SECTION 2 – ENERGY MARKET, PART 1

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

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance for January through March of 2010, including market size, concentration, residual supply index, price-cost markup, net revenue and price.[1] The MMU concludes that the PJM Energy Market results were competitive in the first three months of 2010.

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

1 Analysis of 2010 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the control zones, the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2009 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 June 29, 2009).

Overview

Market Structure

- **Supply.** During the first three months of 2010, the PJM Energy Market received an hourly average of 157,526 MW in supply offers including hydroelectric generation.[3] The January through March 2010 average daily offered supply was 4,994 MW higher than the January through March 2009 average daily offered supply of 152,532 MW. An extended outage at a nuclear power plant in 2009, and increased wind output were the primary causes of the increase.

- **Demand.** The PJM system peak load for January through March 2010 was 101,262 MW in the hour ended 1800 EPT on January 4, 2010, while the PJM peak load for January through March 2009 was 117,169 MW in the hour ended 1800 EPT on January 16, 2009.[4] The January through March 2010 peak load was 15,907 MW, or 13.6 percent, lower than the January through March 2009 peak load.

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

- **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

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 the *2010 Quarterly State of the Market Report for PJM: January through March*, all hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2009 State of the Market Report for PJM*, Appendix N, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

test) as the trigger for offer capping in 2010. PJM offer caps units only when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer-capping levels have historically been low in PJM. In the Day-Ahead Energy Market offer-capped unit hours were 0.1 percent in the first three months of 2010, the same level as in 2009. In the Real-Time Energy Market offer-capped unit hours increased from 0.4 percent in 2009 to 0.6 percent in the first three months of 2010.

- **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 25 or more hours during the first three months of calendar year 2010. During the first three months of 2010, the AEP, AP, BGE, ComEd, DLCO, Dominion, and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 25 or more hours. The analysis of the application of the three pivotal supplier test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.

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 for the first three months of 2010 was -$0.91 per MWh, or -2.0 percent. Coal steam units contributed -$1.08, or 118.7 percent, to the total markup component of LMP. Combined cycle units that use gas as their primary fuel source contributed $0.11 or -12.5 percent to the total markup component of LMP. The markup was -$0.85 per MWh during peak hours and -$0.97 per MWh during off-peak hours.

  The markup component of the overall PJM day-ahead, load-weighted, average LMP for the first three months of 2010 was -$1.22 per MWh, or -2.5 percent. Coal steam units contributed -$0.91 or 74.5 percent to the total markup component of LMP. Natural gas steam units contributed -$0.31 or 25.0 percent to the total markup component of LMP. The markup was -$0.88 per MWh during peak hours and -$1.56 per MWh during off-peak hours.

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

- **Load.** On average, PJM real-time load decreased in the first three months of 2010 by 0.1 percent from the first three months of 2009, falling from 81,174 MW to 81,121 MW. PJM day-ahead load decreased in the first three months of 2010 by 1.1 percent from the first three months of 2009, falling from 94,583 MW to 93,559 MW.

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

  PJM Real-Time Energy Market prices decreased in the first three months of 2010 compared to the first three months of 2009. The system simple average LMP was 6.7 percent lower in the first three months of 2010 than in the first three months of 2009, $44.13 per MWh versus $47.29 per MWh. The load-weighted LMP was 7.4 percent lower in the first three months of 2010 than the first three months of 2009, $45.92 per MWh versus $49.60 per MWh. The real-time fuel cost adjusted, load-weighted, average LMP was 8.0 percent higher for the first three months of 2010 than the load-weighted, average LMP for the first three months of 2009, $53.56 per MWh compared to $49.60 per MWh. In other words, if fuel costs for the first three months of 2010 had been the same as the first three months of 2009, the 2010 load-weighted LMP would have been higher, $53.56 per MWh, than the actual $45.92 per MWh, and 8.0 percent higher than the load-weighted average LMP for 2009. Fuel costs and lower loads in 2010 contributed to downward pressure on LMP.

PJM Day-Ahead Energy Market prices decreased in the first three months of 2010 compared to the first three months of 2009. The system simple average LMP was 2.7 percent lower in the first three months of 2010 than in the first three months of 2009, $46.13 per MWh versus $47.41 per MWh. The load-weighted LMP was 3.4 percent lower in the first three months of 2010 than in the first three months of 2009, $47.77 per MWh versus $49.44 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 PJM parent company that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In the first three months of 2010, 12.6 percent of real-time load was supplied by bilateral contracts, 19.6 percent by spot market purchases and 67.8 percent by self-supply. Compared with 2009, reliance on bilateral contracts decreased by 0.3 percentage points; reliance on spot supply increased by 2.6 percentage points; and reliance on self-supply decreased by 2.3 percentage points in 2010.

Demand-Side Response

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

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

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

- **Demand-Side Response Activity.** In the first three months of 2010, in the Economic Program, participation decreased compared to the first three months of 2009. There were decreases in a range of activity metrics including settlements submitted, settled MWh and credits, Participation levels through calendar year 2009 and through the first three months of 2010 are generally lower compared to prior years due to a number of factors, including lower price levels, lower load levels and improved measurement and verification. On the peak load day for the period January through March 2010, January 4, 2010, there were 2,625.0 MW registered in the Economic Load Response Program.

  In the first three months of 2010, the Emergency Program, specifically, the Load Management (LM) Program, participation increased compared to the same period in 2009.[5] Participants in the LM Program are committed RPM resources and participation remains constant through RPM delivery years. For the 2009/2010 delivery year, there were 7,294.3 MW registered in the LM Program, compared to 4498.2 MW registered in the 2008/2009 delivery year.

  Since the introduction of the capacity market on June 1, 2007 the capacity market has been the source of growth in total demand side revenues and demand side revenues from the capacity market were the only significant source of revenue in 2009. In the first three months of 2010, payments from the Economic Program decreased from 2009 by $461,000 or 63 percent, from $731,000 to $270,000 while capacity revenue increased from 2009 by $44 million or 88 percent, from $49 million to $93 million since 2009.

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

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance for the first three months of 2010, 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 increased by about 4,994 MW when comparing the first quarter of 2010 to the first quarter of 2009, while aggregate peak load decreased by 15,907 MW, modifying the general supply demand balance from the first three months of 2009 with a corresponding impact on Energy Market prices. Average load was also lower than in the first three months of 2009. 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.

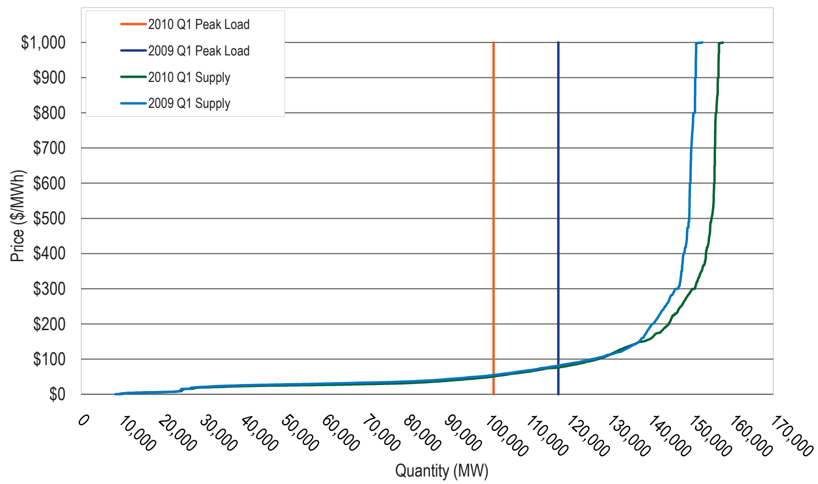
Energy Market results for the first three months of 2010 generally reflected supply-demand fundamentals. Lower prices in the Energy Market were the result of lower fuel costs and of lower demand. PJM Real-Time, load-weighted, average LMP for the first three months of 2010 was $45.92, or 7.4 percent lower than the load-weighted, average LMP for the first three months of 2009, which was $49.60. The real-time fuel cost adjusted, load-weighted, average LMP was 8.0 percent higher for the first three months of 2010 than the load-weighted, average LMP in for the first three months of 2009, $53.56 per MWh compared to $49.60 per MWh. In other words, if fuel costs for the first three months of 2010 had been the same as the first three months of 2009, the 2010 load-weighted LMP would have been higher, $53.56 per MWh, than the actual $45.92 per MWh, and 8.0 percent higher than the load-weighted average LMP for 2009. Lower fuel prices in the first three months of 2010 resulted in lower energy prices in January through March of 2010 than would have occurred if fuel prices had remained at the levels of January through March of 2009. Lower demand also contributed to lower prices.

The overall market results support the conclusion that prices in PJM are set, on average, by marginal units operating at, or close to, their marginal costs. This is evidence of competitive behavior and competitive market outcomes. Given the structure of the Energy Market, tighter markets or a change in participant behavior remain potential sources of concern in the Energy Market. The MMU concludes that the PJM Energy Market results were competitive in the first three months of 2010.

Market Structure

Supply

Figure 2-1 Average PJM aggregate supply curves: January through March, 2009 and 2010 (See 2009 SOM, Figure 2-1)



Demand

Table 2-1 Actual PJM footprint peak loads: January through March of 2003 to 2010 (See 2009 SOM, Table 2-1)

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Difference (MW)	Difference (%)
2003	Thu, January 23	18	54,670	NA	NA
2004	Mon, January 26	18	53,620	(1,050)	(1.9%)
2005	Tue, January 18	18	96,362	42,742	79.7%
2006	Mon, February 13	19	100,065	3,703	3.8%
2007	Mon, February 05	19	118,800	18,736	18.7%
2008	Thu, January 03	18	111,724	(7,076)	(6.0%)
2009	Fri, January 16	18	117,169	5,445	4.9%
2010	Mon, January 04	18	101,262	(15,907)	(13.6%)

Figure 2-2 Actual PJM footprint peak loads: January through March of 2003 to 2010 (See 2009 SOM, Figure 2-2)

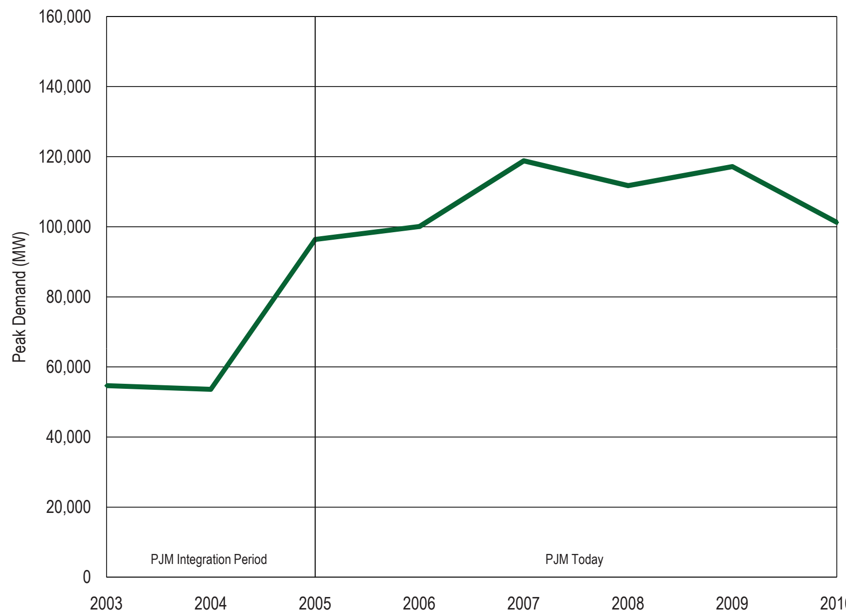
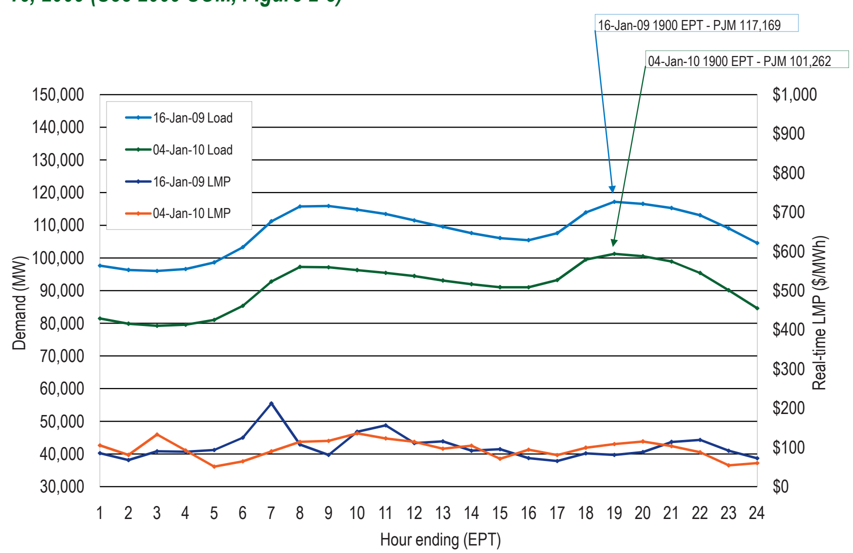


Figure 2-3 PJM 1st quarter peak-load comparison: Monday, January 4, 2010 and Friday, January 16, 2009 (See 2009 SOM, Figure 2-3)



Market Concentration

PJM HHI Results

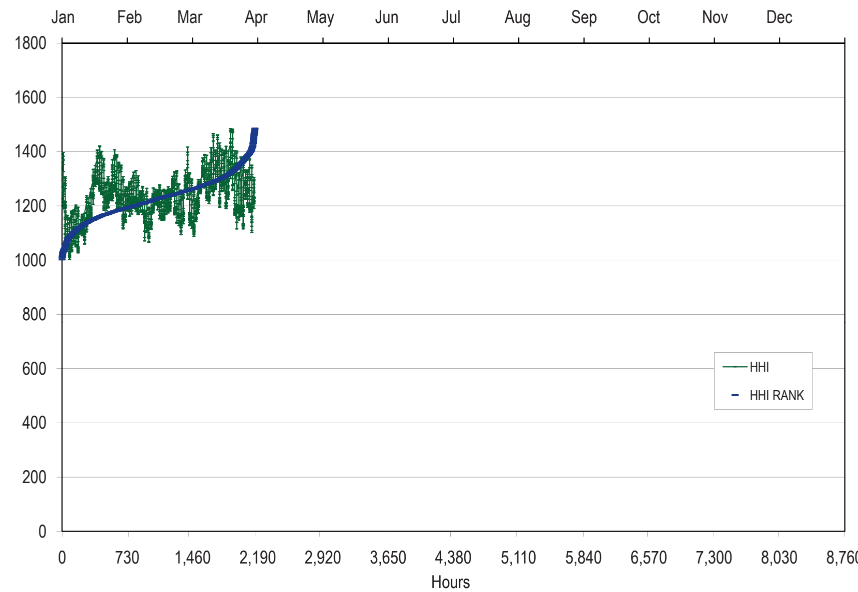
Table 2-2 PJM hourly Energy Market HHI: January through March 2010[6] (See 2009 SOM, Table 2-2)

