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 nine 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 nine 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] 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 the first nine 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).

Overview

Market Structure

- **Supply.** During the July through September 2009 quarter, the PJM Energy Market received an hourly average of 152,314 MW in supply offers.[3] The third quarter 2009 average supply offers were 338 MW higher than the third quarter 2008 average supply of 151,976 MW.

- **Demand.** The PJM system peak load in the third quarter 2009 was 126,805 MW in the hour ended 1700 EPT on August 10, 2009, while the PJM peak load in the third quarter 2008 was 129,481 in the hour ended 1700 on July 18, 2008.[4] The 2009 third quarter peak load was 2,676 MW, or 2.1 percent, lower than the third 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.

- **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 September 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 0.1 percent of all hours in the first nine months of 2009, down from

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 September*, 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).

0.2 percent in 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 nine 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 75 or more hours during the first three quarters of calendar year 2009. During the first three quarters of 2009 (January 1, 2009 through September 30, 2009), the PSEG, AP, AEP, PENELEC, Dominion, AECO, DLCO, ComEd, PECO, BGE and Pepco Control Zones experienced congestion resulting from one or more constraints binding for 75 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

- **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 September 2009 was -0.07 with a monthly average maximum of -0.04 in January and a monthly average minimum of -0.11 in April. In the day ahead market, the average markup index from January to September 2009 was 0.00 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.

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.

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 -$3.67 per MWh, or -9.3 percent. Coal steam units contributed -$3.04, or 82.9 percent, to the total markup component of LMP. Combined cycle units that use gas as their primary fuel source contributed -$0.68 or 18.6 percent to the total markup component of LMP. The markup was -$3.24 per MWh during peak hours and -$4.14 per MWh during off-peak hours.

  The markup component of the overall PJM day-ahead, load-weighted, average LMP was -$0.50 per MWh, or -1.3 percent. Coal steam units contributed -$0.52 or 103.5 percent to the total markup component of LMP. Combined cycle units that use gas as their primary fuel source contributed -$0.03 or 6.9 percent to the total markup component of LMP. The markup was $0.31 per MWh during peak hours and -$1.39 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 nine months of 2009 by 4.5 percent from the first nine months of 2008, falling from 80,611 MW to 76,956 MW. PJM day-ahead load decreased in the first nine months of 2009 by 8.0 percent from the first nine months of 2008, falling from 97,505 MW to 89,680 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 nine months of 2009 compared to the first nine months of 2008. The system simple average LMP was 48.0 percent lower in the first nine months of 2009 than in the first nine months of 2008, \$37.42 per MWh versus \$71.94 per MWh. The load-weighted LMP was 48.8 percent lower in the first nine months of 2009 than in the first nine months of 2008, \$39.57 per MWh versus \$77.27 per MWh. The fuel cost adjusted, load-weighted, average LMP was 11.2 percent lower in the first nine months of 2009 than the load-weighted, average LMP in the first nine months of 2008, \$68.61 per MWh compared to \$77.27 per MWh. In other words, if fuel costs for the first nine months of 2009 had been the same as for the first nine months of 2008, the 2009 load-weighted LMP would have been higher, \$68.61 per MWh, instead of the observed \$39.57 per MWh, and 11.2 percent lower than the load-weighted average LMP for the first nine months of 2008. Fuel costs and lower loads in the first nine months of 2009 contributed to downward pressure on LMP.

  PJM Day-Ahead Energy Market prices decreased in the first nine months of 2009 compared to the first nine months of 2008. The system simple average LMP was 47.7 percent lower in the first nine months of 2009 than in the first nine months of 2008, \$37.35 per MWh versus \$71.43 per MWh. The load-weighted LMP was 48.2 percent lower in the first nine months of 2009 than in the first nine months of 2008, \$39.35 per MWh versus \$75.96 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 nine months of 2009, 13.0 percent of real-time load was supplied by bilateral contracts, 16.6 percent by spot market purchases and 70.4 percent by self-supply. Compared with 2008, reliance on bilateral contracts decreased by 1.7 percentage points, reliance on spot supply decreased by 3.5 percentage points, and reliance on self-supply increased by 5.2 percentage points in January through September 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 August 10, 2009 (the peak day in January through September 2009), were 5,129.8 MW eligible for capacity and emergency energy credits and 2,164.5 MW eligible for capacity payments from the Emergency Load-Response Program and 2,486.6 MW from the Economic Load-Response Program.

