual Auction[28] (New Figure)



27 Prices are only for those generating units inside of MAAC+APS, excluding SWMAAC.

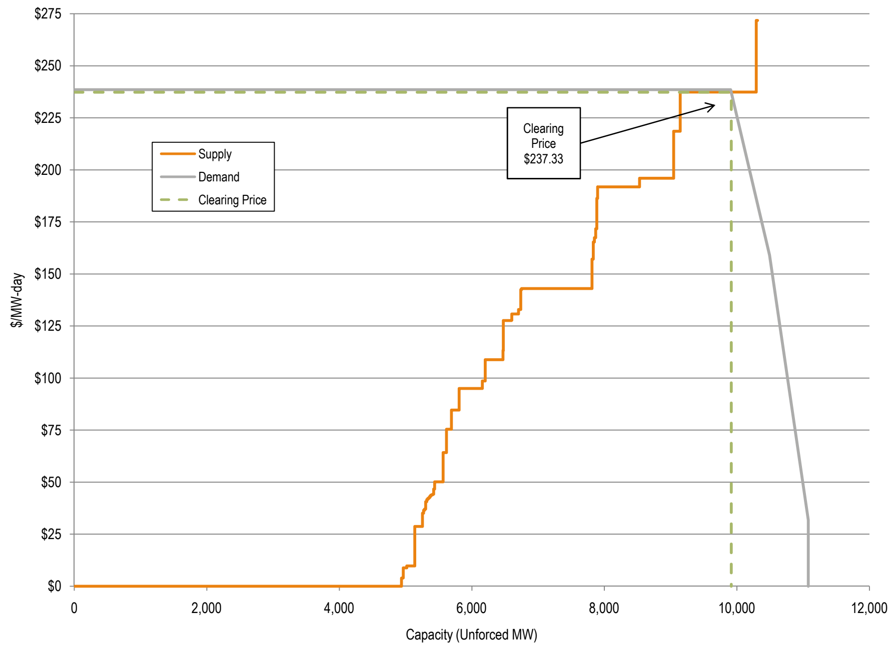
28 The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve excludes incremental demand which cleared in SWMAAC.

SWMAAC

Table 5-14 SWMAAC offer statistics: 2009/2010 RPM Base Residual Auction (See 2008 SOM, Table 5-14)

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total Internal SWMAAC Capacity (Gen and DR)	11,448.6	10,345.2		
Imports	0.0	0.0		
RPM Capacity	11,448.6	10,345.2		
Exports	0.0	0.0		
Excused	(37.0)	(33.5)		
Available	11,411.6	10,311.7	100.0%	100.0%
Generation Offered	11,066.7	9,955.4	97.0%	96.5%
DR Offered	344.9	356.3	3.0%	3.5%
Total Offered	11,411.6	10,311.7	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	7,001.2	6,202.3	61.4%	60.1%
Cleared in MAAC+APS	1,784.3	1,695.7	15.6%	16.4%
Cleared in LDA	2,146.2	2,016.6	18.8%	19.6%
Total Cleared	10,931.7	9,914.6	95.8%	96.1%
Uncleared	479.9	397.1	4.2%	3.9%
Reliability Requirement		16,318.8		
Total Cleared		9,914.6		
CETL		6,391.0		
Total Resources		16,305.6		
ILR Certified		519.3		
RPM Net Excess/(Deficit)		506.1		
Resource Clearing Price ($ per MW-day)		$237.33	A	
Final Zonal Capacity Price ($ per MW-day)		$243.80	B	
Final Zonal CTR Credit Rate ($ per MW-day)		$19.21	C	
Final Zonal ILR Price ($ per MW-day)		$218.12	A-C	
Final Net Load Price ($ per MW-day)		$224.59	B-C	

Figure 5-4 SWMAAC supply/demand curves: 2009/2010 RPM Base Residual Auction (See 2008 SOM, Figure 5-4)



2009/2010 RPM Third Incremental Auction

RTO

Table 5-15 RTO offer statistics: 2009/2010 RPM Third Incremental Auction (See 2008 SOM, Table 5-15)

	Offered (Supply) ICAP (MW)	Offered (Supply) UCAP (MW)	Bid (Demand) UCAP (MW)
Generation	2,918.7	2,724.4	
DR	514.6	531.4	
Total	3,433.3	3,255.8	2,697.6
Cleared in RTO	539.9	523.1	523.1
Cleared in MAAC+APS	1,364.1	1,275.3	1,275.3
Total cleared	1,904.0	1,798.4	1,798.4
Uncleared in RTO	589.6	590.4	221.3
Uncleared in MAAC+APS	939.7	867.0	677.9
Total uncleared	1,529.3	1,457.4	899.2
Resource clearing price ($ per MW-day)	$40.00		

Figure 5-5 RTO supply/demand curves: 2009/2010 RPM Third Incremental Auction[29] (See 2008 SOM, Figure 5-5)

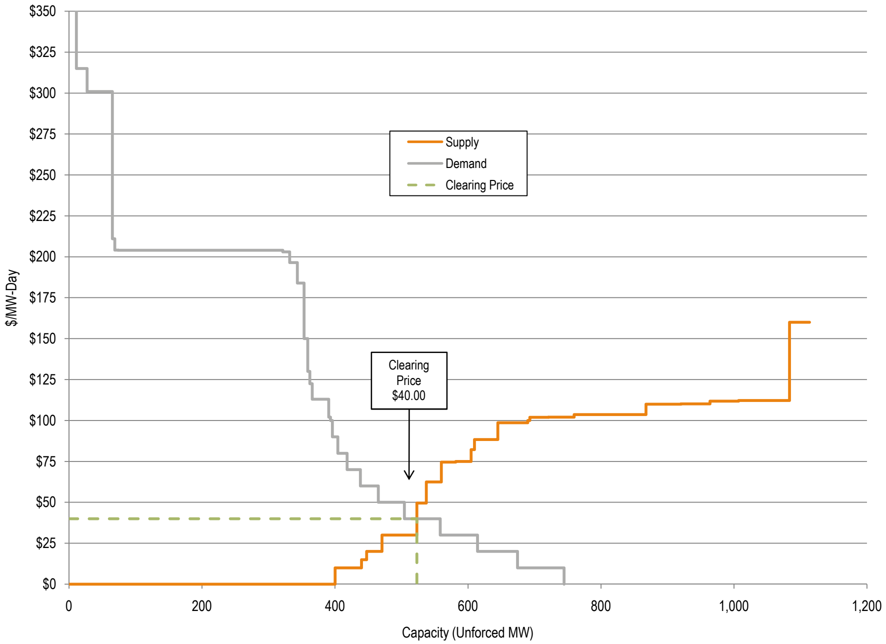
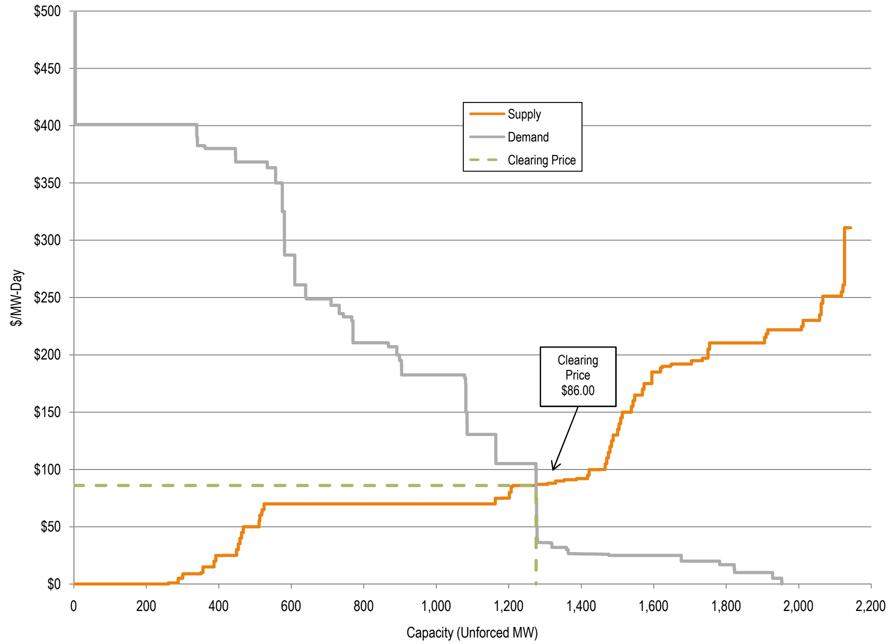


Figure 5-6 MAAC+APS supply/demand curves: 2009/2010 RPM Third Incremental Auction (New Figure)



MAAC+APS

Table 5-16 MAAC+APS offer statistics: 2009/2010 RPM Third Incremental Auction (New Table)

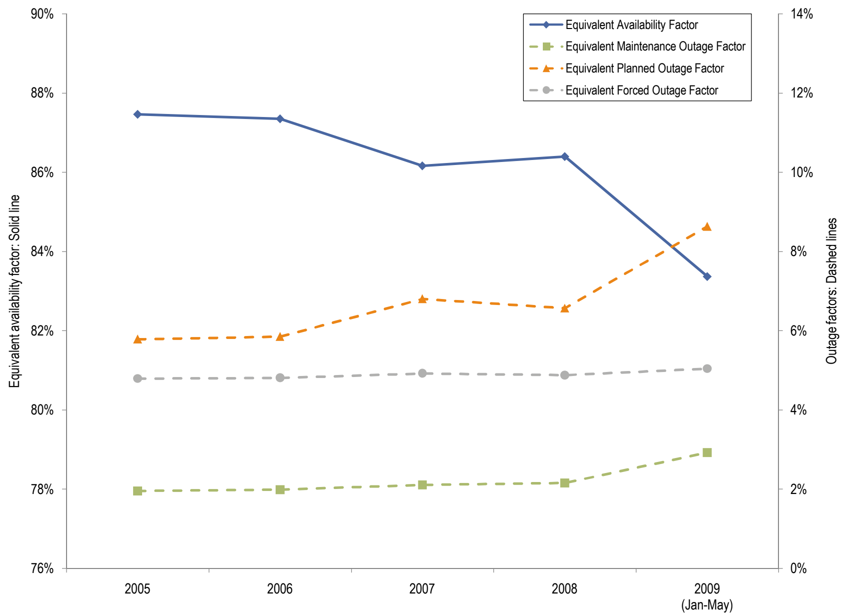
	Offered (Supply)		Bid (Demand)
	ICAP (MW)	UCAP (MW)	UCAP (MW)
Generation	2,043.3	1,873.3	
DR	260.5	269.0	
Total	2,303.8	2,142.3	1,953.2
Cleared in RTO	487.3	462.9	
Cleared in MAAC+APS	876.8	812.4	
Total cleared	1,364.1	1,275.3	1,275.3
Uncleared	939.7	867.0	677.9
Resource clearing price ($ per MW-day)	$86.00		

29 For ease of viewing, the demand curve was truncated at $350 per MW-day and does not show a demand bid of approximately $1,000 per MW-day.

Generator Performance

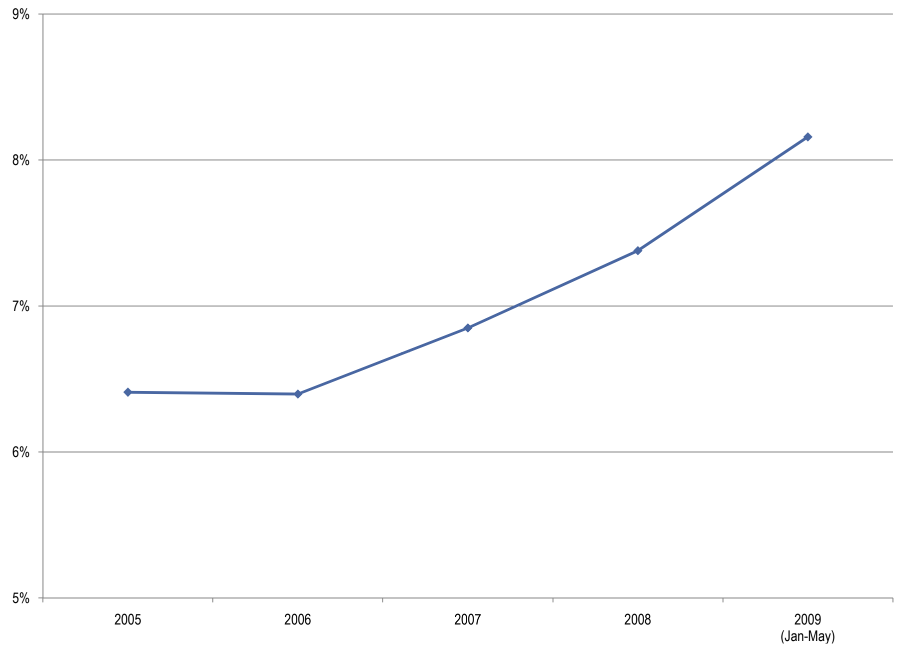
Generator Performance Factors

Figure 5-7 PJM equivalent outage and availability factors: Calendar years 2005 to 2009 (January through May) (See 2008 SOM Figure 5-7)



Generator Forced Outage Rates

Figure 5-8 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2005 to 2009 (January through May) (See 2008 SOM Figure 5-8)



Components of EFORd

Table 5-17 Contribution to EFORd by unit type (Percentage points): Calendar years 2005 to 2009 (January through May)[30] (See 2008 SOM Table 5-17)

	2005	2006	2007	2008	2009 (Jan - May)
Combined Cycle	0.6	0.5	0.4	0.4	0.6
Combustion Turbine	1.3	1.4	1.6	1.5	1.8
Diesel	0.0	0.0	0.0	0.0	0.0
Hydroelectric	0.1	0.1	0.1	0.1	0.1
Nuclear	0.3	0.3	0.2	0.4	0.8
Steam	4.1	4.1	4.4	4.9	4.9
Total	6.4	6.4	6.8	7.4	8.2

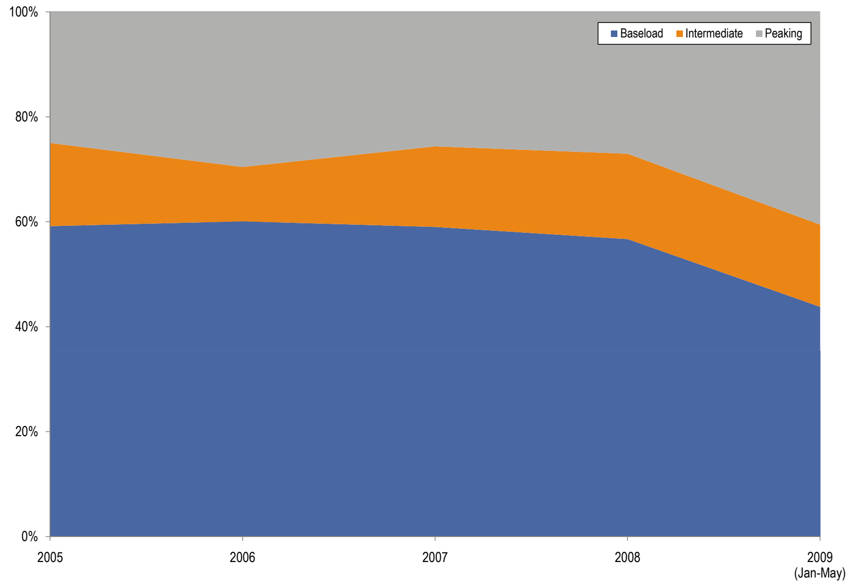
30 Calculated values presented in Section 5, "Capacity Market" at "Generator Performance" are based on unrounded, underlying data and may differ from those derived from the rounded values shown in the tables.

Table 5-18 Five-year PJM EFORd data by unit type: Calendar years 2005 to 2009 (January through May) (See 2008 SOM Table 5-19)

	2005	2006	2007	2008	2009 (Jan-May)
Combined Cycle	5.0%	4.3%	3.5%	3.4%	4.6%
Combustion Turbine	8.9%	9.4%	11.1%	10.9%	12.6%
Diesel	14.0%	13.2%	11.8%	9.6%	7.5%
Hydroelectric	2.5%	1.9%	2.3%	2.4%	2.4%
Nuclear	1.6%	1.4%	1.3%	1.9%	4.0%
Steam	8.1%	8.2%	8.8%	9.8%	9.8%
Total	6.4%	6.4%	6.8%	7.4%	8.2%

Duty Cycle and EFORd

Figure 5-9 Contribution to EFORd by duty cycle: Calendar years 2005 to 2009 (January through May) (See 2008 SOM Figure 5-9)



Forced Outage Analysis

Table 5-19 Outage cause contribution to PJM EFOF: January through May 2009 (See 2008 SOM Table 5-20)

	Percentage Point Contribution to EFOF	Contribution to EFOF
Low Pressure Turbine	1.00	19.8%
Boiler Tube Leaks	0.82	16.2%
Economic	0.51	10.1%
Electrical	0.23	4.6%
Boiler Fuel Supply from Bunkers to Boiler	0.19	3.7%
Fuel Quality	0.18	3.6%
Boiler Air and Gas Systems	0.17	3.4%
Inlet Air System and Compressors	0.12	2.4%
Stack Emission	0.11	2.2%
Miscellaneous (Steam Turbine)	0.10	1.9%
Boiler Tube Fireside Slagging or Fouling	0.09	1.8%
Miscellaneous (Generator)	0.08	1.6%
Valves	0.08	1.6%
Controls	0.08	1.6%
Performance	0.08	1.5%
Condensing System	0.08	1.5%
Feedwater System	0.07	1.5%
Generator	0.07	1.5%
Boiler Piping System	0.06	1.2%
All Other Causes	0.92	18.3%
Total	5.04	100.0%

Table 5-20 Contributions to Economic Outages: January through May 2009 (See 2008 SOM Table 5-21)

	Contribution to Economic Reasons
Lack of Fuel (OMC)	88.6%
Lack of Fuel (Non-OMC)	8.7%
Other Economic Problems	2.4%
Fuel Conservation	0.1%
Lack of Water (Hydro)	0.1%
Problems with Primary Fuel for Units with Secondary Fuel Operation	0.0%
Total	100.0%

Table 5-21 Contribution to EFOF by unit type for the most prevalent causes: January through May 2009 (See 2008 SOM Table 5-22)

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Low Pressure Turbine	0.0%	0.0%	0.0%	0.0%	80.4%	11.6%	19.8%
Boiler Tube Leaks	0.0%	0.0%	0.0%	0.0%	0.0%	22.3%	16.2%
Economic	7.1%	14.0%	0.1%	0.5%	0.0%	12.3%	10.1%
Electrical	2.3%	5.4%	0.9%	0.7%	9.6%	3.9%	4.6%
Boiler Fuel Supply from Bunkers to Boiler	0.2%	0.0%	0.0%	0.0%	0.0%	5.0%	3.7%
Fuel Quality	1.8%	0.1%	13.4%	0.0%	0.0%	4.8%	3.6%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	4.6%	3.4%
Inlet Air System and Compressors	21.0%	22.6%	0.0%	0.0%	0.0%	0.0%	2.4%
Stack Emission	0.1%	0.0%	0.6%	0.0%	0.0%	3.0%	2.2%
Miscellaneous (Steam Turbine)	9.8%	0.0%	0.0%	0.0%	0.0%	1.8%	1.9%
Boiler Tube Fireside Slagging or Fouling	0.0%	0.0%	0.0%	0.0%	0.0%	2.4%	1.8%
Miscellaneous (Generator)	16.2%	1.3%	0.2%	1.2%	0.0%	0.8%	1.6%
Valves	0.1%	0.0%	0.0%	0.0%	0.0%	2.1%	1.6%
Controls	0.1%	1.9%	0.9%	1.4%	0.1%	1.9%	1.6%
Performance	5.8%	1.6%	0.7%	8.0%	0.1%	1.3%	1.5%
Condensing System	0.0%	0.0%	0.0%	0.0%	0.1%	2.1%	1.5%
Feedwater System	0.8%	0.0%	0.0%	0.0%	0.1%	2.0%	1.5%
Generator	5.7%	3.7%	0.8%	55.8%	0.0%	0.0%	1.5%
Boiler Piping System	0.1%	0.0%	0.0%	0.0%	0.0%	1.6%	1.2%
All Other Causes	28.9%	49.4%	82.4%	32.4%	9.6%	16.5%	18.3%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-22 Contribution to EFOF by unit type: January through May 2009 (See 2008 SOM Table 5-23)

Unit Type	EFOF	Contribution to EFOF
Combined Cycle	2.6%	6.1%
Combustion Turbine	1.6%	5.0%
Diesel	6.2%	0.3%
Hydroelectric	2.2%	1.6%
Nuclear	4.0%	14.2%
Steam	7.3%	72.9%
Total	5.0%	100.0%

Outages Deemed Outside Management Control

Table 5-23 PJM EFORd vs. XEFORd by unit type: January through May 2009 (See 2008 SOM Table 5-24)

	EFORd	XEFORd	Difference
Combined Cycle	4.6%	4.2%	0.4%
Combustion Turbine	12.6%	10.5%	2.1%
Diesel	7.5%	6.1%	1.4%
Hydroelectric	2.4%	2.3%	0.1%
Nuclear	4.0%	4.0%	0.0%
Steam	9.8%	8.5%	1.3%
Total	8.2%	7.1%	1.0%

Components of EFORp

Table 5-24 Contribution to EFORp by unit type (Percentage points): Calendar years 2008 to 2009 (January through May) (New Table)

	2008	2009 (Jan-May)
Combined Cycle	0.3	0.2
Combustion Turbine	0.4	1.0
Diesel	0.0	0.0
Hydroelectric	0.1	0.1
Nuclear	0.2	0.7
Steam	3.9	2.8
Total	4.9	4.8

Table 5-25 PJM EFORp data by unit type: Calendar years 2008 to 2009 (January through May) (New Table)

	2008	2009 (Jan-May)
Combined Cycle	2.4%	1.5%
Combustion Turbine	3.0%	7.0%
Diesel	5.3%	4.4%
Hydroelectric	1.7%	1.8%
Nuclear	0.8%	3.7%
Steam	7.9%	5.5%
Total	4.9%	4.8%

EFORd and EFORp

Table 5-26 Contribution to PJM EFORd and EFORp by unit type: Calendar year 2009 (January through May) (New Table)

	EFORd	EFORp
Combined Cycle	0.6	0.2
Combustion Turbine	1.8	1.0
Diesel	0.0	0.0
Hydroelectric	0.1	0.1
Nuclear	0.8	0.7
Steam	4.9	2.8
Total	8.2	4.8

Table 5-27 PJM EFORd and EFORp data by unit type: Calendar year 2009 (January through May) (New Table)

	EFORd	EFORp
Combined Cycle	4.6%	1.5%
Combustion Turbine	12.6%	7.0%
Diesel	7.5%	4.4%
Hydroelectric	2.4%	1.8%
Nuclear	4.0%	3.7%
Steam	9.8%	5.5%
Total	8.2%	4.8%

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.

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 the 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.

PJM does not provide a market for black start services, which are procured and paid zonally, but does ensure that there are adequate black start resources.

The Market Monitoring Unit (MMU) analyzed measures of market structure, conduct and performance for the PJM Regulation Market, the two Synchronized Reserve Markets, and the PJM DASR Market from January through June 2009.

Overview

Regulation Market

The PJM Regulation Market in 2009 continues to be operated as a single market. There have been no structural changes since December 1, 2008. On December 1, 2008, PJM implemented several changes to the Regulation Market including the introduction of the three pivotal supplier test for market power, a change to the calculation of lost opportunity cost and a change to the treatment of regulation revenues with respect to operating reserve credits. The MMU analyzes the impact of these changes using data from December 1, 2008 through June 2009.

1 75 FERC ¶ 61,080 (1996).
2 Regulation is used to help control the area control error (ACE). See *2008 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 2008.
3 See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).

Market Structure

- **Supply.** During the first six months of 2009, the supply of offered and eligible regulation in PJM was generally 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 2009. The ratio of eligible regulation offered to regulation required averaged 2.74 throughout the first six months of 2009, an increase from the 2008 ratio.

- **Demand.** Beginning August 7, 2008, PJM began to calculate on-peak and off-peak regulation requirements. Previously the requirement had been fixed daily at 1.0 percent of the daily forecast operating load. The on-peak requirement is equal to 1.0 percent of the forecast peak load for the PJM RTO for the day. The PJM RTO off-peak Regulation Requirement is equal to 1.0 percent of the forecast valley load for the PJM RTO for the day. The average hourly regulation demand in the first six months of 2009 was 843 MW, compared to 922 MW for the first six months of 2008.

- **Market Concentration.** During the first six months of 2009, the PJM Regulation Market had a load weighted, average Herfindahl-Hirschman Index (HHI) of 1239 which is classified as "moderately concentrated."[4] The minimum hourly HHI was 702 and the maximum hourly HHI was 3519. The largest hourly market share in any single hour was 55 percent, and 64 percent of all hours had a maximum market share greater than 20 percent. In the first six months of 2009, 49 percent of hours had one or more pivotal suppliers. The MMU concludes from these results that the PJM Regulation Market in the first six months of 2009 was characterized by structural market power in 49 percent of the hours.

Market Conduct

- **Offers.** Regulation offer prices are provided by the unit owner, applicable for the entire operating day and, with lost opportunity cost (LOC), comprise the total offer to the Regulation Market. Beginning December 1, 2008 PJM implemented a three pivotal supplier test in the regulation market. As part of the implementation, owners are required to submit unit specific cost based offers which may include up to a $12/MWh margin adder, and owners have the option to submit price based offers. All offers remain subject to the $100 per MWh cap. All units of owners who fail the three pivotal supplier test for an hour are dispatched at the lesser of their cost based or price based offer. As part of the changes to the regulation market implemented on December 1, 2008, PJM no longer nets regulation revenue against operating reserve revenue and PJM now calculates lost opportunity costs using the lower of cost based or price based offers as the reference rather than the cost based offer. The impact on market performance for these December 1, 2008 PJM changes has been significant.

Market Performance

- **Price.** For the PJM Regulation Market during the first six months of 2009 the load weighted, average price per MWh (i.e., the regulation market clearing price, including lost opportunity cost) associated with meeting PJM's demand for regulation was $24.48. This is significantly lower than the load weighted average price in 2008, but this price does not include all the summer months. On December 1, 2008, PJM implemented new Regulation Market rules that cap the offers at cost of units offered by suppliers which are pivotal and do not cap the offers of units whose suppliers are not.

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 two significant changes to the Synchronized Reserve Market during the first six months of 2009. These changes were intended to ensure

4 See the *2008 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).

that the synchronized reserve requirement accurately reflects the needs of PJM dispatch. This includes ensuring that the forecast amount of Tier 1 synchronized reserve is actually available to PJM dispatch during the operating hour. PJM changed the primary constraint which defines the Mid-Atlantic subzone within the RFC Synchronized Reserve Market from Bedington-Black Oak to AP South. PJM reduced from 70 percent to 15 percent the percentage of Tier 1 available south of the AP South interface that it will consider as available to the Mid-Atlantic subzone when it calculates the amount of Tier 2 required. These changes were made to address the fact that PJM Dispatch needed more synchronized reserve than was defined as the requirement to be met by the market. This problem has existed in the Synchronized Reserve Market since late 2007. These changes have reduced the amount of additional, out of market, synchronized reserve required by PJM Dispatch. This reduced LOC payments and aligned the total cost of synchronized reserves with Synchronized Reserve Market prices. Synchronized reserves added out of market were only two percent of all synchronized reserve during April, May, and June of 2009 while they were 58 percent for the same time period in 2008. Similarly, LOC accounted for 11 percent of total costs during April, May, and June of 2009 compared to 59 percent during the same time period in 2008.

Market Structure

- **Supply.** For the period January through June 2009, the offered and eligible excess supply ratio was 1.4[5] for the PJM Mid-Atlantic Synchronized Reserve Region.5 The excess supply ratio is determined using the administratively required synchronized reserve. The actual requirement for Tier 2 synchronized reserve is lower because there is usually a significant amount of Tier 1 synchronized reserve available. Throughout the first six months of 2009, the contribution of DSR resources to the Synchronized Reserve Market remained significant and resulted in lower overall Synchronized Reserve prices.

- **Demand.** The average synchronized reserve requirements were 1,365 MW for the RFC Synchronized Reserve Zone and 1,162 MW for the Mid-Atlantic Subzone. These requirements are a function of administratively determined, regional requirements established by each market zone's reliability council. Since there was usually enough Tier 1 in the RFC Synchronized Reserve Zone to cover the requirement, only five percent of hours cleared a Tier 2 Synchronized Reserve market in the RFC. For the Southern Synchronized Reserve Zone only 1 hour had a non-zero Tier 2 requirement in 2009. For the PJM Mid-Atlantic Synchronized Reserve Region, 62 percent of hours cleared a Tier 2 Synchronized Reserve Market. Market demand is less than the requirement by the amount of forecast Tier 1 synchronized reserve available at the time a Synchronized Reserve Market is cleared. Demand for Tier 2 declined after adjustments were made in December, 2008 to the Tier 1 estimate. Further adjustments were made to the process for estimating Tier 1 in January and February of 2009. Since then demand for Tier 2 has risen. The average demand for Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone was 271 MW. All demand for Tier 2 in the Southern Synchronized Reserve Zone was satisfied by 15-minute quick start units. A Southern Synchronized Reserve Zone market cleared only one hour in the first six months of 2009.

The problem of additional procurement of Tier 2 synchronized reserves by PJM dispatch after Synchronized Reserve Market settlement has been greatly reduced. For January through June 2009, 19 percent of all purchased Tier 2 synchronized reserves were added after the market cleared. Most of the added synchronized reserve occurred in the January through March period. From April through June 2009 only three percent of all purchased Tier 2 synchronized reserves were added after the market cleared.

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

- **Market Concentration.** The average load weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone for January through June 2009 was 2898. For purchased synchronized reserve (cleared plus added) the figure was 4039. Less than one percent of all hours had a market share of 100 percent. In 42 percent of hours the maximum market share was greater than 40 percent (compared to 56 percent of hours in 2008). In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, for the period January through June 2009, 93 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these results that the PJM Synchronized Reserve Markets in 2009 are characterized by structural market power.

Market Conduct

- **Offers.** The offer price is provided by the unit owner, is applicable for the entire operating day and, with lost opportunity cost calculated by PJM, comprises the merit order price to the Synchronized Reserve Market. The synchronized reserve offer made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW, plus lost opportunity cost. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost.