	Hourly Market HHI
Average	1228
Minimum	1003
Maximum	1485
Highest market share (One hour)	30%
Highest market share (All hours)	21%
# Hours	2160
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

Table 2-3 PJM hourly Energy Market HHI (By segment): January through March 2010 (See 2009 SOM, Table 2-3)

	Minimum	Average	Maximum
Base	1118	1258	1462
Intermediate	876	2255	5915
Peak	831	6526	10000

Figure 2-4 PJM hourly Energy Market HHI: January through March 2010 (See 2009 SOM, Figure 2-4)



Local Market Structure and Offer Capping

Table 2-4 Annual real-time offer-capping statistics: Calendar years 2006 through March 2010 (See 2009 SOM, Table 2-4)

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2006	1.0%	0.2%	0.4%	0.1%
2007	1.1%	0.2%	0.2%	0.0%
2008	1.0%	0.2%	0.2%	0.1%
2009	0.4%	0.1%	0.1%	0.0%
2010	0.6%	0.2%	0.1%	0.0%

6 This analysis includes all hours of the first three months of 2010, regardless of congestion.

Table 2-5 Real-time offer-capped unit statistics: January through March 2010 (See 2009 SOM, Table 2-5)

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2010 Offer-Capped Hours					
	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	1	0	28
80% and < 90%	0	0	0	0	0	11
75% and < 80%	1	0	0	0	0	10
70% and < 75%	0	1	0	0	0	1
60% and < 70%	0	0	0	0	0	12
50% and < 60%	0	0	0	0	0	14
25% and < 50%	0	0	0	0	0	23
10% and < 25%	0	0	1	1	1	34

Local Market Structure

Table 2-6 Three pivotal supplier results summary for regional constraints: January through March 2010 (See 2009 SOM, Table 2-6)

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	614	525	86%	170	28%
	Off Peak	428	372	87%	109	25%
AP South	Peak	1,756	875	50%	1,269	72%
	Off Peak	1,509	837	55%	970	64%
Bedington - Black Oak	Peak	NA	NA	NA	NA	NA
	Off Peak	21	14	67%	13	62%
Harrison - Pruntytown	Peak	103	92	89%	25	24%
	Off Peak	275	200	73%	130	47%
West	Peak	107	101	94%	9	8%
	Off Peak	43	37	86%	8	19%

Table 2-7 Three pivotal supplier test details for three regional constraints: January through March 2010 (See 2009 SOM, Table 2-7)

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	81	294	20	16	3
	Off Peak	57	251	18	15	3
AP South	Peak	78	244	10	4	6
	Off Peak	75	256	10	5	5
Bedington - Black Oak	Peak	NA	NA	NA	NA	NA
	Off Peak	46	133	10	5	4
Harrison - Pruntytown	Peak	68	301	19	17	3
	Off Peak	61	209	17	12	5
West	Peak	124	478	18	17	1
	Off Peak	111	640	22	19	3

Table 2-8 Three pivotal supplier results summary for constraints located in the AEP Control Zone: January through March 2010 (See 2009 SOM, Table 2-12)

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
Baker - Broadford	Peak	62	17	27%	48	77%
	Off Peak	276	140	51%	210	76%
Cloverdale - Lexington	Peak	93	39	42%	71	76%
	Off Peak	393	152	39%	299	76%
Kanawha River - Kincaid	Peak	145	0	0%	145	100%
	Off Peak	104	0	0%	104	100%
Sullivan	Peak	106	0	0%	106	100%
	Off Peak	25	0	0%	25	100%

Table 2-9 Three pivotal supplier test details for constraints located in the AEP Control Zone: January through March 2010 (See 2009 SOM, Table2-13)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Baker - Broadford	Peak	40	124	9	2	7
	Off Peak	66	215	9	4	6
Cloverdale - Lexington	Peak	78	185	16	6	10
	Off Peak	73	179	14	5	9
Kanawha River - Kincaid	Peak	5	3	1	0	1
	Off Peak	5	3	1	0	1
Sullivan	Peak	22	0	1	0	1
	Off Peak	78	0	1	0	1

Table 2-10 Three pivotal supplier results summary for constraints located in the AP Control Zone: January through March 2010 (See 2009 SOM, Table 2-14)

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
Doubs	Peak	129	94	73%	45	35%
	Off Peak	13	9	69%	6	46%
Mount Storm - Pruntytown	Peak	1	1	100%	0	0%
	Off Peak	269	148	55%	165	61%
New Martinsville - Paden City	Peak	4	0	0%	4	100%
	Off Peak	NA	NA	NA	NA	NA
Sammis - Wylie Ridge	Peak	24	23	96%	7	29%
	Off Peak	167	105	63%	88	53%
Tiltonsville - Windsor	Peak	511	0	0%	511	100%
	Off Peak	349	0	0%	349	100%

Table 2-11 Three pivotal supplier test details for constraints located in the AP Control Zone: January through March 2010 (See 2009 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
Doubs	Peak	22	0	14	11	3
	Off Peak	22	25	12	9	3
Mount Storm - Pruntytown	Peak	6	169	7	7	0
	Off Peak	76	233	11	6	5
New Martinsville - Paden City	Peak	3	0	1	0	1
	Off Peak	NA	NA	NA	NA	NA
Sammis - Wylie Ridge	Peak	54	0	17	15	2
	Off Peak	42	97	17	10	7
Tiltonsville - Windsor	Peak	9	2	2	0	2
	Off Peak	7	3	2	0	2

Table 2-12 Three pivotal supplier results summary for constraints located in the BGE Control Zone: January through March 2010 (See 2009 SOM, Table 2-16)

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	103	70	68%	58	56%
	Off Peak	28	20	71%	15	54%

Table 2-13 Three pivotal supplier test details for constraints located in the BGE Control Zone: January through March 2010 (See 2009 SOM, Table 2-17)

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	53	137	19	11	8
	Off Peak	48	121	18	12	7

Table 2-14 Three pivotal supplier results summary for constraints located in the ComEd Control Zone: January through March 2010 (See 2009 SOM, Table 2-18)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Burnham - Munster	Peak	31	21	68%	10	32%
	Off Peak	406	123	30%	320	79%
Crete - East Frankfurt	Peak	149	7	5%	145	97%
	Off Peak	2,689	52	2%	2,666	99%
Pleasant Valley - Belvidere	Peak	71	0	0%	71	100%
	Off Peak	176	0	0%	176	100%
Waterman - West Dekalb	Peak	187	0	0%	187	100%
	Off Peak	404	0	0	404	100%
Zion - Pleasant Prairie	Peak	261	0	0%	261	100%
	Off Peak	265	0	0	265	100%

Table 2-15 Three pivotal supplier test details for constraints located in the ComEd Control Zone: January through March 2010 (See 2009 SOM, Table 2-19)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Burnham - Munster	Peak	25	95	22	15	6
	Off Peak	40	89	13	4	9
Crete - East Frankfurt	Peak	32	130	6	0	5
	Off Peak	34	45	5	0	4
Pleasant Valley - Belvidere	Peak	14	0	1	0	1
	Off Peak	11	0	1	0	1
Waterman - West Dekalb	Peak	8	1	1	0	1
	Off Peak	8	3	1	0	1
Zion - Pleasant Prairie	Peak	57	8	2	0	2
	Off Peak	55	6	2	0	2

Table 2-16 Three pivotal supplier results summary for constraints located in the DLCO Control Zone: January through March 2010 (See 2009 SOM, Table 2-20)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Collier - Elwyn	Peak	174	0	0%	174	100%
	Off Peak	NA	NA	NA	NA	NA
Crescent	Peak	359	0	0%	359	100%
	Off Peak	NA	NA	NA	NA	NA

Table 2-17 Three pivotal supplier test details for constraints located in the DLCO Control Zone: January through March 2010 (See 2009 SOM, Table 2-21)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Collier - Elwyn	Peak	15	16	1	0	1
	Off Peak	NA	NA	NA	NA	NA
Crescent	Peak	24	4	1	0	1
	Off Peak	NA	NA	NA	NA	NA

Table 2-18 Three pivotal supplier results summary for constraints located in the Dominion Control Zone: January through March 2010 (See 2009 SOM, Table 2-22)

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	83	0	0%	83	100%
	Off Peak	13	0	0%	13	100%
Clover	Peak	107	5	5%	107	100%
	Off Peak	4	0	0%	4	100%
Fredericksburg	Peak	139	0	0%	139	100%
	Off Peak	10	0	0%	10	100%

Table 2-19 Three pivotal supplier test details for constraints located in the Dominion Control Zone: January through March 2010 (See 2009 SOM, Table 2-23)

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	5	10	1	0	1
	Off Peak	7	15	1	0	1
Clover	Peak	26	86	5	0	5
	Off Peak	7	0	6	0	6
Fredericksburg	Peak	8	82	1	0	1
	Off Peak	19	53	1	0	1

Table 2-20 Three pivotal supplier results summary for constraints located in the PSEG Control Zone: January through March 2010 (See 2009 SOM, Table 2-30)

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	982	1	0%	982	100%
	Off Peak	319	0	0%	319	100%
Hawthorn - Hinchmans Ave	Peak	60	0	0%	60	100%
	Off Peak	92	0	0%	92	100%
Hawthorn - Waldwick	Peak	80	0	0%	80	100%
	Off Peak	18	0	0%	18	100%

Table 2-21 Three pivotal supplier test details for constraints located in the PSEG Control Zone: January through March 2010 (See 2009 SOM, Table 2-31)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Athenia - Saddlebrook	Peak	12	37	2	0	2
	Off Peak	10	35	1	0	1
Hawthorn - Hinchmans Ave	Peak	15	16	2	0	2
	Off Peak	13	12	2	0	2
Hawthorn - Waldwick	Peak	14	15	2	0	2
	Off Peak	14	10	2	0	2

Market Performance: Markup

Real-Time Markup

Ownership of Marginal Resources

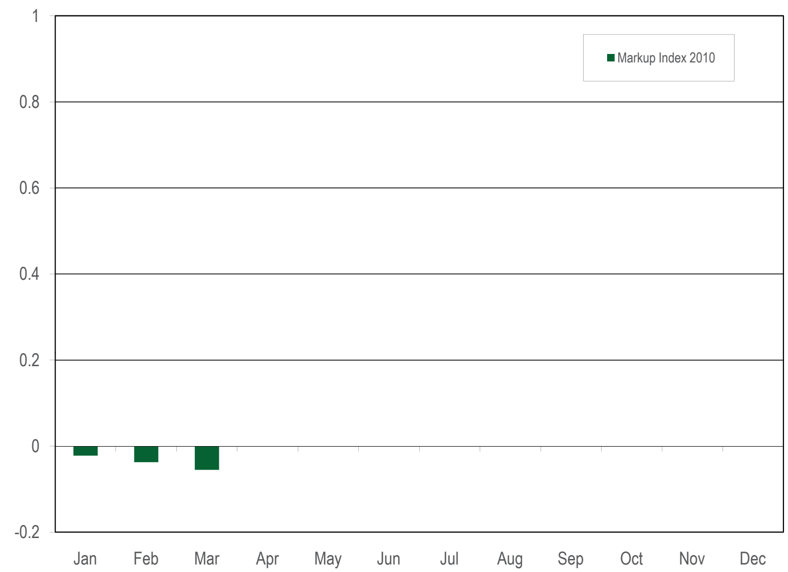
Table 2-22 Marginal unit contribution to PJM real-time, annual, load-weighted LMP (By parent company): January through March 2010 (See 2009 SOM, Table 2-32)

Company	Percent of Price
1	21%
2	11%
3	11%
4	6%
5	6%
6	6%
7	4%
8	3%
9	3%
Other (42 companies)	30%

Table 2-23 Type of fuel used (By real-time marginal units): January through March 2010 (See 2009 SOM, Table 2-33)

Fuel Type	2010
Coal	71%
Natural Gas	24%
Wind	3%
Petroleum	1%
Landfill Gas	1%
Misc	0%

Figure 2-5 Real-time load-weighted unit markup index: January through March 2010 (See 2009 SOM, Figure 2-5)



Unit Markup Characteristics

Table 2-24 The markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January through March 2010 (See 2009 SOM, Table 2-34)

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($1.08)	118.7%
Gas	CC	$0.11	(12.5%)
Gas	CT	$0.01	(1.4%)
Gas	Diesel	($0.00)	0.2%
Gas	Steam	($0.03)	3.0%
Interface	Interface	($0.00)	0.0%
Municipal Waste	Diesel	$0.00	0.0%
Municipal Waste	Steam	$0.03	(2.8%)
Oil	CT	$0.01	(1.5%)
Oil	Diesel	($0.00)	0.5%
Oil	Steam	$0.02	(2.5%)
Wind	Wind	$0.02	(1.8%)
Total		($0.91)	100.0%

Table 2-25 Average, real-time marginal unit markup index (By price category): January through March 2010 (See 2009 SOM, Table2-35)

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.10)	($3.81)
$25 to $50	(0.06)	($2.98)
$50 to $75	0.01	$0.42
$75 to $100	0.02	$0.48
$100 to $125	0.05	$5.44
$125 to $150	0.04	$4.90
> $150	0.11	$21.81

Markup Component of System Price

Table 2-26 Monthly markup components of real-time load-weighted LMP: January through March 2010 (See 2009 SOM, Table 2-36)

	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$0.56	$0.00	$1.03
Feb	($1.53)	($1.19)	($1.88)
Mar	($2.01)	($1.38)	($2.73)
2010	($0.91)	($0.85)	($0.97)

Markup Component of Real-Time Zonal Prices

Table 2-27 Average real-time zonal markup component: January through March 2010 (See 2009 SOM, Table 2-37)

	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	($0.84)	($0.72)	($0.96)
AEP	($2.31)	($1.84)	($2.76)
AP	($1.35)	($0.97)	($1.72)
BGE	$0.39	$0.37	$0.40
ComEd	($0.56)	($1.07)	($0.02)
DAY	($2.80)	($2.31)	($3.31)
DLCO	($1.63)	$0.41	($3.74)
Dominion	$0.74	$0.24	$1.21
DPL	($0.61)	($0.59)	($0.63)
JCPL	($0.80)	($0.46)	($1.16)
Met-Ed	($0.77)	($0.62)	($0.92)
PECO	($0.83)	($0.72)	($0.93)
PENELEC	($2.16)	($1.83)	($2.50)
Pepco	$0.51	$0.24	$0.79
PPL	($0.85)	($0.69)	($1.01)
PSEG	($1.27)	($1.20)	($1.34)
RECO	($2.00)	($3.01)	($0.86)