  Participation in the Economic Load-Response Program, in terms of settlement days submitted and active customers, 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. However, settlement days submitted have increased significantly from June to August, showing participation levels comparable to the same period in 2008. 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 nine 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 increased by about 338 MW when comparing the third quarter of 2009 to the third quarter of 2008 while aggregate peak load decreased by 2,676 MW, modifying the general supply demand balance from 2008 with a corresponding impact on Energy Market prices. Overall load was also lower than in third 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.

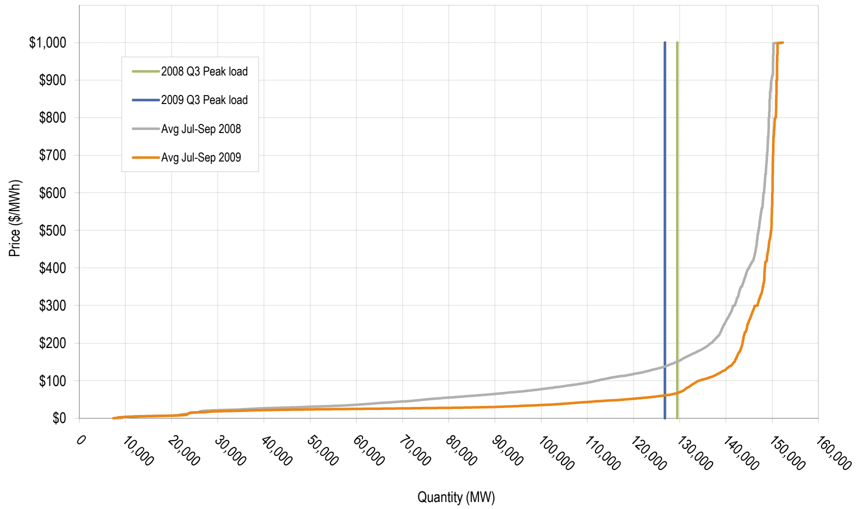
Energy Market results for the first nine months of 2009 generally reflected supply-demand fundamentals. Lower prices in the Energy Market were the result of lower fuel costs and of lower demand. PJM Real-Time, load-weighted, average LMP for the first nine months of 2009 was $39.57, or 48.8 percent lower than the load-weighted, average LMP for the first nine months of 2008, which was $77.27. The real-time, fuel-cost-adjusted, load-weighted, average LMP in the first nine months of 2009 was $68.61, or 11.2 percent lower than the load-weighted, average LMP in the first nine months of 2008, which was $77.27. In other words, if fuel costs for the first nine months of 2009 had been the same as for the first nine months of 2008, the 2009 load-weighted LMP would have been higher, $68.61 per MWh, instead of the observed $39.57 per MWh, and 11.2 percent lower than the load-weighted average LMP for the first nine months of 2008. Lower fuel prices in 2009 resulted in lower energy prices in 2009 than would have occurred if fuel prices had remained at 2008 levels. 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 nine months of 2009.

Market Structure

Supply

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

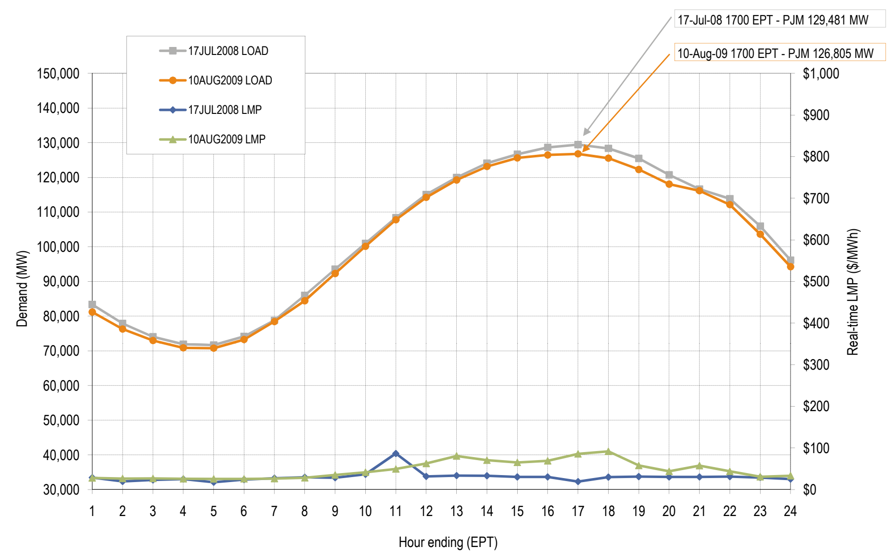


Demand

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

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Difference (MW)
2005	26-Jul-05	1600	133,761	NA
2006	02-Aug-06	1700	144,644	10,883
2007	08-Aug-07	1600	139,428	(5,216)
2008	17-Jul-08	1700	129,481	(9,947)
2009	10-Aug-09	1700	126,805	(2,676)