Market Performance

- **Price.** During January and to a lesser extent February, only a very small amount of Tier 2 was needed. This resulted in lower clearing prices. The load weighted, average PJM price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market was $5.89 per MW for January through June 2009, a $4.76 per MW decrease from calendar year 2008.

- **Demand.** Demand for Tier 2 synchronized reserve was unstable during the first quarter of 2009. On December 1, 2008 PJM significantly increased the amount of Tier 1 forecast during the market solution. This reduced the demand for Tier 2 in January and February 2009. On March 13, 2009 PJM reduced the amount of Tier 1 from outside the Mid-Atlantic subzone that SPREGO will consider as available for the operational hour. This increased demand for Tier 2. Demand stabilized in the second quarter. Demand side resources remained significant participants in the Synchronized Reserve Market from January through June 2009. In 27 percent of hours in which a Tier 2 Synchronized Reserve Market was cleared for the Mid-Atlantic Subzone, all synchronized reserves were provided by DSR.

- **Availability.** 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 deficits during January through June 2009.

DASR

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[6] 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 by the reliability region.[7] 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

The DASR Market from January through June 2009 had three pivotal suppliers in a monthly average of 44 percent of all hours. The MMU concludes from these results that the PJM DASR Market in the first six months of 2009 was characterized by structural market power.

6 See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).
7 PJM Manual 13, Emergency Requirements, Rev 35, 11/07/2008; pp 11-12.

Market Conduct

Economic withholding remains a problem for the DASR market. Continuing a pattern seen since the inception of the DASR market, a significant number of units offered at levels effectively guaranteed not to clear. In June, six percent of units offered at $50 or more and four percent of units offered at $990 or more, which is equivalent to withholding in a market with an average clearing price of $0.05 and a maximum clearing price of $1.00.

Market Performance

For January through June, 2009, the load weighted price of DASR was $0.05, including the 37 percent of hours when the market cleared at a price of $0.00. Demand side resources do participate in the DASR market but remain insignificant.

Black Start Services

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 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.[8]

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 reserve, but compensates black start resource owners for all costs associated with providing this service, as defined in the tariff. For 2008, charges to PJM members for providing black start services were just over $13 million. For the first six months of 2009, charges were about $6 million.

As a consequence of PJM's filing to revise its formula rate for black start service to allow for the recovery of the costs of compliance with Critical Infrastructure Protection standards, black start costs likely will increase substantially. The revised rates also provide a better match between the sellers' commitment period and the cost recovery period.

The MMU recommends that PJM, FERC 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.

Conclusion

PJM consolidated its Regulation Markets into a single Combined Regulation Market, on a trial basis, effective August 1, 2005. The MMU has consistently found since that time that the PJM Regulation Market is characterized by structural market power. This conclusion is based on the results of the three pivotal supplier test.

In 2008, PJM and its stakeholders addressed the issue of market power mitigation for the Regulation Market in the Three Pivotal Supplier Task Force (TPSTF), which was convened pursuant to PJM's 2007 Strategic Report to review market power mitigation issues.[9] The TPSTF achieved a consensus supporting the application of the three pivotal supplier (TPS) test to the Regulation Market, provided that three adjustments to the rules were included, all of which increased margins for regulation units. PJM filed the proposed revisions on October 1, 2008.[10] A number of parties filed comments, including the MMU on October 20, 2008.[11] The MMU supported the consensus but requested that the Commission direct the MMU to report on the three adjustments to the rules: increasing the current $7.50 adder to cost based offers to $12; modifying the calculation of opportunity costs to use the lower of cost based or price based offers as the reference; and eliminating the netting of revenues from the Regulation Market from make whole balancing operating reserve payments. The Commission, in accepting PJM's filing on November 26, 2008, directed the Market Monitoring Unit to prepare a report due on November 26, 2009.[12]

On December 1, 2008, the three pivotal supplier test was implemented in the Regulation Market to address the identified market power problems. As a result, the Regulation Market results in the first half of 2009 were competitive.

8 PJM Tariff, Second Revised Sheet No. 33.01, March 1, 2007.

9 See PJM 2007 Strategic Report at 65 (April 2, 2007). This report is posted on PJM's Website at: <http://www2.pjm.com/documents/downloads/strategic-responses/report/20070402-pjm-strategic-report.pdf>.

10 PJM submitted its initial filing in FERC Docket No. ER09-13-000.

11 Comments and Motion for Leave to Intervene of the Independent Market Monitor for PJM, Docket No. ER09-13-000. These comments are posted on the Monitoring Analytics' Website at <http://www.monitoringanalytics.com>.

12 *PJM Interconnection, L.L.C.*, 125 FERC ¶ 61,231, at P 18 (2008).

The MMU also concludes that the other changes to the Regulation Market implemented on December 1, 2008 have significantly increased the price of regulation. The MMU will provide an updated analysis of results and associated recommendations to FERC, due November 26, 2009.

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. Prices for synchronized reserve in the RFC Synchronized Reserve Zone and in the Southern Synchronized Reserve Zone are market-clearing prices determined by the supply curve and the administratively defined demand. The cost based synchronized reserve offers are defined to be the unit specific incremental cost of providing synchronized reserve plus a margin of $7.50 per MWh plus lost opportunity cost calculated by PJM.

The issue of Tier 2 synchronized reserve purchases after market clearing began in the last quarter of 2007. Beginning in October and increasing substantially in November and December 2007, there was an increase in the amount of combustion turbine, synchronized condenser MW added by PJM market operations to the Synchronized Reserve Market after market clearing. On December 1, 2008, a significant increase in the amount of estimated Tier 1 reduced the amount of Tier 2 needed to meet the required synchronized reserve. The increase in Tier 1 resources did not reduce the amount of Tier 2 synchronized reserve added to the synchronized reserve market after market clearing.

The problem of additional procurement of Tier 2 synchronized reserves by PJM dispatch after Synchronized Reserve Market settlement was greatly reduced by June 2009. For January through June 2009, 19 percent of all purchased Tier 2 synchronized reserves were added after the market cleared. Most of the added synchronized reserve occurred in the January through March period. From April through June 2009 only three percent of all purchased Tier 2 synchronized reserves were added after the market cleared.

The MMU concludes that the DASR Market is not structurally competitive. The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test. The MMU also concludes that the DASR Market results were competitive in the first half of 2009.

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 competitive in the first half of 2009, as a result of the implementation of the three pivotal supplier test in the Regulation Market on December 1. The MMU concludes that the Synchronized Reserve Market results were competitive in the first half of 2009. The MMU concludes that the DASR Market results were competitive in the first half of 2009.

Regulation Market

Market Structure

Supply and Demand

Table 6-1 PJM Regulation Market Required MW and Ratio of Supply to Requirement: January through June 2009 (See 2008 SOM Table 6-1)

Period Type	Average Required Regulation (MW)	Ratio of Supply to Requirement
2009 (Jan - Jun)	843	2.73
Spring	771	2.81
Summer	882	2.69
Winter	938	2.63
Off-Peak	773	2.67
On-Peak	921	2.80

Market Concentration

Table 6-2 PJM regulation capability, daily offer and hourly eligible: January through June 2009 (See 2008 SOM Table 6-2)

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percentage of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
All Hours	7,620	6,231	82%	2,279	30%
Off Peak	7,620			2,023	27%
On Peak	7,620			2,563	34%

Table 6-3 PJM cleared regulation HHI: January through June 2009 Calendar year 2008 (See 2008 SOM Table 6-3)

Market Type	Minimum HHI	Load-Weighted Average HHI	Maximum HHI
Cleared Regulation, 2009	702	1239	3519

Figure 6-1 PJM Regulation Market HHI distribution: January through June 2009 (See 2008 SOM Figure 6-1)

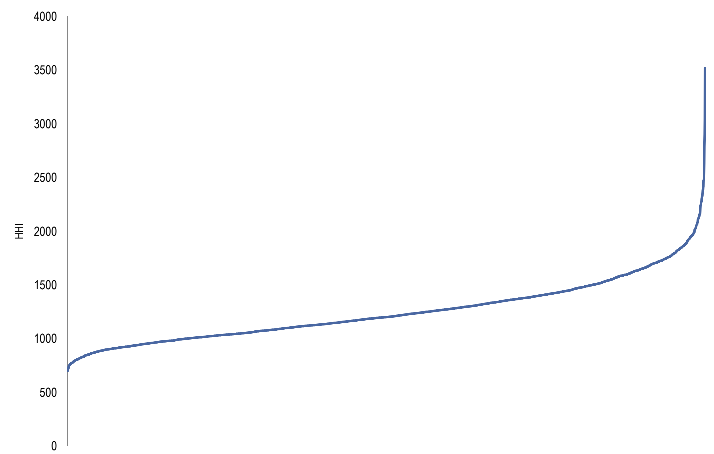


Table 6-4 Highest annual average hourly Regulation Market shares: January through June 2009 (See 2008 SOM Table 6-4)

Company Market Share Rank	Cleared Regulation Top Market Shares
1	18%
2	10%
3	8%
4	8%
5	7%

Table 6-5 Regulation market monthly three pivotal supplier results: January through June 2009 (See 2008 SOM Table 6-5)

Month	Percent of Hours With Three Pivotal Suppliers
Jan	84%
Feb	61%
Mar	42%
Apr	40%
May	31%
Jun	37%

Market Performance

Price

Figure 6-2 PJM Regulation Market daily average market-clearing price, lost opportunity cost and offer price (Dollars per MWh): January through June 2009 (See 2008 SOM Figure 6-2)

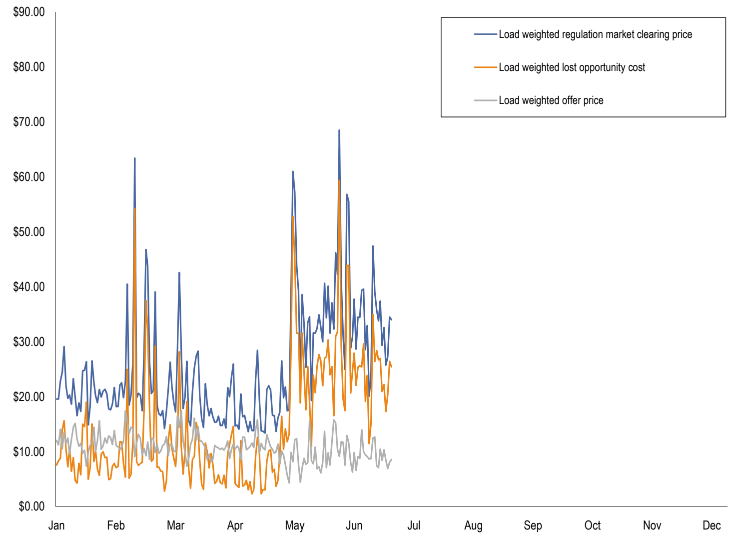


Figure 6-3 Monthly average regulation demand (required) vs. price: January through June 2009 (See 2008 SOM Figure 6-3)

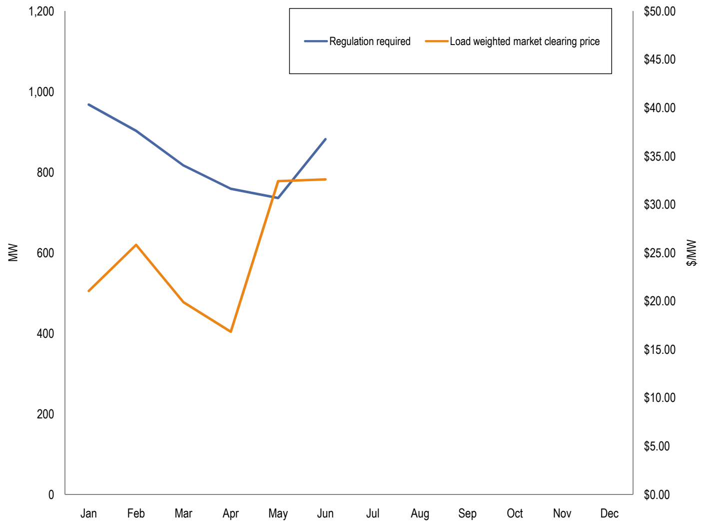


Figure 6-4 Monthly load weighted, average regulation cost and price: January through June 2009 (See 2008 SOM Figure 6-4)

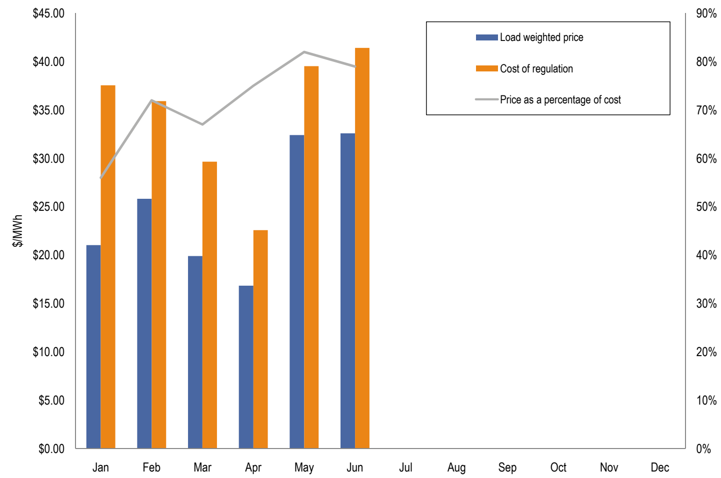


Table 6-6 Total regulation charges: January through June 2009 (See 2008 SOM Table 6-6)

Month	Total Purchased Regulation (MW)	Total Regulation Charges	Weighted Average Regulation Market Price	Regulation Cost (per MW Regulation)	Regulation Cost (per MW of Load)
Jan	708,801	$26,614,050	$21.04	$37.55	$0.40
Feb	597,418	$21,455,212	$25.83	$35.91	$0.39
Mar	601,980	$17,853,025	$19.90	$29.66	$0.33
Apr	538,993	$12,172,449	$16.84	$22.58	$0.25
May	535,862	$21,180,526	$32.41	$39.53	$0.42
Jun	595,554	$24,665,164	$32.59	$41.42	$0.45

Analysis of Changes to PJM Regulation Market

On December 1, 2008 PJM implemented four changes to the Regulation Market. The first change was the implementation of the three pivotal supplier test for market power, in a manner comparable to the energy market and the capacity market. The offers of suppliers that fail the three pivotal supplier test are capped at the lesser of their price offer or their cost offer. The percentage of hours with pivotal suppliers has decreased since the introduction of the new market rules.

Prior to December 1, 2008, regulation revenue above offer price plus LOC was used to offset unit specific operating reserve credits. The second change to the Regulation Market was to eliminate this offset against operating reserve credits, resulting in higher revenue to units for given regulation price levels. Although the amount of regulation revenue eligible for operating reserve offset was significant (15 percent to 50 percent of the total credits earned for regulation), the impact of this rule change was small because the actual operating reserves credits earned by the units that cleared in the regulation market were low (Table 6-7).

The third change to the Regulation Market was an increase in the profit margin that could be included in cost based regulation offers, from $7.50 to $12.00 per MW. The increased margin had an impact on clearing prices in the regulation market, based on an analysis of the amount of the margin above $7.50 that was included in the marginal unit's offer for every period and whether that additional adder impacted the regulation market clearing price. In approximately 85 percent of hours the marginal unit had a cost based offer greater than cost plus $7.50. In approximately 33 percent of hours, offers above cost plus $7.50 impacted the regulation market clearing price. A marginal unit's cost based offer greater than cost plus $7.50 would not affect the clearing price if the unit's owner passed the TPS test or its price offer was lower than its cost plus $7.50. The increase in the margin resulted in an increase in the final regulation market clearing prices (Table 6-8). This impact has decreased since December 2008.

Table 6-7 Regulation credits offset against operating reserves: September 2008 through June 2009 (New Table)

Year	Month	Load Weighted Regulation Market Clearing Price	Regulation Credits Before Offset	Regulation Credits Eligible for Operating Reserve Offset	Actual Credits Offset Against Operating Reserves	Final Regulation Credits	Percentage of Total Regulation Credits Offset Against Operating Reserves
2008	Sep	$39.99	$36,137,080	$10,715,728	$297,125	$35,839,955	1%
2008	Oct	$29.58	$23,801,953	$6,117,145	$210,407	$23,591,545	1%
2008	Nov	$29.48	$25,335,645	$7,049,813	$172,452	$25,163,193	1%
2008	Dec	$24.71	$25,608,469	$5,740,097	$0	$25,608,469	0%
2009	Jan	$21.04	$26,614,105	$4,055,087	$0	$26,614,105	0%
2009	Feb	$25.83	$21,455,214	$6,433,040	$0	$21,455,214	0%
2009	Mar	$19.90	$17,853,247	$3,916,361	$0	$17,853,247	0%
2009	Apr	$16.84	$12,172,532	$2,888,677	$0	$12,172,532	0%
2009	May	$32.41	$21,180,576	$11,355,085	$0	$21,180,576	0%
2009	Jun	$32.59	$24,665,686	$15,220,119	$0	$24,665,686	0%

Table 6-8 Payments to generation from offers greater than costs plus $7.50: December 2008 through June 2009. (New Table)

Year	Month	Periods When Marginal Unit Offer Greater than Cost Plus $7.50	Periods When Marginal Unit Offer Greater Than Cost Plus $7.50 Impacts Regulation Price	RMCP Credits Attributable To Marginal Unit's Cost Offer > Cost Plus $7.50	Percent Increase in Total RMCP Credits Due To Marginal Unit With Offer > Cost Plus $7.50
2008	Dec	627	454	$1,829,441	11%
2009	Jan	610	380	$1,281,527	9%
2009	Feb	590	274	$845,440	6%
2009	Mar	667	154	$389,591	3%
2009	Apr	659	155	$369,023	4%
2009	May	638	125	$290,392	2%
2009	Jun	596	130	$380,387	2%

The fourth change to the Regulation Market was to change the definition of lost opportunity cost (LOC). Prior to December 1, 2008, SPREGO solved the regulation market using a forecast LOC based on the (energy) offer curve in use by the unit. If the unit was operating on its price based offer curve, the price based curve was used. The change was to use the lower of the highest cost based offer curve or the price based offer curve. The result was to significantly increase the measured LOC and to increase regulation market clearing prices (Table 6-9). If the original method of calculation LOC had remained in place, clearing prices in the regulation market would have been approximately 23 percent lower.

Table 6-9 Impact on RMCP of revised LOC calculation: December 2008 through June 2009, (New Table)

Year	Month	Actual RMCP	Percent Reduction RMCP by Using Higher of Price/ Cost Curve	Reduced RMCP
2008	Dec	$24.79	19%	$20.23
2009	Jan	$21.04	23%	$16.20
2009	Feb	$25.83	26%	$19.11
2009	Mar	$19.90	23%	$15.32
2009	Apr	$16.84	19%	$13.64
2009	May	$32.41	25%	$24.31
2009	Jun	$32.59	28%	$23.46

Synchronized Reserve Market

Figure 6-5 RFC Synchronized Reserve Zone monthly average synchronized reserve required vs. Tier 2 scheduled MW: January through June 2009 (See 2008 SOM Figure 6-5)

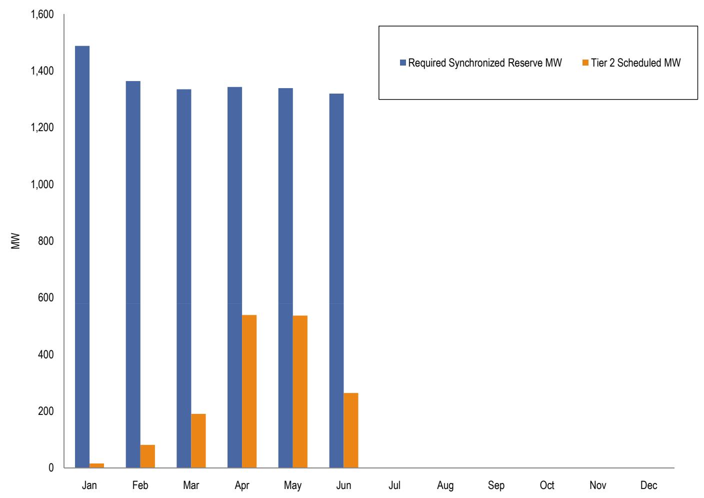
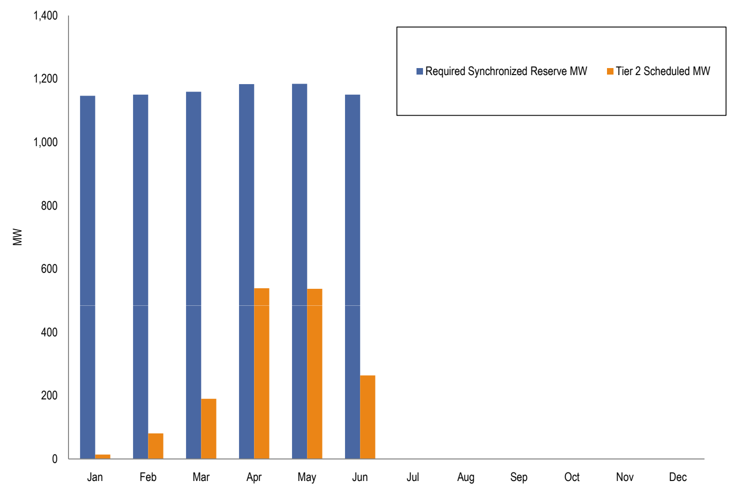


Figure 6-6 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone average hourly synchronized reserve required vs. Tier 2 scheduled: January through June 2009 (See 2008 SOM Figure 6-6)



Market Concentration

Figure 6-7 Cleared Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market seasonal HHI: January through June 2009 (See 2008 SOM Figure 6-7)

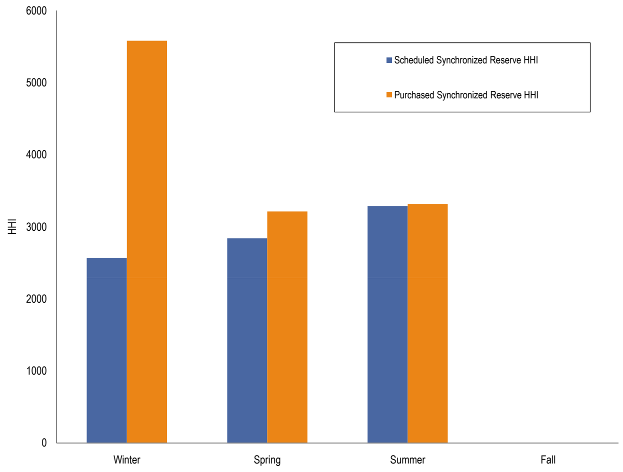
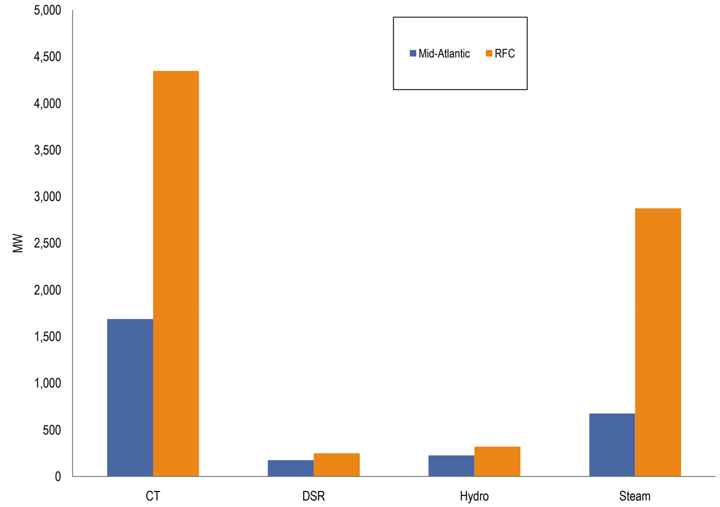


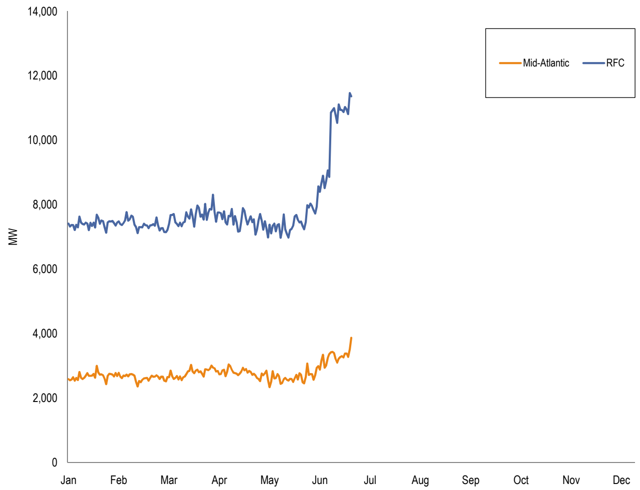
Figure 6-9 Average daily Tier 2 synchronized reserve offer by unit type (MW): January through June 2009 (See 2008 SOM Figure 6-9)



Market Conduct

Offers

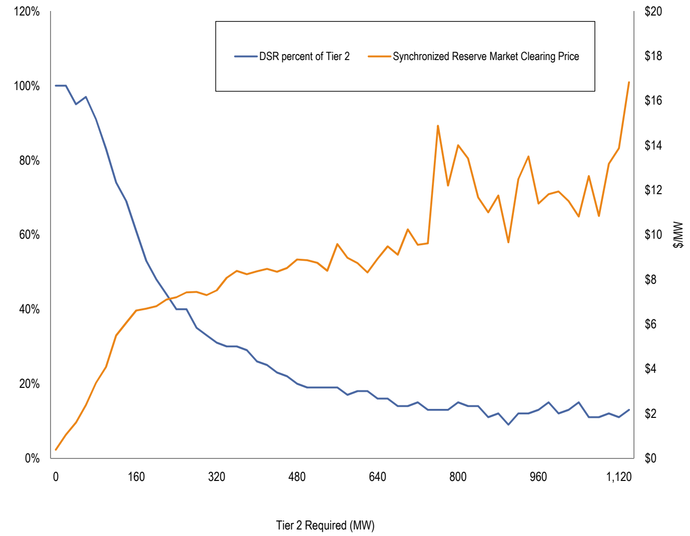
Figure 6-8 Tier 2 synchronized reserve average hourly offer volume (MW): January through June 2009 (See 2008 SOM Figure 6-8)



Market Performance

Price

Figure 6-10 Required Tier 2 synchronized reserve, synchronized reserve market clearing price, and DSR percent of Tier 2: January through June 2009 (See 2008 SOM Figure 6-10)



Price and Cost

Figure 6-11 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone daily average hourly synchronized reserve required, Tier 2 MW scheduled, and Tier 1 MW estimated: January through June 2009 (See 2008 SOM Figure 6-11)

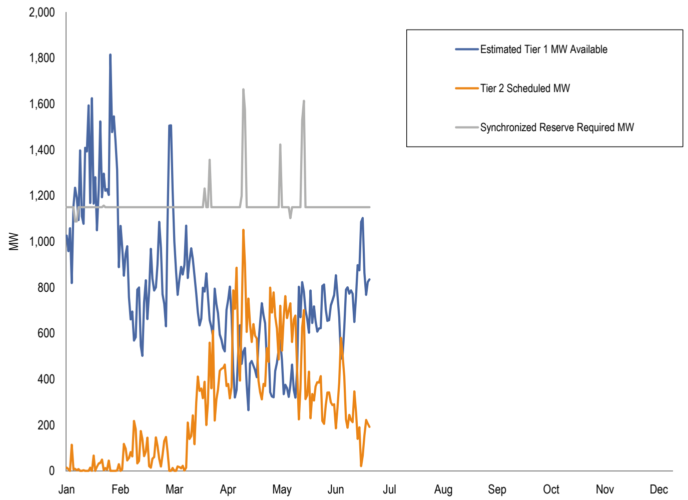


Figure 6-12 Synchronized reserve purchases by month; PJM scheduled, self-scheduled, and added: January through June 2009 (See 2008 SOM Figure 6-12)

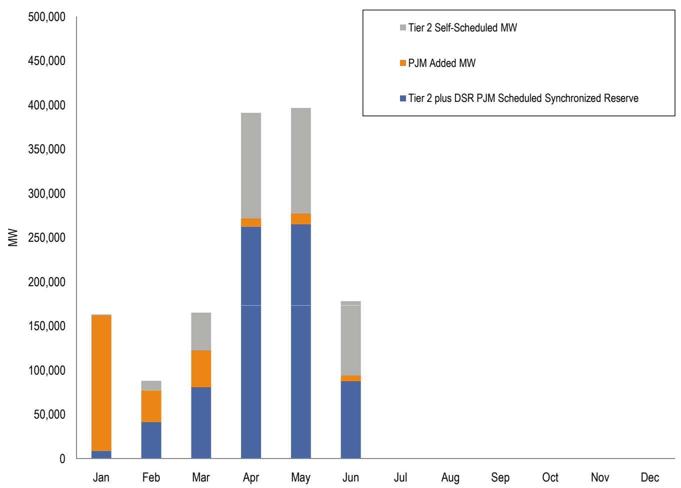


Figure 6-13 Impact of Tier 2 synchronized reserve added MW to the RFC Synchronized Reserve Zone, Mid-Atlantic subzone: January through June 2009 (See 2008 SOM Figure 6-13)

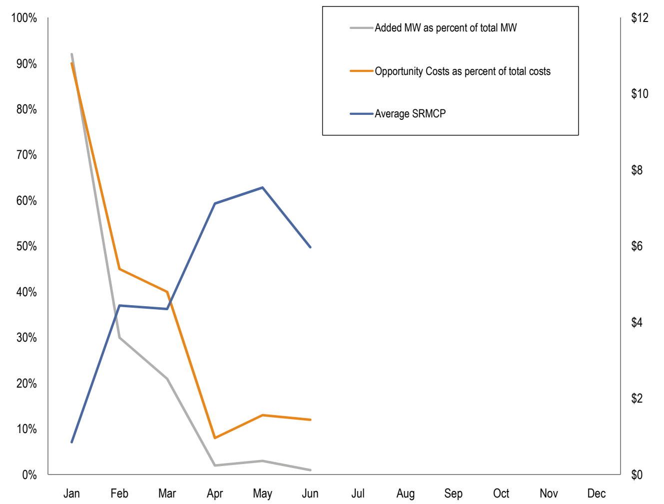
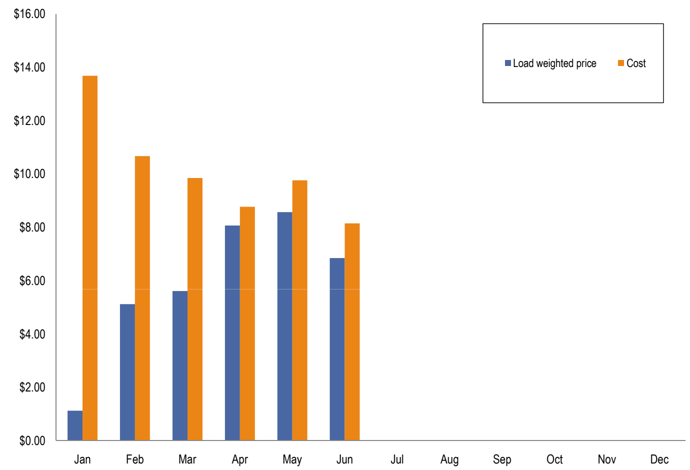