Markup by Real-Time System Price Levels

Table 2-28 Average real-time markup component (By price category): January through March 2010 (See 2009 SOM, Table 2-38)

	Average Markup Component	Frequency
Below $20	($5.97)	1.5%
$20 to $40	($3.33)	86.9%
$40 to $60	($1.41)	43.9%
$60 to $80	$3.11	10.9%
$80 to $100	$10.42	4.1%
$100 to $120	$12.81	2.5%
$120 to $140	$25.54	1.8%
$140 to $160	$12.91	0.5%
Above $160	$33.65	0.4%

Day-Ahead Markup

Ownership of Marginal Resources

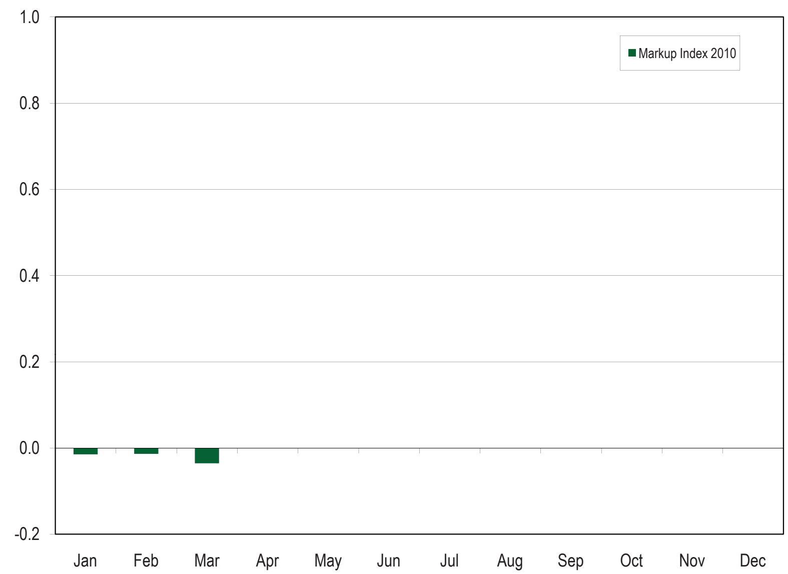
Table 2-29 Marginal unit contribution to PJM day-ahead, annual, load-weighted LMP (By parent company): January through March 2010 (See 2009 SOM, Table 2-39)

Company	Percent of Price
1	23%
2	6%
3	6%
4	6%
5	6%
6	5%
7	5%
8	5%
9	4%
Other (84 companies)	34%

Table 2-30 Day-ahead marginal resources by type/fuel: January through March 2010 (See 2009 SOM, Table 2-40)

Type/Fuel	2010
Transaction	32%
DEC	30%
INC	23%
Coal	10%
Natural gas	4%
Price sensitive demand	1%
Wind	0%
Oil	0%
Municipal waste	0%

Figure 2-6 Day-ahead load-weighted unit markup index: January through March 2010 (See 2009 SOM, Figure 2-6)



Unit Markup Characteristics

Table 2-31 Average, day-ahead marginal unit markup index (By primary fuel and unit type): January through March 2010 (See 2009 SOM, Table 2-41)

Fuel Type	Unit Type	Average Markup Index	Average Dollar Markup
Coal	Steam	(0.06)	($2.49)
Municipal waste	Steam	0.02	$0.70
Natural gas	CT	0.09	$8.14
Natural gas	Diesel	(0.18)	($13.59)
Natural gas	Steam	(0.01)	($0.54)
Oil	Steam	(0.11)	($12.42)
Wind	Wind	0.00	$0.00

Table 2-32 Average, day-ahead marginal unit markup index (By price category): January through March 2010 (See 2009 SOM, Table 2-42)

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.09)	($2.56)
$25 to $50	(0.05)	($2.48)
$50 to $75	0.01	$0.07
$75 to $100	(0.05)	($7.39)
$100 to $125	0.00	($1.19)
$125 to $150	0.04	$4.03
> $150	0.33	$51.27

Markup Component of System Price

Table 2-33 Monthly markup components of day-ahead, load-weighted LMP: January through March 2010 (See 2009 SOM, Table 2-43)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($1.21)	($0.85)	($1.51)
Feb	($0.86)	($0.61)	($1.11)
Mar	($1.61)	($1.18)	($2.12)
Annual	($1.22)	($0.88)	($1.56)

Markup Component of Zonal Prices

Table 2-34 Day-ahead, average, zonal markup component: January through March 2010 (See 2009 SOM, Table 2-44)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($1.06)	($0.59)	($1.53)
AEP	($1.79)	($1.20)	($2.36)
AP	($1.23)	($0.87)	($1.58)
BGE	($0.89)	($0.55)	($1.24)
ComEd	($1.07)	($1.03)	($1.11)
DAY	($1.93)	($1.20)	($2.67)
DLCO	($1.74)	($1.08)	($2.43)
Dominion	($0.86)	($0.95)	($0.77)
DPL	($1.03)	($0.57)	($1.47)
JCPL	($1.06)	($0.64)	($1.51)
Met-Ed	($1.04)	($0.63)	($1.46)
PECO	($1.03)	($0.57)	($1.49)
PENELEC	($1.47)	($1.01)	($1.94)
Pepco	($0.91)	($0.66)	($1.15)
PPL	($1.00)	($0.56)	($1.46)
PSEG	($1.05)	($0.57)	($1.58)
RECO	($1.03)	($0.57)	($1.57)

Markup by System Price Levels

Table 2-35 Average, day-ahead markup (By price category): January through March 2010 (See 2009 SOM, Table 2-45)

	Average Markup Component	Frequency
$20 to $40	($2.19)	43%
$40 to $60	($0.38)	43%
$60 to $80	($2.22)	10%
$80 to $100	($0.18)	3%
$100 to $120	$0.53	1%
$120 to $140	$10.49	0%
$140 to $160	$0.00	0%
Above $160	$0.00	0%

Markup Component by Fuel, Unit Type

Table 2-36 Markup component of the overall PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through March 2010 (See 2009 SOM, Table 2-46)

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($0.91)	74.5%
Municipal waste	Steam	$0.00	(0.0%)
Natural gas	CT	$0.01	(0.5%)
Natural gas	Diesel	($0.01)	0.5%
Natural gas	Steam	($0.31)	25.0%
Oil	Steam	($0.01)	0.5%
Wind	Wind	$0.00	0.0%
Total		($1.22)	100.0%

Frequently Mitigated Unit and Associated Unit Adders – Component of Price

Table 2-37 Frequently mitigated units and associated units (By month): January through March 2010 (See 2009 SOM, Table 2-47)

	FMUs and AUs			Total Eligible for
	Tier 1	Tier 2	Tier 3	Any Adder
January	35	31	27	93
February	35	28	31	94
March	42	16	44	102

Table 2-38 Frequently mitigated units and associated units total months eligible: January through March 2010 (See 2009 SOM, Table 2-48)

Months Adder-Eligible	FMU & AU Count
1	8
2	13
3	85
Total	106

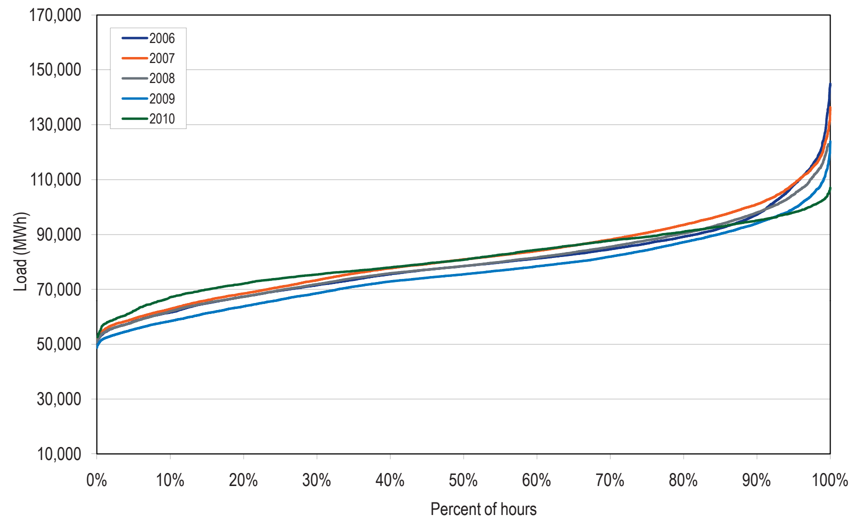
Market Performance: Load and LMP

Load

Real-Time Load

PJM Real-Time Load Duration

Figure 2-7 PJM real-time load duration curves: Calendar years 2006 through March 2010 (See 2009 SOM, Figure 2-7)



PJM Real-Time, Annual Average Load

Table 2-39 PJM real-time average load: Calendar years 1998 through March 2010 (See 2009 SOM, Table 2-49)

	PJM Real-Time Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	28,578	28,653	5,511	NA	NA	NA
1999	29,641	29,341	5,956	3.7%	2.4%	8.1%
2000	30,113	30,170	5,529	1.6%	2.8%	(7.2%)
2001	30,297	30,219	5,873	0.6%	0.2%	6.2%
2002	35,731	34,746	8,013	17.9%	15.0%	36.5%
2003	37,398	37,031	6,832	4.7%	6.6%	(14.7%)
2004	49,963	48,103	13,004	33.6%	29.9%	90.3%
2005	78,150	76,247	16,296	56.4%	58.5%	25.3%
2006	79,471	78,473	14,534	1.7%	2.9%	(10.8%)
2007	81,681	80,914	14,618	2.8%	3.1%	0.6%
2008	79,515	78,481	13,758	(2.7%)	(3.0%)	(5.9%)
2009	76,035	75,471	13,260	(4.4%)	(3.8%)	(3.6%)
2010	81,121	80,773	10,694	6.7%	7.0%	(19.4%)

PJM Real-Time, Monthly Average Load

Figure 2-8 PJM real-time average load: Calendar years 2009 through March 2010 (See 2009 SOM, Figure 2-8)

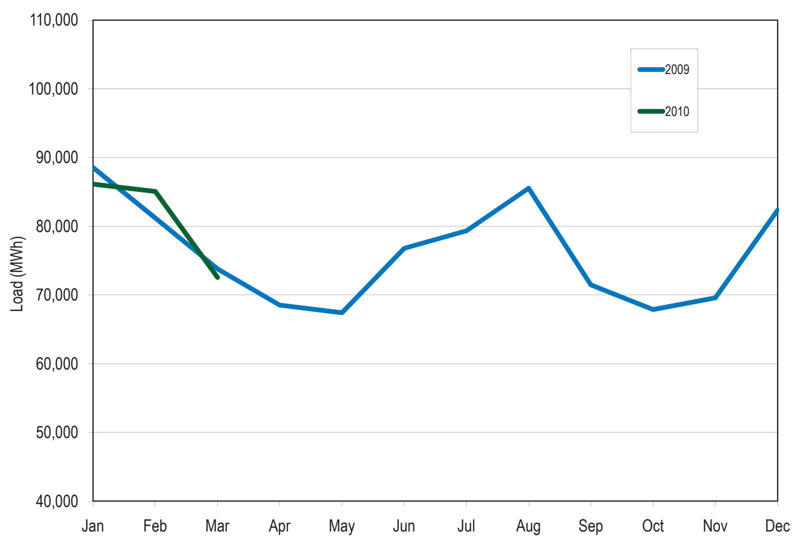


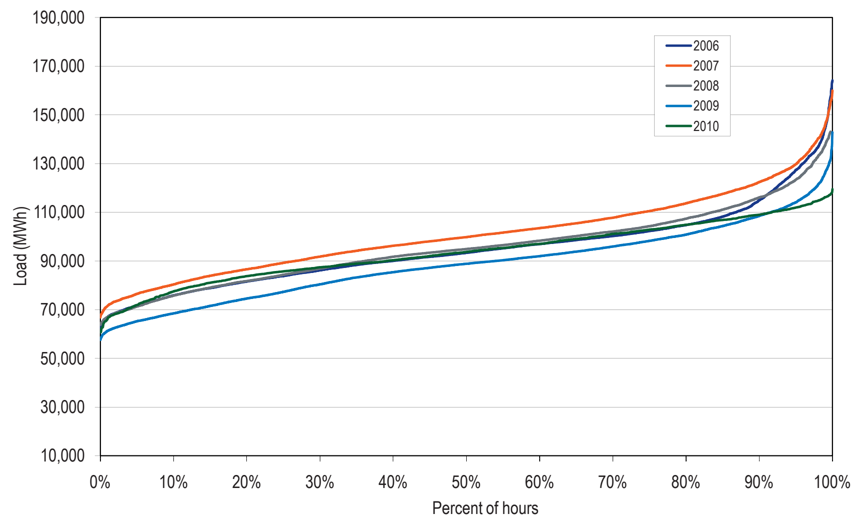
Table 2-40 PJM annual Summer THI, Winter WWP and average temperature: cooling, heating and shoulder months of 2006 through March 2010 (See 2009 SOM, Table 2-51)

	Summer THI	Winter WWP	Shoulder Average Temperature
2006	75.59	31.67	54.62
2007	75.45	27.10	56.55
2008	75.35	27.52	54.10
2009	74.23	25.56	55.09
2010	NA	24.47	46.37

Day-Ahead Load

PJM Day-Ahead Load Duration

Figure 2-9 PJM day-ahead load duration curves: Calendar years 2006 through March 2010 (See 2009 SOM, Figure 2-9)



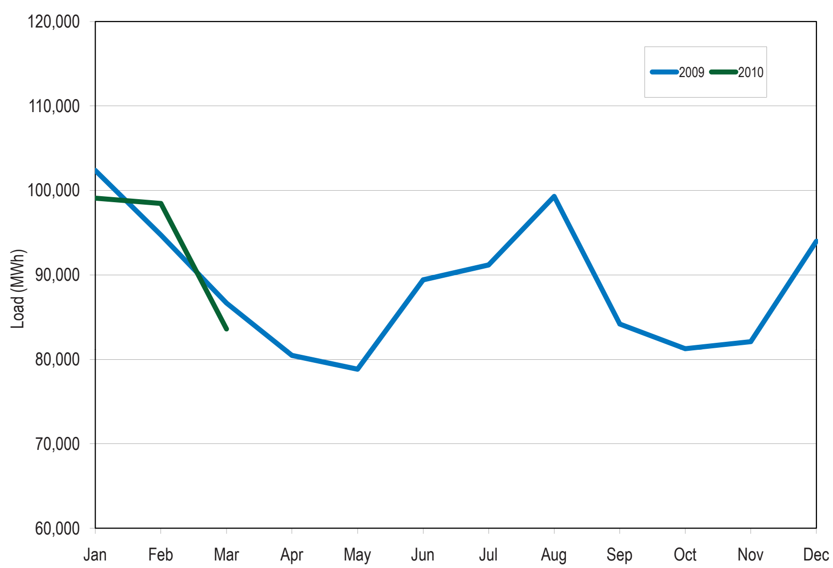
PJM Day-Ahead, Annual Average Load

Table 2-41 PJM day-ahead average load: Calendar years 2000 through March 2010 (See 2009 SOM, Table 2-52)