Figure 2-2 PJM quarter three peak-load comparison: Monday, August 10, 2009, and Friday, July 18, 2008 (See 2008 SOM, Figure 2-2)



Market Concentration

PJM HHI Results

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

	Hourly Market HHI
Average	1231
Minimum	935
Maximum	1628
Highest market share (One hour)	32%
Highest market share (All hours)	22%
# Hours	6551
# 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 September 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%	0.1%	0.1%	0.0%

Table 2-4 Offer-capped unit statistics: January through September 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	1	5
80% and < 90%	0	0	0	1	1	16
75% and < 80%	0	0	0	1	0	6
70% and < 75%	0	0	0	0	2	8
60% and < 70%	0	0	2	0	0	28
50% and < 60%	0	0	0	1	0	18
25% and < 50%	0	0	0	0	1	51
10% and < 25%	2	0	1	0	2	53

Local Market Structure

Table 2-5 Three pivotal supplier results summary for regional constraints: January through September 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	657	635	97%	48	7%
	Off Peak	165	158	96%	20	12%
AP South	Peak	1,236	689	56%	803	65%
	Off Peak	566	310	55%	376	66%
Bedington - Black Oak	Peak	243	216	89%	117	48%
	Off Peak	110	84	76%	41	37%
Kammer	Peak	3,786	3,508	93%	624	16%
	Off Peak	4,145	3,619	87%	1,064	26%
West	Peak	332	321	97%	30	9%
	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 through September 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	347	19	19	1
	Off Peak	54	314	18	17	1
AP South	Peak	97	293	12	6	6
	Off Peak	102	303	11	5	6
Bedington - Black Oak	Peak	67	193	12	9	3
	Off Peak	57	214	13	9	4
Kammer	Peak	51	249	21	19	2
	Off Peak	52	221	17	14	3
West	Peak	125	627	22	21	1
	Off Peak	121	738	18	18	0

Table 2-7 Three pivotal supplier results summary for the East and Central interfaces: January through September 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

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 through September 2009. The Central Interface constraint occurred for eight hours from January through September 2009.

Table 2-8 Three pivotal supplier test details for the East and Central interfaces: January through September 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 through September 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	333	8	2%	329	99%
	Off Peak	135	5	4%	134	99%
Brunswick - Edison	Peak	226	6	3%	226	100%
	Off Peak	84	0	0%	84	100%
Plainsboro - Trenton	Peak	592	0	0%	592	100%
	Off Peak	13	0	0%	13	100%

Table 2-10 Three pivotal supplier test details for constraints located in the PSEG Control Zone: January through September 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 - Saddlebrook	Peak	13	38	3	0	3
	Off Peak	10	42	3	0	3
Brunswick - Edison	Peak	8	89	1	0	1
	Off Peak	6	65	1	0	1
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 through September 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	895	125	14%	895	100%
	Off Peak	333	11	3%	333	100%
Elrama - Mitchell	Peak	649	357	55%	383	59%
	Off Peak	278	184	66%	123	44%
Mount Storm - Pruntytown	Peak	461	331	72%	248	54%
	Off Peak	254	165	65%	143	56%
Sammis - Wylie Ridge	Peak	346	245	71%	154	45%
	Off Peak	504	365	72%	239	47%
Tiltonsville - Windsor	Peak	1,179	1	0%	1,178	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 through September 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	31	5	3	0	3
	Off Peak	38	4	3	0	3
Elrama - Mitchell	Peak	20	65	12	9	4
	Off Peak	16	62	12	9	2
Mount Storm - Pruntytown	Peak	85	306	12	8	4
	Off Peak	97	273	11	6	4
Sammis - Wylie Ridge	Peak	44	118	20	13	7
	Off Peak	56	128	17	11	6
Tiltonsville - Windsor	Peak	11	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 through September 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	306	164	54%	207	68%
	Off Peak	1,504	838	56%	1,009	67%
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	461	0	0%	461	100%
	Off Peak	39	0	0%	39	100%
Ruth - Turner	Peak	1,353	0	0%	1,353	100%
	Off Peak	1,480	0	0%	1,480	100%