Figure 6-14 Comparison of RFC Tier 2 synchronized reserve price and cost (Dollars per MW): January through June 2009 (See 2008 SOM Figure 6-14)



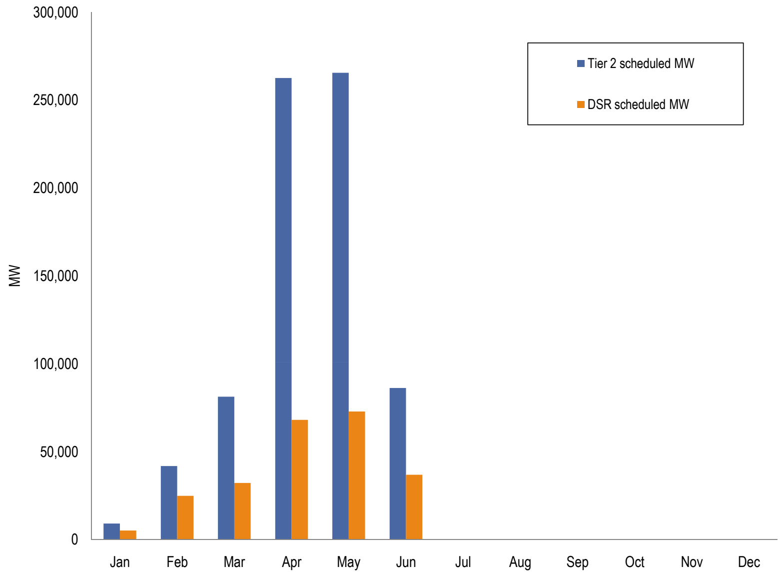
Market Solution and Actual Dispatch of Ancillary Services

DSR

Table 6-10 Average SRMCP when all cleared synchronized reserve is DSR: January through June 2009 (See 2008 SOM Table 6-8)

Month	Average SRMCP when all cleared synchronized reserve is DSR	Average SRMCP	Percent of cleared hours all synchronized reserve is DSR
Jan	$1.24	$5.90	43%
Feb	$2.01	$5.09	47%
Mar	$1.98	$5.50	26%
Apr	$2.49	$7.12	9%
May	$1.91	$7.56	12%
Jun	$1.76	$5.97	27%

Figure 6-15 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: January through June 2009 (See 2008 SOM Figure 6-15)



Availability

Day Ahead Scheduling Reserve (DASR)

Table 6-11 PJM, Day-Ahead Scheduling Reserve Market MW and clearing prices: January through June 2009 (See 2008 SOM Table 6-9)

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	5,875	$0.00	$0.50	$0.09	4,103,463	$381,735
Feb	5,517	$0.00	$0.25	$0.05	3,510,983	$180,767
Mar	5,068	$0.00	$1.00	$0.03	3,499,722	$113,507
Apr	4,910	$0.00	$0.50	$0.03	3,354,999	$92,158
May	4,957	$0.00	$0.07	$0.02	3,478,374	$77,850
Jun	5,936	$0.00	$0.75	$0.05	4,006,547	$191,578

Table 6-12 2008 PJM, Day-Ahead Scheduling Reserve Market pivotal supplier results: January through June 2009 (See 2008 SOM Table 6-10)

Month	Percentage of Hours With Three Pivotal Suppliers
Jan	16%
Feb	61%
Mar	75%
Apr	55%
May	48%
Jun	6%

Black Start Service

Table 6-13 Black Start yearly zonal charges for network transmission use: January through June 2009 (See 2008 SOM Table 6-11)

Zone	Network Charges
AECO	$206,192
AEP	$360,676
AP	$66,715
BGE	$236,356
ComEd	$3,340,231
DAY	$71,702
DLCO	$13,083
DPL	$176,763
JCPL	$214,109
Met-Ed	$199,072
PECO	$354,606
PENELEC	$165,245
Pepco	$109,389
PPL	$62,238
PSEG	$464,511

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 to some loads. 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 during the first six months of 2009.

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 *2008 State of the Market Report for PJM*, Volume II, Section 8, "Financial Transmission and Auction Revenue Rights," at "ARR and FTR Revenue and Congestion."

Overview

Congestion Cost

- **Total Congestion.** During the first six months of 2009, total congestion costs decreased by $757.9 million or 65 percent, from $1.116 billion to $408.2 million. Day-ahead congestion costs decreased by $882.4 million or 63 percent, from $1.403.8 billion during the first six months of 2008 to $521.7 million during the first six months of 2009. Balancing congestion costs increased by $124.1 million or 52 percent, from -$237.7 million during the first six months of 2008 to -$113.6 during the first six months of 2009. Total congestion costs have ranged from 6 percent to 9 percent of PJM annual total billings since 2003. Congestion costs were 3 percent of total PJM billings for the first six months of 2009. Total PJM billings for the first six months of 2009 were $13.457 billion, an 18 percent decrease from the $16.369 billion billed during the first six months of 2008.

- **Monthly Congestion.** Fluctuations in monthly congestion costs continued to be substantial. During the first six months of 2009, 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.

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. This 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.** As was the case in 2008, congestion frequency was significantly higher in the Day-Ahead Market than in the Real-Time Market in 2008.[3] Day-ahead congestion frequency increased in during the first six months of 2009 compared to the first six months of 2008. During the first six months of 2009, there were 36,099 day-ahead, congestion-event hours compared to 34,707 congestion-event hours during the first six months of 2008. Day-ahead, congestion-event hours increased on PJM transmission lines and the flowgates between PJM and the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) while congestion frequency on internal PJM interfaces and transformers decreased. Real-time congestion frequency decreased during the first six months of 2009 compared to the first six months of 2008. During the first six months of 2009, there were 8,605 real-time, congestion-event hours compared to 10,108 congestion-event hours. Real-time, congestion-event hours increased on the flowgates between PJM and the Midwest ISO, while interfaces, transmission lines and transformers saw decreases. The AP South Interface was the largest contributor to congestion costs during the first six months of 2009. With $119.9 million in total congestion costs, it accounted for 29 percent of the total PJM congestion costs during the first six months of 2009. The top five constraints in terms of congestion costs together contributed $228 million, or 56 percent, of the total PJM congestion costs during the first six months of 2009. The top five constraints included the AP South Interface, the West Interface, the East Frankfort - Crete line, the 5004/5005 Interface, and the Kammer transformer.

- **Zonal Congestion.** During the first six months of 2009, the ComEd Control Zone experienced the highest congestion costs of the control zones in PJM. However, during the first six months of 2009, the average congestion component of LMP in ComEd was -$6.40 and -$7.26 for day-ahead and real-time, respectively. The negative congestion components in ComEd resulted in -$153.0 million in load congestion payments, -$279.2 million in generation congestion credits, and -$3.1 in explicit congestion charges. The net positive congestion number in ComEd is an example of how accounting congestion can be a misleading measure of congestion when it results from generation congestion credits which are more negative than load congestion payments. In fact, congestion reduces prices in ComEd, and as a result, load incurs lower charges and generation receives lower credits. The $123.1 million in net congestion costs in the ComEd Control Zone represented a 10.4 percent decrease from the $137.4 million in congestion costs the zone had experienced during the first six months of 2008. The Pleasant Valley – Belvidere line, the East Frankfort – Crete line, and the Dunes Acres – Michigan City flowgate contributed $43.1 million, or 35 percent of the total ComEd Control Zone congestion costs (Table 7-44). The Dominion Control Zone had the second highest congestion cost in PJM during the first six months of 2009. The $59.2 million in congestion costs in the Dominion Control Zone represented a 68 percent decrease from the $184.9 million in congestion costs the zone had experienced during the first six months of 2008. The AP South Interface contributed $38.5 million, or 65 percent of the total Dominion Control Zone congestion cost.

Conclusion

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. Total congestion costs decreased by $757.9 million or 65 percent, from $1.116 billion to $408.2 million. Day-ahead congestion costs decreased by $882.4 million or 63 percent, from $1.403 billion during the first six months of 2008 to $521.7 million during the first six months of 2009. Balancing congestion costs increased by $124.1 million or 52 percent, from -$237.7 million during the first six months of 2008 to -$113.6 million during the first six months of 2009. Congestion costs were significantly higher in the Day-Ahead Market than in the balancing market. Congestion frequency was also significantly higher in the Day-Ahead Market than in the Real-Time Market. During the first six months of 2009, there were 36,099 day-ahead, congestion-event

3 Prior state of the market reports measured real-time congestion frequency using the convention that a congestion-event hour exists if the particular facility is constrained for four or more of the 12 five-minute intervals comprising that hour. In the *2008 State of the Market Report for PJM*, 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. Comparisons to previous periods use the new standard for both current and prior periods.

hours compared to 34,707 congestion-event hours during the first six months of 2008. During the first six months of 2009, there were 8,605 real-time, congestion-event hours compared to 10,108 congestion-event hours during the first six months of 2008.

ARRs and FTRs served as an effective, but not total, hedge against congestion. ARR and FTR revenues hedged 97.4 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2007 to 2008 planning period. For the 2008 to 2009 planning period, ARR and FTR revenue hedged more than 100 percent of the total congestion costs within PJM.[4] FTRs were paid at 100 percent of their target allocation for the planning year ended May 31, 2008, and at 100 percent of their target allocation for the planning year ended May 31, 2009.

One constraint accounted for over a quarter of total congestion costs during the first six months of 2009 and the top five constraints accounted for more than half of total congestion costs. The AP South interface was the largest contributor to congestion costs during the first six months of 2009.

The congestion metric requires careful review. 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.[5] 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).

As an example, total congestion during the first six months of 2009 in PJM was $408.2 million, which was comprised of load congestion payments of $142.3 million, negative generation credits of $301.8 million and negative explicit congestion of $35.9 million (see Table 7-2).

4 See the *2008 State of the Market Report for PJM*, Volume II, Section 8, "Financial Transmission and Auction Revenue Rights," at Table 8-28, "ARR and FTR congestion hedging: Planning periods 2007 to 2008 and 2008 to 2009."
5 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.

Congestion

Total Calendar Year Congestion

Table 7-1 Total annual PJM congestion (Dollars (Millions)): Calendar years 2003 through June 2009 (See 2008 SOM Table 7-1)

	Congestion Charges	Percent Change	Total PJM Billing	Percent of PJM Billing
2003	$464	NA	$6,900	7%
2004	$750	62%	$8,700	9%
2005	$2,092	179%	$22,630	9%
2006	$1,603	(23%)	$20,945	8%
2007	$1,846	15%	$30,556	6%
2008	$2,117	15%	$34,306	6%
2009	$408	NA	$13,457	3%
Total	$9,280		$137,494	7%

Table 7-2 Total annual PJM congestion costs by category (Dollars (Millions)): January through June 2008 and 2009

Year	Load Payments	Generation Credits	Explicit	Total
2008 (Jan - Jun)	$625.2	($521.3)	$19.6	$1,166.1
2009 (Jan - Jun)	$142.3	($301.8)	($35.9)	$408.2

Monthly Congestion

Table 7-3 Monthly PJM congestion charges (Dollars (Millions)): January through June 2008 and 2009 (See 2008 SOM Table 7-2)

	2008	2009	Change
Jan	$231.0	$149.3	($81.7)
Feb	$168.1	$83.0	($85.2)
Mar	$86.4	$74.6	($11.8)
Apr	$126.2	$25.6	($100.6)
May	$182.8	$25.9	($157.0)
Jun	$371.5	$49.8	($321.7)

Congestion Component of LMP

Table 7-4 Annual average congestion component of LMP: January through June 2008 and 2009 (See 2008 SOM Table 7-3)

	2008 (Jan - Jun)		2009 (Jan - Jun)	
Control Zone	Day Ahead	Real Time	Day Ahead	Real Time
AECO	$8.01	$10.85	$2.61	$2.60
AEP	($10.69)	($11.32)	($2.41)	($2.38)
AP	($0.02)	$0.30	$0.75	$1.79
BGE	$11.68	$11.44	$3.72	$3.49
ComEd	($12.30)	($13.81)	($6.40)	($7.26)
DAY	($11.10)	($11.86)	($3.37)	($3.22)
DLCO	($11.83)	($14.31)	($4.56)	($4.12)
Dominion	$7.96	$7.78	$2.93	$2.90
DPL	$7.83	$8.29	$2.92	$3.02
JCPL	$11.02	$12.25	$2.51	$2.72
Met-Ed	$7.46	$7.25	$2.69	$2.70
PECO	$5.95	$5.92	$2.43	$2.19
PENELEC	($0.21)	($1.69)	($0.01)	$0.09
Pepco	$13.25	$12.51	$3.67	$3.60
PPL	$6.61	$6.56	$2.46	$2.29
PSEG	$9.45	$11.13	$2.99	$3.17
RECO	$8.50	$10.36	$2.06	$2.21

Congested Facilities

Congestion by Facility Type and Voltage

Table 7-5 Congestion summary (By facility type): January through June 2009 (See 2008 SOM Table 7-4)

	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	$12.4	($28.8)	$12.3	$53.4	($8.3)	$3.3	($51.7)	($63.3)	($9.9)	3,601	1,963
Interface	$31.1	($149.7)	$2.3	$183.1	$2.9	($1.8)	$1.3	$6.1	$189.2	2,580	837
Line	$58.5	($118.8)	$29.8	$207.1	($3.6)	$4.1	($23.3)	($31.0)	$176.1	25,942	4,196
Transformer	$55.2	($1.6)	$18.2	$75.0	($8.0)	($7.9)	($25.3)	($25.4)	$49.7	3,976	1,609
Unclassified	$2.2	($0.5)	$0.5	$3.1	$0.0	$0.0	$0.0	$0.0	$3.1	NA	NA
Total	$159.3	($299.4)	$63.1	$521.7	($17.0)	($2.4)	($99.0)	($113.6)	$408.2	36,099	8,605

Table 7-6 Congestion summary (By facility type): January through June 2008 (See 2008 SOM Table 7-5)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Flowgate	$2.2	($4.7)	$3.9	$10.8	($0.7)	$2.8	($14.2)	($17.7)	($7.0)	1,024	641
Interface	$236.5	($338.1)	$23.0	$597.6	($19.9)	$11.7	$0.5	($31.0)	$566.6	4,226	1,260
Line	$317.2	($182.5)	$49.1	$548.8	($51.7)	$40.8	($48.9)	($141.4)	$407.5	23,166	5,966
Transformer	$169.4	($59.5)	$9.8	$238.7	($30.2)	$12.9	($4.6)	($47.6)	$191.1	6,291	2,241
Unclassified	$2.4	($4.6)	$0.9	$7.8	$0.0	$0.0	$0.0	$0.0	$7.8	NA	NA
Total	$727.6	($589.4)	$86.7	$1,403.8	($102.4)	$68.2	($67.1)	($237.7)	$1,166.1	34,707	10,108

Table 7-7 Congestion summary (By facility voltage): January through June 2009 (See 2008 SOM Table 7-6)

	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	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	7	0
500	$68.1	($165.3)	$10.6	$244.0	$1.2	($12.5)	($7.4)	$6.3	$250.3	5,455	1,704
345	$23.2	($34.4)	$29.7	$87.3	($4.2)	$2.0	($41.7)	($47.9)	$39.4	4,767	1,310
230	$15.0	($15.1)	$5.2	$35.2	$0.0	$3.6	($3.2)	($6.7)	$28.5	7,590	1,038
138	$42.9	($83.2)	$16.7	$142.8	($11.2)	$3.0	($46.3)	($60.5)	$82.3	14,098	4,010
115	$4.2	($1.4)	$0.3	$5.9	$0.4	$0.7	($0.2)	($0.6)	$5.3	2,133	346
69	$3.7	$0.4	$0.2	$3.5	($3.3)	$0.8	($0.1)	($4.2)	($0.8)	1,877	197
12	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	172	0
Unclassified	$2.2	($0.5)	$0.5	$3.1	$0.0	$0.0	$0.0	$0.0	$3.1	NA	NA
Total	$159.3	($299.4)	$63.1	$521.7	($17.0)	($2.4)	($99.0)	($113.6)	$408.2	36,099	8,605

Table 7-8 Congestion summary (By facility voltage): January through June 2008 (See 2008 SOM Table 7-7)

	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	$1.6	($3.0)	$0.1	$4.7	$1.4	$0.6	($0.0)	$0.8	$5.5	83	19
500	$393.4	($412.8)	$38.3	$844.5	($38.2)	$6.8	$3.8	($41.2)	$803.3	7,975	3,202
345	$17.8	($16.8)	$10.3	$45.0	($13.3)	$5.3	($38.2)	($56.8)	($11.8)	1,378	800
230	$159.7	($69.5)	$19.1	$248.4	($30.2)	$37.9	($12.7)	($80.7)	$167.6	7,819	2,285
138	$91.8	($81.1)	$17.2	$190.0	($9.5)	$5.0	($16.0)	($30.5)	$159.5	10,064	2,656
115	$46.2	($0.2)	$0.6	$46.9	($11.6)	$10.1	($3.9)	($25.6)	$21.3	3,463	712
69	$14.8	($1.5)	$0.2	$16.5	($1.1)	$2.4	($0.1)	($3.6)	$12.9	3,925	420
34	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	14
12	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
Unclassified	$2.4	($4.6)	$0.9	$7.8	$0.0	$0.0	$0.0	$0.0	$7.8	NA	NA
Total	$727.6	($589.4)	$86.7	$1,403.8	($102.4)	$68.2	($67.1)	($237.7)	$1,166.1	34,707	10,108

Constraint Duration

Table 7-9 Top 25 constraints with frequent occurrence: January through June 2008 and 2009 (See 2008 SOM Table 7-8)[6]

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2008	2009	Change	2008	2009	Change	2008	2009	Change	2008	2009	Change
1	Dunes Acres - Michigan City	Flowgate	0	1,713	1,713	159	672	513	0%	39%	39%	4%	15%	12%
2	Cloverdale - Lexington	Line	1,975	666	(1,309)	890	239	(651)	45%	15%	(30%)	20%	6%	(15%)
3	Leonia - New Milford	Line	337	2,164	1,827	45	30	(15)	8%	50%	42%	1%	1%	(0%)
4	Pleasant Valley - Belvidere	Line	0	1,534	1,534	7	213	206	0%	35%	35%	0%	5%	5%
5	Atlantic - Larrabee	Line	1,466	188	(1,278)	341	45	(296)	34%	4%	(29%)	8%	1%	(7%)
6	Burlington - Croydon	Line	41	1,531	1,490	5	3	(2)	1%	35%	34%	0%	0%	(0%)
7	Branchburg - Readington	Line	1,103	21	(1,082)	271	0	(271)	25%	0%	(25%)	6%	0%	(6%)
8	East Frankfort - Crete	Line	61	1,333	1,272	0	0	0	1%	31%	29%	0%	0%	0%
9	Bedington - Black Oak	Interface	1,170	74	(1,096)	186	61	(125)	27%	2%	(25%)	4%	1%	(3%)
10	Pinehill - Stratford	Line	2,030	859	(1,171)	0	0	0	47%	20%	(27%)	0%	0%	0%
11	East Towanda	Transformer	803	0	(803)	306	0	(306)	18%	0%	(18%)	7%	0%	(7%)
12	Kammer - Ormet	Line	0	552	552	0	509	509	0%	13%	13%	0%	12%	12%
13	Tiltonsville - Windsor	Line	0	794	794	5	198	193	0%	18%	18%	0%	5%	4%
14	Athenia - Saddlebrook	Line	70	979	909	74	130	56	2%	23%	21%	2%	3%	1%
15	Meadow Brook	Transformer	757	0	(757)	171	0	(171)	17%	0%	(17%)	4%	0%	(4%)
16	Waterman - West Dekalb	Line	16	911	895	1	28	27	0%	21%	21%	0%	1%	1%
17	Ruth - Turner	Line	0	639	639	0	275	275	0%	15%	15%	0%	6%	6%
18	State Line - Wolf Lake	Flowgate	834	109	(725)	133	18	(115)	19%	3%	(17%)	3%	0%	(3%)
19	Oak Grove - Galesburg	Flowgate	0	400	400	0	383	383	0%	9%	9%	0%	9%	9%
20	Wylie Ridge	Transformer	1	354	353	0	336	336	0%	8%	8%	0%	8%	8%
21	Crete - St Johns Tap	Flowgate	0	539	539	0	132	132	0%	12%	12%	0%	3%	3%
22	Glidden - West Dekalb	Line	1	668	667	0	1	1	0%	15%	15%	0%	0%	0%
23	Elrama - Mitchell	Line	563	21	(542)	116	1	(115)	13%	0%	(12%)	3%	0%	(3%)
24	Mahans Lane - Tidd	Line	498	15	(483)	121	23	(98)	11%	0%	(11%)	3%	1%	(2%)
25	Central	Interface	582	19	(563)	22	8	(14)	13%	0%	(13%)	1%	0%	(0%)

6 Presented in descending order of absolute change between January through June 2008 and January through June 2009 day-ahead and real-time congestion-event hours.

Constraint Costs

Table 7-10 Top 25 constraints affecting annual PJM congestion costs (By facility): January through June 2009 (See 2008 SOM Table 7-9)

				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 (Jan - Jun)
1	AP South	Interface	500	$6.4	($106.1)	$0.5	$113.0	$2.3	($2.7)	$1.9	$6.9	$119.9	29%
2	West	Interface	500	$17.8	($21.4)	$0.6	$39.7	$0.3	($0.1)	($0.1)	$0.4	$40.1	10%
3	East Frankfort - Crete	Line	ComEd	$4.5	($11.7)	$7.0	$23.2	$0.0	$0.0	$0.0	$0.0	$23.2	6%
4	5004/5005 Interface	Interface	500	$5.6	($15.7)	$0.8	$22.1	$0.9	$0.3	$0.1	$0.6	$22.7	6%
5	Kammer	Transformer	500	$28.2	$9.4	$6.4	$25.1	($2.2)	($6.1)	($6.9)	($2.9)	$22.2	5%
6	Mount Storm - Pruntytown	Line	AP	$1.8	($16.8)	$0.5	$19.1	$1.1	($0.8)	($0.2)	$1.7	$20.8	5%
7	Pleasant Valley - Belvidere	Line	ComEd	($2.7)	($20.9)	$2.4	$20.5	$0.7	$1.6	($3.5)	($4.5)	$16.0	4%
8	Cloverdale - Lexington	Line	AEP	$6.2	($4.0)	$1.5	$11.7	($0.0)	($2.7)	($1.9)	$0.7	$12.4	3%
9	Pana North	Flowgate	Midwest ISO	$0.1	($1.6)	$1.2	$2.9	($0.4)	$1.0	($11.5)	($13.0)	($10.1)	(2%)
10	Ruth - Turner	Line	AEP	$2.4	($6.3)	$0.5	$9.2	($1.3)	($0.7)	($0.6)	($1.2)	$8.0	2%
11	Crete - St Johns Tap	Flowgate	Midwest ISO	$2.5	($8.3)	$2.5	$13.2	($0.7)	$0.4	($4.3)	($5.4)	$7.9	2%
12	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$9.5	($14.4)	$6.8	$30.7	($5.4)	($1.2)	($19.8)	($24.0)	$6.7	2%
13	Kanawha River	Transformer	AEP	$2.0	($3.6)	$0.3	$5.8	$0.1	($0.5)	($0.1)	$0.5	$6.3	2%
14	Kammer - Ormet	Line	AEP	$4.3	($4.1)	($0.1)	$8.3	($1.6)	$0.5	($0.0)	($2.2)	$6.2	2%
15	Sammis - Wylie Ridge	Line	AP	$3.1	($2.7)	$3.4	$9.2	($0.8)	($0.3)	($2.6)	($3.2)	$6.0	1%
16	Tiltonsville - Windsor	Line	AP	$5.6	($0.4)	$0.4	$6.4	($0.3)	($0.6)	($0.9)	($0.6)	$5.8	1%
17	Kanawha - Kincaid	Line	AEP	$1.9	($3.5)	$0.2	$5.6	$0.0	$0.0	$0.0	$0.0	$5.6	1%
18	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%)
19	Kanawha River - Bradley	Line	AEP	($0.1)	($4.6)	$0.3	$4.7	($0.0)	$0.1	($0.0)	($0.1)	$4.7	1%
20	Breed - Wheatland	Line	AEP	($0.1)	($4.2)	$0.5	$4.6	$0.0	$0.0	$0.0	$0.0	$4.6	1%
21	Mount Storm	Transformer	AP	$0.8	($3.9)	($0.1)	$4.7	($0.2)	($0.2)	($0.1)	($0.1)	$4.5	1%
22	Bedington - Black Oak	Interface	500	$0.7	($3.7)	$0.1	$4.5	($0.4)	($0.0)	$0.2	($0.3)	$4.2	1%
23	Glidden - West Dekalb	Line	ComEd	($0.3)	($4.0)	$0.3	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	1%
24	Crete - East Frankfurt	Line	ComEd	$0.0	$0.0	$0.0	$0.0	($0.6)	$0.0	($3.3)	($3.9)	($3.9)	(1%)
25	Graceton - Raphael Road	Line	BGE	$0.9	($2.2)	$0.4	$3.4	$1.0	$0.3	($0.5)	$0.2	$3.6	1%

Table 7-11 Top 25 constraints affecting annual PJM congestion costs (By facility): January through June 2008 (See 2008 SOM Table 7-10)

				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	2008 (Jan - Jun)
1	AP South	Interface	500	$131.8	($191.6)	$11.2	$334.5	($14.2)	$3.9	($2.2)	($20.4)	$314.2	27%
2	Bedington - Black Oak	Interface	500	$43.7	($90.1)	$5.9	$139.7	($0.7)	($0.2)	$1.0	$0.5	$140.2	12%
3	Cloverdale - Lexington	Line	AEP	$83.9	($40.7)	$7.6	$132.2	($1.0)	($4.0)	($0.6)	$2.4	$134.5	12%
4	Mount Storm - Pruntytown	Line	AP	$12.9	($44.7)	$2.2	$59.7	($4.3)	($1.8)	$0.4	($2.0)	$57.7	5%
5	West	Interface	500	$34.7	($24.5)	$2.8	$62.0	($3.2)	$5.6	$0.9	($8.0)	$54.0	5%
6	Kammer	Transformer	500	$57.8	$11.5	$5.2	$51.5	($11.1)	($1.1)	$3.0	($7.0)	$44.5	4%
7	Atlantic - Larrabee	Line	JCPL	$40.2	($14.9)	$5.3	$60.4	($8.2)	$7.6	($4.4)	($20.2)	$40.2	3%
8	Meadow Brook	Transformer	AP	$21.6	($17.3)	$0.8	$39.8	($4.4)	($1.2)	($0.4)	($3.6)	$36.2	3%
9	Bedington	Transformer	AP	$12.4	($22.4)	$0.8	$35.6	($0.8)	($0.6)	$0.2	($0.0)	$35.6	3%
10	Sammis - Wylie Ridge	Line	AP	$1.9	($0.5)	$3.9	$6.3	($13.8)	$1.4	($22.5)	($37.8)	($31.5)	(3%)
11	Branchburg - Readington	Line	PSEG	$30.4	($11.8)	$4.7	$46.9	($6.4)	$8.8	($2.0)	($17.2)	$29.7	3%
12	5004/5005 Interface	Interface	500	$9.0	($18.3)	$1.4	$28.7	($1.7)	$2.2	$0.9	($3.0)	$25.6	2%
13	Harwood - Susquehanna	Line	PPL	$8.9	($19.6)	$0.4	$28.9	($2.7)	$2.7	($0.6)	($6.0)	$22.9	2%
14	Central	Interface	500	$11.5	($9.1)	$1.3	$21.9	($0.0)	$0.0	$0.1	($0.0)	$21.9	2%
15	Aqueduct - Doubs	Line	AP	$15.4	($1.7)	$0.3	$17.4	$0.0	($0.1)	($0.0)	$0.1	$17.4	1%
16	Axton	Transformer	AEP	$6.9	($8.8)	$0.9	$16.6	$0.0	$0.0	$0.0	$0.0	$16.6	1%
17	Buckingham - Pleasant Valley	Line	PECO	$13.0	$1.0	$1.1	$13.0	($0.7)	$1.0	$0.2	($1.5)	$11.6	1%
18	East	Interface	500	$5.8	($4.6)	$0.3	$10.8	($0.1)	($0.0)	$0.0	($0.0)	$10.7	1%
19	Black Oak	Transformer	AP	$5.9	($4.3)	$0.3	$10.5	($0.0)	($0.1)	($0.0)	$0.1	$10.5	1%
20	Seward	Transformer	PENELEC	$22.7	$13.0	($0.1)	$9.6	$0.0	$0.0	$0.0	$0.0	$9.6	1%
21	Dickerson - Plesant View	Line	Pepco	$21.0	$12.2	$1.3	$10.1	($0.2)	($0.1)	($0.6)	($0.7)	$9.4	1%
22	Cedar Grove - Clifton	Line	PSEG	$0.3	($0.2)	$0.3	$0.7	($1.9)	$6.8	($0.5)	($9.3)	($8.5)	(1%)
23	Branchburg - Flagtown	Line	PSEG	$6.4	($2.2)	$0.1	$8.7	$0.1	$0.2	($0.7)	($0.7)	$8.0	1%
24	Unclassified	Unclassified	Unclassified	$2.4	($4.6)	$0.9	$7.8	$0.0	$0.0	$0.0	$0.0	$7.8	1%
25	Amos	Transformer	AEP	$4.7	($3.3)	$0.0	$8.0	$0.2	$0.4	($0.4)	($0.6)	$7.4	1%