	PJM Day-Ahead Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	33,045	33,217	6,850	NA	NA	NA
2001	33,318	32,812	6,489	0.8%	(1.2%)	(5.3%)
2002	42,131	40,720	10,130	26.4%	24.1%	56.1%
2003	44,340	44,368	7,883	5.2%	9.0%	(22.2%)
2004	61,034	58,544	16,318	37.7%	32.0%	107.0%
2005	92,002	90,424	17,381	50.7%	54.5%	6.5%
2006	94,793	93,331	16,048	3.0%	3.2%	(7.7%)
2007	100,912	99,799	16,190	6.5%	6.9%	0.9%
2008	95,522	94,886	15,439	(5.3%)	(4.9%)	(4.6%)
2009	88,707	88,833	14,896	(7.1%)	(6.4%)	(3.5%)
2010	93,559	93,720	11,907	5.5%	5.5%	(20.1%)

PJM Day-Ahead, Monthly Average Load

Figure 2-10 PJM day-ahead average load: Calendar years 2009 through March 2010 (See 2009 SOM, Figure 2-10)

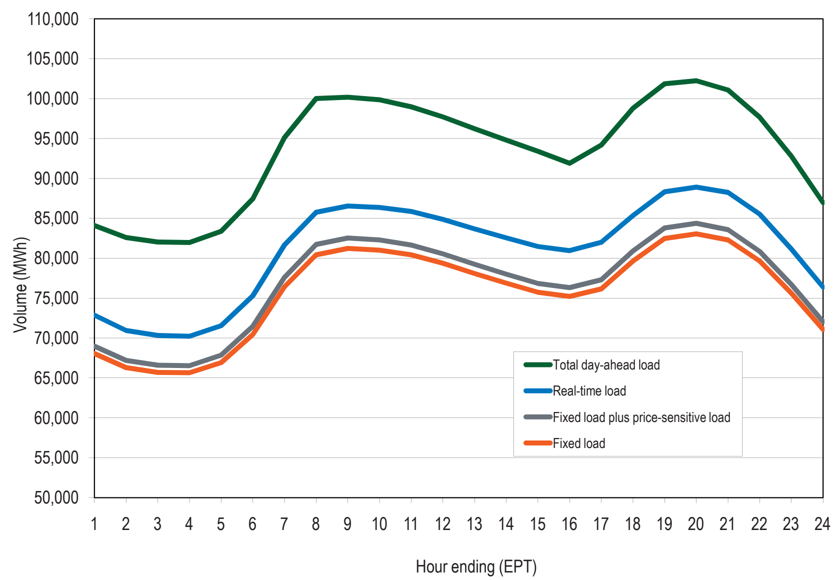


Real-Time and Day-Ahead Load

Table 2-42 Cleared day-ahead and real-time load (MWh): January through March 2010 (See 2009 SOM, Table 2-53)

	Day Ahead				Real Time	Average Difference	
	Cleared Fixed Demand	Cleared Price Sensitive	Cleared DEC Bid	Total Load	Total Load	Total Load	Total Load Minus Cleared DEC Bid
Average	75,744	1,132	16,683	93,559	81,121	12,438	(4,245)
Median	75,870	1,091	16,698	93,720	80,773	12,947	(3,751)
Standard deviation	9,860	331	2,187	11,907	10,694	1,213	(974)

Figure 2-11 Day-ahead and real-time loads (Average hourly volumes): January through March 2010 (See 2009 SOM, Figure 2-11)

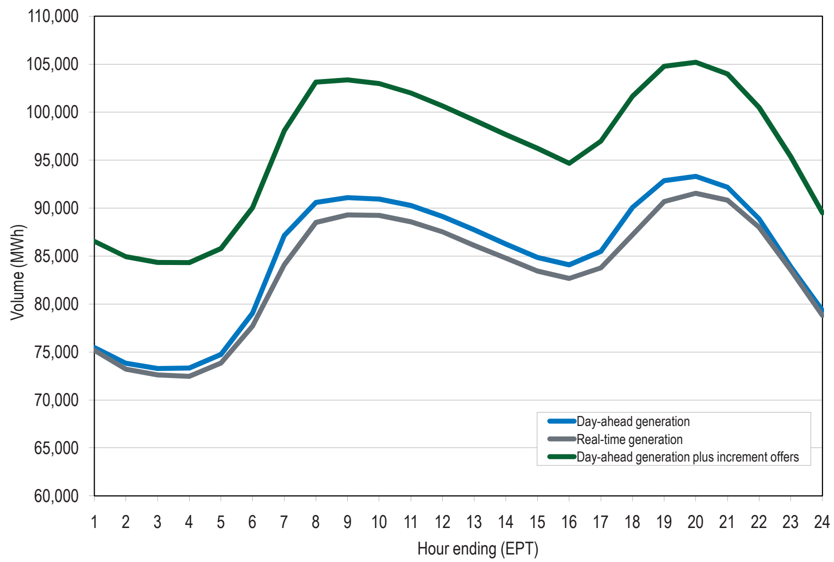


Real-Time and Day-Ahead Generation

Table 2-43 Day-ahead and real-time generation (MWh): January through March 2010 (See 2009 SOM, Table 2-54)

	Day Ahead			Real Time	Average Difference	
	Cleared Generation	Cleared INC Offer	Cleared Generation Plus INC Offer	Generation	Cleared Generation	Cleared Generation Plus INC Offer
Average	84,909	11,416	96,325	83,487	1,422	12,838
Median	85,270	11,357	96,667	83,422	1,848	13,245
Standard deviation	11,374	1,604	12,239	10,998	376	1,242

Figure 2-12 Day-ahead and real-time generation (Average hourly volumes): January through March 2010 (See 2009 SOM, Figure 2-12)



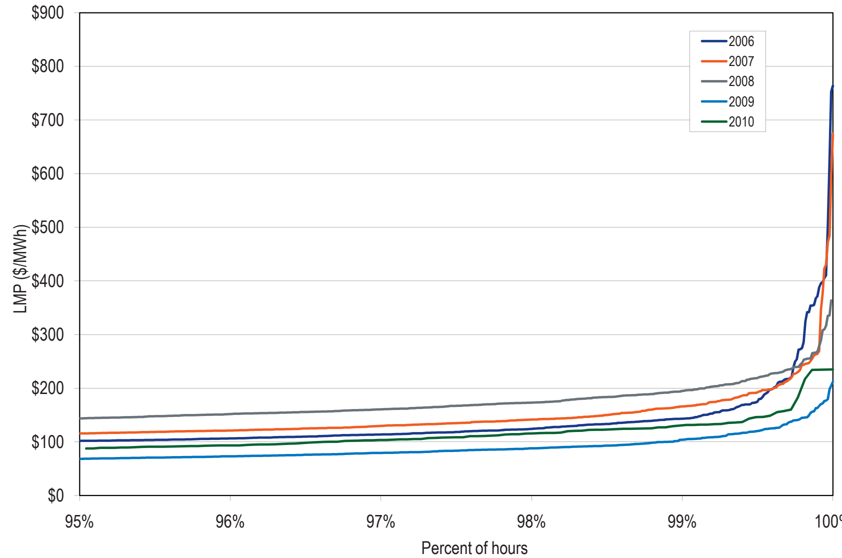
Locational Marginal Price (LMP)

Real-Time LMP

Real-Time Average LMP

PJM Real-Time LMP Duration

Figure 2-13 Price duration curves for the PJM Real-Time Energy Market during hours above the 95th percentile: Calendar years 2006 through March 2010 (See 2009 SOM, Figure 2-13)



PJM Real-Time, Annual Average LMP

Table 2-44 PJM real-time, simple average LMP (Dollars per MWh): Calendar years 1998 through March 2010 (See 2009 SOM, Table 2-55)

	Real-Time LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.72	$16.60	$31.45	NA	NA	NA
1999	$28.32	$17.88	$72.42	30.4%	7.7%	130.3%
2000	$28.14	$19.11	$25.69	(0.6%)	6.9%	(64.5%)
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.41	(12.6%)	(8.3%)	(50.2%)
2003	$38.28	$30.79	$24.71	35.2%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	(15.2%)	(12.1%)	(8.9%)
2007	$57.58	$49.92	$34.60	16.9%	20.4%	5.8%
2008	$66.40	$55.53	$38.62	15.3%	11.2%	11.6%
2009	$37.08	$32.71	$17.12	(44.1%)	(41.1%)	(55.7%)
2010	$44.13	$37.82	$21.87	19.0%	15.6%	27.7%

Zonal Real-Time, Annual Average LMP

Table 2-45 Zonal real-time, simple average LMP (Dollars per MWh): January through March 2009 and 2010 (See 2009 SOM, Table 2-56)

	2009 (Jan -Mar)	2010 (Jan -Mar)	Difference	Difference as Percent of 2009
AECO	$54.45	$48.31	($6.14)	(11.3%)
AEP	$41.22	$39.41	($1.81)	(4.4%)
AP	$49.09	$43.67	($5.42)	(11.0%)
BGE	$54.17	$50.44	($3.73)	(6.9%)
ComEd	$34.34	$34.64	$0.30	0.9%
DAY	$40.20	$38.69	($1.50)	(3.7%)
DLCO	$37.12	$39.65	$2.54	6.8%
Dominion	$51.96	$49.43	($2.53)	(4.9%)
DPL	$55.26	$49.01	($6.25)	(11.3%)
JCPL	$54.41	$47.96	($6.45)	(11.9%)
Met-Ed	$53.07	$47.27	($5.80)	(10.9%)
PECO	$53.17	$47.54	($5.63)	(10.6%)
PENELEC	$47.15	$41.83	($5.32)	(11.3%)
Pepco	$53.76	$50.44	($3.33)	(6.2%)
PPL	$52.69	$46.66	($6.03)	(11.4%)
PSEG	$55.20	$49.91	($5.29)	(9.6%)
RECO	$53.65	$46.66	($6.98)	(13.0%)
PJM	$47.29	$44.13	($3.16)	(6.7%)

Real-Time, Annual Average LMP by Jurisdiction

Table 2-46 Jurisdiction real-time, simple average LMP (Dollars per MWh): January through March 2009 and 2010 (See 2009 SOM, Table 2-57)

	2009 (Jan -Mar)	2010 (Jan - Mar)	Difference	Difference as Percent of 2009
Delaware	$54.79	$48.30	($6.48)	(11.8%)
Illinois	$34.34	$34.64	$0.30	0.9%
Indiana	$39.87	$37.85	($2.02)	(5.1%)
Kentucky	$41.31	$40.21	($1.10)	(2.7%)
Maryland	$54.24	$50.18	($4.05)	(7.5%)
Michigan	$41.09	$38.54	($2.54)	(6.2%)
New Jersey	$54.85	$49.08	($5.77)	(10.5%)
North Carolina	$50.10	$48.01	($2.09)	(4.2%)
Ohio	$39.89	$38.04	($1.85)	(4.6%)
Pennsylvania	$50.11	$45.06	($5.04)	(10.1%)
Tennessee	$41.73	$41.90	$0.17	0.4%
Virginia	$50.90	$48.59	($2.31)	(4.5%)
West Virginia	$43.66	$39.81	($3.86)	(8.8%)
District of Columbia	$53.82	$50.72	($3.10)	(5.8%)

Hub Real-Time, Annual Average LMP

Table 2-47 Hub real-time, simple average LMP (Dollars per MWh): January through March 2009 and 2010 (See 2009 SOM, Table 2-58)

	2009 (Jan - Mar)	2010 (Jan - Mar)	Difference	Difference as Percent of 2009
AEP Gen Hub	$38.21	$36.33	($1.88)	(4.9%)
AEP-DAY Hub	$40.29	$38.26	($2.03)	(5.0%)
Chicago Gen Hub	$33.34	$33.98	$0.64	1.9%
Chicago Hub	$34.57	$34.78	$0.21	0.6%
Dominion Hub	$50.94	$48.75	($2.19)	(4.3%)
Eastern Hub	$54.89	$48.93	($5.96)	(10.9%)
N Illinois Hub	$34.09	$34.47	$0.38	1.1%
New Jersey Hub	$54.80	$48.90	($5.90)	(10.8%)
Ohio Hub	$40.09	$38.22	($1.88)	(4.7%)
West Interface Hub	$42.39	$40.96	($1.43)	(3.4%)
Western Hub	$49.19	$44.54	($4.65)	(9.4%)

Real-Time, Load-Weighted, Average LMP

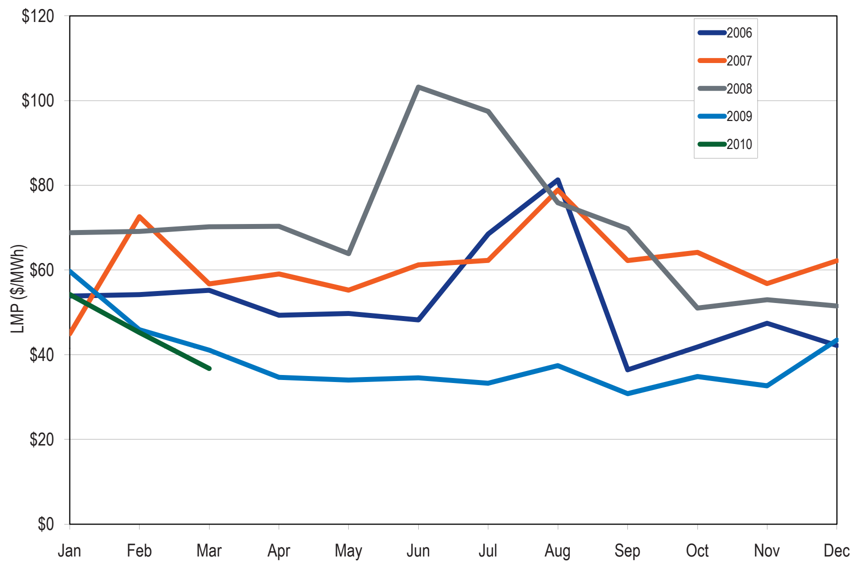
PJM Real-Time, Annual, Load-Weighted, Average LMP

Table 2-48 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 1998 through March 2010 (See 2009 SOM, Table 2-59)

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.7%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	15.4%	8.9%	10.9%
2009	$39.05	$34.23	$18.21	(45.1%)	(42.5%)	(55.6%)
2010	$45.92	$39.01	$22.99	17.6%	14.0%	26.3%