Table 2-14 Three pivotal supplier test details for constraints located in the AEP Control Zone: January through September 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	76	219	16	7	9
	Off Peak	70	190	14	7	8
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	8	14	1	0	1
	Off Peak	11	18	1	0	1
Ruth - Turner	Peak	18	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 through September 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	540	22	4%	529	98%
	Off Peak	140	3	2%	140	100%

Table 2-16 Three pivotal supplier test details for constraints located in the PENELEC Control Zone: January through September 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	25	59	4	0	4
	Off Peak	41	55	5	0	5

Table 2-17 Three pivotal supplier results summary for constraints located in the Dominion Control Zone: January through September 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	919	0	0%	919	100%
	Off Peak	125	0	0%	125	100%

Table 2-18 Three pivotal supplier test details for constraints located in the Dominion Control Zone: January through September 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	3	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 through September 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 through September 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 through September 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 through September 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 through September 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	102	21	21%	98	96%
	Off Peak	1,250	73	6%	1,225	98%
Electric Jct - Nelson	Peak	262	5	2%	261	100%
	Off Peak	740	1	0%	740	100%
Pleasant Valley - Belvidere	Peak	436	0	0%	436	100%
	Off Peak	921	0	0%	921	100%

Table 2-24 Three pivotal supplier test details for constraints located in the ComEd Control Zone: January through September 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	33	113	5	1	4
	Off Peak	35	48	4	0	4
Electric Jct - Nelson	Peak	31	15	3	0	3
	Off Peak	35	4	2	0	2
Pleasant Valley - Belvidere	Peak	11	1	1	0	1
	Off Peak	12	0	1	0	1

Table 2-25 Three pivotal supplier results summary for constraints located in the PECO Control Zone: January through September, 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
Emilie	Peak	1,374	35	3%	1,365	99%
	Off Peak	712	3	0%	712	100%

Table 2-26 Three pivotal supplier test details for constraints located in the PECO Control Zone: January through September 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
Emilie	Peak	15	59	4	0	4
	Off Peak	14	83	4	0	4

Table 2-27 Three pivotal supplier results summary for constraints located in the BGE Control Zone: January through September 2009 (New Table)

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	489	447	91%	76	16%
	Off Peak	250	225	90%	50	20%

Table 2-28 Three pivotal supplier test details for constraints located in the BGE Control Zone: January through September 2009 (New Table)

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	116	19	18	2
	Off Peak	41	142	21	19	2

Table 2-29 Three pivotal supplier results summary for constraints located in the Pepco Control Zone: January through September 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
Buzzard - Ritchie	Peak	366	0	0%	366	100%
	Off Peak	NA	NA	NA	NA	NA

Table 2-30 Three pivotal supplier test details for constraints located in the Pepco Control Zone: January through September 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
Buzzard - Ritchie	Peak	6	26	2	0	2
	Off Peak	NA	NA	NA	NA	NA

Market Performance: Markup

Real-Time Markup

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

Company	Percent of Price
1	17%
2	14%
3	9%
4	8%
5	8%
6	6%
7	6%
8	4%
9	3%
Other (46 companies)	27%

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

Fuel Type	Percent on the Margin
Coal	73%
Natural Gas	20%
Petroleum	5%
Landfill Gas	1%
Interface	1%
Misc	0%