Congestion-Event Summary for Midwest ISO Flowgates

Table 7-12 Top congestion cost impacts from Midwest ISO flowgates affecting PJM dispatch (By facility): January through June 2009 (See 2008 SOM Table 7-11)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Pana North	$0.1	($1.6)	$1.2	$2.9	($0.4)	$1.0	($11.5)	($13.0)	($10.1)	581	300
Crete - St Johns Tap	$2.5	($8.3)	$2.5	$13.2	($0.7)	$0.4	($4.3)	($5.4)	$7.9	539	132
Dunes Acres - Michigan City	$9.5	($14.4)	$6.8	$30.7	($5.4)	($1.2)	($19.8)	($24.0)	$6.7	1,713	672
Schahfer - Burr Oak	$0.4	($1.3)	$0.6	$2.3	($2.0)	$0.4	($5.4)	($7.8)	($5.6)	62	81
Breed - Wheatland	$0.0	$0.0	$0.0	$0.0	$0.1	$0.6	($2.2)	($2.7)	($2.7)	0	128
Pleasant Prairie - Zion	($0.0)	($0.1)	$0.1	$0.2	$0.3	$0.5	($1.9)	($2.2)	($2.0)	30	45
Eugene - Bunsonville	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($1.1)	($1.3)	($1.3)	0	44
Oak Grove - Galesburg	($0.4)	($2.6)	$0.2	$2.4	$0.6	$1.1	($3.1)	($3.6)	($1.1)	400	383
State Line - Roxana	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.0	($0.4)	($0.6)	($0.6)	0	30
Lanesville	$0.2	($0.1)	$0.1	$0.4	$0.0	$0.1	($0.8)	($0.9)	($0.5)	65	32
Pawnee	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.4)	($0.4)	($0.4)	0	35
Pierce - Foster	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.3	($0.0)	($0.4)	($0.4)	0	4
State Line - Wolf Lake	$0.1	($0.2)	$0.2	$0.4	($0.0)	($0.0)	($0.2)	($0.2)	$0.3	109	18
Bunsonville - Eugene	$0.0	($0.1)	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	24	0
Burr Oak	$0.1	($0.2)	$0.4	$0.7	($0.2)	$0.0	($0.6)	($0.9)	($0.2)	24	37

Table 7-13 Top congestion cost impacts from Midwest ISO flowgates affecting PJM dispatch (By facility): January through June 2008 (See 2008 SOM Table 7-12)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
State Line - Wolf Lake	$1.5	($2.9)	$3.3	$7.7	$0.0	$0.4	($1.5)	($1.8)	$5.8	834	133
Dunes Acres - Michigan City	$0.0	$0.0	$0.0	$0.0	($0.3)	$0.8	($4.3)	($5.4)	($5.4)	0	159
Lanesville	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.4	($3.5)	($4.1)	($4.1)	0	81
Pana North	$0.7	($1.8)	$0.6	$3.1	($0.1)	$0.8	($4.3)	($5.2)	($2.1)	190	182
Breed - Wheatland	$0.0	$0.0	$0.0	$0.0	$0.1	$0.2	($0.3)	($0.4)	($0.4)	0	9
State Line - Roxana	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($0.3)	($0.3)	($0.3)	0	28
Krendale - Seneca	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.0	($0.0)	($0.2)	($0.2)	0	23
Ontario Hydro - NYISO	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.2	$0.2	($0.1)	($0.1)	0	3
Pleasant Prairie - Zion	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.1)	($0.1)	($0.1)	0	7
Eau Claire - Arpin	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	0	8
Greenfield - Lakeview	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	0	7
State Line	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
Rising	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	0	1

Congestion-Event Summary for the 500 kV System

Table 7-14 Regional constraints summary (By facility): January through June 2009 (See 2008 SOM Table 7-13)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$6.4	($106.1)	$0.5	$113.0	$2.3	($2.7)	$1.9	$6.9	$119.9	1,650	282
West	Interface	500	$17.8	($21.4)	$0.6	$39.7	$0.3	($0.1)	($0.1)	$0.4	$40.1	391	55
5004/5005 Interface	Interface	500	$5.6	($15.7)	$0.8	$22.1	$0.9	$0.3	$0.1	$0.6	$22.7	334	198
Kammer	Transformer	500	$28.2	$9.4	$6.4	$25.1	($2.2)	($6.1)	($6.9)	($2.9)	$22.2	1,554	726
Bedington - Black Oak	Interface	500	$0.7	($3.7)	$0.1	$4.5	($0.4)	($0.0)	$0.2	($0.3)	$4.2	74	61
AEP-DOM	Interface	500	$0.5	($2.7)	$0.3	$3.5	($0.5)	($0.0)	($0.3)	($0.8)	$2.7	101	57
East	Interface	500	$0.1	($0.0)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	11	0
Central	Interface	500	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.1	($0.0)	($0.1)	$0.1	19	8
Harrison - Pruntytown	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	0	4

Table 7-15 Regional constraints summary (By facility): January through June 2008 (See 2008 SOM Table 7-14)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$131.8	($191.6)	$11.2	$334.5	($14.2)	$3.9	($2.2)	($20.4)	$314.2	1,291	605
Bedington - Black Oak	Interface	500	$43.7	($90.1)	$5.9	$139.7	($0.7)	($0.2)	$1.0	$0.5	$140.2	1,170	186
West	Interface	500	$34.7	($24.5)	$2.8	$62.0	($3.2)	$5.6	$0.9	($8.0)	$54.0	700	285
Kammer	Transformer	500	$57.8	$11.5	$5.2	$51.5	($11.1)	($1.1)	$3.0	($7.0)	$44.5	1,386	767
5004/5005 Interface	Interface	500	$9.0	($18.3)	$1.4	$28.7	($1.7)	$2.2	$0.9	($3.0)	$25.6	301	143
Central	Interface	500	$11.5	($9.1)	$1.3	$21.9	($0.0)	$0.0	$0.1	($0.0)	$21.9	582	22
East	Interface	500	$5.8	($4.6)	$0.3	$10.8	($0.1)	($0.0)	$0.0	($0.0)	$10.7	182	9
Fort Martin - Harrison	Line	500	$2.0	($0.3)	$0.4	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	45	0
Juniata - Keystone	Line	500	$0.0	$0.0	$0.0	$0.0	($0.8)	$0.4	$0.2	($1.0)	($1.0)	0	20
Conemaugh - Keystone	Line	500	$0.0	($0.0)	$0.0	$0.0	($0.4)	$1.0	$0.3	($1.0)	($1.0)	2	22
Cabot - Wylie Ridge	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	$0.7	($0.1)	($0.8)	($0.8)	0	6

Zonal Congestion

Summary

Table 7-16 Congestion cost summary (By control zone): January through June 2009 (See 2008 SOM Table 7-16)

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$14.5	$5.8	$0.2	$8.9	($0.6)	$0.7	$0.4	($0.9)	$8.0
AEP	($32.1)	($91.3)	$7.9	$67.1	($3.9)	$4.0	($9.7)	($17.6)	$49.5
AP	$20.5	($48.7)	$10.5	$79.7	($4.0)	($0.6)	($18.5)	($21.9)	$57.8
BGE	$52.5	$44.5	$0.7	$8.7	$4.6	($3.3)	($0.7)	$7.2	$15.9
ComEd	($147.7)	($280.3)	($2.1)	$130.5	($5.3)	$1.1	($1.0)	($7.4)	$123.1
DAY	($6.0)	($11.0)	$0.1	$5.0	$0.6	$1.4	($0.2)	($0.9)	$4.1
DLCO	($33.2)	($52.4)	($0.0)	$19.2	($2.9)	$3.8	($0.1)	($6.7)	$12.5
DPL	$31.2	$10.0	$0.3	$21.5	($2.2)	$1.1	($0.3)	($3.6)	$17.8
Dominion	$52.8	($2.3)	$4.9	$59.9	$0.6	($3.5)	($4.8)	($0.8)	$59.2
External	($13.7)	($36.7)	$28.1	$51.2	($1.4)	($2.6)	($57.6)	($56.4)	($5.3)
JCPL	$32.1	$12.4	$0.0	$19.8	($0.1)	($2.1)	($0.1)	$1.9	$21.6
Met-Ed	$23.9	$23.5	$0.2	$0.6	($0.2)	($0.4)	($0.3)	($0.1)	$0.5
PECO	$9.4	$23.4	$0.1	($13.9)	($0.1)	$0.8	($0.1)	($1.0)	($14.9)
PENELEC	($1.9)	($20.6)	$0.3	$19.0	$1.8	$1.6	($0.2)	$0.1	$19.1
PPL	$8.1	$12.2	$1.9	($2.1)	$0.1	($0.8)	$0.2	$1.1	($1.0)
PSEG	$50.6	$40.7	$8.4	$18.3	($0.7)	$3.9	($4.4)	($9.0)	$9.3
Pepco	$96.7	$71.4	$1.5	$26.8	($3.2)	($7.5)	($1.4)	$2.8	$29.6
RECO	$1.6	$0.0	$0.1	$1.6	($0.1)	($0.0)	($0.1)	($0.2)	$1.4
Total	$159.3	($299.4)	$63.1	$521.7	($17.0)	($2.4)	($99.0)	($113.6)	$408.2

Table 7-17 Congestion cost summary (By control zone): January through June 2008 (See 2008 SOM Table 7-17)

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$43.9	$12.7	$0.3	$31.5	($0.4)	$4.4	($0.5)	($5.4)	$26.1
AEP	($198.7)	($374.9)	$6.8	$182.9	($51.4)	$10.2	($0.8)	($62.4)	$120.6
AP	$88.5	($190.5)	$21.5	$300.5	($2.2)	$10.1	($8.5)	($20.8)	$279.7
BGE	$150.1	$119.5	$1.7	$32.3	$8.1	($8.1)	($2.1)	$14.0	$46.3
ComEd	($229.4)	($374.1)	($0.3)	$144.4	($6.5)	($0.4)	($0.8)	($6.9)	$137.4
DAY	($21.6)	($34.8)	$0.2	$13.3	$0.4	$3.2	($0.0)	($2.9)	$10.4
DLCO	($80.9)	($116.7)	($0.0)	$35.8	($26.2)	$8.2	$0.0	($34.4)	$1.4
DPL	$68.4	$26.2	$0.1	$42.4	$5.9	$4.3	($0.7)	$0.8	$43.2
Dominion	$155.6	($19.9)	$13.3	$188.8	$7.4	$1.8	($9.6)	($3.9)	$184.9
External	($36.8)	($15.1)	$6.4	($15.3)	($28.8)	($9.6)	($29.6)	($48.8)	($64.1)
JCPL	$188.8	$45.9	$8.8	$151.8	($3.3)	$0.0	($9.0)	($12.4)	$139.4
Met-Ed	$54.7	$51.0	$1.7	$5.4	$1.7	$0.6	$12.3	$13.4	$18.8
PECO	$27.6	$58.3	$0.2	($30.5)	$1.3	$8.5	($0.2)	($7.5)	($38.0)
PENELEC	$1.6	($108.9)	$2.2	$112.6	($9.1)	$10.6	$1.1	($18.5)	$94.1
PPL	$17.9	$17.8	$5.9	$6.0	($0.0)	$5.5	($2.0)	($7.5)	($1.5)
PSEG	$168.4	$99.1	$12.9	$82.2	$1.2	$22.4	($11.0)	($32.2)	$50.0
Pepco	$323.4	$214.8	$5.0	$113.6	($0.8)	($3.6)	($5.5)	($2.7)	$110.9
RECO	$6.0	$0.1	$0.1	$6.0	$0.4	($0.1)	($0.1)	$0.4	$6.4
Total	$727.6	($589.4)	$86.7	$1,403.8	($102.4)	$68.2	($67.1)	($237.7)	$1,166.1

Details of Regional and Zonal Congestion

Mid-Atlantic Region Congestion-Event Summaries

AECO Control Zone

Table 7-18 AECO Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2008 SOM Table 7-18)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
West	Interface	500	$4.6	$2.2	$0.0	$2.4	$0.0	($0.0)	($0.0)	$0.0	$2.4	391	55
Kammer	Transformer	500	$2.1	$0.8	$0.0	$1.3	$0.1	($0.0)	$0.0	$0.2	$1.5	1,554	726
5004/5005 Interface	Interface	500	$1.9	$0.9	$0.0	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	334	198
Wylie Ridge	Transformer	AP	$1.8	$0.9	$0.0	$0.9	($0.0)	$0.1	$0.1	($0.0)	$0.9	354	336
Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.8	$0.2	$0.0	$0.7	$0.1	($0.0)	$0.0	$0.2	$0.8	1,713	672
Absecon - Lewis	Line	AECO	$1.0	$0.1	$0.0	$1.0	($1.2)	$0.5	($0.0)	($1.7)	($0.8)	22	149
Graceton - Raphael Road	Line	BGE	($0.7)	($0.2)	($0.0)	($0.5)	$0.1	$0.1	$0.0	$0.0	($0.5)	174	90
AP South	Interface	500	$0.7	$0.4	$0.0	$0.4	$0.0	$0.0	$0.1	$0.1	$0.5	1,650	282
Sammis - Wylie Ridge	Line	AP	$0.6	$0.2	$0.0	$0.3	$0.0	($0.0)	($0.0)	$0.0	$0.4	622	101
East Frankfort - Crete	Line	ComEd	$0.5	$0.1	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	1,333	0
Tiltonsville - Windsor	Line	AP	$0.4	$0.1	$0.0	$0.3	$0.0	($0.0)	($0.0)	$0.1	$0.3	794	198
Atlantic - Larrabee	Line	JCPL	($0.3)	($0.0)	$0.0	($0.3)	($0.1)	($0.0)	$0.0	($0.0)	($0.3)	188	45
Cloverdale - Lexington	Line	AEP	$0.4	$0.2	$0.0	$0.2	$0.0	($0.0)	$0.0	$0.1	$0.3	666	239
Crete - St Johns Tap	Flowgate	Midwest ISO	$0.3	$0.0	$0.0	$0.2	$0.0	($0.0)	$0.0	$0.0	$0.3	539	132
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

Table 7-19 AECO Control Zone top congestion cost impacts (By facility): January through June 2008 (See 2008 SOM Table 7-19)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$7.9	$3.5	$0.1	$4.5	$0.1	$0.1	($0.0)	$0.0	$4.5	1,291	605
Atlantic - Larrabee	Line	JCPL	($6.4)	($2.8)	($0.0)	($3.6)	($0.3)	$0.4	$0.0	($0.7)	($4.2)	1,466	341
West	Interface	500	$6.3	$2.7	$0.0	$3.7	$0.3	($0.2)	($0.0)	$0.4	$4.1	700	285
Churchtown	Transformer	AECO	($0.3)	($3.0)	$0.0	$2.7	$0.4	$0.3	$0.0	$0.1	$2.8	179	90
Cloverdale - Lexington	Line	AEP	$4.4	$2.2	$0.0	$2.3	$0.3	($0.1)	($0.0)	$0.4	$2.6	1,975	890
Quinton - Roadstown	Line	AECO	$6.2	$1.0	$0.0	$5.2	($1.3)	$1.4	($0.1)	($2.8)	$2.5	279	124
Kammer	Transformer	500	$3.9	$1.9	$0.0	$2.0	$0.2	($0.0)	($0.0)	$0.2	$2.3	1,386	767
Central	Interface	500	$3.6	$1.9	$0.0	$1.7	$0.0	$0.0	($0.0)	($0.0)	$1.7	582	22
Monroe	Transformer	AECO	$5.0	$0.9	$0.0	$4.1	($0.5)	$1.9	($0.1)	($2.5)	$1.6	258	113
5004/5005 Interface	Interface	500	$2.1	$0.8	$0.0	$1.2	($0.0)	($0.0)	($0.0)	$0.0	$1.3	301	143
Bedington - Black Oak	Interface	500	$2.1	$1.0	$0.0	$1.1	$0.0	$0.0	($0.0)	$0.0	$1.1	1,170	186
Sickler	Transformer	AECO	$0.9	$0.1	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	31	0
Sickler	Transformer	AECO	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.4	($0.2)	($0.8)	($0.8)	0	55
East	Interface	500	$1.5	$0.7	$0.0	$0.8	($0.0)	$0.0	$0.0	($0.0)	$0.8	182	9
Laurel - Roadstown	Line	AECO	$0.7	$0.1	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	147	0

BGE Control Zone

Table 7-20 BGE Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2008 SOM Table 7-20)

			Congestion Costs (Millions)									Event Hours	
			Day Ahead				Balancing						
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$14.1	$13.5	$0.1	$0.7	$1.2	($0.9)	($0.1)	$2.0	$2.7	1,650	282
Kammer	Transformer	500	$6.2	$5.0	$0.1	$1.3	$0.7	($0.5)	($0.2)	$1.0	$2.4	1,554	726
West	Interface	500	$8.1	$6.8	$0.2	$1.4	$0.1	($0.1)	($0.0)	$0.2	$1.6	391	55
Wylie Ridge	Transformer	AP	$3.6	$3.4	$0.1	$0.3	$0.6	($0.7)	($0.2)	$1.2	$1.5	354	336
5004/5005 Interface	Interface	500	$1.4	$0.8	$0.1	$0.6	$0.2	($0.2)	($0.1)	$0.4	$1.0	334	198
Graceton - Raphael Road	Line	BGE	$2.9	$2.0	$0.0	$1.0	$0.1	$0.1	($0.1)	($0.1)	$0.9	174	90
Mount Storm - Pruntytown	Line	AP	$3.2	$2.9	$0.0	$0.2	$0.4	($0.2)	($0.0)	$0.6	$0.8	523	25
Pumphrey - Westport	Line	Pepco	$0.5	($0.1)	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	573	0
Dunes Acres - Michigan City	Flowgate	Midwest ISO	$2.1	$1.8	$0.0	$0.3	$0.3	($0.0)	($0.0)	$0.3	$0.6	1,713	672
Cloverdale - Lexington	Line	AEP	$2.2	$2.0	$0.0	$0.2	$0.2	($0.1)	($0.0)	$0.3	$0.5	666	239
Sammis - Wylie Ridge	Line	AP	$1.4	$1.1	$0.0	$0.3	$0.1	($0.1)	($0.0)	$0.1	$0.4	622	101
Tiltonsville - Windsor	Line	AP	$0.8	$0.6	$0.0	$0.2	$0.1	($0.0)	($0.0)	$0.1	$0.3	794	198
Five Forks - Rock Ridge	Line	BGE	$0.4	$0.1	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	55	0
East Frankfort - Crete	Line	ComEd	$1.2	$1.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	1,333	0
Bedington - Black Oak	Interface	500	$0.8	$0.7	$0.0	$0.1	$0.1	($0.0)	($0.0)	$0.1	$0.2	74	61

Table 7-21 BGE Control Zone top congestion cost impacts (By facility): January through June 2008 (See 2008 SOM Table 7-21)

			Congestion Costs (Millions)									Event Hours	
			Day Ahead				Balancing						
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$50.7	$40.9	$0.4	$10.1	$4.0	($3.1)	($0.6)	$6.5	$16.6	1,291	605
West	Interface	500	$10.2	$7.4	$0.1	$2.9	$0.8	($0.7)	($0.4)	$1.1	$4.1	700	285
Kammer	Transformer	500	$9.9	$8.0	$0.2	$2.2	$0.8	($0.8)	($0.2)	$1.4	$3.6	1,386	767
Aqueduct - Doubs	Line	AP	$7.8	$4.6	$0.0	$3.2	($0.0)	($0.0)	($0.0)	$0.0	$3.2	145	7
Pumphrey - Westport	Line	Pepco	$2.7	($0.3)	$0.0	$3.0	$0.0	$0.0	$0.0	$0.0	$3.0	297	0
Bedington - Black Oak	Interface	500	$20.3	$18.9	$0.2	$1.7	$0.8	($0.5)	($0.1)	$1.2	$3.0	1,170	186
Mount Storm - Pruntytown	Line	AP	$8.9	$7.4	$0.0	$1.5	$0.4	($1.0)	($0.0)	$1.4	$2.9	333	223
Dickerson - Plesant View	Line	Pepco	$5.4	$3.4	$0.2	$2.2	$0.3	($0.1)	($0.1)	$0.3	$2.6	418	118
Brandon Shores - Riverside	Line	BGE	$1.1	($0.6)	$0.0	$1.7	($0.4)	$0.2	($0.0)	($0.6)	$1.1	94	30
Branchburg - Readington	Line	PSEG	($2.5)	($2.0)	($0.1)	($0.6)	($0.2)	$0.3	$0.0	($0.5)	($1.1)	1,103	271
Cloverdale - Lexington	Line	AEP	$21.0	$22.4	$0.3	($1.0)	$1.4	($0.9)	($0.3)	$2.0	$1.0	1,975	890
5004/5005 Interface	Interface	500	$1.8	$1.0	$0.1	$0.9	$0.1	($0.1)	($0.0)	$0.2	$1.0	301	143
Green Street - Westport	Line	BGE	$0.9	$0.0	$0.0	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	94	0
Sammis - Wylie Ridge	Line	AP	$0.6	$0.5	$0.0	$0.1	$0.5	($0.5)	($0.2)	$0.7	$0.9	249	405
Atlantic - Larrabee	Line	JCPL	($1.9)	($1.4)	($0.1)	($0.5)	($0.2)	$0.2	$0.1	($0.3)	($0.8)	1,466	341

DPL Control Zone

Table 7-22 DPL Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2008 SOM Table 7-22)

			Congestion Costs (Millions)									Event Hours	
			Day Ahead				Balancing						
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
West	Interface	500	$8.6	$3.6	$0.0	$5.1	($0.0)	$0.0	($0.0)	($0.1)	$5.0	391	55
Kammer	Transformer	500	$4.1	$1.0	$0.0	$3.2	($0.1)	$0.1	($0.0)	($0.3)	$2.9	1,554	726
Short - Laurel	Line	DPL	$0.0	$0.0	$0.0	$0.0	($2.1)	$0.2	($0.1)	($2.4)	($2.4)	0	0
Wylie Ridge	Transformer	AP	$3.4	$1.3	$0.0	$2.1	$0.2	$0.2	($0.0)	($0.0)	$2.1	354	336
5004/5005 Interface	Interface	500	$3.7	$1.5	$0.0	$2.2	$0.0	$0.2	($0.1)	($0.3)	$2.0	334	198
AP South	Interface	500	$2.0	$0.6	$0.0	$1.4	$0.0	$0.1	($0.0)	($0.1)	$1.4	1,650	282
Dunes Acres - Michigan City	Flowgate	Midwest ISO	$1.5	$0.2	($0.0)	$1.3	($0.1)	$0.0	$0.0	($0.1)	$1.3	1,713	672
Sammis - Wylie Ridge	Line	AP	$1.2	$0.2	$0.0	$1.0	($0.0)	($0.0)	($0.0)	($0.0)	$0.9	622	101
East Frankfort - Crete	Line	ComEd	$0.9	$0.2	($0.0)	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	1,333	0
Cloverdale - Lexington	Line	AEP	$0.9	$0.2	$0.0	$0.7	($0.0)	$0.0	($0.0)	($0.0)	$0.6	666	239
Church - I.B. Corners	Line	DPL	$0.7	$0.1	$0.0	$0.6	($0.0)	$0.0	($0.0)	($0.0)	$0.6	45	5
Tiltonsville - Windsor	Line	AP	$0.7	$0.1	$0.0	$0.6	($0.0)	$0.0	($0.0)	($0.1)	$0.5	794	198
Graceton - Raphael Road	Line	BGE	($1.3)	($0.3)	($0.0)	($1.0)	$0.3	($0.3)	$0.0	$0.5	($0.5)	174	90
Crete - St Johns Tap	Flowgate	Midwest ISO	$0.5	$0.0	($0.0)	$0.5	($0.0)	$0.0	$0.0	($0.0)	$0.5	539	132
Edgemoor - Harmony	Line	DPL	$0.8	$0.3	$0.0	$0.5	($0.1)	($0.0)	($0.0)	($0.1)	$0.4	28	7

Table 7-23 DPL Control Zone top congestion cost impacts (By facility): January through June 2008 (See 2008 SOM Table 7-23)

			Congestion Costs (Millions)									Event Hours	
			Day Ahead				Balancing						
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$14.6	$6.7	$0.1	$8.0	$1.3	$1.0	($0.0)	$0.3	$8.2	1,291	605
West	Interface	500	$9.8	$3.5	$0.0	$6.3	$0.8	$0.5	($0.0)	$0.2	$6.5	700	285
Cloverdale - Lexington	Line	AEP	$8.0	$2.9	$0.1	$5.2	$0.8	$0.0	($0.1)	$0.7	$5.9	1,975	890
Kammer	Transformer	500	$6.6	$2.7	$0.0	$3.9	$0.7	$0.3	($0.0)	$0.4	$4.3	1,386	767
Central	Interface	500	$6.1	$2.9	$0.0	$3.3	$0.0	($0.0)	$0.0	$0.1	$3.3	582	22
North Seaford - Pine Street	Line	DPL	$4.3	$1.0	$0.0	$3.3	$0.1	$0.1	$0.0	$0.0	$3.3	114	39
Atlantic - Larrabee	Line	JCPL	($4.3)	($1.9)	($0.0)	($2.5)	($0.4)	($0.0)	$0.0	($0.4)	($2.9)	1,466	341
Bedington - Black Oak	Interface	500	$4.3	$1.6	$0.0	$2.6	$0.2	$0.0	($0.0)	$0.1	$2.7	1,170	186
Red Lion At5n	Transformer	DPL	$3.8	$1.4	$0.1	$2.5	$0.0	($0.1)	$0.0	$0.1	$2.5	53	3
5004/5005 Interface	Interface	500	$3.3	$1.2	$0.0	$2.1	$0.3	$0.1	($0.0)	$0.2	$2.4	301	143
Branchburg - Readington	Line	PSEG	($3.3)	($1.4)	($0.1)	($1.9)	($0.2)	$0.3	$0.1	($0.4)	($2.3)	1,103	271
East	Interface	500	$2.4	$0.9	$0.0	$1.6	$0.0	($0.0)	$0.0	$0.0	$1.6	182	9
Dickerson - Plesant View	Line	Pepco	$2.2	$1.0	$0.0	$1.2	$0.1	($0.1)	($0.0)	$0.2	$1.4	418	118
Buckingham - Pleasant Valley	Line	PECO	($1.7)	($0.6)	($0.1)	($1.2)	($0.1)	$0.0	$0.0	($0.0)	($1.2)	556	60
Mount Storm - Pruntytown	Line	AP	$1.2	$0.5	($0.0)	$0.7	$0.2	$0.1	$0.0	$0.0	$0.8	333	223

JCPL Control Zone

Table 7-24 JCPL Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2008 SOM Table 7-24)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
West	Interface	500	$9.7	$3.9	$0.0	$5.7	$0.0	($0.1)	($0.0)	$0.1	$5.8	391	55
5004/5005 Interface	Interface	500	$4.8	$1.9	$0.0	$2.9	$0.1	($0.9)	($0.0)	$0.9	$3.8	334	198
Kammer	Transformer	500	$4.5	$1.7	$0.0	$2.8	($0.0)	($0.4)	($0.0)	$0.3	$3.2	1,554	726
Wylie Ridge	Transformer	AP	$3.9	$1.4	$0.0	$2.5	$0.1	($0.6)	($0.0)	$0.7	$3.2	354	336
Atlantic - Larrabee	Line	JCPL	$1.8	$0.4	$0.0	$1.5	($0.6)	($0.5)	($0.0)	($0.1)	$1.3	188	45
Athenia - Saddlebrook	Line	PSEG	($1.3)	($0.3)	($0.0)	($1.0)	($0.0)	$0.1	$0.0	($0.1)	($1.1)	979	130
Dunes Acres - Michigan City	Flowgate	Midwest ISO	$1.9	$0.8	($0.1)	$1.0	($0.0)	($0.1)	$0.0	$0.1	$1.1	1,713	672
Sammis - Wylie Ridge	Line	AP	$1.4	$0.5	$0.0	$0.9	$0.0	$0.0	($0.0)	$0.0	$0.9	622	101
East Frankfort - Crete	Line	ComEd	$1.2	$0.5	($0.0)	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	1,333	0
Cloverdale - Lexington	Line	AEP	$0.8	$0.3	$0.0	$0.5	$0.0	($0.0)	($0.0)	$0.0	$0.6	666	239
Graceton - Raphael Road	Line	BGE	($1.3)	($0.7)	($0.0)	($0.6)	$0.2	$0.2	$0.0	$0.1	($0.5)	174	90
Buckingham - Pleasant Valley	Line	PECO	$0.7	$0.2	$0.0	$0.4	($0.1)	($0.1)	($0.0)	$0.0	$0.5	131	59
Crete - St Johns Tap	Flowgate	Midwest ISO	$0.7	$0.3	$0.0	$0.4	$0.0	$0.0	($0.0)	$0.0	$0.4	539	132
Tiltonsville - Windsor	Line	AP	$0.9	$0.5	$0.0	$0.4	($0.0)	($0.0)	($0.0)	($0.0)	$0.4	794	198
Leonia - New Milford	Line	PSEG	($0.5)	($0.1)	($0.0)	($0.3)	($0.0)	$0.0	$0.0	($0.0)	($0.4)	2,164	30