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

Figure 2-14 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2006 through March 2010 (See 2009 SOM, Figure 2-14)



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

Table 2-49 Zonal real-time, annual, load-weighted, average LMP (Dollars per MWh): January through March 2009 and 2010 (See 2009 SOM, Table 2-60)

	2009 (Jan - Mar)	2010 (Jan - Mar)	Difference	Difference as Percent of 2009
AECO	$56.96	$50.19	($6.77)	(11.9%)
AEP	$43.00	$40.81	($2.19)	(5.1%)
AP	$51.70	$45.27	($6.43)	(12.4%)
BGE	$57.47	$53.28	($4.19)	(7.3%)
ComEd	$35.88	$35.85	($0.03)	(0.1%)
DAY	$41.96	$40.06	($1.91)	(4.5%)
DLCO	$37.93	$40.83	$2.89	7.6%
Dominion	$55.71	$52.88	($2.84)	(5.1%)
DPL	$59.09	$51.74	($7.36)	(12.4%)
JCPL	$57.12	$49.95	($7.17)	(12.5%)
Met-Ed	$55.94	$49.14	($6.80)	(12.2%)
PECO	$55.69	$49.39	($6.30)	(11.3%)
PENELEC	$48.92	$42.93	($6.00)	(12.3%)
Pepco	$57.00	$53.24	($3.75)	(6.6%)
PPL	$55.70	$48.69	($7.01)	(12.6%)
PSEG	$57.34	$51.60	($5.74)	(10.0%)
RECO	$55.96	$48.33	($7.63)	(13.6%)
PJM	$49.60	$45.92	($3.68)	(7.4%)

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

Table 2-50 Jurisdiction real-time, annual, load-weighted, average LMP (Dollars per MWh): January through March 2009 and 2010 (See 2009 SOM, Table 2-61)

	2009 (Jan - Mar)	2010 (Jan - Mar)	Difference	Difference as Percent of 2009
Delaware	$58.16	$50.55	($7.61)	(13.1%)
Illinois	$35.88	$35.85	($0.03)	(0.1%)
Indiana	$40.97	$38.66	($2.32)	(5.7%)
Kentucky	$43.91	$42.29	($1.62)	(3.7%)
Maryland	$57.89	$53.22	($4.68)	(8.1%)
Michigan	$42.34	$39.63	($2.71)	(6.4%)
New Jersey	$57.20	$50.87	($6.33)	(11.1%)
North Carolina	$54.06	$51.81	($2.25)	(4.2%)
Ohio	$41.34	$39.15	($2.18)	(5.3%)
Pennsylvania	$52.44	$46.66	($5.78)	(11.0%)
Tennessee	$44.63	$45.24	$0.61	1.4%
Virginia	$54.64	$51.95	($2.69)	(4.9%)
West Virginia	$45.99	$41.36	($4.64)	(10.1%)
District of Columbia	$56.10	$52.70	($3.40)	(6.1%)

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

Fuel Cost

Figure 2-15 Spot average fuel price comparison: Calendar years 2009 through March 2010 (See 2009 SOM, Figure 2-15)

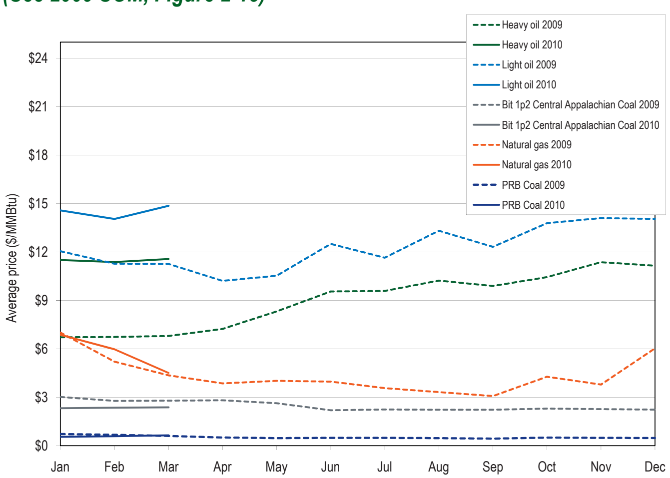


Figure 2-16 Spot average emission price comparison: Calendar years 2009 through March 2010 (See 2009 SOM, Figure 2-16)

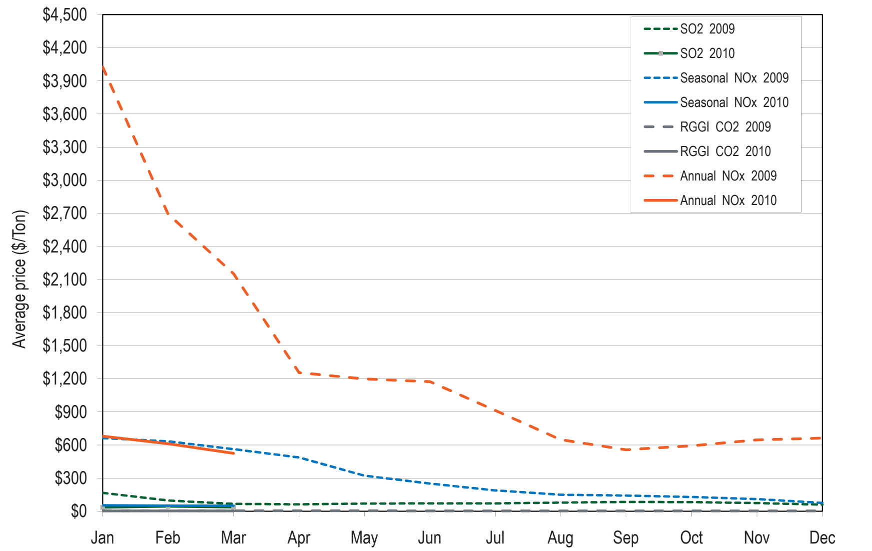


Table 2-51 RGGI CO_2 allowance auction prices and quantities: 2009-2011 Compliance Period (See 2009 SOM, Table 2-62)

Auction Date	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.07	12,565,387	12,565,387
December 17, 2008	$3.38	31,505,898	31,505,898
March 18, 2009	$3.51	31,513,765	31,513,765
June 17, 2009	$3.23	30,887,620	30,887,620
September 9, 2009	$2.19	28,408,945	28,408,945
December 2, 2009	$2.05	28,591,698	28,591,698
March 10, 2010	$2.07	40,612,408	40,612,408

Table 2-52 PJM real-time annual, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): January 1, 2010, through March 31, 2010 (See 2009 SOM, Table 2-63)

	2009 Load-Weighted LMP	2010 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$49.60	$53.56	8.0%

Components of Real-Time, Load-Weighted LMP

Table 2-53 Components of PJM real-time, annual, load-weighted, average LMP: January 1, 2010, through March 31, 2010 (See 2009 SOM, Table 2-64)

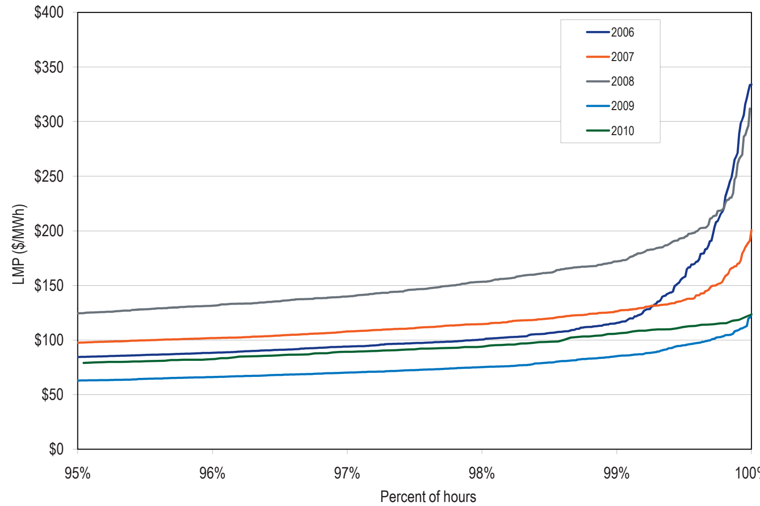
Element	Contribution to LMP	Percent
Coal	$21.06	45.9%
Gas	$16.91	36.8%
10% Cost Adder	$4.24	9.2%
VOM	$2.32	5.1%
NOX	$1.17	2.5%
CO2	$0.45	1.0%
Oil	$0.38	0.8%
SO2	$0.28	0.6%
Dispatch Differential	$0.07	0.2%
NA	$0.06	0.1%
FMU Adder	$0.04	0.1%
Shadow Price Limit Adder	$0.03	0.1%
M2M Adder	$0.01	0.0%
Offline CT Adder	$0.01	0.0%
Municipal Waste	$0.00	0.0%
UDS Override Differential	($0.20)	(0.4%)
Markup	($0.91)	(2.0%)
LMP	$45.92	100.0%

Day-Ahead LMP

Day-Ahead Average LMP

PJM Day-Ahead LMP Duration

Figure 2-17 Price duration curves for the PJM Day-Ahead Energy Market during hours above the 95th percentile: Calendar years 2006 through March 2010 (See 2009 SOM, Figure 2-17)



PJM Day-Ahead, Annual Average LMP

Table 2-54 PJM day-ahead, simple average LMP (Dollars per MWh): Calendar years 2000 through March 2010 (See 2009 SOM, Table 2-65)

	Day-Ahead LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$31.97	$24.42	$21.33	NA	NA	NA
2001	$32.75	$27.05	$30.42	2.4%	10.8%	42.6%
2002	$28.46	$23.28	$17.68	(13.1%)	(14.0%)	(41.9%)
2003	$38.73	$35.22	$20.84	36.1%	51.3%	17.8%
2004	$41.43	$40.36	$16.60	7.0%	14.6%	(20.4%)
2005	$57.89	$50.08	$30.04	39.7%	24.1%	81.0%
2006	$48.10	$44.21	$23.42	(16.9%)	(11.7%)	(22.0%)
2007	$54.67	$52.34	$23.99	13.7%	18.4%	2.4%
2008	$66.12	$58.93	$30.87	20.9%	12.6%	28.7%
2009	$37.00	$35.16	$13.39	(44.0%)	(40.3%)	(56.6%)
2010	$46.13	$41.99	$15.93	24.7%	19.4%	19.0%

Zonal Day-Ahead, Annual Average LMP

Table 2-55 Zonal day-ahead, simple average LMP (Dollars per MWh): January through March 2009 and 2010 (See 2009 SOM, Table 2-66)

	2009 (Jan - Mar)	2010 (Jan - Mar)	Difference	Difference as Percent of 2009
AECO	$55.65	$50.98	($4.66)	(8.4%)
AEP	$40.92	$40.38	($0.54)	(1.3%)
AP	$48.30	$45.11	($3.19)	(6.6%)
BGE	$55.94	$53.96	($1.98)	(3.5%)
ComEd	$35.01	$35.75	$0.74	2.1%
DAY	$39.43	$39.22	($0.21)	(0.5%)
DLCO	$36.44	$39.71	$3.27	9.0%
Dominion	$53.16	$53.30	$0.14	0.3%
DPL	$56.29	$51.32	($4.97)	(8.8%)
JCPL	$55.70	$51.09	($4.61)	(8.3%)
Met-Ed	$54.25	$50.23	($4.02)	(7.4%)
PECO	$54.81	$50.53	($4.29)	(7.8%)
PENELEC	$47.55	$44.51	($3.04)	(6.4%)
Pepco	$55.46	$54.23	($1.23)	(2.2%)
PPL	$53.77	$49.71	($4.06)	(7.5%)
PSEG	$56.49	$52.23	($4.26)	(7.5%)
RECO	$54.80	$50.69	($4.11)	(7.5%)
PJM	$47.41	$46.13	($1.28)	(2.7%)

Day-Ahead, Annual Average LMP by Jurisdiction

Table 2-56 Jurisdiction day-ahead, simple average LMP (Dollars per MWh): January through March 2009 and 2010 (See 2009 SOM, Table 2-67)

	2009 (Jan - Mar)	2010 (Jan - Mar)	Difference	Difference as Percent of 2009
Delaware	$55.52	$50.73	($4.79)	(8.6%)
Illinois	$35.01	$35.75	$0.74	2.1%
Indiana	$39.30	$38.60	($0.71)	(1.8%)
Kentucky	$40.93	$40.81	($0.13)	(0.3%)
Maryland	$55.83	$53.50	($2.32)	(4.2%)
Michigan	$40.28	$39.18	($1.10)	(2.7%)
New Jersey	$56.12	$51.73	($4.40)	(7.8%)
North Carolina	$51.10	$51.71	$0.60	1.2%
Ohio	$39.32	$38.58	($0.74)	(1.9%)
Pennsylvania	$50.85	$47.48	($3.38)	(6.6%)
Tennessee	$41.94	$43.18	$1.24	3.0%
Virginia	$52.03	$52.22	$0.20	0.4%
West Virginia	$43.10	$40.63	($2.48)	(5.7%)
District of Columbia	$55.54	$54.58	($0.96)	(1.7%)

Day-Ahead, Load-Weighted, Average LMP

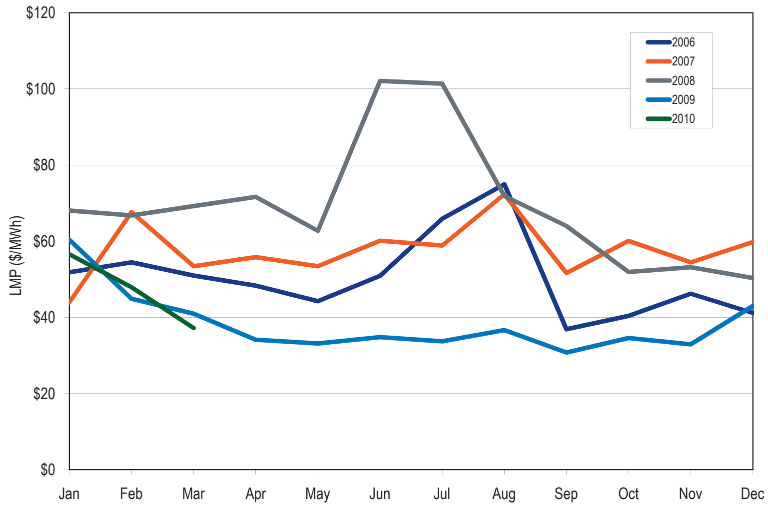
PJM Day-Ahead, Annual, Load-Weighted, Average LMP

Table 2-57 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2000 through March 2010 (See 2009 SOM, Table 2-68)