Table 7-25 JCPL Control Zone top congestion cost impacts (By facility): January through June 2008 (See 2008 SOM Table 7-25)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Atlantic - Larrabee	Line	JCPL	$46.9	$2.3	$2.2	$46.8	($2.6)	$2.7	($2.4)	($7.6)	$39.1	1,466	341
Branchburg - Readington	Line	PSEG	$27.7	$4.5	$2.2	$25.3	($2.2)	($0.8)	($1.8)	($3.3)	$22.1	1,103	271
West	Interface	500	$16.0	$5.9	$0.2	$10.3	($0.0)	($0.4)	($0.6)	($0.2)	$10.1	700	285
AP South	Interface	500	$15.5	$6.1	$0.7	$10.1	$0.1	($0.3)	($1.0)	($0.6)	$9.5	1,291	605
Cloverdale - Lexington	Line	AEP	$11.1	$3.1	$0.7	$8.7	$0.2	($0.1)	($0.5)	($0.2)	$8.5	1,975	890
Central	Interface	500	$10.0	$2.9	$0.5	$7.5	$0.0	($0.0)	($0.0)	($0.0)	$7.5	582	22
Kammer	Transformer	500	$10.8	$3.5	$0.4	$7.7	($0.1)	($0.1)	($0.3)	($0.3)	$7.4	1,386	767
Buckingham - Pleasant Valley	Line	PECO	$9.9	$3.5	$0.2	$6.7	($0.1)	($0.1)	($0.1)	($0.1)	$6.5	556	60
Branchburg - Flagtown	Line	PSEG	$6.2	$1.7	$0.0	$4.5	$0.8	$0.3	($0.1)	$0.4	$4.9	105	27
5004/5005 Interface	Interface	500	$6.4	$2.0	$0.3	$4.6	$0.0	$0.0	($0.2)	($0.2)	$4.5	301	143
Cedar Grove - Roseland	Line	PSEG	($4.5)	($0.8)	($0.1)	($3.7)	($0.1)	($0.2)	$0.1	$0.1	($3.6)	398	71
Harwood - Susquehanna	Line	PPL	$4.5	$1.3	$0.0	$3.2	$0.0	($0.0)	($0.0)	$0.0	$3.2	110	95
East	Interface	500	$3.3	$1.0	$0.0	$2.3	($0.0)	($0.0)	($0.0)	($0.0)	$2.3	182	9
Bedington - Black Oak	Interface	500	$3.2	$1.3	$0.5	$2.3	($0.0)	($0.0)	($0.2)	($0.2)	$2.2	1,170	186
Dickerson - Plesant View	Line	Pepco	$3.1	$1.2	$0.2	$2.2	$0.0	($0.1)	($0.1)	($0.1)	$2.1	418	118

Met-Ed Control Zone

Table 7-26 Met-Ed Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2008 SOM Table 7-26)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Brunner Island - Yorkana	Line	Met-Ed	$0.1	($0.3)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	33	16
Graceton - Raphael Road	Line	BGE	($1.0)	($1.5)	($0.0)	$0.5	$0.1	$0.2	$0.0	($0.1)	$0.4	174	90
AP South	Interface	500	$1.6	$1.3	$0.0	$0.4	($0.0)	($0.0)	($0.0)	($0.0)	$0.4	1,650	282
5004/5005 Interface	Interface	500	$3.1	$3.5	$0.0	($0.4)	($0.1)	($0.3)	($0.0)	$0.1	($0.3)	334	198
Kammer	Transformer	500	$3.4	$3.9	$0.0	($0.4)	($0.0)	($0.2)	($0.1)	$0.1	($0.3)	1,554	726
Wylie Ridge	Transformer	AP	$3.1	$2.8	$0.0	$0.3	($0.1)	($0.2)	($0.0)	$0.0	$0.3	354	336
Dunes Acres - Michigan City	Flowgate	Midwest ISO	$1.3	$1.5	$0.0	($0.3)	($0.0)	($0.0)	($0.0)	$0.0	($0.3)	1,713	672
Tiltonsville - Windsor	Line	AP	$0.6	$0.9	$0.0	($0.3)	$0.0	($0.1)	($0.0)	$0.0	($0.2)	794	198
East Frankfort - Crete	Line	ComEd	$0.8	$0.9	$0.0	($0.2)	$0.0	$0.0	$0.0	$0.0	($0.2)	1,333	0
Middletown Jct	Transformer	Met-Ed	$0.2	($0.0)	$0.0	$0.3	($0.1)	$0.0	($0.0)	($0.1)	$0.2	59	12
West	Interface	500	$6.9	$6.8	$0.0	$0.1	($0.0)	($0.1)	($0.0)	$0.0	$0.2	391	55
Crete - St Johns Tap	Flowgate	Midwest ISO	$0.4	$0.6	$0.0	($0.1)	$0.0	$0.0	($0.0)	($0.0)	($0.1)	539	132
Sammis - Wylie Ridge	Line	AP	$1.0	$1.2	$0.0	($0.2)	$0.0	($0.0)	($0.0)	$0.0	($0.1)	622	101
Cloverdale - Lexington	Line	AEP	$0.7	$0.8	$0.0	($0.1)	($0.0)	($0.0)	($0.0)	$0.0	($0.1)	666	239
Bedington	Transformer	AP	$0.1	($0.0)	$0.0	$0.2	($0.0)	$0.0	($0.0)	($0.0)	$0.1	247	103

Table 7-27 Met-Ed Control Zone top congestion cost impacts (By facility): January through June 2008 (See 2008 SOM Table 7-27)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$11.3	$11.7	$0.4	$0.0	$0.4	($0.1)	$3.6	$4.1	$4.1	1,291	605
Kammer	Transformer	500	$5.7	$5.6	$0.4	$0.6	$0.0	($0.1)	$1.5	$1.6	$2.2	1,386	767
Cloverdale - Lexington	Line	AEP	$7.0	$6.5	$0.5	$1.1	$0.1	$0.0	$0.8	$0.8	$1.9	1,975	890
Bedington - Black Oak	Interface	500	$3.6	$2.8	$0.1	$0.8	$0.0	$0.0	$0.7	$0.7	$1.5	1,170	186
Bedington	Transformer	AP	$1.1	$0.2	$0.0	$0.9	$0.0	$0.0	$0.2	$0.2	$1.1	593	149
West	Interface	500	$7.2	$8.1	$0.3	($0.7)	$0.2	($0.0)	$1.4	$1.6	$0.9	700	285
Collins - Middletown Jct	Line	Met-Ed	$1.0	($0.0)	$0.0	$1.0	($0.0)	$0.2	$0.1	($0.1)	$0.9	265	31
Sammis - Wylie Ridge	Line	AP	$0.5	$0.4	$0.0	$0.1	$0.2	($0.0)	$0.5	$0.7	$0.7	249	405
East Towanda	Transformer	PENELEC	$0.3	$0.4	$0.0	$0.0	$0.1	($0.1)	$0.4	$0.6	$0.6	803	306
Harwood - Susquehanna	Line	PPL	$1.2	$0.4	$0.0	$0.8	$0.0	$0.2	($0.0)	($0.2)	$0.6	110	95
Mount Storm - Pruntytown	Line	AP	$1.0	$0.7	($0.0)	$0.2	($0.0)	$0.0	$0.3	$0.3	$0.6	333	223
Altoona - Raystown	Line	PENELEC	$0.3	$0.3	$0.0	$0.0	$0.0	($0.1)	$0.4	$0.5	$0.5	77	48
Meadow Brook	Transformer	AP	$0.4	$0.3	$0.1	$0.1	$0.0	$0.0	$0.3	$0.3	$0.4	757	171
5004/5005 Interface	Interface	500	$2.8	$2.8	($0.2)	($0.2)	$0.1	($0.0)	$0.5	$0.6	$0.4	301	143
Aqueduct - Doubs	Line	AP	($0.5)	($0.1)	$0.0	($0.4)	$0.0	$0.0	$0.0	$0.0	($0.3)	145	7

PECO Control Zone

Table 7-28 PECO Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2008 SOM Table 7-28)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Kammer	Transformer	500	$1.4	$4.9	$0.0	($3.6)	($0.2)	$0.1	$0.0	($0.2)	($3.8)	1,554	726
West	Interface	500	$3.0	$6.2	$0.0	($3.1)	($0.0)	($0.0)	($0.0)	($0.0)	($3.1)	391	55
AP South	Interface	500	$0.4	$2.4	$0.0	($2.0)	($0.0)	$0.0	$0.0	($0.0)	($2.1)	1,650	282
Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.8	$2.2	($0.0)	($1.4)	($0.0)	$0.0	($0.0)	($0.1)	($1.5)	1,713	672
Graceton - Raphael Road	Line	BGE	($0.6)	($2.0)	($0.0)	$1.4	$0.3	$0.4	($0.0)	($0.1)	$1.2	174	90
5004/5005 Interface	Interface	500	$2.0	$3.1	$0.0	($1.2)	$0.0	$0.0	$0.0	($0.0)	($1.2)	334	198
Wylie Ridge	Transformer	AP	$1.3	$2.3	$0.0	($0.9)	($0.1)	$0.0	($0.1)	($0.1)	($1.1)	354	336
East Frankfort - Crete	Line	ComEd	$0.4	$1.2	($0.0)	($0.8)	$0.0	$0.0	$0.0	$0.0	($0.8)	1,333	0
Crete - St Johns Tap	Flowgate	Midwest ISO	$0.2	$0.9	($0.0)	($0.7)	($0.0)	$0.0	($0.0)	($0.1)	($0.8)	539	132
Sammis - Wylie Ridge	Line	AP	$0.5	$1.1	$0.0	($0.7)	($0.0)	($0.0)	($0.0)	($0.0)	($0.7)	622	101
Tiltonsville - Windsor	Line	AP	$0.3	$1.0	$0.0	($0.7)	($0.0)	($0.0)	$0.0	$0.0	($0.7)	794	198
Cloverdale - Lexington	Line	AEP	$0.3	$1.0	$0.0	($0.6)	($0.0)	($0.0)	($0.0)	$0.0	($0.6)	666	239
Mount Storm - Pruntytown	Line	AP	$0.1	$0.5	$0.0	($0.5)	$0.0	$0.0	$0.0	($0.0)	($0.5)	523	25
Conastone	Transformer	BGE	($0.0)	($0.3)	$0.0	$0.3	$0.0	($0.0)	$0.0	$0.0	$0.3	17	1
Krendale - Seneca	Line	AP	$0.2	$0.5	$0.0	($0.3)	$0.0	$0.0	$0.0	$0.0	($0.3)	225	0

Table 7-29 PECO Control Zone top congestion cost impacts (By facility): January through June 2008 (See 2008 SOM Table 7-29)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$5.0	$17.9	$0.0	($12.9)	$0.1	$1.2	$0.0	($1.0)	($14.0)	1,291	605
West	Interface	500	$3.6	$11.4	$0.1	($7.7)	$0.2	$1.4	$0.0	($1.2)	($8.9)	700	285
Cloverdale - Lexington	Line	AEP	$3.8	$8.4	$0.0	($4.6)	$0.3	$0.9	$0.1	($0.5)	($5.1)	1,975	890
Kammer	Transformer	500	$3.2	$7.5	$0.0	($4.3)	$0.3	$0.6	$0.0	($0.3)	($4.6)	1,386	767
Bedington - Black Oak	Interface	500	$1.2	$5.3	$0.0	($4.0)	$0.0	$0.2	$0.0	($0.1)	($4.2)	1,170	186
East	Interface	500	$2.5	($0.1)	$0.0	$2.6	($0.0)	($0.1)	$0.0	$0.1	$2.6	182	9
Whitpain	Transformer	PECO	$2.5	($0.8)	$0.1	$3.4	($0.3)	$0.5	($0.1)	($1.0)	$2.4	60	48
Branchburg - Readington	Line	PSEG	($1.8)	($4.5)	($0.0)	$2.6	($0.0)	$0.2	($0.0)	($0.3)	$2.3	1,103	271
5004/5005 Interface	Interface	500	$1.4	$3.4	$0.0	($2.0)	$0.1	$0.3	$0.0	($0.1)	($2.1)	301	143
Dickerson - Plesant View	Line	Pepco	$1.2	$3.3	$0.0	($2.0)	($0.0)	($0.0)	$0.0	$0.0	($2.0)	418	118
Bradford - Planebrook	Line	PECO	$0.7	($1.1)	($0.0)	$1.8	$0.0	$0.1	$0.0	($0.1)	$1.7	124	23
Mount Storm - Pruntytown	Line	AP	$0.3	$1.5	($0.0)	($1.2)	$0.0	$0.2	$0.0	($0.1)	($1.3)	333	223
Buckingham - Pleasant Valley	Line	PECO	($3.9)	($2.6)	($0.0)	($1.3)	$0.1	$0.1	$0.0	($0.0)	($1.3)	556	60
Atlantic - Larrabee	Line	JCPL	($5.4)	($4.1)	($0.0)	($1.4)	($0.1)	($0.3)	($0.1)	$0.1	($1.3)	1,466	341
Central	Interface	500	$4.8	$6.1	$0.0	($1.3)	$0.0	$0.0	$0.0	$0.0	($1.3)	582	22

PENELEC Control Zone

Table 7-30 PENELEC Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2008 SOM Table 7-30)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
West	Interface	500	($2.2)	($15.2)	($0.0)	$13.0	$0.1	$0.1	$0.0	($0.1)	$13.0	391	55
AP South	Interface	500	($9.9)	($20.7)	($0.0)	$10.8	$0.8	$0.3	$0.1	$0.5	$11.3	1,650	282
Wylie Ridge	Transformer	AP	$1.5	$10.3	$0.1	($8.8)	($0.6)	($0.7)	($0.0)	$0.1	($8.7)	354	336
5004/5005 Interface	Interface	500	($1.6)	($9.2)	($0.0)	$7.6	$0.4	$1.5	$0.0	($1.1)	$6.5	334	198
Kammer	Transformer	500	$2.8	$9.0	$0.2	($6.0)	($0.2)	($0.7)	($0.1)	$0.4	($5.6)	1,554	726
Sammis - Wylie Ridge	Line	AP	$1.0	$3.7	$0.1	($2.7)	($0.1)	($0.1)	$0.0	($0.0)	($2.7)	622	101
Mount Storm - Pruntytown	Line	AP	($2.4)	($4.6)	($0.0)	$2.2	$0.3	$0.1	$0.0	$0.3	$2.5	523	25
Dunes Acres - Michigan City	Flowgate	Midwest ISO	$2.6	$5.1	($0.0)	($2.5)	$0.2	($0.5)	($0.0)	$0.6	($1.8)	1,713	672
Seward	Transformer	PENELEC	$3.2	$1.8	($0.0)	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	57	0
Tiltonsville - Windsor	Line	AP	$0.7	$2.1	$0.0	($1.4)	$0.1	$0.0	($0.0)	$0.0	($1.4)	794	198
Homer City - Seward	Line	PENELEC	$2.8	$1.5	($0.0)	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	58	0
East Frankfort - Crete	Line	ComEd	$1.5	$2.7	$0.0	($1.2)	$0.0	$0.0	$0.0	$0.0	($1.2)	1,333	0
Krendale - Seneca	Line	AP	$0.5	$1.4	$0.0	($0.9)	$0.0	$0.0	$0.0	$0.0	($0.9)	225	0
Homer City	Transformer	PENELEC	$0.9	$0.1	($0.0)	$0.8	($0.0)	$0.0	$0.0	($0.0)	$0.8	145	2
Homer City - Shelocta	Line	PENELEC	($1.7)	($2.5)	($0.0)	$0.8	($0.1)	$0.1	$0.0	($0.1)	$0.7	200	55

Table 7-31 PENELEC Control Zone top congestion cost impacts (By facility): January through June 2008 (See 2008 SOM Table 7-31)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
West	Interface	500	($3.2)	($25.9)	($0.3)	$22.5	$0.2	$1.2	$0.2	($0.8)	$21.6	700	285
AP South	Interface	500	($18.8)	($37.2)	$0.2	$18.6	$1.9	$0.4	$0.7	$2.2	$20.8	1,291	605
Bedington - Black Oak	Interface	500	($14.6)	($32.0)	$0.1	$17.5	$0.6	$0.3	$0.1	$0.4	$18.0	1,170	186
Kammer	Transformer	500	$6.0	$19.2	$0.3	($12.9)	($1.0)	($0.9)	$0.5	$0.4	($12.5)	1,386	767
5004/5005 Interface	Interface	500	($2.0)	($12.2)	($0.0)	$10.2	($0.4)	$0.5	$0.0	($0.8)	$9.4	301	143
Seward	Transformer	PENELEC	$22.2	$13.1	$0.0	$9.2	$0.0	$0.0	$0.0	$0.0	$9.2	200	0
Mount Storm - Pruntytown	Line	AP	($7.0)	($14.4)	($0.0)	$7.3	$0.4	$0.1	$0.0	$0.4	$7.7	333	223
Central	Interface	500	($0.4)	($7.0)	($0.0)	$6.6	$0.0	$0.0	$0.0	$0.0	$6.6	582	22
East Towanda	Transformer	PENELEC	$14.1	($8.8)	$1.0	$23.8	($9.2)	$8.4	($0.5)	($18.1)	$5.7	803	306
Krendale - Seneca	Line	AP	$1.6	$4.4	$0.1	($2.7)	$0.0	($0.0)	($0.0)	$0.0	($2.7)	407	16
Bedington	Transformer	AP	($0.5)	($3.0)	$0.0	$2.5	$0.1	$0.0	$0.0	$0.2	$2.7	593	149
Branchburg - Readington	Line	PSEG	$0.7	($1.8)	($0.0)	$2.5	($0.0)	($0.1)	$0.0	$0.1	$2.6	1,103	271
Sammis - Wylie Ridge	Line	AP	$0.5	$2.1	$0.1	($1.5)	($0.7)	($0.1)	($0.1)	($0.7)	($2.2)	249	405
Elrama - Mitchell	Line	AP	$1.0	$3.1	$0.1	($2.1)	($0.1)	($0.1)	$0.0	($0.0)	($2.1)	563	116
Krendale - Shanorma	Line	AP	$1.0	$2.7	$0.0	($1.6)	$0.0	$0.0	$0.0	$0.0	($1.6)	326	0

Pepco Control Zone

Table 7-32 Pepco Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2008 SOM Table 7-32)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$32.9	$25.1	$0.5	$8.3	($0.9)	($2.2)	($0.5)	$0.9	$9.1	1,650	282
Kammer	Transformer	500	$11.8	$8.5	$0.2	$3.5	($0.6)	($1.4)	($0.2)	$0.6	$4.1	1,554	726
Mount Storm - Pruntytown	Line	AP	$7.5	$5.8	$0.1	$1.9	($0.0)	($0.5)	($0.0)	$0.5	$2.3	523	25
West	Interface	500	$8.1	$6.0	$0.0	$2.1	($0.0)	($0.1)	($0.0)	$0.0	$2.2	391	55
Wylie Ridge	Transformer	AP	$6.2	$4.9	$0.0	$1.3	($0.3)	($0.7)	($0.0)	$0.3	$1.7	354	336
Cloverdale - Lexington	Line	AEP	$5.0	$3.7	$0.1	$1.4	($0.1)	($0.3)	($0.1)	$0.1	$1.5	666	239
Dunes Acres - Michigan City	Flowgate	Midwest ISO	$3.9	$2.7	($0.0)	$1.2	($0.1)	($0.4)	($0.0)	$0.3	$1.5	1,713	672
Graceton - Raphael Road	Line	BGE	$3.1	$2.1	$0.1	$1.0	($0.4)	($0.5)	($0.1)	($0.0)	$1.0	174	90
Sammis - Wylie Ridge	Line	AP	$2.4	$1.7	$0.0	$0.8	($0.1)	($0.1)	($0.0)	($0.0)	$0.8	622	101
Mount Storm	Transformer	AP	$1.7	$1.3	$0.0	$0.5	($0.0)	($0.3)	($0.0)	$0.2	$0.7	123	46
East Frankfort - Crete	Line	ComEd	$2.2	$1.5	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	1,333	0
Bedington - Black Oak	Interface	500	$1.8	$1.3	$0.0	$0.5	($0.0)	($0.1)	($0.0)	$0.1	$0.6	74	61
Tiltonsville - Windsor	Line	AP	$1.4	$0.9	$0.1	$0.5	($0.0)	($0.1)	($0.1)	($0.0)	$0.5	794	198
Crete - St Johns Tap	Flowgate	Midwest ISO	$1.3	$1.0	$0.0	$0.3	$0.0	($0.2)	$0.0	$0.2	$0.5	539	132
5004/5005 Interface	Interface	500	$1.2	$0.8	$0.0	$0.4	($0.0)	($0.1)	($0.0)	$0.1	$0.4	334	198

Table 7-33 Pepco Control Zone top congestion cost impacts (By facility): January through June 2008 (See 2008 SOM Table 7-33)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$110.2	$76.5	$1.2	$34.9	($2.0)	($0.9)	($1.3)	($2.4)	$32.5	1,291	605
Cloverdale - Lexington	Line	AEP	$51.8	$34.5	$1.6	$18.9	$1.5	($1.8)	($1.4)	$1.9	$20.8	1,975	890
Bedington - Black Oak	Interface	500	$50.1	$33.5	$0.5	$17.1	($0.3)	($0.3)	($0.2)	($0.2)	$16.9	1,170	186
Aqueduct - Doubs	Line	AP	$24.1	$14.8	$0.1	$9.3	$0.1	($0.0)	($0.0)	$0.1	$9.4	145	7
Kammer	Transformer	500	$21.0	$13.3	$0.5	$8.2	($1.0)	($0.8)	($0.4)	($0.6)	$7.6	1,386	767
Mount Storm - Pruntytown	Line	AP	$21.4	$15.2	$0.1	$6.3	$0.1	($1.1)	($0.1)	$1.1	$7.4	333	223
Dickerson - Plesant View	Line	Pepco	$16.6	$11.2	$0.5	$5.9	($0.2)	($0.3)	($0.5)	($0.4)	$5.5	418	118
West	Interface	500	$11.0	$6.3	$0.3	$5.1	($0.6)	($0.4)	($0.5)	($0.6)	$4.5	700	285
Central	Interface	500	($6.7)	($4.9)	($0.1)	($1.9)	$0.0	$0.0	($0.0)	$0.0	($1.9)	582	22
Black Oak	Transformer	AP	$5.6	$3.8	$0.0	$1.8	($0.0)	($0.1)	($0.0)	$0.0	$1.8	337	11
Branchburg - Readington	Line	PSEG	($5.3)	($3.5)	($0.2)	($2.0)	$0.3	$0.2	$0.2	$0.2	($1.8)	1,103	271
Brighton	Transformer	Pepco	$5.0	$3.3	$0.0	$1.7	($0.1)	$0.2	($0.1)	($0.4)	$1.4	20	24
Atlantic - Larrabee	Line	JCPL	($3.9)	($2.7)	($0.1)	($1.3)	$0.2	$0.2	$0.1	$0.1	($1.2)	1,466	341
Buckingham - Pleasant Valley	Line	PECO	($2.2)	($1.3)	($0.1)	($1.0)	$0.0	$0.0	$0.0	$0.0	($1.0)	556	60
Burnham - Munster	Line	ComEd	$2.4	$1.9	$0.0	$0.6	$0.6	$0.2	($0.0)	$0.4	$1.0	416	140

PPL Control Zone

Table 7-34 PPL Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2008 SOM Table 7-34)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Kammer	Transformer	500	$0.8	$2.3	$0.4	($1.1)	($0.1)	($0.2)	($0.1)	($0.1)	($1.1)	1,554	726
Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.3	$1.4	($0.1)	($1.1)	($0.2)	($0.1)	$0.0	$0.0	($1.1)	1,713	672
AP South	Interface	500	$0.4	($0.2)	$0.2	$0.7	$0.0	($0.0)	$0.1	$0.1	$0.9	1,650	282
West	Interface	500	$2.8	$4.1	$0.5	($0.8)	($0.0)	($0.1)	($0.0)	$0.1	($0.7)	391	55
Graceton - Raphael Road	Line	BGE	($0.3)	($0.9)	($0.0)	$0.6	$0.1	$0.0	$0.0	$0.1	$0.6	174	90
Harwood - Susquehanna	Line	PPL	$0.1	($0.4)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	13	0
Sammis - Wylie Ridge	Line	AP	$0.1	$0.7	$0.1	($0.5)	$0.0	($0.0)	$0.0	$0.1	($0.4)	622	101
Brunner Island - Yorkana	Line	Met-Ed	($0.0)	($0.4)	($0.0)	$0.4	$0.0	$0.0	($0.0)	($0.0)	$0.4	33	16
Wylie Ridge	Transformer	AP	$1.1	$1.8	$0.3	($0.4)	$0.2	$0.1	$0.0	$0.1	($0.3)	354	336
PL North	Interface	PPL	$0.0	$0.0	$0.0	$0.0	$0.4	$0.6	($0.0)	($0.3)	($0.3)	0	176
Mount Storm - Pruntytown	Line	AP	$0.1	($0.1)	$0.0	$0.3	($0.0)	($0.0)	($0.0)	($0.0)	$0.3	523	25
East Frankfort - Crete	Line	ComEd	$0.2	$0.5	$0.0	($0.3)	$0.0	$0.0	$0.0	$0.0	($0.3)	1,333	0
Atlantic - Larrabee	Line	JCPL	$0.0	$0.1	$0.0	($0.1)	($0.1)	$0.1	$0.0	($0.2)	($0.3)	188	45
5004/5005 Interface	Interface	500	$1.4	$2.4	$0.3	($0.6)	$0.1	($0.8)	($0.1)	$0.8	$0.2	334	198
Crete - St Johns Tap	Flowgate	Midwest ISO	$0.2	$0.4	($0.0)	($0.2)	($0.1)	($0.1)	$0.0	($0.0)	($0.2)	539	132

Table 7-35 PPL Control Zone top congestion cost impacts (By facility): January through June 2008 (See 2008 SOM Table 7-35)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Harwood - Susquehanna	Line	PPL	$2.6	($14.3)	($0.1)	$16.7	($1.2)	$1.8	$0.2	($2.8)	$13.9	110	95
West	Interface	500	$1.5	$6.8	$0.6	($4.7)	$0.1	$0.9	$0.0	($0.7)	($5.5)	700	285
East Towanda	Transformer	PENELEC	$0.4	$1.8	$0.0	($1.4)	$0.1	$1.1	($2.9)	($3.8)	($5.2)	803	306
Cloverdale - Lexington	Line	AEP	$0.9	$4.8	$0.9	($3.0)	($0.1)	$0.3	$0.2	($0.2)	($3.2)	1,975	890
Kammer	Transformer	500	$1.0	$4.2	$0.7	($2.5)	$0.2	$0.7	($0.0)	($0.6)	($3.0)	1,386	767
Central	Interface	500	$0.8	$3.8	$0.3	($2.7)	$0.0	($0.1)	($0.0)	$0.1	($2.7)	582	22
5004/5005 Interface	Interface	500	$0.7	$2.7	$0.4	($1.6)	($0.0)	($0.0)	($0.0)	($0.1)	($1.7)	301	143
Branchburg - Readington	Line	PSEG	$0.7	($0.7)	($0.1)	$1.4	$0.0	($0.1)	$0.1	$0.2	$1.6	1,103	271
Bedington - Black Oak	Interface	500	$1.3	$0.5	$0.4	$1.2	$0.0	$0.1	$0.1	$0.1	$1.3	1,170	186
East	Interface	500	$0.0	($1.2)	($0.0)	$1.3	$0.0	($0.0)	$0.0	$0.0	$1.3	182	9
Mount Storm - Pruntytown	Line	AP	$0.4	($0.3)	$0.2	$0.8	$0.0	$0.1	$0.2	$0.1	$1.0	333	223
AP South	Interface	500	$2.9	$5.1	$1.2	($1.1)	$0.3	$0.3	$0.2	$0.2	($0.9)	1,291	605
Lackawana - Stanton	Line	PPL	$0.0	($0.5)	$0.4	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	83	0
Burnham - Munster	Line	ComEd	$0.2	$1.0	($0.0)	($0.8)	$0.0	($0.1)	$0.0	$0.2	($0.6)	416	140
Krendale - Seneca	Line	AP	$0.2	$0.8	$0.1	($0.5)	($0.0)	$0.0	($0.0)	($0.0)	($0.5)	407	16

PSEG Control Zone

Table 7-36 PSEG Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2008 SOM Table 7-36)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Plainsboro - Trenton	Line	PSEG	$3.5	($0.1)	$0.1	$3.8	($0.3)	$0.4	($0.1)	($0.7)	$3.1	389	164
Leonia - New Milford	Line	PSEG	$1.5	$0.5	$2.3	$3.3	($0.0)	$0.0	($0.3)	($0.3)	$3.0	2,164	30
Athenia - Saddlebrook	Line	PSEG	$3.2	$0.5	$1.3	$3.9	($0.3)	$0.1	($0.5)	($0.9)	$3.0	979	130
AP South	Interface	500	$0.5	$2.5	$0.7	($1.3)	$0.0	($0.1)	($0.3)	($0.2)	($1.5)	1,650	282
Fairlawn - Saddlebrook	Line	PSEG	$1.0	$0.1	$0.5	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	673	0
Wylie Ridge	Transformer	AP	$4.3	$5.4	$0.5	($0.6)	$0.0	$0.1	($0.6)	($0.7)	($1.3)	NA	NA
West	Interface	500	$10.9	$12.7	$0.8	($1.0)	($0.0)	$0.0	($0.1)	($0.2)	($1.2)	391	55
Cedar Grove - Clifton	Line	PSEG	$1.0	$0.2	$0.4	$1.2	($0.0)	$0.0	($0.0)	($0.1)	$1.1	413	18
Hillsdale - Waldwick	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.3	($0.4)	($0.7)	($0.7)	0	42
Buckingham - Pleasant Valley	Line	PECO	$0.9	($0.1)	$0.0	$1.0	($0.0)	$0.2	($0.0)	($0.3)	$0.7	131	59
5004/5005 Interface	Interface	500	$5.6	$5.4	$0.3	$0.5	$0.0	$0.8	($0.4)	($1.2)	($0.7)	334	198
Atlantic - Larrabee	Line	JCPL	$0.3	($0.5)	$0.0	$0.8	$0.0	$0.1	($0.1)	($0.2)	$0.6	188	45
Bayway - Federal Square	Line	PSEG	$0.4	($0.2)	$0.0	$0.6	($0.0)	($0.0)	($0.0)	$0.0	$0.6	144	9
Brunswick - Edison	Line	PSEG	$1.0	($0.0)	$0.0	$1.1	($0.1)	$0.2	($0.2)	($0.5)	$0.6	138	76
Cedar Grove - Roseland	Line	PSEG	$0.4	$0.0	$0.0	$0.4	($0.2)	$0.5	($0.2)	($0.9)	($0.5)	52	70

Table 7-37 PSEG Control Zone top congestion cost impacts (By facility): January through June 2008 (See 2008 SOM Table 7-37)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Atlantic - Larrabee	Line	JCPL	$13.1	($5.8)	$0.3	$19.3	$0.5	$2.3	($0.7)	($2.5)	$16.8	1,466	341
Branchburg - Readington	Line	PSEG	$16.3	$0.8	$0.6	$16.1	$0.2	$2.9	($0.7)	($3.3)	$12.7	1,103	271
Buckingham - Pleasant Valley	Line	PECO	$10.3	$2.3	$0.5	$8.4	($0.1)	$0.4	($0.1)	($0.6)	$7.9	556	60
Cedar Grove - Clifton	Line	PSEG	$0.6	$0.1	$0.3	$0.8	($0.6)	$4.4	($1.6)	($6.7)	($5.8)	81	187
AP South	Interface	500	$17.3	$20.9	$1.9	($1.7)	($0.2)	$1.0	($1.3)	($2.6)	($4.2)	1,291	605
Branchburg - Flagtown	Line	PSEG	$3.7	$0.0	$0.1	$3.7	$0.3	$0.1	($0.2)	$0.1	$3.8	105	27
Cedar Grove - Roseland	Line	PSEG	$6.2	$0.9	$0.1	$5.4	($0.1)	$1.1	($0.3)	($1.6)	$3.8	398	71
Unclassified	Unclassified	Unclassified	$1.7	($0.8)	$0.1	$2.5	$0.0	$0.0	$0.0	$0.0	$2.5	NA	NA
Bedington - Black Oak	Interface	500	$3.2	$6.1	$0.8	($2.0)	$0.0	($0.0)	($0.2)	($0.2)	($2.2)	1,170	186
Brunswick - Edison	Line	PSEG	$2.2	$0.1	$0.1	$2.2	$0.0	$0.5	($0.1)	($0.5)	$1.6	192	103
West	Interface	500	$18.6	$17.0	$1.1	$2.8	$0.7	$1.4	($0.6)	($1.3)	$1.4	700	285
North Ave - Pvsc	Line	PSEG	$0.5	($0.9)	$0.0	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	399	0
Cloverdale - Lexington	Line	AEP	$12.7	$13.5	$1.3	$0.4	$0.0	$1.0	($0.8)	($1.7)	($1.3)	1,975	890
Harwood - Susquehanna	Line	PPL	$3.6	$1.3	$0.2	$2.5	($0.4)	$0.6	($0.3)	($1.3)	$1.3	110	95
Mount Storm - Pruntytown	Line	AP	$0.1	$1.3	$0.3	($0.9)	$0.0	($0.1)	($0.4)	($0.2)	($1.2)	333	223

RECO Control Zone

Table 7-38 RECO Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2008 SOM Table 7-38)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
West	Interface	500	$0.5	$0.0	$0.0	$0.5	($0.0)	($0.0)	($0.0)	($0.0)	$0.5	391	55
Kammer	Transformer	500	$0.2	$0.0	$0.0	$0.2	($0.0)	($0.0)	($0.0)	($0.0)	$0.2	1,554	726
5004/5005 Interface	Interface	500	$0.2	$0.0	$0.0	$0.2	($0.0)	($0.0)	($0.0)	($0.1)	$0.2	334	198
Wylie Ridge	Transformer	AP	$0.2	$0.0	$0.0	$0.2	($0.0)	($0.0)	($0.0)	($0.0)	$0.2	354	336
Athenia - Saddlebrook	Line	PSEG	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	$0.0	($0.0)	$0.1	979	130
Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.1	$0.0	($0.0)	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	1,713	672
Graceton - Raphael Road	Line	BGE	($0.1)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	174	90
East Frankfort - Crete	Line	ComEd	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	1,333	0
AP South	Interface	500	($0.1)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	1,650	282
Sammis - Wylie Ridge	Line	AP	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	622	101
Fairlawn - Saddlebrook	Line	PSEG	($0.0)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	673	0
Tiltonsville - Windsor	Line	AP	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	794	198
Crete - St Johns Tap	Flowgate	Midwest ISO	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	539	132
Krendale - Seneca	Line	AP	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	225	0
Cloverdale - Lexington	Line	AEP	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	666	239

Table 7-39 RECO Control Zone top congestion cost impacts (By facility): January through June 2008 (See 2008 SOM Table 7-39)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Branchburg - Readington	Line	PSEG	$0.9	$0.0	$0.0	$0.9	$0.0	($0.0)	($0.0)	$0.0	$1.0	1,103	271
West	Interface	500	$0.7	$0.0	$0.0	$0.7	$0.1	($0.0)	($0.0)	$0.1	$0.7	700	285
Atlantic - Larrabee	Line	JCPL	$0.6	$0.0	$0.0	$0.6	$0.0	($0.0)	($0.0)	($0.0)	$0.6	1,466	341
AP South	Interface	500	$0.5	$0.0	$0.0	$0.5	$0.0	($0.0)	($0.0)	$0.0	$0.5	1,291	605
Kammer	Transformer	500	$0.4	$0.0	$0.0	$0.4	$0.0	($0.0)	($0.0)	$0.0	$0.5	1,386	767
Cedar Grove - Roseland	Line	PSEG	$0.4	$0.0	$0.0	$0.4	$0.1	($0.0)	$0.0	$0.1	$0.4	398	71
Buckingham - Pleasant Valley	Line	PECO	$0.4	$0.0	$0.0	$0.4	$0.0	($0.0)	($0.0)	$0.0	$0.4	556	60
Central	Interface	500	$0.4	$0.0	$0.0	$0.4	$0.0	($0.0)	$0.0	$0.0	$0.4	582	22
Cloverdale - Lexington	Line	AEP	$0.4	$0.0	$0.0	$0.4	$0.0	($0.0)	($0.0)	$0.0	$0.4	1,975	890
5004/5005 Interface	Interface	500	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.3	301	143
Harwood - Susquehanna	Line	PPL	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)	$0.0	$0.0	$0.2	110	95
East	Interface	500	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	182	9
Dickerson - Plesant View	Line	Pepco	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	($0.0)	$0.1	418	118
Burnham - Munster	Line	ComEd	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	416	140
Branchburg - Flagtown	Line	PSEG	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	105	27

Western Region Congestion-Event Summaries

AEP Control Zone

Table 7-40 AEP Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2008 SOM Table 7-40)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	($13.6)	($22.9)	$0.9	$10.1	($0.6)	$0.1	$0.2	($0.6)	$9.6	1,650	282
Ruth - Turner	Line	AEP	$4.6	($1.6)	$0.5	$6.7	($1.2)	($0.4)	($0.1)	($0.9)	$5.8	639	275
Kammer	Transformer	500	($11.6)	($18.5)	($0.3)	$6.7	($0.5)	$1.4	$0.6	($1.4)	$5.3	1,554	726
Kanawha - Kincaid	Line	AEP	$2.8	($2.1)	$0.2	$5.1	$0.0	$0.0	$0.0	$0.0	$5.1	291	0
Kammer - Ormet	Line	AEP	$7.8	$1.1	$0.3	$6.9	($1.6)	$0.5	($0.1)	($2.2)	$4.7	552	509
Dunes Acres - Michigan City	Flowgate	Midwest ISO	$12.6	$5.8	$1.0	$7.8	($2.2)	($0.9)	($2.1)	($3.4)	$4.4	1,713	672
Kanawha River	Transformer	AEP	$3.2	($0.3)	$0.5	$4.0	$0.1	($0.3)	($0.1)	$0.4	$4.3	159	37
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
Breed - Wheatland	Line	AEP	$0.1	($3.1)	($0.3)	$2.9	$0.0	$0.0	$0.0	$0.0	$2.9	408	0
East Frankfort - Crete	Line	ComEd	$3.2	$1.9	$1.3	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	1,333	0
Sammis - Wylie Ridge	Line	AP	($4.3)	($2.3)	($0.1)	($2.1)	($0.2)	$0.1	($0.0)	($0.4)	($2.5)	622	101
Mount Storm - Pruntytown	Line	AP	($3.1)	($5.2)	$0.2	$2.3	$0.2	$0.0	$0.0	$0.2	$2.5	523	25
Cloverdale - Lexington	Line	AEP	($5.9)	($4.1)	($0.4)	($2.1)	$0.4	$0.2	$0.1	$0.3	($1.8)	666	239
Schahfer - Burr Oak	Flowgate	Midwest ISO	$0.6	$0.2	$0.2	$0.5	($0.1)	$0.0	($1.8)	($1.9)	($1.4)	62	81
AEP-DOM	Interface	500	$0.4	($1.2)	$0.1	$1.7	($0.2)	$0.4	($0.0)	($0.6)	$1.1	101	57

Table 7-41 AEP Control Zone top congestion cost impacts (By facility): January through June 2008 (See 2008 SOM Table 7-41)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	($55.8)	($90.6)	$1.1	$35.9	($13.2)	$0.4	$0.2	($13.4)	$22.4	1,291	605
Kammer	Transformer	500	($16.2)	($48.5)	($0.6)	$31.7	($7.1)	$2.5	$0.1	($9.4)	$22.2	1,386	767
Bedington - Black Oak	Interface	500	($18.3)	($40.6)	$1.5	$23.7	($2.0)	$0.9	($0.0)	($2.8)	$20.9	1,170	186
Axton	Transformer	AEP	$1.5	($9.1)	$1.4	$12.0	$0.0	$0.0	$0.0	$0.0	$12.0	204	0
Mount Storm - Pruntytown	Line	AP	($6.9)	($19.7)	$1.1	$13.9	($4.0)	$1.0	($0.1)	($5.1)	$8.8	333	223
Amos	Transformer	AEP	$5.9	($1.6)	$0.2	$7.7	$0.4	$0.6	$0.1	($0.2)	$7.5	31	19
West	Interface	500	($12.1)	($22.8)	$0.2	$10.8	($3.4)	$0.6	$0.0	($4.0)	$6.9	700	285
Axton - Jacksons Ferry	Line	AEP	$0.5	($2.3)	$0.3	$3.1	$0.0	$0.0	$0.0	$0.0	$3.1	83	0
Mahans Lane - Tidd	Line	AEP	($1.1)	($2.8)	$1.6	$3.4	($0.2)	$0.2	($0.0)	($0.4)	$2.9	498	121
Cloverdale - Lexington	Line	AEP	($51.9)	($61.3)	($4.2)	$5.2	($7.4)	$1.0	$0.3	($8.0)	($2.8)	1,975	890
Central	Interface	500	($5.2)	($8.1)	$0.0	$2.9	($0.1)	$0.0	($0.0)	($0.1)	$2.8	582	22
Bedington	Transformer	AP	($3.1)	($5.6)	$0.2	$2.8	($0.4)	($0.1)	$0.0	($0.3)	$2.5	593	149
Sammis - Wylie Ridge	Line	AP	($1.8)	($1.5)	$0.4	$0.1	($2.2)	($0.1)	($0.3)	($2.4)	($2.3)	249	405
5004/5005 Interface	Interface	500	($4.5)	($8.5)	$0.2	$4.1	($1.3)	$0.6	$0.0	($1.9)	$2.2	301	143
Aqueduct - Doubs	Line	AP	($3.8)	($5.7)	$0.1	$2.0	($0.1)	($0.0)	$0.0	($0.1)	$1.9	145	7

AP Control Zone

Table 7-42 AP Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2008 SOM Table 7-42)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	($9.8)	($41.2)	($3.2)	$28.1	$1.5	$1.2	$2.5	$2.8	$31.0	1,650	282
Mount Storm - Pruntytown	Line	AP	($2.0)	($10.1)	($0.6)	$7.4	$0.4	$0.2	$0.4	$0.7	$8.1	523	25
Kammer	Transformer	500	$10.4	$15.3	$4.8	($0.2)	($1.3)	($1.7)	($5.4)	($5.0)	($5.2)	1,554	726
Wylie Ridge	Transformer	AP	$6.1	$7.4	$5.4	$4.1	($1.1)	($0.5)	($7.2)	($7.7)	($3.6)	354	336
5004/5005 Interface	Interface	500	($4.9)	($7.1)	($0.6)	$1.7	$0.8	$0.7	$1.6	$1.7	$3.4	334	198
Tiltonsville - Windsor	Line	AP	$5.1	$1.7	$0.3	$3.8	($0.5)	($0.2)	($0.8)	($1.0)	$2.8	794	198
Bedington - Harmony	Line	AP	$1.8	($0.1)	$0.4	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	199	0
Cloverdale - Lexington	Line	AEP	$1.1	($1.3)	$0.8	$3.2	($0.1)	$0.0	($0.8)	($1.0)	$2.2	666	239
Carroll - Catoctin	Line	AP	$0.4	$0.0	($0.0)	$0.3	$0.7	($0.8)	$0.2	$1.6	$2.0	99	22
Yukon	Transformer	AP	$2.1	$0.4	$0.0	$1.7	$0.0	$0.2	$0.1	($0.1)	$1.6	123	36
Bedington - Black Oak	Interface	500	($0.4)	($2.1)	($0.1)	$1.7	($0.3)	$0.2	$0.4	($0.2)	$1.5	74	61
Doubs	Transformer	AP	$1.5	($0.0)	$0.0	$1.5	$0.0	$0.0	($0.1)	($0.1)	$1.4	36	13
Unclassified	Unclassified	Unclassified	$1.1	$0.0	$0.2	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	NA	NA
Bedington	Transformer	AP	$4.2	($0.3)	$0.1	$4.5	($3.8)	($0.2)	($2.3)	($5.8)	($1.3)	247	103
West	Interface	500	($12.5)	($15.3)	($2.0)	$0.8	$0.2	$0.1	$0.2	$0.3	$1.1	391	55

Table 7-43 AP Control Zone top congestion cost impacts (By facility): January through June 2008 (See 2008 SOM Table 7-43)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$13.3	($75.8)	$1.0	$90.1	($0.1)	$6.1	$0.3	($5.9)	$84.2	1,291	605
Bedington - Black Oak	Interface	500	($2.8)	($48.9)	($0.9)	$45.2	$0.5	$0.1	$0.6	$1.0	$46.2	1,170	186
Cloverdale - Lexington	Line	AEP	$12.1	($14.6)	$3.2	$29.9	($0.7)	$0.1	($1.7)	($2.5)	$27.4	1,975	890
Meadow Brook	Transformer	AP	$28.1	($1.5)	$0.6	$30.2	($3.1)	($0.1)	($0.1)	($3.1)	$27.1	757	171
Bedington	Transformer	AP	$19.8	($6.1)	$0.3	$26.3	($0.1)	($0.1)	$0.1	$0.1	$26.4	593	149
Mount Storm - Pruntytown	Line	AP	($2.0)	($24.3)	($1.0)	$21.3	$2.6	$1.7	$0.9	$1.8	$23.1	333	223
Aqueduct - Doubs	Line	AP	($10.2)	($3.4)	($0.1)	($7.0)	$0.1	$0.1	$0.0	$0.0	($6.9)	145	7
Sammis - Wylie Ridge	Line	AP	$1.1	$0.7	$1.1	$1.6	($2.2)	($0.0)	($5.5)	($7.7)	($6.1)	249	405
Kammer	Transformer	500	$14.9	$21.1	$3.3	($2.9)	($1.7)	($2.1)	($2.7)	($2.4)	($5.3)	1,386	767
West	Interface	500	($6.0)	($9.8)	$0.3	$4.1	$1.2	$0.6	$0.5	$1.0	$5.1	700	285
Branchburg - Readington	Line	PSEG	$1.7	($0.2)	$2.7	$4.6	$0.3	$0.1	$0.2	$0.3	$4.9	1,103	271
Eureka - Willow Island	Line	AP	($0.3)	($4.4)	($0.1)	$4.1	($0.2)	$0.0	$0.0	($0.2)	$3.9	257	37
Kingwood - Pruntytown	Line	AP	$3.8	$0.0	$0.0	$3.8	($0.0)	$0.0	$0.0	($0.0)	$3.8	198	1
Atlantic - Larrabee	Line	JCPL	$1.0	$0.9	$3.2	$3.3	$0.2	$0.1	$0.1	$0.2	$3.5	1,466	341
Krendale - Seneca	Line	AP	$2.2	($0.4)	$0.9	$3.5	($0.0)	$0.1	($0.0)	($0.1)	$3.4	407	16

ComEd Control Zone

Table 7-44 ComEd Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2008 SOM Table 7-44)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Pleasant Valley - Belvidere	Line	ComEd	($1.9)	($19.9)	$0.1	$18.1	$0.9	$1.4	$0.0	($0.5)	$17.6	1,534	213
East Frankfort - Crete	Line	ComEd	($13.5)	($27.4)	($0.1)	$13.9	$0.0	$0.0	$0.0	$0.0	$13.9	1,333	0
Dunes Acres - Michigan City	Flowgate	Midwest ISO	($29.5)	($44.6)	($2.2)	$12.9	($2.4)	($0.5)	$0.6	($1.3)	$11.6	1,713	672
Kammer	Transformer	500	($15.0)	($25.2)	($0.0)	$10.2	($0.4)	($0.6)	($0.1)	$0.2	$10.4	1,554	726
AP South	Interface	500	($18.7)	($29.2)	($0.0)	$10.4	($0.9)	($0.3)	($0.1)	($0.7)	$9.7	1,650	282
Crete - St Johns Tap	Flowgate	Midwest ISO	($8.5)	($17.9)	($0.2)	$9.2	($0.4)	($0.1)	($0.0)	($0.4)	$8.9	539	132
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
Wylie Ridge	Transformer	AP	($7.9)	($10.9)	($0.0)	$3.0	($0.8)	($1.5)	$0.0	$0.8	$3.8	354	336
Glidden - West Dekalb	Line	ComEd	($0.2)	($3.8)	$0.0	$3.7	$0.0	$0.0	$0.0	$0.0	$3.7	668	1
West	Interface	500	($11.4)	($14.9)	($0.0)	$3.5	($0.0)	($0.0)	($0.0)	($0.0)	$3.5	391	55
Mount Storm - Pruntytown	Line	AP	($4.1)	($6.8)	($0.0)	$2.7	($0.1)	($0.3)	($0.0)	$0.3	$3.0	523	25
5004/5005 Interface	Interface	500	($5.1)	($7.7)	($0.0)	$2.6	($0.6)	($0.9)	($0.0)	$0.3	$2.9	334	198
Cloverdale - Lexington	Line	AEP	($4.2)	($7.3)	($0.0)	$3.1	($0.5)	($0.3)	($0.0)	($0.3)	$2.8	666	239
Electric Jct - Nelson	Line	ComEd	$0.0	($2.2)	$0.1	$2.3	$1.6	$1.0	($0.1)	$0.4	$2.8	279	119
Sammis - Wylie Ridge	Line	AP	($3.1)	($5.5)	($0.0)	$2.4	($0.2)	($0.1)	($0.0)	($0.1)	$2.3	622	101

Table 7-45 ComEd Control Zone top congestion cost impacts (By facility): January through June 2008 (See 2008 SOM Table 7-45)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Cloverdale - Lexington	Line	AEP	($36.4)	($66.2)	($0.1)	$29.8	$0.6	($1.3)	($0.0)	$1.9	$31.7	1,975	890
AP South	Interface	500	($52.9)	($81.5)	($0.1)	$28.6	($2.3)	$0.1	($0.0)	($2.5)	$26.1	1,291	605
Bedington - Black Oak	Interface	500	($20.9)	($34.3)	($0.1)	$13.3	$0.1	($0.0)	$0.0	$0.2	$13.4	1,170	186
Kammer	Transformer	500	($21.9)	($35.9)	($0.0)	$14.0	($0.2)	$1.1	($0.0)	($1.4)	$12.6	1,386	767
Burnham - Munster	Line	ComEd	($14.5)	($23.7)	($0.0)	$9.2	($2.6)	($2.6)	($0.5)	($0.5)	$8.7	416	140
West	Interface	500	($12.5)	($18.9)	($0.0)	$6.4	$0.6	($1.0)	($0.0)	$1.6	$8.0	700	285
Central	Interface	500	($4.5)	($7.9)	($0.0)	$3.4	($0.0)	($0.0)	($0.0)	($0.0)	$3.4	582	22
State Line - Wolf Lake	Flowgate	Midwest ISO	($5.7)	($9.2)	($0.0)	$3.5	($0.0)	$0.2	($0.0)	($0.3)	$3.1	834	133
5004/5005 Interface	Interface	500	($4.8)	($7.4)	($0.0)	$2.6	$0.1	($0.2)	$0.0	$0.3	$2.8	301	143
Mount Storm - Pruntytown	Line	AP	($10.1)	($15.6)	($0.0)	$5.6	($2.0)	$0.6	($0.1)	($2.7)	$2.8	333	223
Axton	Transformer	AEP	($4.9)	($7.5)	($0.0)	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	204	0
Dickerson - Plesant View	Line	Pepco	($2.6)	($4.2)	$0.0	$1.6	$0.2	($0.1)	($0.0)	$0.3	$1.9	418	118
Pana North	Flowgate	Midwest ISO	($1.2)	($4.0)	($0.0)	$2.9	($0.2)	$0.9	($0.0)	($1.1)	$1.7	190	182
Krendale - Seneca	Line	AP	($1.8)	($3.4)	($0.0)	$1.6	$0.0	($0.0)	$0.0	$0.0	$1.6	407	16
Aqueduct - Doubs	Line	AP	($3.4)	($4.7)	($0.0)	$1.4	($0.0)	$0.0	($0.0)	($0.0)	$1.3	145	7

DAY Control Zone

Table 7-46 DAY Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2008 SOM Table 7-46)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Kammer	Transformer	500	($1.0)	($2.4)	($0.0)	$1.4	$0.2	$0.1	$0.0	$0.1	$1.5	1,554	726
West	Interface	500	($0.8)	($1.4)	$0.0	$0.7	$0.0	$0.0	($0.0)	$0.0	$0.7	391	55
AP South	Interface	500	($1.6)	($2.3)	$0.0	$0.7	$0.0	$0.2	($0.0)	($0.1)	$0.5	1,650	282
Wylie Ridge	Transformer	AP	($0.6)	($1.1)	($0.0)	$0.5	$0.2	$0.2	$0.0	($0.0)	$0.4	354	336
Cloverdale - Lexington	Line	AEP	($0.3)	($0.7)	($0.0)	$0.5	$0.0	$0.1	$0.0	($0.1)	$0.4	666	239
Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.3	$0.6	$0.0	($0.3)	($0.0)	($0.0)	($0.1)	($0.1)	($0.3)	1,713	672
Tiltonsville - Windsor	Line	AP	($0.2)	($0.5)	($0.0)	$0.3	$0.0	$0.1	$0.0	($0.1)	$0.2	794	198
Marquis - Waverly	Line	AEP	($0.0)	($0.2)	($0.0)	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	41	9
Sammis - Wylie Ridge	Line	AP	($0.2)	($0.4)	($0.0)	$0.2	$0.0	$0.1	($0.0)	($0.0)	$0.2	622	101
Pierce - Foster	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.2)	($0.2)	0	4
5004/5005 Interface	Interface	500	($0.4)	($0.6)	$0.0	$0.2	$0.1	$0.1	($0.0)	($0.0)	$0.1	334	198
Kammer - Ormet	Line	AEP	($0.1)	($0.2)	($0.0)	$0.1	$0.0	$0.0	$0.0	($0.0)	$0.1	552	509
East Frankfort - Crete	Line	ComEd	$0.2	$0.3	$0.0	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	1,333	0
Kanawha River	Transformer	AEP	($0.1)	($0.2)	$0.0	$0.1	$0.0	$0.0	$0.0	($0.0)	$0.1	159	37
Breed - Wheatland	Line	AEP	$0.0	$0.1	$0.0	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	408	0

Table 7-47 DAY Control Zone top congestion cost impacts (By facility): January through June 2008 (See 2008 SOM Table 7-47)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Cloverdale - Lexington	Line	AEP	($3.9)	($7.0)	$0.1	$3.1	$0.0	$0.1	$0.0	($0.1)	$3.0	1,975	890
AP South	Interface	500	($5.3)	($7.9)	$0.0	$2.6	$0.3	$0.3	($0.0)	($0.1)	$2.5	1,291	605
Kammer	Transformer	500	($2.5)	($4.2)	$0.0	$1.7	$0.1	$0.4	$0.0	($0.3)	$1.4	1,386	767
Bedington - Black Oak	Interface	500	($2.3)	($3.7)	($0.0)	$1.4	$0.1	$0.3	$0.0	($0.2)	$1.1	1,170	186
West	Interface	500	($1.1)	($2.3)	$0.0	$1.2	$0.1	$0.6	$0.0	($0.5)	$0.7	700	285
Central	Interface	500	($0.5)	($0.9)	$0.0	$0.4	($0.0)	$0.0	($0.0)	($0.0)	$0.4	582	22
Mount Storm - Pruntytown	Line	AP	($1.3)	($1.4)	($0.0)	$0.1	($0.1)	$0.5	($0.0)	($0.5)	($0.4)	333	223
5004/5005 Interface	Interface	500	($0.5)	($0.9)	$0.0	$0.5	($0.0)	$0.1	$0.0	($0.1)	$0.4	301	143
Axton	Transformer	AEP	($0.5)	($0.8)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	204	0
Axton - Jacksons Ferry	Line	AEP	($0.1)	($0.3)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	83	0
Sammis - Wylie Ridge	Line	AP	($0.1)	($0.2)	($0.0)	$0.0	$0.1	$0.0	($0.0)	$0.1	$0.1	249	405
Black Oak	Transformer	AP	($0.2)	($0.3)	$0.0	$0.1	($0.0)	($0.0)	$0.0	($0.0)	$0.1	337	11
Wakefield - Sargents	Line	AEP	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	15	0
Danville - East Danville	Line	Dominion	($0.2)	($0.3)	($0.0)	$0.1	($0.0)	$0.0	$0.0	($0.0)	$0.1	276	86
Juniata - Keystone	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.1)	($0.1)	0	20

DLCO Control Zone

Table 7-48 DLCO Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2008 SOM Table 7-48)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Sammis - Wylie Ridge	Line	AP	($4.0)	($8.0)	($0.0)	$4.0	($0.1)	$0.5	$0.0	($0.6)	$3.4	622	101
AP South	Interface	500	($8.4)	($11.9)	($0.0)	$3.5	($0.5)	$0.3	$0.0	($0.8)	$2.7	1,650	282
West	Interface	500	($3.8)	($5.5)	($0.0)	$1.6	($0.1)	$0.0	$0.0	($0.1)	$1.5	391	55
Logans Ferry - Universal	Line	DLCO	$0.2	($1.2)	$0.0	$1.4	$0.0	$0.1	($0.0)	($0.1)	$1.4	388	156
Wylie Ridge	Transformer	AP	($8.5)	($12.9)	($0.0)	$4.4	($1.2)	$2.2	$0.0	($3.3)	$1.1	354	336
Mount Storm - Pruntytown	Line	AP	($1.9)	($2.8)	($0.0)	$0.9	($0.1)	$0.1	$0.0	($0.1)	$0.8	523	25
Dunes Acres - Michigan City	Flowgate	Midwest ISO	$1.1	$1.6	($0.0)	($0.5)	$0.1	$0.1	($0.0)	$0.1	($0.4)	1,713	672
Kammer	Transformer	500	($1.8)	($2.5)	$0.0	$0.7	($0.3)	($0.0)	($0.0)	($0.3)	$0.3	1,554	726
East Frankfort - Crete	Line	ComEd	$0.7	$1.0	$0.0	($0.3)	$0.0	$0.0	$0.0	$0.0	($0.3)	1,333	0
Krendale - Seneca	Line	AP	($0.6)	($0.9)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	225	0
Cloverdale - Lexington	Line	AEP	($0.7)	($1.1)	$0.0	$0.4	($0.1)	$0.0	($0.0)	($0.1)	$0.3	666	239
Beaver - Clinton	Line	DLCO	$0.1	($0.2)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	20	0
Tiltonsville - Windsor	Line	AP	($0.7)	($1.0)	($0.0)	$0.3	($0.1)	$0.0	$0.0	($0.1)	$0.2	794	198
Yukon	Transformer	AP	$0.1	$0.1	$0.0	$0.0	$0.0	($0.1)	($0.0)	$0.2	$0.2	123	36
Ruth - Turner	Line	AEP	($0.4)	($0.6)	$0.0	$0.2	($0.1)	$0.0	($0.0)	($0.1)	$0.2	639	275

Table 7-49 DLCO Control Zone top congestion cost impacts (By facility): January through June 2008 (See 2008 SOM Table 7-49)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Sammis - Wylie Ridge	Line	AP	($1.8)	($3.9)	($0.0)	$2.1	($8.8)	$1.9	$0.0	($10.7)	($8.6)	249	405
Bedington - Black Oak	Interface	500	($11.4)	($16.0)	($0.0)	$4.5	($0.9)	$0.6	$0.0	($1.5)	$3.1	1,170	186
Cheswick - Universal	Line	DLCO	($1.3)	($3.7)	$0.0	$2.4	$0.1	$0.3	($0.0)	($0.2)	$2.3	411	158
AP South	Interface	500	($21.6)	($30.4)	($0.0)	$8.9	($5.6)	$1.1	$0.0	($6.7)	$2.2	1,291	605
West	Interface	500	($5.4)	($6.2)	($0.0)	$0.8	($1.4)	$0.9	$0.0	($2.3)	($1.5)	700	285
Krendale - Seneca	Line	AP	($1.6)	($2.9)	($0.0)	$1.3	($0.1)	$0.0	$0.0	($0.1)	$1.2	407	16
Central	Interface	500	($1.7)	($2.8)	($0.0)	$1.1	($0.1)	$0.0	$0.0	($0.1)	$1.0	582	22
Mount Storm - Pruntytown	Line	AP	($5.6)	($8.5)	($0.0)	$2.8	($2.2)	$1.5	$0.0	($3.8)	($0.9)	333	223
Cloverdale - Lexington	Line	AEP	($6.4)	($9.1)	($0.0)	$2.8	($1.7)	$0.3	($0.0)	($1.9)	$0.9	1,975	890
Krendale - Shanorma	Line	AP	($0.9)	($1.7)	($0.0)	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	326	0
Black Oak	Transformer	AP	($1.0)	($1.5)	($0.0)	$0.5	($0.0)	$0.0	$0.0	($0.0)	$0.4	337	11
Beaver - Clinton	Line	DLCO	$0.1	($0.3)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	54	0
East Towanda	Transformer	PENELEC	$0.0	($0.0)	$0.0	$0.0	($0.3)	$0.1	$0.0	($0.4)	($0.4)	803	306
Kammer	Transformer	500	($2.4)	($3.5)	$0.0	$1.1	($0.7)	$0.1	($0.0)	($0.7)	$0.4	1,386	767
Branchburg - Flagtown	Line	PSEG	($0.1)	($0.2)	$0.0	$0.0	($0.3)	$0.1	$0.0	($0.4)	($0.4)	105	27