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$35.12	$28.50	$22.26	NA	NA	NA
2001	$36.01	$29.02	$37.48	2.5%	1.8%	68.3%
2002	$31.80	$26.00	$20.68	(11.7%)	(10.4%)	(44.8%)
2003	$41.43	$38.29	$21.32	30.3%	47.3%	3.1%
2004	$42.87	$41.96	$16.32	3.5%	9.6%	(23.4%)
2005	$62.50	$54.74	$31.72	45.8%	30.4%	94.3%
2006	$51.33	$46.72	$26.45	(17.9%)	(14.6%)	(16.6%)
2007	$57.88	$55.91	$25.02	12.8%	19.7%	(5.4%)
2008	$70.25	$62.91	$33.14	21.4%	12.5%	32.4%
2009	$38.82	$36.67	$14.03	(44.7%)	(41.7%)	(57.7%)
2010	$47.77	$43.62	$16.52	23.1%	19.0%	17.8%

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

Figure 2-18 Day-ahead, monthly, load-weighted, average LMP: Calendar years 2006 through March 2010 (See 2009 SOM, Figure 2-18)



Zonal Day-Ahead, Annual, Load-Weighted LMP

Table 2-58 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): January through March 2009 to 2010 (See 2009 SOM, Table 2-69)

	2009 (Jan - Mar)	2010 (Jan - Mar)	Difference	Difference as Percent of 2009
AECO	$58.96	$53.66	($5.30)	(9.0%)
AEP	$42.44	$41.63	($0.80)	(1.9%)
AP	$50.54	$46.61	($3.93)	(7.8%)
BGE	$58.82	$56.54	($2.28)	(3.9%)
ComEd	$36.04	$36.57	$0.53	1.5%
DAY	$40.93	$40.48	($0.45)	(1.1%)
DLCO	$37.34	$41.01	$3.67	9.8%
Dominion	$56.48	$56.74	$0.26	0.5%
DPL	$59.40	$53.72	($5.68)	(9.6%)
JCPL	$58.00	$52.89	($5.11)	(8.8%)
Met-Ed	$57.37	$52.07	($5.30)	(9.2%)
PECO	$57.28	$52.47	($4.81)	(8.4%)
PENELEC	$49.56	$45.47	($4.09)	(8.3%)
Pepco	$58.12	$56.02	($2.10)	(3.6%)
PPL	$56.40	$51.86	($4.54)	(8.1%)
PSEG	$58.73	$53.75	($4.98)	(8.5%)
RECO	$57.40	$53.11	($4.29)	(7.5%)
PJM	$49.44	$47.77	($1.67)	(3.4%)

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

Table 2-59 Jurisdiction day-ahead, load weighted LMP (Dollars per MWh): January through March 2009 and 2010 (See 2009 SOM, Table 2-70)

	2009 (Jan - Mar)	2010 (Jan - Mar)	Difference	Difference as Percent of 2009
Delaware	$58.69	$53.05	($5.64)	(9.6%)
Illinois	$36.04	$36.57	$0.53	1.5%
Indiana	$40.64	$39.57	($1.06)	(2.6%)
Kentucky	$42.67	$42.19	($0.48)	(1.1%)
Maryland	$58.96	$55.89	($3.06)	(5.2%)
Michigan	$41.47	$39.96	($1.51)	(3.6%)
New Jersey	$58.49	$53.46	($5.03)	(8.6%)
North Carolina	$54.41	$54.78	$0.37	0.7%
Ohio	$40.74	$39.65	($1.09)	(2.7%)
Pennsylvania	$53.17	$49.00	($4.17)	(7.8%)
Tennessee	$43.74	$45.10	$1.36	3.1%
Virginia	$55.06	$55.36	$0.29	0.5%
West Virginia	$44.76	$41.98	($2.77)	(6.2%)
District of Columbia	$57.75	$55.86	($1.89)	(3.3%)

Components of Day-Ahead, Load-Weighted LMP

Table 2-60 Components of PJM day-ahead, annual, load-weighted, average LMP (Dollars per MWh): January through March 2010 (See 2009 SOM, Table 2-71)

Element	Contribution to LMP	Percent
INC	$17.56	36.8%
DEC	$12.78	26.7%
Coal	$7.45	15.6%
Natural gas	$4.55	9.5%
Transaction	$2.22	4.6%
Price sensitive demand	$1.77	3.7%
%10 Cost offer	$1.34	2.8%
VOM	$0.69	1.4%
NOx	$0.40	0.8%
SO2	$0.14	0.3%
CO2	$0.10	0.2%
Oil	$0.05	0.1%
Constrained off	$0.00	0.0%
Markup	($1.22)	(2.5%)
NA	($0.06)	(0.1%)
Total	$47.77	100.0%

Marginal Losses

Table 2-61 PJM real-time, simple average LMP components (Dollars per MWh): Calendar years 2006 through March 2010 (See 2009 SOM, Table 2-72)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2006	$49.27	$47.19	$2.08	$0.00
2007	$57.58	$56.56	$1.00	$0.02
2008	$66.40	$66.30	$0.06	$0.04
2009	$37.08	$37.01	$0.05	$0.03
2010	$44.13	$44.02	$0.06	$0.05

Table 2-62 Zonal real-time, simple average LMP components (Dollars per MWh): January through March 2009 and 2010 (See 2009 SOM, Table 2-73)

	2009 (Jan - Mar)				2010 (Jan - Mar)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$54.45	$47.21	$4.68	$2.56	$48.31	$44.02	$1.73	$2.55
AEP	$41.22	$47.21	($4.29)	($1.70)	$39.41	$44.02	($2.98)	($1.64)
AP	$49.09	$47.21	$1.97	($0.09)	$43.67	$44.02	($0.33)	($0.02)
BGE	$54.17	$47.21	$4.85	$2.12	$50.44	$44.02	$4.06	$2.36
ComEd	$34.34	$47.21	($9.76)	($3.11)	$34.64	$44.02	($6.15)	($3.23)
DAY	$40.20	$47.21	($5.72)	($1.30)	$38.69	$44.02	($4.15)	($1.18)
DLCO	$37.12	$47.21	($8.13)	($1.96)	$39.65	$44.02	($2.67)	($1.70)
Dominion	$51.96	$47.21	$4.19	$0.57	$49.43	$44.02	$4.52	$0.89
DPL	$55.26	$47.21	$5.19	$2.86	$49.01	$44.02	$2.18	$2.81
JCPL	$54.41	$47.21	$4.27	$2.93	$47.96	$44.02	$1.34	$2.59
Met-Ed	$53.07	$47.21	$4.36	$1.50	$47.27	$44.02	$1.71	$1.54
PECO	$53.17	$47.21	$3.99	$1.97	$47.54	$44.02	$1.72	$1.80
PENELEC	$47.15	$47.21	($0.04)	($0.01)	$41.83	$44.02	($1.93)	($0.26)
Pepco	$53.76	$47.21	$5.20	$1.36	$50.44	$44.02	$4.86	$1.56
PPL	$52.69	$47.21	$4.16	$1.32	$46.66	$44.02	$1.47	$1.16
PSEG	$55.20	$47.21	$5.04	$2.96	$49.91	$44.02	$3.31	$2.58
RECO	$53.65	$47.21	$3.81	$2.63	$46.66	$44.02	$0.44	$2.20

Table 2-63 Hub real-time, simple average LMP components (Dollars per MWh): January through March 2010 (See 2009 SOM, 2-74)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$36.33	$44.02	($4.48)	($3.21)
AEP-DAY Hub	$38.26	$44.02	($3.86)	($1.91)
Chicago Gen Hub	$33.98	$44.02	($6.26)	($3.78)
Chicago Hub	$34.78	$44.02	($6.03)	($3.21)
Dominion Hub	$48.75	$44.02	$4.36	$0.37
Eastern Hub	$48.93	$44.02	$1.98	$2.93
N Illinois Hub	$34.47	$44.02	($6.12)	($3.44)
New Jersey Hub	$48.90	$44.02	$2.35	$2.53
Ohio Hub	$38.22	$44.02	($3.91)	($1.90)
West Interface Hub	$40.96	$44.02	($1.59)	($1.48)
Western Hub	$44.54	$44.02	$0.68	($0.16)

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

Table 2-64 Zonal and PJM real-time, annual, load-weighted, average LMP components (Dollars per MWh): January through March 2010 (See 2009 SOM, Table 2-75)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$50.19	$45.66	$1.89	$2.64
AEP	$40.81	$45.75	($3.26)	($1.68)
AP	$45.27	$45.85	($0.54)	($0.03)
BGE	$53.28	$46.16	$4.62	$2.50
ComEd	$35.85	$45.26	($6.11)	($3.30)
DAY	$40.06	$45.73	($4.50)	($1.18)
DLCO	$40.83	$45.33	($2.73)	($1.77)
Dominion	$52.88	$46.50	$5.39	$0.98
DPL	$51.74	$46.31	$2.44	$2.98
JCPL	$49.95	$45.78	$1.47	$2.70
Met-Ed	$49.14	$45.71	$1.83	$1.59
PECO	$49.39	$45.69	$1.85	$1.85
PENELEC	$42.93	$45.39	($2.16)	($0.30)
Pepco	$53.24	$46.16	$5.44	$1.64
PPL	$48.69	$45.89	$1.60	$1.20
PSEG	$51.60	$45.38	$3.56	$2.65
RECO	$48.33	$45.48	$0.57	$2.28
PJM	$45.92	$45.81	$0.06	$0.05

Table 2-65 PJM day-ahead, simple average LMP components (Dollars per MWh): Calendar years 2006 through March 2010 (See 2009 SOM, Table 2-76)

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2006	$48.10	$46.45	$1.65	$0.00
2007	$54.67	$54.60	$0.25	($0.18)
2008	$66.12	$66.43	($0.10)	($0.21)
2009	$37.00	$37.15	($0.06)	($0.09)
2010	$46.13	$46.10	$0.01	$0.02

Table 2-66 Zonal day-ahead, simple average LMP components (Dollars per MWh): January through March 2009 and 2010 (See 2009 SOM, Table 2-77)

	2009 (Jan - Mar)				2010 (Jan - Mar)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$55.65	$47.72	$4.63	$3.29	$50.98	$46.10	$2.11	$2.77
AEP	$40.92	$47.72	($4.64)	($2.17)	$40.38	$46.10	($3.49)	($2.23)
AP	$48.30	$47.72	$0.42	$0.15	$45.11	$46.10	($1.04)	$0.05
BGE	$55.94	$47.72	$5.79	$2.43	$53.96	$46.10	$4.64	$3.22
ComEd	$35.01	$47.72	($8.40)	($4.32)	$35.75	$46.10	($6.12)	($4.23)
DAY	$39.43	$47.72	($6.27)	($2.02)	$39.22	$46.10	($4.79)	($2.09)
DLCO	$36.44	$47.72	($8.88)	($2.41)	$39.71	$46.10	($4.39)	($2.00)
Dominion	$53.16	$47.72	$4.46	$0.97	$53.30	$46.10	$5.61	$1.58
DPL	$56.29	$47.72	$5.10	$3.46	$51.32	$46.10	$2.36	$2.85
JCPL	$55.70	$47.72	$4.18	$3.80	$51.09	$46.10	$1.77	$3.21
Met-Ed	$54.25	$47.72	$4.61	$1.91	$50.23	$46.10	$2.32	$1.81
PECO	$54.81	$47.72	$4.34	$2.75	$50.53	$46.10	$2.14	$2.28
PENELEC	$47.55	$47.72	($0.37)	$0.19	$44.51	$46.10	($1.97)	$0.37
Pepco	$55.46	$47.72	$5.79	$1.95	$54.23	$46.10	$5.69	$2.44
PPL	$53.77	$47.72	$4.30	$1.74	$49.71	$46.10	$2.23	$1.38
PSEG	$56.49	$47.72	$4.78	$3.99	$52.23	$46.10	$2.76	$3.37
RECO	$54.80	$47.72	$3.44	$3.64	$50.69	$46.10	$1.69	$2.90

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

Table 2-67 Zonal and PJM day-ahead, load-weighted, average LMP components (Dollars per MWh): January through March 2010 (See 2009 SOM, Table 2-78)

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$53.66	$48.41	$2.28	$2.96
AEP	$41.63	$47.76	($3.82)	($2.31)
AP	$46.61	$47.84	($1.27)	$0.04
BGE	$56.54	$48.05	$5.09	$3.39
ComEd	$36.57	$47.12	($6.23)	($4.32)
DAY	$40.48	$47.83	($5.20)	($2.15)
DLCO	$41.01	$47.40	($4.33)	($2.06)
Dominion	$56.74	$48.42	$6.62	$1.70
DPL	$53.72	$48.19	$2.54	$2.99
JCPL	$52.89	$47.70	$1.85	$3.35
Met-Ed	$52.07	$47.74	$2.45	$1.88
PECO	$52.47	$47.84	$2.26	$2.36
PENELEC	$45.47	$47.20	($2.09)	$0.36
Pepco	$56.02	$47.47	$6.03	$2.52
PPL	$51.86	$48.00	$2.39	$1.47
PSEG	$53.75	$47.40	$2.89	$3.47
RECO	$53.11	$48.22	$1.82	$3.06
PJM	$47.77	$47.74	$0.01	$0.02

Marginal Loss Accounting

Monthly Marginal Loss Costs

Table 2-68 Marginal loss costs by type (Dollars (Millions)): January through March 2010 (See 2009 SOM, Table 2-79)

	Marginal Loss Costs (Millions)								
	Day Ahead				Balancing				
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
Jan	$45.5	($136.3)	$7.0	$188.9	$1.2	($2.8)	($4.0)	$0.0	$188.9
Feb	$31.6	($100.1)	$3.0	$134.7	$0.4	($0.6)	($1.3)	($0.4)	$134.3
Mar	$21.0	($70.5)	$2.7	$94.2	$0.2	($0.2)	($1.2)	($0.8)	$93.4
Total	$98.0	($307.0)	$12.8	$417.8	$1.8	($3.5)	($6.5)	($1.2)	$416.6

Zonal Marginal Loss Costs

Table 2-69 Marginal loss costs by control zone and type (Dollars (Millions)): January through March 2010 (See 2009 SOM, Table 2-80)