Southern Region Congestion-Event Summaries

Dominion Control Zone

Table 7-50 Dominion Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2008 SOM Table 7-50)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$20.4	($16.4)	$0.3	$37.1	$1.1	($0.2)	$0.1	$1.4	$38.5	1,650	282
Cloverdale - Lexington	Line	AEP	$5.2	$2.3	$0.8	$3.7	($0.0)	($1.6)	($0.8)	$0.8	$4.5	666	239
Kammer	Transformer	500	$5.5	$4.2	$1.0	$2.3	$0.1	($0.5)	($1.1)	($0.5)	$1.8	1,554	726
Dunes Acres - Michigan City	Flowgate	Midwest ISO	$2.8	$1.2	$0.1	$1.6	($0.2)	($0.5)	($0.1)	$0.2	$1.8	1,713	672
Beechwood - Kerr Dam	Line	Dominion	$0.9	($0.5)	($0.0)	$1.4	($0.1)	$0.1	$0.0	($0.1)	$1.3	390	155
Wylie Ridge	Transformer	AP	$2.5	$1.7	$0.4	$1.2	($0.1)	($0.2)	($0.4)	($0.2)	$1.0	354	336
West	Interface	500	($2.4)	($3.3)	$0.0	$1.0	$0.0	$0.1	$0.0	($0.1)	$0.9	391	55
Crozet - Dooms	Line	Dominion	$0.6	($0.3)	$0.0	$0.9	($0.3)	($0.2)	($0.0)	($0.1)	$0.8	48	26
Clover - Farmville	Line	Dominion	($0.0)	($0.7)	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	41	0
Mount Storm	Transformer	AP	$1.3	$0.2	$0.1	$1.2	($0.2)	$0.0	($0.3)	($0.5)	$0.7	123	46
Sammis - Wylie Ridge	Line	AP	$1.1	$0.7	$0.2	$0.6	$0.0	($0.1)	($0.1)	$0.1	$0.7	622	101
Crete - St Johns Tap	Flowgate	Midwest ISO	$1.0	$0.5	$0.1	$0.6	($0.0)	($0.2)	($0.1)	$0.0	$0.6	539	132
East Frankfort - Crete	Line	ComEd	$1.2	$0.7	$0.1	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	1,333	0
Crozet - Barracks Rd	Line	Dominion	$0.8	$0.4	($0.0)	$0.4	$0.1	($0.1)	$0.0	$0.2	$0.6	35	11
Mount Storm - Pruntytown	Line	AP	$4.9	$4.7	$0.6	$0.8	($0.0)	($0.0)	($0.4)	($0.4)	$0.5	523	25

Table 7-51 Dominion Control Zone top congestion cost impacts (By facility): January through June 2008 (See 2008 SOM Table 7-51)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$47.9	($53.6)	$2.6	$104.1	$2.8	$5.1	($1.5)	($3.8)	$100.3	1,291	605
Cloverdale - Lexington	Line	AEP	$56.6	$24.6	$5.8	$37.8	$6.2	($0.5)	($2.7)	$3.9	$41.7	1,975	890
Bedington - Black Oak	Interface	500	$28.5	$15.7	$1.7	$14.5	$0.4	($0.7)	($0.4)	$0.7	$15.2	1,170	186
Aqueduct - Doubs	Line	AP	$5.9	($1.8)	$0.1	$7.9	$0.0	($0.0)	($0.0)	$0.0	$7.9	145	7
Meadow Brook	Transformer	AP	($0.7)	($6.8)	($0.0)	$6.1	($0.0)	$0.3	$0.1	($0.2)	$5.8	757	171
Dickerson - Plesant View	Line	Pepco	($6.1)	($2.7)	($0.1)	($3.5)	($0.1)	$0.6	$0.1	($0.7)	($4.2)	418	118
Pleasantville - Ashburn	Line	Dominion	$3.2	$0.2	$0.0	$3.1	$0.0	$0.0	$0.0	$0.0	$3.1	10	0
Kammer	Transformer	500	$8.4	$7.3	$0.9	$2.0	$0.1	($1.2)	($0.6)	$0.7	$2.7	1,386	767
Central	Interface	500	($4.3)	($2.5)	($0.0)	($1.9)	($0.0)	$0.0	$0.0	($0.0)	($1.9)	582	22
Danville - East Danville	Line	Dominion	$2.6	$1.0	$0.1	$1.6	($0.1)	($0.2)	$0.2	$0.2	$1.9	276	86
Black Oak	Transformer	AP	$1.9	($0.1)	($0.1)	$1.9	($0.0)	($0.0)	($0.0)	($0.0)	$1.9	337	11
Harrisonburg - Endless Caverns	Line	Dominion	$1.2	($0.5)	($0.0)	$1.7	$0.0	$0.0	$0.0	$0.0	$1.7	72	0
West	Interface	500	($7.9)	($6.4)	$0.1	($1.4)	$0.2	$0.4	$0.1	($0.1)	($1.6)	700	285
Branchburg - Readington	Line	PSEG	($2.1)	($1.3)	($0.1)	($1.0)	($0.2)	$0.4	$0.1	($0.5)	($1.5)	1,103	271
Burnham - Munster	Line	ComEd	$2.3	$1.2	$0.0	$1.1	$0.1	($0.1)	($0.0)	$0.2	$1.3	416	140

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 *2009 Quarterly State of the Market Report for PJM: January through June* 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 2008 to 2009 planning period which covers June 1, 2008, through May 31, 2009, and the 2009 to 2010 planning period which covers June 1, 2009, through May 31, 2010.

1 87 FERC ¶ 61,054 (1999).

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 second Long Term FTR Auction is being operated during the 2009 to 2010 planning period and covers three consecutive planning periods between 2010 and 2013. The 2010 to 2013 Long Term FTR Auction results are not presented in this report because the second round has not yet been conducted. 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 Annual FTR Auction for the 2009 to 2010 planning period include the AP South Interface and the Mahans Lane — Tidd line.[2] Market participants can also sell FTRs. In the Annual FTR Auction for the 2009 to 2010 planning period, total FTR sell offers were 142,154 MW, up from 83,453 MW during the 2008 to 2009 planning period. In the Monthly Balance of Planning Period FTR Auctions for the first month (June 2009) of the 2009 to 2010 planning period, there were 346,576 MW of FTR sell offers.

2 During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones. Four of these, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion, were eligible for direct allocation FTRs during the 2006 to 2007 planning period, but not the 2007 to 2008, the 2008 to 2009 or the 2009 to 2010 planning period. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2008 State of the Market Report for PJM,* Volume II, Appendix A, "PJM Geography."

- **Demand.** There is no limit on FTR demand in any FTR auction. In the Annual FTR Auction for the 2009 to 2010 planning period, total FTR buy bids were 1,436,335 MW, down from 2,181,273 MW during the 2008 to 2009 planning period. Total FTR self scheduled bids were 68,589 MW for the 2009 to 2010 planning period, a decrease from 72,851 MW for the 2008 to 2009 planning period. In the Monthly Balance of Planning Period FTR Auctions for the first month (June 2009) of the 2009 to 2010 planning period, total FTR buy bids were 847,991 MW.

- **FTR Credit Issues.** While no participants defaulted in the first six months of 2009, one participant had losses on annual FTRs that extended into 2009. Six participants had FTR related payment obligations in default in 2008. Three of those participants had defaulted on their FTR related payment obligations in 2007. There were four participants who defaulted in 2007, after accounting for collateral. The magnitude of the defaults was the result of both the size of the FTR positions defaulted and of the PJM credit policies, which did not require sufficient collateral to cover the participants' losses. The 2007 defaults made it clear that PJM credit polices related to FTRs and particularly to counter flow FTRs were inadequate. PJM made multiple filings in 2008 and 2009 to reform its credit policies, focusing particularly on ensuring an appropriate level of credit to cover positions acquired by market participants in counter flow FTRs. The defaults also raised potential market gaming issues, which were addressed, in part, in a PJM filing.[3] On April 3, 2009, the FERC conditionally approved the second in a series of filings by PJM aimed at reform of its credit policies.[4] Effective June 1, 2009, PJM performs weekly rather than monthly billing and payment for the great majority of invoice line items; has reduced the Unsecured Credit Allowance by two-thirds, eliminated the Unsecured Credit Allowance in support of trading in FTRs, and has procedures that allow it to close out and liquidate forward FTR positions held by Market Participants who have defaulted on their obligations.

- **Patterns of Ownership.** The ownership concentration of cleared FTR buy bids resulting from the 2009 to 2010 Annual FTR Auction was low to moderate for FTR obligations and 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 evaluate the ownership of prevailing flow and counter flow FTRs, the Market Monitoring Unit (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. During the 2009 to 2010 planning period, physical entities own two thirds of prevailing flow Annual FTRs while financial entities own more than half of counter flow Annual FTRs. Overall, financial entities own about 38 percent of all Annual FTRs. Financial entities own about 70 percent of prevailing flow and 78 percent of counter flow Monthly Balance of Planning Period FTRs from January 2009 through June 2009. Overall, financial entities own about 74 percent of all Monthly Balance of Planning Period FTRs.

Market Performance

- **Volume.** For the 2009 to 2010 planning period, the Annual FTR Auction cleared 155,612 MW (10.8 percent) of FTR buy bids, down from 204,349 MW (9.4 percent of demand) for the 2008 to 2009 planning period. The Annual FTR Auction also cleared 7,399 MW (5.2 percent) of FTR sell offers for the 2009 to 2010 planning period, up from 4,534 MW (5.4 percent) for the 2008 to 2009 planning period. For the first month of the 2009 to 2010 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 75,503 MW (8.9 percent) of FTR buy bids and 36,081 MW (10.4 percent) of FTR sell offers.

3 PJM Interconnection, L.L.C. made a filing under section 205 of the Federal Power Act to amend section 15.2 of the PJM Operating Agreement concerning defaults on short FTR portfolios in Docket No. ER08-455-000, (January 18, 2008).

4 127 FERC ¶61,017. The FERC has approved PJM's proposed revisions to its credit policy in Docket No. ER08-376-000. 122 FERC ¶61,279 (2008). PJM has notified the Commission of its intent to file in 2009 an additional proposal that will provide "clarification and definition of the commercial and legal relationship of PJM to its market participants in context of both pool and non-pool transactions. 127 FERC ¶61,017 at P 3.

- **Price.** For the 2009 to 2010 planning period, 83.2 percent of the Annual FTRs were purchased for less than $1 per MWh and 90.6 percent for less than $2 per MWh. For the 2009 to 2010 planning period, the weighted-average prices paid for annual buy-bid FTR obligations were $0.66 per MWh for 24-hour FTRs, $0.57 per MWh for on peak FTRs and $0.40 per MWh for off peak FTRs. Comparable, weighted-average prices paid for annual buy-bid FTR obligations for the 2008 to 2009 planning period were $1.96 per MWh for 24-hour FTRs and $0.55 per MWh for on peak FTRs and $0.26 per MWh for off peak FTRs. The weighted-average prices paid for 2009 to 2010 planning period annual buy-bid FTR obligations and options were $0.53 per MWh and $0.35 per MWh, respectively, compared to $0.69 per MWh and $0.24 per MWh, respectively, in the 2008 to 2009 planning period.[5] The weighted-average price paid for buy-bid FTRs in the Monthly Balance of Planning Period FTR Auctions for the first month of the 2009 to 2010 planning period was $0.38 per MWh, compared with $0.30 per MWh in the Monthly Balance of Planning Period FTR Auctions for the full 12-month 2008 to 2009 planning period.

- **Revenue.** The Annual FTR Auction generated $1,329.8 million of net revenue for all FTRs during the 2009 to 2010 planning period, down from $2,422.6 million for the 2008 to 2009 planning period. The Monthly Balance of Planning Period FTR Auctions generated $2.9 million in net revenue for all FTRs during the first month of the 2009 to 2010 planning period.

- **Revenue Adequacy.** FTRs were 100 percent revenue adequate for the 2008 to 2009 planning period. FTRs were paid at 100 percent of the target allocation level for the first month of the 2009 to 2010 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $54.6 million of FTR revenues during the first month of the 2009 to 2010 planning period and $1,748.3 million during the 2008 to 2009 planning period. For the full twelve months of the 2008 to 2009 planning period, the top sink and top source with the highest positive FTR target allocations were the AP Control Zone and the Northern Illinois Hub, respectively. Similarly, the top sink and top source with the largest negative FTR target allocations were the Western Hub and the Pepco Control Zone, respectively.

5 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 2009 to 2010 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 (4,096 hours) and off peak (4,664 hours).

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 2009 to 2010 planning period were the AP South Interface and the Electric Junction — Frontenac line. A new ARR product was added for the 2007 to 2008 planning period. Long Term ARRs are in effect for 10 consecutive planning periods and are available in Stage 1A of the annual ARR allocation. Residual ARRs were also introduced and are available to holders with prorated Stage 1A or 1B ARRs if additional transmission capability is added during the planning period.

- **Demand.** Total demand in the annual ARR allocation was 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. This is down from 140,668 MW for the 2008 to 2009 planning period with 64,546 MW bid in Stage 1A, 27,291 MW bid in Stage 1B and 48,831 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 3,603 MW of ARRs associated with approximately $66,200 per MW-day of revenue that were reassigned in the first month of the 2009 to 2010 planning period. There were 15,326 MW of ARRs associated with approximately $533,900 per MW-day of revenue that were reassigned for the full 2008 to 2009 planning period.

Market Performance

- **Volume.** 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 (62.7 percent) of these allocated ARRs as Annual FTRs. Of 140,668 MW in ARR requests for the 2008 to 2009 planning period, 112,011 MW (79.6 percent) were allocated. There were 64,520 MW allocated in Stage 1A, 26,685 MW allocated in Stage 1B and 20,806 MW allocated in Stage 2. Eligible market participants self scheduled 72,851 MW (65.0 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 2009 to 2010 planning period, ARR holders will receive $1,273.5 million in ARR credits, with an average hourly ARR credit of $1.33 per MWh. During the 2009 to 2010 planning period, the ARR target allocations were $1,273.5 million while PJM collected $1,332.7 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions through Jun 30, 2009, making ARRs revenue adequate. During the 2008 to 2009 planning period, ARR holders received $2,361.3 million in ARR credits, with an average hourly ARR credit of $2.41 per MWh. For the 2008 to 2009 planning period, the ARR target allocations were $2,361.3 million while PJM collected $2,489.6 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.

- **ARR Proration.** When ARRs were allocated for the 2009 to 2010 planning period, some of the requested ARRs were prorated in Stage 2 as a result of binding transmission constraints. No ARRs were prorated in Stage 1A and Stage 1B since there were no constraints affecting the ARR allocation in these two stages. For the 2008 to 2009 planning period, no ARRs were prorated in Stage 1A of the annual ARR allocation. In Stage 1B, the only constraint affecting the ARR allocation was the Cedar Grove — Clifton line. There were 605.4 MW of Stage 1B ARRs denied to participants whose requested ARRs affected that binding transmission constraint.

- **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 first is to compare the revenue received by ARR holders to the congestion costs experienced by these ARR holders. The second is to compare the revenue received by FTR holders to the total congestion costs within PJM. The final and comprehensive method is to compare the revenue received by all ARR and FTR holders to total actual congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM. During the 2007 to 2008 planning period, total ARR and FTR revenues hedged 97.4 percent of the congestion costs within PJM. For the 2008 to 2009 planning period, all ARRs and FTRs hedged more than 100 percent of the congestion costs within PJM.

Conclusion

The annual ARR allocation and the FTR auctions provide market participants with hedging instruments. These instruments can be used for hedging positions or for speculation. 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 2009 to 2010 planning period were competitive and succeeded in providing all qualified market participants with equal access to FTRs. The MMU recommends that the rules for ARR reassignment when load shifts should address the fact that in the case of ARRs self scheduled as FTRs, the underlying FTRs do not follow the load while the ARRs do.

ARRs were 100 percent revenue adequate for both the 2008 to 2009 and the 2009 to 2010 planning periods. FTRs were paid at 100 percent of the target allocation level for the 12-month period of the 2008 to 2009 planning period, and at 100 percent of the target allocation level for the first month of the 2009 to 2010 planning period.

The total of ARR and FTR revenues hedged 97.4 percent of the congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2007 to 2008 planning period and more than 100 percent of the congestion costs in PJM during the 2008 to 2009 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 FTR holders, their revenues or those paying congestion.

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.

PJM faced substantial participant defaults in 2007 and 2008 as a result of participant counter flow positions in the FTR markets and inadequate participant financial resources. The magnitude of the defaults was the result of both the size of the FTR positions defaulted and of the PJM credit policies, which did not require sufficient collateral to cover the participants' losses. PJM also faced additional defaults in 2008 and 2009, although the 2009 default amounts were the result of defaults on annual FTR positions that defaulted in 2008. PJM has taken significant steps to address the credit issue. The defaults also raised potential market gaming issues, which were addressed, in part, in a PJM filing. These continue to be investigated.

Financial Transmission Rights

Supply

Table 8-1 Top 10 principal binding transmission constraints limiting the Annual FTR Auction: Planning period 2009 to 2010 (See 2008 SOM Table 8-2)

			Severity Ranking by Auction Round			
Constraint	Type	Control Zone	1	2	3	4
AP South	Interface	AP	1	1	1	1
Mahans Lane - Tidd	Line	AEP	2	3	2	2
Albright - Mt. Zion	Line	AP	36	2	7	13
Kingwood - Pruntytown	Line	AP	22	4	3	5
Mount Storm - Pruntytown	Line	AP	3	6	4	4
Pana North	Flowgate	External	8	5	6	3
Mt. Jackson - Edinburg	Line	Dominion	4	7	9	6
Monroe - Shieldalloy	Line	AECO	5	10	8	7
Tiltonsville - Windsor	Line	AP	9	9	5	8
Keisters - Campbell OE	Flowgate	External	10	8	45	166

Patterns of Ownership

Table 8-2 Annual FTR Auction patterns of ownership by FTR direction: Planning period 2009 to 2010 (See 2008 SOM Table 8-4)

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	66.9%	44.1%	61.6%
Financial	33.1%	55.9%	38.4%
Total	100.0%	100.0%	100.0%

Table 8-3 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January through June 2009 (See 2008 SOM Table 8-5)

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	29.7%	21.9%	26.4%
Financial	70.3%	78.1%	73.6%
Total	100.0%	100.0%	100.0%

Market Performance

Volume

Table 8-4 Annual FTR Auction market volume: Planning period 2009 to 2010 (See 2008 SOM Table 8-7)

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	80,464	304,889	45,356	14.9%	259,533	85.1%
		Prevailing Flow	179,814	986,613	84,161	8.5%	902,452	91.5%
		Total	260,278	1,291,502	129,517	10.0%	1,161,984	90.0%
	Options	Counter Flow	26	2,861	2,661	93.0%	200	7.0%
		Prevailing Flow	6,242	141,972	23,433	16.5%	118,538	83.5%
		Total	6,268	144,833	26,095	18.0%	118,738	82.0%
	Total	Counter Flow	80,490	307,750	48,017	15.6%	259,733	84.4%
		Prevailing Flow	186,056	1,128,585	107,595	9.5%	1,020,990	90.5%
		Total	266,546	1,436,335	155,612	10.8%	1,280,723	89.2%
Self-scheduled bids	Obligations	Counter Flow	620	3,175	3,175	100.0%	0	0.0%
		Prevailing Flow	8,796	65,414	65,414	100.0%	0	0.0%
		Total	9,416	68,589	68,589	100.0%	0	0.0%
Buy and self-scheduled bids	Obligations	Counter Flow	81,084	308,064	48,531	15.8%	259,533	84.2%
		Prevailing Flow	188,610	1,052,027	149,576	14.2%	902,452	85.8%
		Total	269,694	1,360,091	198,107	14.6%	1,161,985	85.4%
	Options	Counter Flow	26	2,861	2,661	93.0%	200	7.0%
		Prevailing Flow	6,242	141,972	23,433	16.5%	118,538	83.5%
		Total	6,268	144,833	26,095	18.0%	118,738	82.0%
	Total	Counter Flow	81,110	310,925	51,192	16.5%	259,733	83.5%
		Prevailing Flow	194,852	1,193,999	173,009	14.5%	1,020,990	85.5%
		Total	275,962	1,504,924	224,201	14.9%	1,280,723	85.1%
Sell offers	Obligations	Counter Flow	13,789	42,950	2,390	5.6%	40,560	94.4%
		Prevailing Flow	21,608	83,797	4,869	5.8%	78,929	94.2%
		Total	35,397	126,747	7,259	5.7%	119,489	94.3%
	Options	Counter Flow	19	1,822	0	0.0%	1,822	100.0%
		Prevailing Flow	940	13,584	140	1.0%	13,444	99.0%
		Total	959	15,406	140	0.9%	15,266	99.1%
	Total	Counter Flow	13,808	44,772	2,390	5.3%	42,383	94.7%
		Prevailing Flow	22,548	97,381	5,009	5.1%	92,372	94.9%
		Total	36,356	142,154	7,399	5.2%	134,755	94.8%

Table 8-5 Comparison of self scheduled FTRs: Planning periods 2008 to 2009 and 2009 to 2010 (See 2008 SOM Table 8-8)

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	109,413	62.7%

Table 8-6 Monthly Balance of Planning Period FTR Auction market volume: January through June 2009 (See 2008 SOM Table 8-9)

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-09	Obligations	Buy bids	166,943	648,482	59,472	9.2%	589,011	90.8%
		Sell offers	36,552	172,413	17,489	10.1%	154,924	89.9%
	Options	Buy bids	473	25,043	3,628	14.5%	21,415	85.5%
		Sell offers	475	13,010	1,871	14.4%	11,139	85.6%
Feb-09	Obligations	Buy bids	167,297	613,252	54,064	8.8%	559,188	91.2%
		Sell offers	33,278	135,132	13,663	10.1%	121,469	89.9%
	Options	Buy bids	1,000	26,021	1,408	5.4%	24,613	94.6%
		Sell offers	399	11,925	1,370	11.5%	10,555	88.5%
Mar-09	Obligations	Buy bids	153,613	542,094	54,409	10.0%	487,685	90.0%
		Sell offers	43,579	176,838	14,931	8.4%	161,907	91.6%
	Options	Buy bids	738	38,982	4,626	11.9%	34,356	88.1%
		Sell offers	472	12,300	1,382	11.2%	10,918	88.8%
Apr-09	Obligations	Buy bids	121,034	417,636	49,603	11.9%	368,034	88.1%
		Sell offers	31,574	131,945	12,924	9.8%	119,021	90.2%
	Options	Buy bids	204	22,992	614	2.7%	22,379	97.3%
		Sell offers	353	8,776	1,607	18.3%	7,168	81.7%
May-09	Obligations	Buy bids	79,272	285,448	31,020	10.9%	254,428	89.1%
		Sell offers	19,030	70,521	8,843	12.5%	61,678	87.5%
	Options	Buy bids	131	9,750	183	1.9%	9,567	98.1%
		Sell offers	195	2,585	1,345	52.0%	1,240	48.0%
Jun-09	Obligations	Buy bids	202,097	807,023	72,951	9.0%	734,073	91.0%
		Sell offers	79,699	276,795	24,514	8.9%	252,281	91.1%
	Options	Buy bids	734	40,968	2,552	6.2%	38,416	93.8%
		Sell offers	5,377	69,781	11,567	16.6%	58,214	83.4%
2008/2009*	Obligations	Buy bids	2,143,034	9,449,644	782,007	8.3%	8,667,637	91.7%
		Sell offers	504,152	1,991,496	226,544	11.4%	1,764,952	88.6%
	Options	Buy bids	11,754	773,793	22,209	2.9%	751,584	97.1%
		Sell offers	6,550	180,904	32,203	17.8%	148,701	82.2%
2009/2010*	Obligations	Buy bids	202,097	807,023	72,951	9.0%	734,073	91.0%
		Sell offers	79,699	276,795	24,514	8.9%	252,281	91.1%
	Options	Buy bids	734	40,968	2,552	6.2%	38,416	93.8%
		Sell offers	5,377	69,781	11,567	16.6%	58,214	83.4%

* Shows twelve months for 2008/2009 and one month ended 30-Jun-2009 for 2009/2010

Table 8-7 Monthly Balance of Planning Period FTR Auction buy-bid bid and cleared volume (MW per period): January through June 2009 (See 2008 SOM Table 8-10)

Monthly Auction	MW Type	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-09	Bid	299,268	129,139	99,968				145,151	673,525
	Cleared	41,932	9,425	3,985				7,758	63,100
Feb-09	Bid	311,274	106,999	93,220				127,781	639,274
	Cleared	37,183	6,216	5,347				6,727	55,472
Mar-09	Bid	305,146	120,085	115,103				40,741	581,075
	Cleared	41,859	8,073	6,687				2,415	59,034
Apr-09	Bid	306,763	133,866						440,629
	Cleared	41,884	8,332						50,216
May-09	Bid	295,198							295,198
	Cleared	31,204							31,204
Jun-09	Bid	283,451	121,774	119,403	24,320	104,418	102,266	92,358	847,992
	Cleared	33,822	9,100	8,599	2,500	7,967	7,524	5,991	75,503

Table 8-8 Secondary bilateral FTR market volume: Planning periods 2008 to 2009 and 2009 to 2010[6] (See 2008 SOM Table 8-11)

Planning Period	Hedge Type	Class Type	Secondary (MW)
2008/2009	Obligation	24-Hour	800
		On Peak	1,133
		Off Peak	9
		Total	1,942
	Option	24-Hour	0
		On Peak	6
		Off Peak	0
		Total	6
2009/2010*	Obligation	24-Hour	1,438
		On Peak	0
		Off Peak	0
		Total	1,438

* Shows one month ended 30-Jun-2009

6 The 2009 to 2010 planning period covers the 2009 to 2010 Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions through June 30, 2009.

Price

Table 8-9 Annual FTR Auction weighted-average cleared prices by FTR direction (Dollars per MWh): Planning period 2009 to 2010 (See 2008 SOM Table 8-13)

			Class Type			
Trade Type	Hedge Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($0.75)	($0.56)	($0.49)	($0.58)
		Prevailing Flow	$1.35	$1.13	$0.95	$1.13
		Total	$0.66	$0.57	$0.40	$0.53
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.53	$0.50	$0.32	$0.41
		Total	$0.18	$0.46	$0.30	$0.35
Self-scheduled bids	Obligations	Counter Flow	($0.32)	NA	NA	($0.32)
		Prevailing Flow	$1.67	NA	NA	$1.67
		Total	$1.58	NA	NA	$1.58
Buy and self-scheduled bids	Obligations	Counter Flow	($0.61)	($0.56)	($0.49)	($0.55)
		Prevailing Flow	$1.62	$1.13	$0.95	$1.44
		Total	$1.37	$0.57	$0.40	$1.03
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.53	$0.50	$0.32	$0.41
		Total	$0.18	$0.46	$0.30	$0.35
Sell offers	Obligations	Counter Flow	($1.76)	($0.24)	($0.37)	($0.42)
		Prevailing Flow	$0.49	$0.80	$0.37	$0.63
		Total	($0.28)	$0.52	$0.06	$0.28
	Options	Counter Flow	NA	NA	NA	NA
		Prevailing Flow	$0.04	$0.03	$0.26	$0.11
		Total	$0.04	$0.03	$0.26	$0.11

Figure 8-1 Annual FTR auction clearing price duration curves: Planning period 2009 to 2010 (See 2008 SOM Figure 8-2)

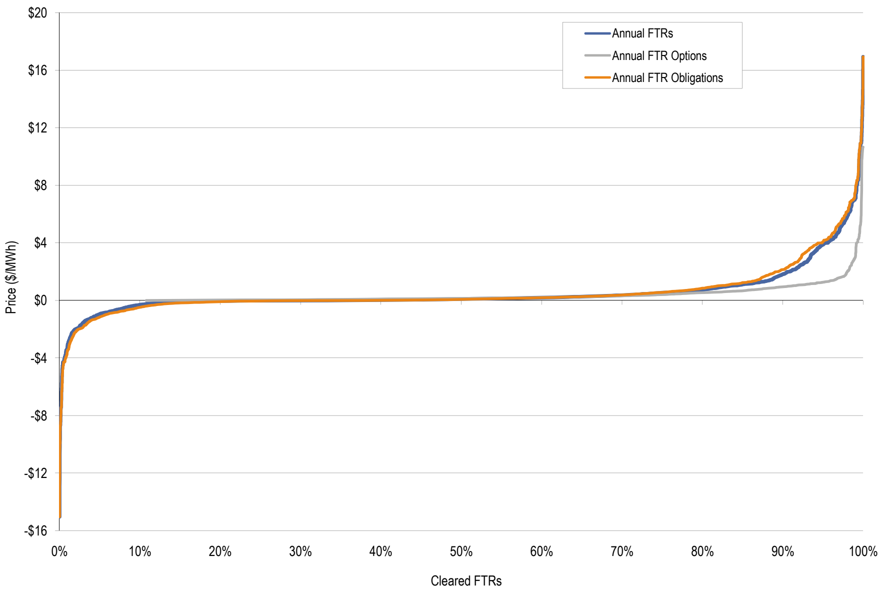


Table 8-10 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MWh): January through June 2009 (See 2008 SOM Table 8-14)

Monthly Auction	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-09	$0.08	$0.18	$0.24				$0.04	$0.09
Feb-09	$0.10	$0.28	$0.21				$0.21	$0.16
Mar-09	$0.11	$0.25	$0.20				$0.55	$0.18
Apr-09	$0.12	$0.27						$0.15
May-09	$0.10							$0.10
Jun-09	$0.17	$0.25	$0.17	$1.16	$0.37	$0.48	$0.46	$0.38

Revenue

Annual FTR Auction Revenue

Table 8-11 Annual FTR Auction revenue by FTR direction: Planning period 2009 to 2010 (See 2008 SOM Table 8-16)