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	$6.8	$2.1	$0.0	$4.7	$0.7	($0.2)	($0.0)	$0.8	$5.6
AEP	($17.3)	($96.5)	$5.6	$84.7	($1.1)	$1.3	($0.0)	($2.4)	$82.3
AP	$0.7	($30.6)	$3.2	$34.5	$0.8	$1.3	($2.1)	($2.7)	$31.8
BGE	$23.9	$7.6	$1.4	$17.6	$1.7	($0.9)	($1.1)	$1.5	$19.2
ComEd	($56.4)	($136.2)	$0.1	$79.9	($0.7)	($0.7)	($0.1)	($0.2)	$79.8
DAY	($1.6)	($17.8)	$1.4	$17.6	$0.0	$0.5	($0.9)	($1.3)	$16.2
DLCO	($13.0)	($20.3)	$0.1	$7.4	($0.6)	($0.2)	($0.0)	($0.4)	$6.9
Dominion	$34.6	($8.5)	$1.6	$44.7	$0.8	($0.2)	($0.7)	$0.3	$45.0
DPL	$14.3	$2.6	$0.1	$11.9	($0.4)	($0.4)	($0.0)	$0.0	$11.9
JCPL	$18.2	$5.1	$0.1	$13.2	$0.1	($0.4)	($0.1)	$0.5	$13.7
Met-Ed	$7.7	$2.1	$0.0	$5.6	$0.0	($0.2)	($0.0)	$0.2	$5.8
PECO	$15.9	$6.4	$0.0	$9.5	($0.1)	($0.7)	($0.0)	$0.6	$10.2
PENELEC	($2.7)	($21.6)	($0.0)	$18.9	$0.7	($1.5)	$0.1	$2.3	$21.2
Pepco	$35.6	$18.0	$1.0	$18.6	($0.7)	$0.3	($0.7)	($1.7)	$16.8
PJM	($14.8)	($25.8)	($6.5)	$4.5	$0.8	($3.9)	$3.0	$7.6	$12.1
PPL	$15.4	($2.6)	$0.5	$18.5	$0.6	$0.2	($0.1)	$0.3	$18.8
PSEG	$29.7	$8.7	$4.2	$25.2	($1.0)	$2.5	($3.6)	($7.0)	$18.2
RECO	$1.0	$0.2	$0.0	$0.7	$0.1	($0.2)	($0.0)	$0.3	$1.0
Total	$98.0	($307.0)	$12.8	$417.8	$1.8	($3.5)	($6.5)	($1.2)	$416.6

Table 2-70 Monthly marginal loss costs by control zone (Dollars (Millions)): January through March 2010 (See 2009 SOM, Table 2-81)

	Marginal Loss Costs by Control Zone (Millions)			
	Jan	Feb	Mar	Grand Total
AECO	$2.6	$1.5	$1.4	$5.6
AEP	$40.0	$25.9	$16.4	$82.3
AP	$13.7	$11.2	$6.8	$31.8
BGE	$8.8	$6.7	$3.7	$19.2
ComEd	$36.1	$23.9	$19.8	$79.8
DAY	$6.6	$5.3	$4.2	$16.2
DLCO	$3.0	$2.3	$1.6	$6.9
Dominion	$20.1	$15.9	$9.0	$45.0
DPL	$5.7	$3.6	$2.6	$11.9
JCPL	$6.3	$4.0	$3.3	$13.7
Met-Ed	$2.8	$1.6	$1.4	$5.8
PECO	$4.2	$3.7	$2.3	$10.2
PENELEC	$10.4	$7.2	$3.6	$21.2
Pepco	$6.7	$5.7	$4.5	$16.8
PJM	$5.5	$3.7	$2.9	$12.1
PPL	$8.8	$6.3	$3.7	$18.8
PSEG	$7.0	$5.4	$5.8	$18.2
RECO	$0.5	$0.2	$0.2	$1.0
Total	$188.9	$134.3	$93.4	$416.6

Virtual Offers and Bids

Table 2-71 Monthly volume of cleared and submitted INCs, DECs: January through March 2010 (See 2009 SOM, Table 2-82)

	Increment Offers				Decrement Bids			
	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
Jan	11,144	21,634	282	936	266	893	17,513	29,406
Feb	12,387	23,827	387	1,122	270	883	17,602	28,542
Mar	10,811	21,062	308	915	253	763	15,019	24,968
Apr								
May								
Jun								
Jul								
Aug								
Sep								
Oct								
Nov								
Dec								
Annual	11,416	22,120	324	987	263	845	16,683	27,610

Table 2-72 Type of day-ahead marginal units: January through March 2010 (See 2009 SOM, Table 2-83)

	Generation	Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	16.5%	30.9%	32.5%	19.4%	0.7%
Feb	14.9%	34.1%	24.3%	26.1%	0.6%
Mar	10.6%	29.9%	34.1%	24.7%	0.7%
Annual	14.0%	31.5%	30.5%	23.3%	0.7%

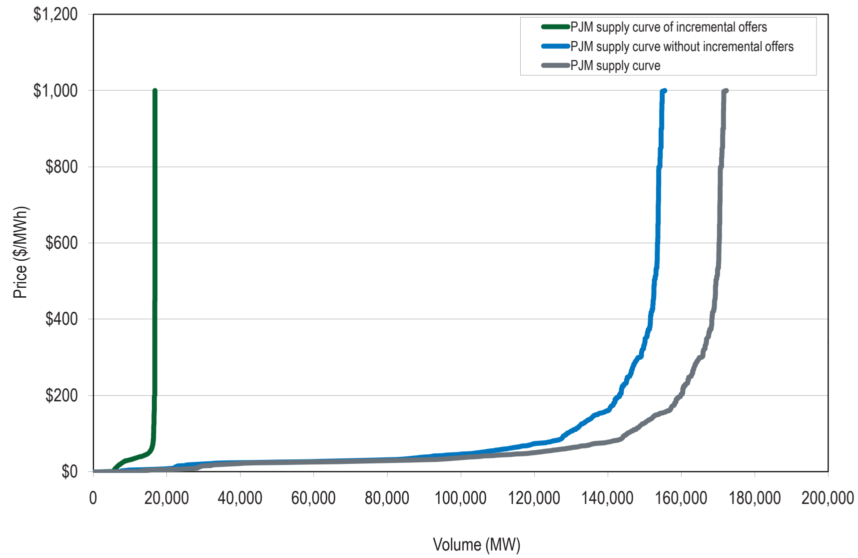
Table 2-73 PJM virtual bids by type of bid parent organization (MW): January through March 2010 (See 2009 SOM, Table 2-84)

	Category	Total Virtual Bids MW	Percentage
2010	Financial	31,153,605	29.0%
2010	Physical	76,211,805	71.0%
2010	Total	107,365,411	100%

Table 2-74 PJM virtual bids by top ten locations (MW): January through March 2010 (See 2009 SOM, Table 2-85)

Aggregate Name	Aggregate Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	15,893,424	20,073,663	35,967,087
N ILLINOIS HUB	HUB	2,240,556	2,230,829	4,471,386
AEP-DAYTON HUB	HUB	1,479,029	1,861,400	3,340,428
PSEG	ZONE	687,928	1,666,222	2,354,149
PPL	ZONE	142,046	2,122,986	2,265,032
PEPCO	ZONE	1,793,453	409,615	2,203,068
BGE	ZONE	1,060,024	1,060,062	2,120,086
JCPL	ZONE	1,133,979	818,916	1,952,895
IMO	INTERFACE	1,057,722	439,498	1,497,220
MISO	INTERFACE	401,712	621,594	1,023,306

Figure 2-19 PJM day-ahead aggregate supply curves: 2010 example day (See 2009 SOM, Figure 2-19)



Price Convergence

Table 2-75 Day-ahead and real-time simple annual average LMP (Dollars per MWh): January through March 2010 (See 2009 SOM, Table 2-86)

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
Average	$46.13	$44.13	($2.00)	(4.5%)
Median	$41.99	$37.82	($4.17)	(11.0%)
Standard deviation	$15.93	$21.87	$5.93	27.1%

Table 2-76 Day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar years 2000 through March 2010 (See 2009 SOM, Table 2-87)

	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	$37.00	$37.08	$0.08	0.2%
2010	$46.13	$44.13	($2.00)	(4.5%)

Table 2-77 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): Calendar years 2006 through March 2010 (See 2009 SOM, Table 2-88)

	2006		2007		2008		2009		2010	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($150)	1	0.01%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($150) to ($100)	1	0.02%	0	0.00%	1	0.01%	0	0.00%	0	0.00%
($100) to ($50)	9	0.13%	33	0.38%	88	1.01%	3	0.03%	5	0.23%
($50) to $0	5,205	59.54%	4,600	52.89%	5,120	59.30%	5,108	58.34%	1,569	72.90%
$0 to $50	3,372	98.04%	3,827	96.58%	3,247	96.27%	3,603	99.47%	547	98.24%
$50 to $100	152	99.77%	255	99.49%	284	99.50%	41	99.94%	33	99.77%
$100 to $150	9	99.87%	31	99.84%	37	99.92%	5	100.00%	1	99.81%
$150 to $200	4	99.92%	5	99.90%	4	99.97%	0	100.00%	4	100.00%
$200 to $250	1	99.93%	1	99.91%	2	99.99%	0	100.00%	0	100.00%
$250 to $300	3	99.97%	3	99.94%	0	99.99%	0	100.00%	0	100.00%
$300 to $350	0	99.97%	2	99.97%	1	100.00%	0	100.00%	0	100.00%
$350 to $400	1	99.98%	1	99.98%	0	100.00%	0	100.00%	0	100.00%
$400 to $450	0	99.98%	1	99.99%	0	100.00%	0	100.00%	0	100.00%
$450 to $500	1	99.99%	1	100.00%	0	100.00%	0	100.00%	0	100.00%
>= $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

Figure 2-20 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: January through March 2010 (See 2009 SOM, Figure 2-20)

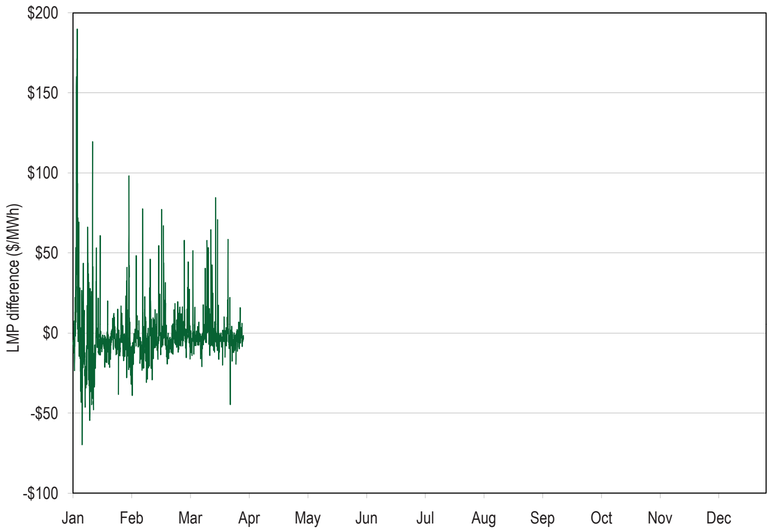


Figure 2-21 Monthly simple average of real-time minus day-ahead LMP: January through March 2010 (See 2009 SOM, Figure 2-21)

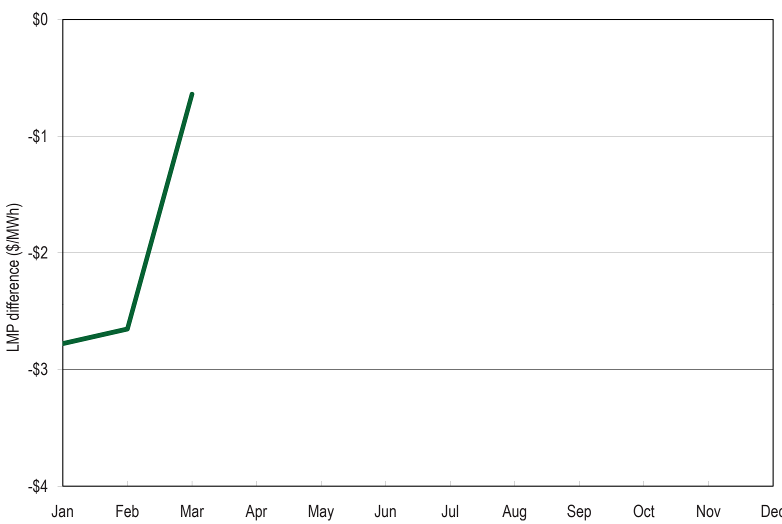
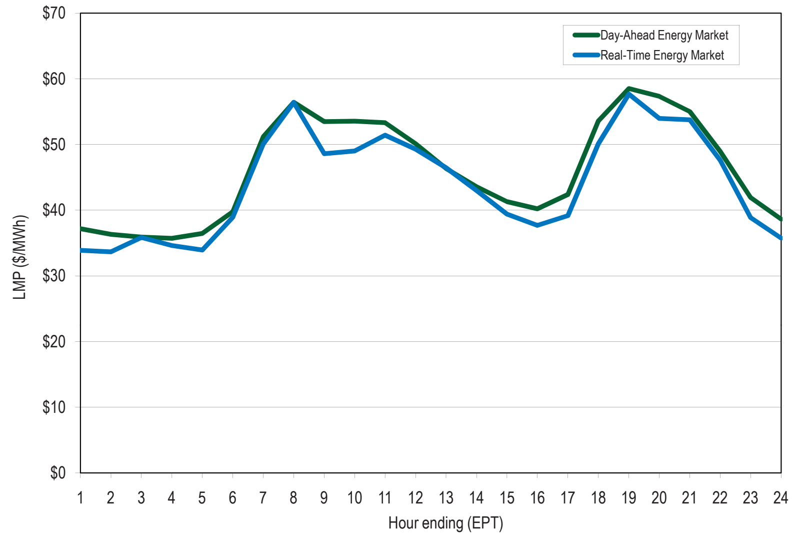


Figure 2-22 PJM system simple hourly average LMP: January through March 2010 (See 2009 SOM, Figure 2-22)



Zonal Price Convergence

Table 2-78 Zonal day-ahead and real-time simple annual average LMP (Dollars per MWh): January through March 2010 (See 2009 SOM, Table 2-89)

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$50.98	$48.31	($2.68)	(5.5%)
AEP	$40.38	$39.41	($0.97)	(2.5%)
AP	$45.11	$43.67	($1.44)	(3.3%)
BGE	$53.96	$50.44	($3.52)	(7.0%)
ComEd	$35.75	$34.64	($1.11)	(3.2%)
DAY	$39.22	$38.69	($0.52)	(1.4%)
DLCO	$39.71	$39.65	($0.06)	(0.1%)
Dominion	$53.30	$49.43	($3.87)	(7.8%)
DPL	$51.32	$49.01	($2.30)	(4.7%)
JCPL	$51.09	$47.96	($3.13)	(6.5%)
Met-Ed	$50.23	$47.27	($2.96)	(6.3%)
PECO	$50.53	$47.54	($2.99)	(6.3%)
PENELEC	$44.51	$41.83	($2.67)	(6.4%)
Pepco	$54.23	$50.44	($3.79)	(7.5%)
PPL	$49.71	$46.66	($3.05)	(6.5%)
PSEG	$52.23	$49.91	($2.31)	(4.6%)
RECO	$50.69	$46.66	($4.02)	(8.6%)