						Class Type
Trade Type	Hedge Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($43,363,985)	($44,760,870)	($43,432,206)	($131,557,061)
		Prevailing Flow	$158,105,703	$185,216,383	$136,397,384	$479,719,470
		Total	$114,741,718	$140,455,513	$92,965,178	$348,162,410
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$2,457,455	$22,913,596	$17,326,182	$42,697,232
		Total	$2,457,455	$22,913,596	$17,326,182	$42,697,232
	Total	Counter Flow	($43,363,985)	($44,760,870)	($43,432,206)	($131,557,061)
		Prevailing Flow	$160,563,158	$208,129,979	$153,723,566	$522,416,703
		Total	$117,199,173	$163,369,109	$110,291,360	$390,859,642
Self-scheduled bids	Obligations	Counter Flow	($8,772,739)	NA	NA	($8,772,739)
		Prevailing Flow	$956,797,012	NA	NA	$956,797,012
		Total	$948,024,273	NA	NA	$948,024,273
Buy and self-scheduled bids	Obligations	Counter Flow	($52,136,724)	($44,760,870)	($43,432,206)	($140,329,799)
		Prevailing Flow	$1,114,902,715	$185,216,383	$136,397,384	$1,436,516,482
		Total	$1,062,765,992	$140,455,513	$92,965,178	$1,296,186,683
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$2,457,455	$22,913,596	$17,326,182	$42,697,232
		Total	$2,457,455	$22,913,596	$17,326,182	$42,697,232
	Total	Counter Flow	($52,136,724)	($44,760,870)	($43,432,206)	($140,329,799)
		Prevailing Flow	$1,117,360,170	$208,129,979	$153,723,566	$1,479,213,715
		Total	$1,065,223,446	$163,369,109	$110,291,360	$1,338,883,915
Sell offers	Obligations	Counter Flow	($1,385,244)	($1,089,452)	($2,094,504)	($4,569,201)
		Prevailing Flow	$736,568	$9,964,413	$2,864,123	$13,565,105
		Total	($648,676)	$8,874,961	$769,619	$8,995,904
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$15,598	$5,268	$68,488	$89,353
		Total	$15,598	$5,268	$68,488	$89,353
	Total	Counter Flow	($1,385,244)	($1,089,452)	($2,094,504)	($4,569,201)
		Prevailing Flow	$752,166	$9,969,681	$2,932,611	$13,654,458
		Total	($633,078)	$8,880,229	$838,107	$9,085,257

Figure 8-2 Ten largest positive and negative revenue producing FTR sinks purchased in the Annual FTR Auction: Planning period 2009 to 2010[7] (See 2008 SOM Figure 8-5)

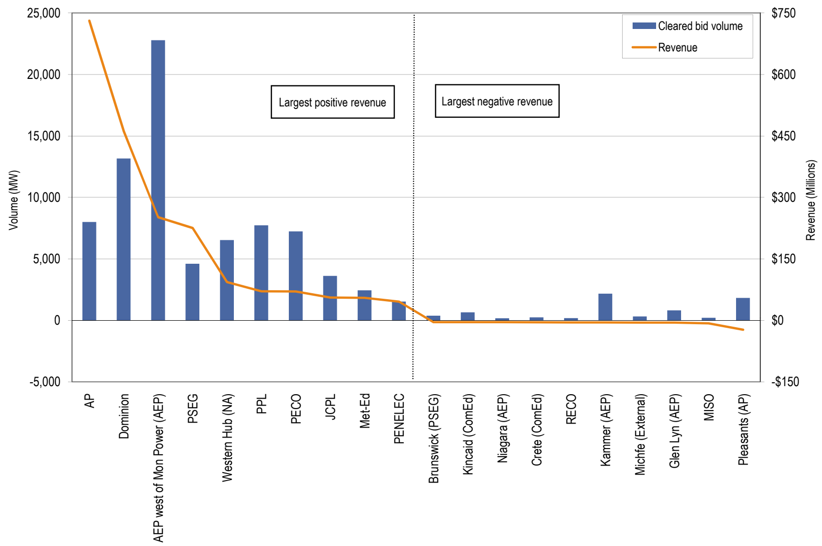
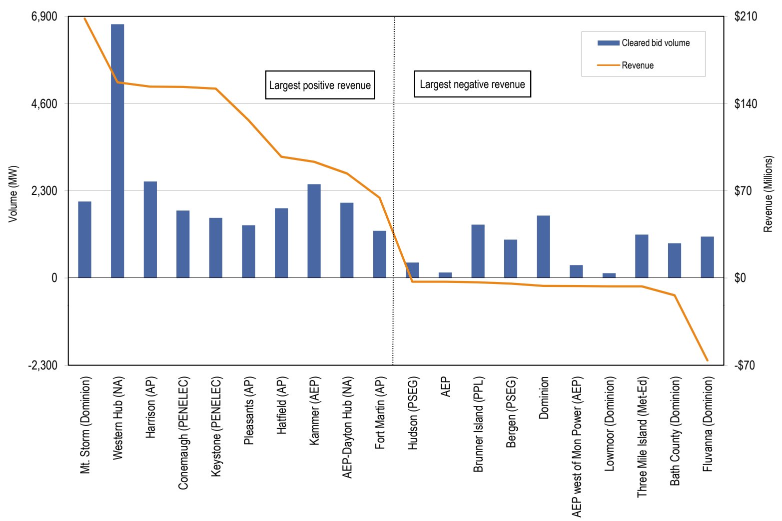


Figure 8-3 Ten largest positive and negative revenue producing FTR sources purchased in the Annual FTR Auction: Planning period 2009 to 2010 (See 2008 SOM Figure 8-6)



7 For Figure 8-2 through Figure 8-7, 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.

Monthly Balance of Planning Period FTR Auction Revenue

Figure 8-4 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2008 to 2009 through May 31, 2009 (See 2008 SOM Figure 8-7)

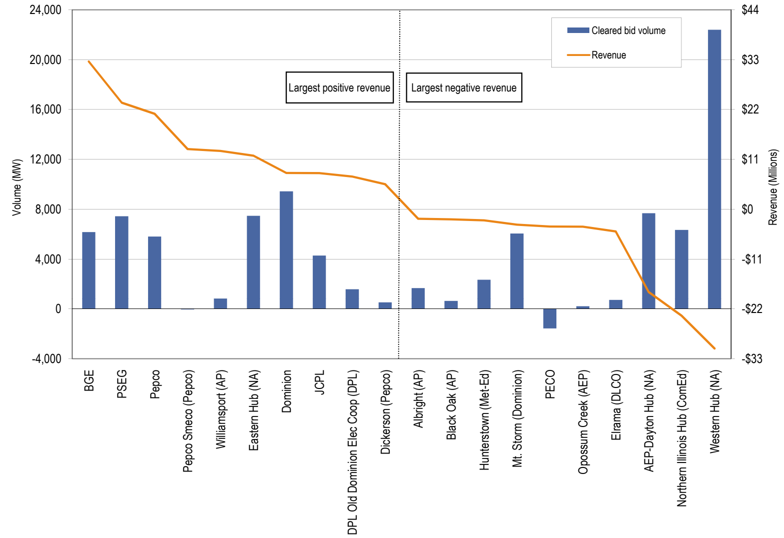


Figure 8-5 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2008 to 2009 through May 31, 2009 (See 2008 SOM Figure 8-8)

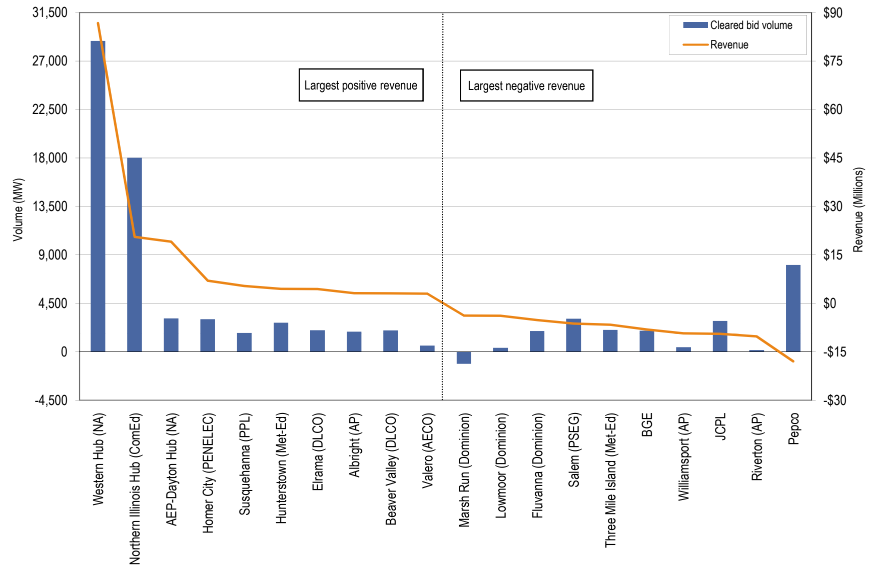


Table 8-12 Monthly Balance of Planning Period FTR Auction revenue: January through June 2009 (See 2008 SOM Table 8-17)

			Class Type			
Monthly Auction	Hedge Type	Trade Type	24-Hour	On Peak	Off Peak	All
Jan-09	Obligations	Buy bids	$1,207,292	$934,011	$244,584	$2,385,888
		Sell offers	$248,591	$573,963	$77,911	$900,466
	Options	Buy bids	$26,505	$140,359	$145,245	$312,108
		Sell offers	$0	$203,453	$129,447	$332,900
Feb-09	Obligations	Buy bids	($83,145)	$2,193,269	$1,332,926	$3,443,050
		Sell offers	$413,446	$1,442,454	$530,041	$2,385,941
	Options	Buy bids	$31,233	$278,934	$178,062	$488,229
		Sell offers	$0	$193,821	$118,916	$312,737
Mar-09	Obligations	Buy bids	$395,276	$2,107,188	$1,467,981	$3,970,446
		Sell offers	$308,687	$1,724,949	$1,167,153	$3,200,789
	Options	Buy bids	$34,097	$435,416	$54,453	$523,967
		Sell offers	$0	$181,733	$52,487	$234,221
Apr-09	Obligations	Buy bids	($223,411)	$1,471,041	$1,062,859	$2,310,489
		Sell offers	$19,324	$954,279	$602,223	$1,575,826
	Options	Buy bids	$1,511	$291,731	$15,883	$309,126
		Sell offers	$0	$260,520	$67,733	$328,253
May-09	Obligations	Buy bids	($234,075)	$902,305	$371,453	$1,039,683
		Sell offers	($12,927)	$429,537	$118,031	$534,641
	Options	Buy bids	$0	$10,099	$8,754	$18,854
		Sell offers	$1,336	$115,521	$48,174	$165,031
Jun-09	Obligations	Buy bids	($455,827)	$9,859,792	$7,471,308	$16,875,272
		Sell offers	$940,697	$4,742,041	$3,783,072	$9,465,811
	Options	Buy bids	$0	$454,961	$67,016	$521,977
		Sell offers	$21,245	$3,150,642	$1,819,405	$4,991,291
2008/2009*	Obligations	Buy bids	$18,536,366	$62,983,127	$39,113,790	$120,633,283
		Sell offers	$10,238,514	$20,746,786	$12,003,977	$42,989,277
	Options	Buy bids	$164,213	$5,175,296	$2,995,811	$8,335,320
		Sell offers	$26,515	$13,614,983	$5,286,634	$18,928,133
2009/2010*	Obligations	Buy bids	($455,827)	$9,859,792	$7,471,308	$16,875,272
		Sell offers	$940,697	$4,742,041	$3,783,072	$9,465,811
	Options	Buy bids	$0	$454,961	$67,016	$521,977
		Sell offers	$21,245	$3,150,642	$1,819,405	$4,991,291

* Shows twelve months for 2008/2009 and one month ended 30-Jun-2009 for 2009/2010

Revenue Adequacy

Table 8-13 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2008 to 2009 and 2009 to 2010 (See 2008 SOM Table 8-18)

Accounting Element	2008/2009	2009/2010*
ARR information		
ARR target allocations	$2,361.3	$104.8
FTR auction revenue	$2,489.6	$111.8
ARR excess	$128.3	$7.0
FTR targets		
FTR target allocations	$1,747.9	$44.0
Adjustments:		
Adjustments to FTR target allocations	($4.1)	$0.0
Total FTR targets	$1,743.8	$44.0
FTR revenues		
ARR excess	$128.3	$7.0
Competing uses	$0.7	$0.0
Congestions		
Net Negative Congestion (enter as negative)	($59.0)	($1.0)
Hourly congestion revenue	$1,735.7	$50.6
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($52.3)	($1.9)
Consolidated Edison Company of New York and Public Service Electric and Gas Company Wheel (CEPSW) congestion credit to Con Edison (enter as negative)	($3.1)	($0.1)
Adjustments:		
Excess revenues carried forward into future months	$36.8	$0.0
Excess revenues distributed back to previous months	$16.1	$0.0
Other adjustments to FTR revenues	($2.0)	$0.0
Total FTR revenues	$1,801.2	$54.6
Excess revenues distributed to other months	($30.0)	($10.7)
Excess revenues distributed to CEPSW for end-of-year distribution	$0.5	$0.0
Excess revenues distributed to FTR holders	$4.0	$0.0
Total FTR congestion credits	$1,743.8	$44.0
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$1,751.4	$44.0
Remaining deficiency	$0.0	$0.0

* Shows one month ended 30-Jun-09

Figure 8-6 Ten largest positive and negative FTR target allocations summed by sink: Planning period 2008 to 2009 through May 31, 2009 (See 2008 SOM Figure 8-9)

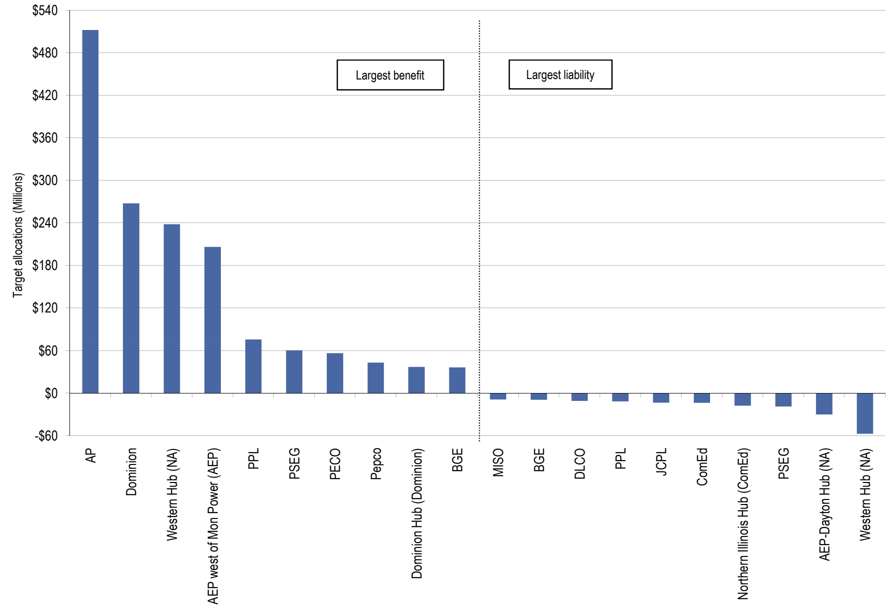


Figure 8-7 Ten largest positive and negative FTR target allocations summed by source: Planning period 2008 to 2009 through May 31, 2009 (See 2008 SOM Figure 8-10)

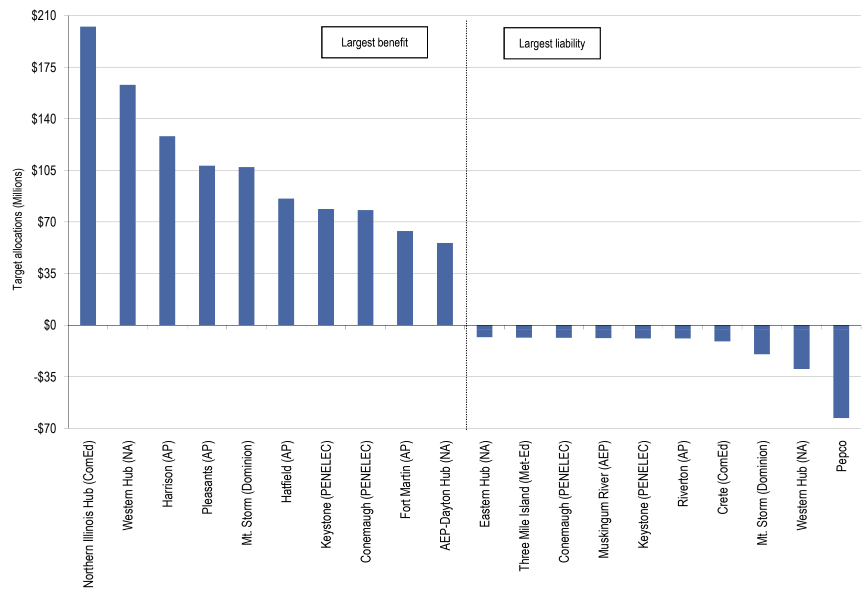


Table 8-14 Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2008 to 2009 and 2009 to 2010 (See 2008 SOM Table 8-19)

Period	FTR Revenues	FTR Target Allocations	FTR Credits	FTR Payout Ratio	Credits Deficiency	Credits Excess
Jun-08	$436.9	$432.3	$432.3	100%	$0	$4.7
Jul-08	$371.4	$364.2	$364.2	100%	$0	$7.2
Aug-08	$140.5	$125.0	$125.0	100%	$0	$15.4
Sep-08	$154.6	$154.6	$154.6	100%	$0	$0.0
Oct-08	$109.4	$109.4	$109.4	100%	$0	$0.0
Nov-08	$97.2	$97.2	$97.2	100%	$0	$0.0
Dec-08	$85.3	$77.6	$77.6	100%	$0	$7.7
Jan-09	$159.5	$151.1	$151.1	100%	$0	$8.4
Feb-09	$92.0	$84.3	$84.3	100%	$0	$7.7
Mar-09	$86.7	$86.7	$86.7	100%	$0	$0.0
Apr-09	$32.8	$31.1	$31.1	100%	$0	$1.7
May-09	$34.8	$30.3	$30.3	100%	$0	$4.5
Summary for Planning Period 2008 to 2009						
Total	$1,748.3	$1,743.8	$1,743.8	100%	$0	$4.5
Jun-09	$54.6	$44.0	$44.0	100%	$0	$10.7
Summary for Planning Period 2009 to 2010 through June 30, 2009						
Total	$54.6	$44.0	$44.0	100%	$0	$10.7

Auction Revenue Rights

Market Structure

Supply

Incremental ARRs

Table 8-15 Incremental ARR allocation volume: Planning periods 2008 to 2009 and 2009 to 2010 (See 2008 SOM Table 8-20)

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%

Table 8-16 Top 10 principal binding transmission constraints limiting the annual ARR allocation: Planning period 2009 to 2010 (See 2008 SOM Table 8-21)

Constraint	Type	Control Zone
AP South	Interface	AP
Electric Junction - Frontenac	Line	ComEd
Linden - North Ave	Line	PSEG
East Frankfort - Braidwood	Line	ComEd
Des Plaines	Transformer	ComEd
Doubs	Transformer	AP
North Seaford - Pine Street	Line	DPL
Garman - Westover	Line	PENELEC
Logans Ferry - Universal	Line	DLCO
Joliet - Joliet Central	Line	ComEd

ARR Reassignment for Retail Load Switching

Table 8-17 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2008, through June 30, 2009 (See 2008 SOM Table 8-22)

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2008/2009 (12 months)	2009/2010 (1 month)*	2008/2009 (12 months)	2009/2010 (1 month)*
AECO	501	233	$16.1	$4.3
AEP	11	0	$0.2	$0.0
AP	707	133	$164.7	$14.8
BGE	3,361	612	$124.3	$12.7
ComEd	3,074	621	$10.0	$1.9
DAY	1	0	$0.0	$0.0
DLCO	471	92	$2.1	$0.2
Dominion	5	0	$0.4	$0.0
DPL	1,404	239	$24.8	$2.7
JCPL	1,094	493	$45.0	$7.5
Met-Ed	0	0	$0.0	$0.0
PECO	47	9	$1.4	$0.1
PENELEC	0	0	$0.0	$0.0
Pepco	3,040	473	$79.9	$4.8
PPL	35	2	$2.2	$0.1
PSEG	1,537	686	$62.7	$17.1
RECO	40	10	$0.0	$0.0
Total	15,326	3,603	$533.9	$66.2

* Through 30-Jun-09

Market Performance

Volume

Table 8-18 Annual ARR allocation volume: Planning periods 2008 to 2009 and 2009 to 2010 (See 2008 SOM Table 8-23)

Planning Period	Stage	Round	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2008/2009	1A	0	7,845	64,546	64,520	100.0%	26	0.0%
	1B	1	3,147	27,291	26,685	97.8%	606	2.2%
	2	2	1,691	16,737	6,753	40.3%	9,984	59.7%
		3	1,312	15,464	6,304	40.8%	9,160	59.2%
		4	1,118	16,630	7,749	46.6%	8,881	53.4%
		Total	4,121	48,831	20,806	42.6%	28,025	57.4%
	Total		15,113	140,668	112,011	79.6%	28,657	20.4%
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%

Revenue Adequacy

Table 8-19 ARR revenue adequacy (Dollars (Millions)): Planning periods 2007 to 2008 and 2008 to 2009 (See 2008 SOM Table 8-24)

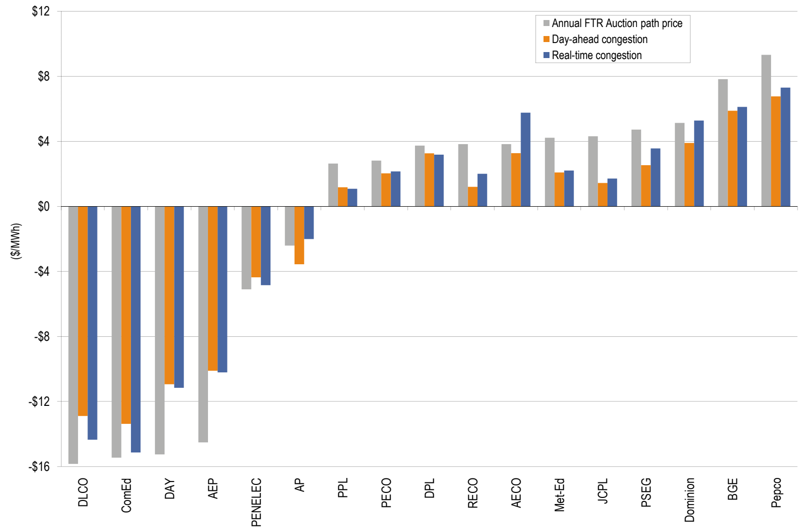
	2008/2009	2009/2010
Total FTR auction net revenue	$2,489.6	$1,332.7
Annual FTR Auction net revenue	$2,422.6	$1,329.8
Monthly Balance of Planning Period FTR Auction net revenue*	$67.1	$2.9
ARR target allocations	$2,361.3	$1,273.5
ARR credits	$2,361.3	$1,273.5
Surplus auction revenue	$128.3	$59.2
ARR payout ratio	100%	100%
FTR payout ratio*	100%	100%

* Shows twelve months for 2008/2009 and one month ended 30-Jun-09 for 2009/2010

ARR and FTR Revenue and Congestion

FTR Prices and Zonal Price Differences

Figure 8-8 Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: Planning period 2008 to 2009 through May 31, 2009 (See 2008 SOM Figure 8-11)



Effectiveness of ARRs as a Hedge against Congestion

Table 8-20 ARR and self scheduled FTR congestion hedging by control zone: Planning period 2008 to 2009 (See 2008 SOM Table 8-25)

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference	Percent Hedged
AECO	$26,640,842	$5,126,844	$31,767,686	$86,973,434	($55,205,748)	36.5%
AEP	$4,952,682	$231,856,718	$236,809,400	$205,479,068	$31,330,332	>100%
AP	$50,310,148	$512,353,151	$562,663,299	$336,175,310	$226,487,989	>100%
BGE	$93,238,869	$4,134,804	$97,373,673	($411,324)	$97,784,997	>100%
ComEd	$15,791,877	$12,658,294	$28,450,171	$147,739,297	($119,289,126)	19.3%
DAY	$9,353,214	$1,119,768	$10,472,982	$5,461,253	$5,011,729	>100%
DLCO	$4,691,151	$0	$4,691,151	$31,068,597	($26,377,446)	15.1%
Dominion	$24,970,748	$4,221,089	$29,191,837	$56,924,114	($27,732,277)	51.3%
DPL	$6,990,231	$246,078,596	$253,068,827	$106,753,425	$146,315,402	>100%
JCPL	$64,463,301	$5,636,585	$70,099,886	$84,986,431	($14,886,545)	82.5%
Met-Ed	$220,814	$28,242,556	$28,463,370	$47,764,282	($19,300,912)	59.6%
PECO	$4,336,906	$55,831,240	$60,168,146	($16,483,569)	$76,651,715	>100%
PENELEC	$49,024,464	$24,861,452	$73,885,916	$52,667,452	$21,218,464	>100%
Pepco	$58,344,157	$648,017	$58,992,174	$294,035,180	($235,043,006)	20.1%
PJM	$10,528,746	($9,203,133)	$1,325,613	$9,233,073	($7,907,460)	14.4%
PPL	$1,841,709	$63,076,348	$64,918,057	$32,450,329	$32,467,728	>100%
PSEG	$119,733,671	$17,949,360	$137,683,031	($2,672,958)	$140,355,989	>100%
RECO	$0	$0	$0	$6,794,177	($6,794,177)	0.0%
Total	$545,433,530	$1,204,591,689	$1,750,025,219	$1,484,937,571	$265,087,648	>100%

Effectiveness of FTRs as a Hedge against Congestion

Table 8-21 FTR congestion hedging by control zone: Planning period 2008 to 2009 (See 2008 SOM Table 8-26)

Control Zone	FTR Credits	FTR Auction Revenue	FTR Hedge	Congestion	FTR Hedge - Congestion Difference	Percent Hedged
AECO	$36,858,894	$32,933,548	$3,925,346	$44,016,104	($40,090,758)	8.9%
AEP	$209,802,906	$204,085,063	$5,717,843	$163,137,494	($157,419,651)	3.5%
AP	$527,925,980	$780,244,128	($252,318,148)	$308,763,117	($561,081,265)	<0%
BGE	$38,944,903	$57,160,496	($18,215,593)	$88,353,266	($106,568,859)	<0%
ComEd	($26,152,262)	($4,320,075)	($21,832,187)	$270,705,356	($292,537,543)	<0%
DAY	$1,744,872	($2,026,571)	$3,771,443	$4,965,895	($1,194,452)	75.9%
DLCO	($9,342,004)	($16,286,386)	$6,944,382	$17,171,947	($10,227,565)	40.4%
Dominion	$344,212,309	$522,524,367	($178,312,058)	$258,555,954	($436,868,012)	<0%
DPL	$50,222,866	$42,813,893	$7,408,973	$79,859,232	($72,450,259)	9.3%
JCPL	$5,730,251	$104,255,372	($98,525,121)	$92,084,709	($190,609,830)	<0%
Met-Ed	$36,542,204	$60,190,813	($23,648,609)	($1,869,811)	($21,778,798)	<0%
PECO	$65,545,964	$76,721,387	($11,175,423)	($45,096,152)	$33,920,729	>100%
PENELEC	$118,697,998	$134,333,128	($15,635,130)	$112,232,762	($127,867,892)	<0%
Pepco	$204,600,376	$260,910,557	($56,310,181)	$168,144,210	($224,454,391)	<0%
PJM	($3,803,359)	$2,995,857	($6,799,216)	($101,307,205)	$94,507,989	>100%
PPL	$74,910,276	$82,036,315	($7,126,039)	$5,081,971	($12,208,010)	<0%
PSEG	$71,755,534	$148,376,631	($76,621,097)	$18,995,919	($95,617,016)	<0%
RECO	$3,877	$2,660,947	($2,657,070)	$5,852,897	($8,509,967)	<0%
Total	$1,748,201,585	$2,489,609,470	($741,407,885)	$1,489,647,665	($2,231,055,550)	<0%

Effectiveness of ARRs and FTRs as a Hedge against Congestion

Table 8-22 ARR and FTR congestion hedging by control zone: Planning period 2008 to 2009 (See 2008 SOM Table 8-27)

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
AECO	$31,771,370	$36,858,894	$32,933,548	$35,696,716	$44,016,104	($8,319,388)	81.1%
AEP	$286,629,442	$209,802,906	$204,085,063	$292,347,285	$163,137,494	$129,209,791	>100%
AP	$786,115,867	$527,925,980	$780,244,128	$533,797,719	$308,763,117	$225,034,602	>100%
BGE	$98,283,955	$38,944,903	$57,160,496	$80,068,362	$88,353,266	($8,284,904)	90.6%
ComEd	$24,695,477	($26,152,262)	($4,320,075)	$2,863,290	$270,705,356	($267,842,066)	1.1%
DAY	$9,926,586	$1,744,872	($2,026,571)	$13,698,029	$4,965,895	$8,732,134	>100%
DLCO	$4,691,151	($9,342,004)	($16,286,386)	$11,635,533	$17,171,947	($5,536,414)	67.8%
Dominion	$463,320,908	$344,212,309	$522,524,367	$285,008,850	$258,555,954	$26,452,896	>100%
DPL	$28,077,406	$50,222,866	$42,813,893	$35,486,379	$79,859,232	($44,372,853)	44.4%
JCPL	$98,171,902	$5,730,251	$104,255,372	($353,219)	$92,084,709	($92,437,928)	<0%
Met-Ed	$50,979,701	$36,542,204	$60,190,813	$27,331,092	($1,869,811)	$29,200,903	>100%
PECO	$75,104,737	$65,545,964	$76,721,387	$63,929,314	($45,096,152)	$109,025,466	>100%
PENELEC	$95,333,189	$118,697,998	$134,333,128	$79,698,059	$112,232,762	($32,534,703)	71.0%
Pepco	$59,162,442	$204,600,376	$260,910,557	$2,852,261	$168,144,210	($165,291,949)	1.7%
PJM	$20,562,228	($3,803,359)	$2,995,857	$13,763,012	($101,307,205)	$115,070,217	>100%
PPL	$73,844,704	$74,910,276	$82,036,315	$66,718,665	$5,081,971	$61,636,694	>100%
PSEG	$154,621,742	$71,755,534	$148,376,631	$78,000,645	$18,995,919	$59,004,726	>100%
RECO	$0	$3,877	$2,660,947	($2,657,070)	$5,852,897	($8,509,967)	<0%
Total	$2,361,292,807	$1,748,201,585	$2,489,609,470	$1,619,884,922	$1,489,647,665	$130,237,257	>100%

Table 8-23 ARR and FTR congestion hedging: Planning periods 2007 to 2008 and 2008 to 2009 (See 2008 SOM Table 8-28)

Planning Period	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
2007/2008	$1,640,453,406	$2,038,912,131	$1,736,137,908	$1,943,227,629	$1,995,477,234	($52,249,605)	97.4%
2008/2009	$2,361,292,807	$1,748,201,585	$2,489,609,470	$1,619,884,922	$1,489,647,665	$130,237,257	>100%