Price Convergence by Jurisdiction

Table 2-79 Jurisdiction day-ahead and real-time simple annual average LMP (Dollars per MWh): January through March 2010 (See 2009 SOM, Table 2-90)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Delaware	$50.73	$48.30	($2.43)	(5.0%)
Illinois	$35.75	$34.64	($1.11)	(3.2%)
Indiana	$38.60	$37.85	($0.75)	(2.0%)
Kentucky	$40.81	$40.21	($0.59)	(1.5%)
Maryland	$53.50	$50.18	($3.32)	(6.6%)
Michigan	$39.18	$38.54	($0.64)	(1.7%)
New Jersey	$51.73	$49.08	($2.65)	(5.4%)
North Carolina	$51.71	$48.01	($3.70)	(7.7%)
Ohio	$38.58	$38.04	($0.54)	(1.4%)
Pennsylvania	$47.48	$45.06	($2.42)	(5.4%)
Tennessee	$43.18	$41.90	($1.28)	(3.1%)
Virginia	$52.22	$48.59	($3.63)	(7.5%)
West Virginia	$40.63	$39.81	($0.82)	(2.1%)
District of Columbia	$54.58	$50.72	($3.87)	(7.6%)

Load and Spot Market

Real-Time Load and Spot Market

Table 2-80 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: Calendar years 2009 to March 31, 2010 (See 2009 SOM, Table 2-91)

	2009			2010			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	12.6%	15.4%	72.0%	11.9%	19.5%	68.6%	(0.8%)	4.2%	(3.4%)
Feb	13.4%	14.5%	72.1%	13.3%	19.5%	67.2%	(0.1%)	5.0%	(4.9%)
Mar	13.8%	16.7%	69.5%	12.6%	19.8%	67.6%	(1.2%)	3.1%	(1.9%)
Apr	13.5%	17.2%	69.3%						
May	14.6%	18.8%	66.7%						
Jun	12.5%	16.5%	71.0%						
Jul	12.6%	16.9%	70.5%						
Aug	11.7%	16.0%	72.3%						
Sep	12.5%	18.1%	69.4%						
Oct	13.0%	19.8%	67.2%						
Nov	13.2%	19.0%	67.8%						
Dec	11.7%	16.8%	71.5%						
Annual	12.9%	17.0%	70.1%	12.6%	19.6%	67.8%	(0.3%)	2.6%	(2.3%)

Day-Ahead Load and Spot Market

Table 2-81 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: Calendar years 2009 to March 31, 2010 (See 2009 SOM, Table 2-92)

	2009			2010			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	4.4%	13.7%	81.9%	4.7%	19.4%	75.9%	0.3%	5.7%	(6.0%)
Feb	4.5%	12.3%	83.2%	5.1%	19.3%	75.5%	0.7%	7.0%	(7.7%)
Mar	4.3%	12.8%	82.9%	5.3%	19.4%	75.3%	0.9%	6.7%	(7.6%)
Apr	4.4%	13.8%	81.7%						
May	4.6%	15.6%	79.8%						
Jun	4.7%	13.9%	81.4%						
Jul	5.6%	16.0%	78.4%						
Aug	5.2%	15.3%	79.5%						
Sep	4.8%	16.1%	79.2%						
Oct	5.0%	17.8%	77.2%						
Nov	5.8%	15.9%	78.3%						
Dec	5.2%	15.6%	79.2%						
Annual	4.9%	14.9%	80.2%	5.0%	19.4%	75.6%	0.1%	4.5%	(4.7%)

Demand-Side Response (DSR)

PJM Load Response Programs Overview

Table 2-82 Overview of Demand Side Programs (See 2009 SOM, Table 2-93)

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

Participation

Economic Program

Table 2-83 Economic Program registration on peak load days: Calendar years 2002 to 2009 and January through March 2010 (See 2009 SOM, Table 2-94)

	Registrations	Peak-Day, Registered MW
14-Aug-02	96	335.4
22-Aug-03	240	650.6
03-Aug-04	782	875.6
26-Jul-05	2,548	2,210.2
02-Aug-06	253	1,100.7
08-Aug-07	2,897	2,498.0
09-Jun-08	956	2,294.7
10-Aug-09	1,321	2,486.6
04-Jan-10	1,852	2,625.0

Table 2-84 Economic Program registrations on the last day of the month: January 2007 through March 2010 (See 2009 SOM, Table 2-95)

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

Table 2-85 Distinct registrations and sites in the Economic Program: January 4, 2010[7] (See 2009 SOM, Table 2-96)

	Registrations	Sites	MW
AECO	37	42	18.5
AEP	47	47	220.7
AP	91	91	196.7
BGE	147	159	649.5
ComEd	773	774	459.4
DAY	10	10	14.2
DLCO	34	34	72.2
Dominion	100	100	231.0
DPL	66	75	132.1
JCPL	40	75	102.1
Met-Ed	47	47	75.1
PECO	159	186	137.6
PENELEC	42	42	31.6
Pepco	22	23	21.1
PPL	139	145	195.5
PSEG	94	159	66.5
RECO	4	9	1.3
Total	1,852	2,018	2,625.0

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

Figure 2-23 Economic Program payments: Calendar years 2007[8] through 2009 and January through March 2010[9] (See 2009 SOM, Figure 2-24)

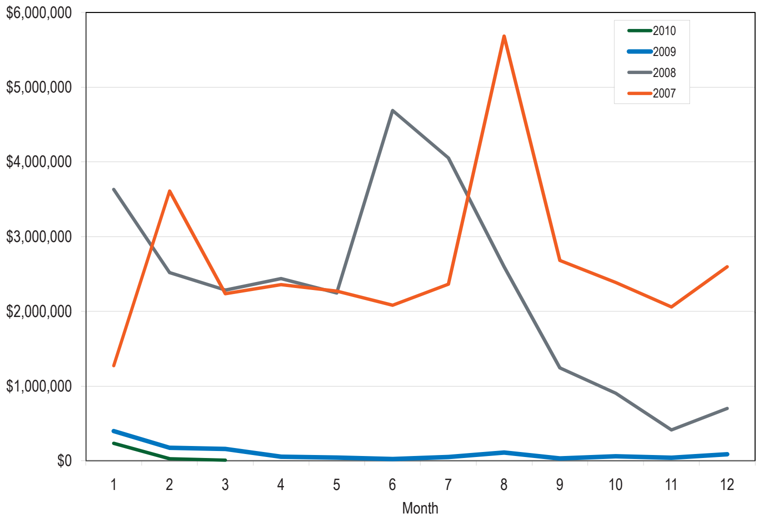


Table 2-86 PJM Economic Program by zonal reduction: January through March 2010 (See 2009 SOM, Table 2-99)

	Real Time			Day Ahead			Dispatched in Real Time			Totals		
	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours
AECO							0	$25	3	0	$25	3
AEP										0	$0	0
AP	1,039	$14,045	314				5	$806	1	1,044	$14,851	315
BGE										0	$0	0
ComEd	27	$1,105	28				319	$9,587	185	346	$10,692	213
DAY												
DLCO												
Dominion	2,272	$151,347	110	491	$7,566	70	255	$12,527	110	3,017	$171,439	290
DPL										0	$0	0
JCPL							8	$733	16	8	$733	16
Met-Ed	2	$16	8							2	$16	8
PECO	1,871	$54,485	4,190				78	$7,227	375	1,949	$61,712	4,565
PENELEC							1	$156	6	1	$156	6
Pepco							11	$270	57	11	$270	57
PPL	366	$8,622	244				12	$1,194	40	377	$9,815	284
PSEG										0	$0	0
RECO										0	$0	0
Total	5,576	$229,620	4,894	491	$7,566	70	689	$32,525	793	6,756	$269,710	5,757
Max	2,272	$151,347	4,190	491	$7,566	70	319	$12,527	375	3,017	$171,439	4,565
Avg	929	$38,270	816	491	$7,566	70	77	$3,614	88	450	$17,981	384

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

9 March 2010 credits are likely understated due to the lag associated with the submittal and processing of settlements. Settlements may be submitted up to 60 days following an event day. EDC/LSEs have up to 10 business days to approve settlements, which could account for a maximum of approximately 74 calendar days.

Table 2-87 Settlement days submitted by month in the Economic Program: January 2007 through March 2010 (See 2009 SOM, Table 2-100)

Month	2007	2008	2009	2010
Jan	937	2,916	1,264	1,423
Feb	1,170	2,811	654	546
Mar	1,255	2,818	574	411
Apr	1,540	3,406	337	
May	1,649	3,336	918	
Jun	1,856	3,184	2,727	
Jul	2,534	3,339	2,879	
Aug	3,962	3,848	3,760	
Sep	3,388	3,264	2,570	
Oct	3,508	1,977	2,361	
Nov	2,842	1,105	2,321	
Dec	2,675	986	1,240	
Total	26,423	32,990	21,605	2,380

Table 2-88 Distinct customers and CSPs submitting settlements in the Economic Program by month: January 2007 through March 2010 (See 2009 SOM, Table 2-101)

	2007		2008		2009		2010	
Month	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers
Jan	11	72	13	261	17	257	11	162
Feb	10	89	13	243	12	129	9	92
Mar	9	87	11	216	11	149	7	124
Apr	11	98	12	208	9	76		
May	12	109	12	233	9	201		
Jun	12	195	17	317	20	231		
Jul	15	259	16	295	21	183		
Aug	19	321	17	306	15	400		
Sep	15	279	17	312	11	181		
Oct	11	245	13	226	11	93		
Nov	10	204	14	208	9	143		
Dec	11	243	13	193	10	160		
Total Distinct Active	21	405	24	522	25	747	12	167

Table 2-89 Hourly distribution of Economic Program MWh reductions and credits: January through March 2010 (See 2009 SOM, Table 2-102)

	MWh Reductions				Program Credits			
Hour	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
1	30	0.44%	30	0.44%	$429	0.16%	$429	0.16%
2	38	0.56%	68	1.00%	$408	0.15%	$837	0.31%
3	70	1.04%	138	2.04%	$1,012	0.38%	$1,849	0.69%
4	82	1.22%	220	3.26%	$2,319	0.86%	$4,168	1.55%
5	78	1.15%	298	4.40%	$1,034	0.38%	$5,202	1.93%
6	77	1.14%	374	5.54%	$1,163	0.43%	$6,365	2.36%
7	368	5.44%	742	10.98%	$23,760	8.81%	$30,124	11.17%
8	758	11.22%	1,500	22.20%	$56,168	20.83%	$86,293	31.99%
9	705	10.44%	2,205	32.64%	$35,903	13.31%	$122,195	45.31%
10	459	6.79%	2,664	39.43%	$19,749	7.32%	$141,944	52.63%
11	287	4.25%	2,951	43.68%	$8,999	3.34%	$150,943	55.96%
12	241	3.57%	3,192	47.25%	$7,100	2.63%	$158,043	58.60%
13	242	3.58%	3,434	50.83%	$5,632	2.09%	$163,674	60.69%
14	253	3.75%	3,687	54.58%	$5,515	2.04%	$169,189	62.73%
15	226	3.34%	3,913	57.92%	$3,494	1.30%	$172,684	64.03%
16	191	2.83%	4,104	60.75%	$2,505	0.93%	$175,189	64.95%
17	241	3.56%	4,345	64.31%	$3,841	1.42%	$179,029	66.38%
18	425	6.29%	4,770	70.60%	$16,948	6.28%	$195,977	72.66%
19	620	9.18%	5,390	79.78%	$26,583	9.86%	$222,561	82.52%
20	538	7.96%	5,928	87.74%	$21,601	8.01%	$244,161	90.53%
21	309	4.58%	6,237	92.32%	$15,256	5.66%	$259,418	96.18%
22	238	3.53%	6,475	95.85%	$5,895	2.19%	$265,313	98.37%
23	191	2.82%	6,666	98.67%	$2,969	1.10%	$268,281	99.47%
24	90	1.33%	6,756	100.00%	$1,429	0.53%	$269,710	100.00%

Table 2-90 Distribution of Economic Program zonal, load-weighted, average LMP (By hours): January through March 2010 (See 2009 SOM, Table 2-103)

	MWh Reductions				Program Credits			
LMP	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
$0 to $25	7	0.11%	7	0.11%	$0	0.00%	$0	0.00%
$25 to $50	2,434	36.03%	2,441	36.14%	$26,670	9.89%	$26,670	9.89%
$50 to $75	1,490	22.06%	3,932	58.20%	$36,756	13.63%	$63,426	23.52%
$75 to $100	837	12.39%	4,769	70.59%	$35,563	13.19%	$98,989	36.70%
$100 to $125	728	10.77%	5,496	81.36%	$42,098	15.61%	$141,087	52.31%
$125 to $150	519	7.68%	6,016	89.04%	$27,607	10.24%	$168,694	62.55%
$150 to $200	402	5.95%	6,418	94.99%	$34,787	12.90%	$203,481	75.44%
$200 to $250	172	2.54%	6,589	97.54%	$29,826	11.06%	$233,307	86.50%
$250 to $300	81	1.20%	6,670	98.73%	$15,662	5.81%	$248,969	92.31%
> $300	86	1.27%	6,756	100.00%	$20,741	7.69%	$269,710	100.00%

Emergency Program

Table 2-91 Registered sites and MW in the Emergency Program[10] (By zone and option): January 4, 2010 (See 2009 SOM, Table 2-104)

	Energy Only		Full		Capacity Only	
	Sites	MW	Sites	MW	Sites	MW
AECO	0	0.0	131	45.7	12	15.9
AEP	0	0.0	588	1,259.9	99	504.3
AP	0	0.0	524	424.9	42	72.2
BGE	0	0.0	485	615.8	29	26.1
ComEd	0	0.0	805	646.6	526	697.1
DAY	0	0.0	159	147.5	13	57.2
DLCO	0	0.0	160	86.7	34	33.7
Dominion	0	0.0	444	469.2	46	40.6
DPL	0	0.0	169	127.2	15	39.5
JCPL	0	0.0	285	124.3	28	22.4
Met-Ed	0	0.0	174	182.3	42	42.2
PECO	0	0.0	414	136.5	235	215.3
PENELEC	0	0.0	248	192.7	45	27.6
Pepco	0	0.0	269	88.7	32	29.0
PPL	0	0.0	555	292.1	127	315.0
PSEG	0	0.0	582	286.8	79	26.0
RECO	0	0.0	15	3.0	6	0.5
Total	0	0.0	6,007	5,129.8	1,410	2,164.5

10 Table 2-90 shows registered sites and MW in the Emergency Program as of January 4, 2010, the peak load day through the first three months of 2010. As all resources are registered in either the Capacity Only or Full options, all resources in the Emergency Program are considered RPM Resources participating in the Load Management (LM) Program. Registered sites and MW remain constant in the LM Program through delivery years. For more information on LM Program participation and testing, see the *2009 State of the Market Report*, Section 2 – Energy Market, Part 1: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2009/2009-som-pjm-volume2-sec2.pdf