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

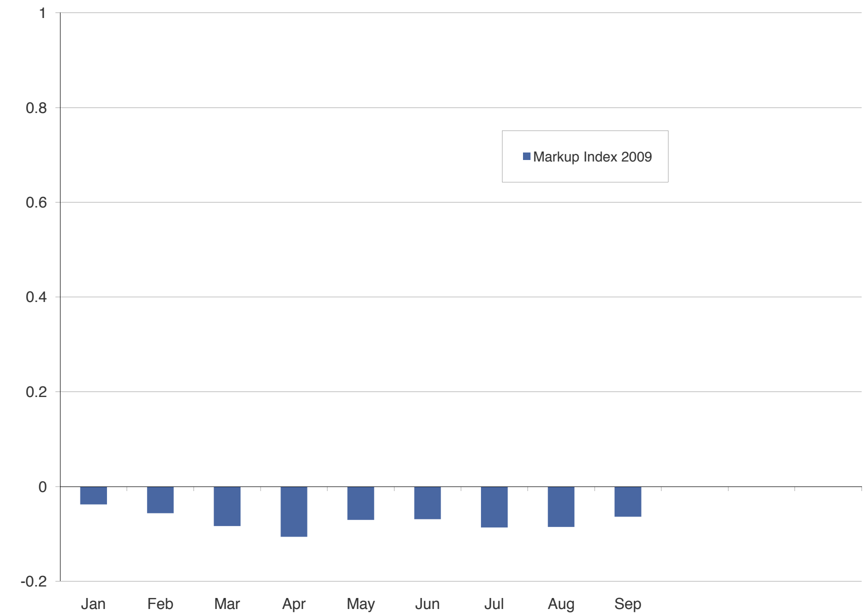


Table 2-33 Average, real-time marginal unit markup index (By price category): January through September 2009 (See 2007 SOM, Table 2-34)

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.09)	($3.41)
$25 to $50	(0.11)	($5.50)
$50 to $75	(0.02)	($2.97)
$75 to $100	0.04	$2.69
$100 to $125	0.08	$6.70
$125 to $150	0.05	$4.96
> $150	0.04	$7.80

Table 2-34 The markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January through September 2009

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($3.04)	82.9%
Gas	CC	($0.68)	18.6%
Gas	CT	$0.02	(0.5%)
Gas	Diesel	$0.00	(0.1%)
Gas	Steam	$0.01	(0.3%)
Interface	Interface	($0.00)	0.0%
Municipal Waste	Diesel	$0.00	0.0%
Municipal Waste	Steam	($0.02)	0.5%
Oil	CC	($0.00)	0.0%
Oil	CT	$0.04	(1.1%)
Oil	Diesel	($0.02)	0.4%
Oil	Steam	$0.02	(0.5%)
Uranium	Steam	($0.00)	0.0%
Water	Hydro	$0.00	0.0%
Wind	Wind	$0.00	(0.0%)
Total		($3.67)	100.0%

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

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($1.53)	($0.49)	($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)
Jul	($3.61)	($3.67)	($3.54)
Aug	($5.84)	($3.88)	($7.93)
Sep	($4.73)	($6.56)	($2.67)
2009 (Jan - Sep)	($3.67)	($3.24)	($4.14)

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

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($3.66)	($3.43)	($3.90)
AEP	($4.29)	($3.87)	($4.73)
AP	($3.17)	($2.48)	($3.91)
BGE	($3.49)	($2.71)	($4.33)
ComEd	($4.28)	($4.04)	($4.55)
DAY	($4.61)	($4.19)	($5.08)
DLCO	($4.45)	($3.98)	($4.98)
Dominion	($2.98)	($2.23)	($3.79)
DPL	($2.87)	($3.06)	($2.68)
JCPL	($3.52)	($3.17)	($3.93)
Met-Ed	($3.00)	($3.05)	($2.94)
PECO	($3.45)	($3.23)	($3.68)
PENELEC	($3.59)	($3.30)	($3.91)
Pepco	($3.16)	($2.35)	($4.05)
PPL	($3.38)	($3.11)	($3.67)
PSEG	($3.53)	($3.18)	($3.93)
RECO	($3.54)	($3.12)	($4.04)

Table 2-37 Average real-time markup component (By price category): January through September 2009 (See 2008 SOM, Table 2-41)

	Average Markup Component	Frequency
Below $20	($0.29)	5.1%
$20 to $40	($5.49)	73.7%
$40 to $60	($3.44)	23.6%
$60 to $80	$0.72	5.7%
$80 to $100	$9.01	2.3%
$100 to $120	$0.76	0.7%
$120 to $140	$40.38	0.4%
$140 to $160	$13.87	0.2%
Above $160	$52.56	0.2%

Day-Ahead Markup

Table 2-38 Marginal unit contribution to PJM day-ahead, annual, load-weighted LMP (By parent company): January through September 2009 (See 2007 SOM, Table 2-31)

Company	Percent of Price
1	33%
2	9%
3	6%
4	5%
5	5%
6	4%
7	3%
8	3%
9	2%
Other (118 companies)	30%

Table 2-39 Day-ahead marginal resources by type/fuel: January through September 2009 (See 2007 SOM, Table 2-32)

Type/Fuel	Percent on the Margin
Transaction	35%
DEC	30%
INC	19%
Coal	12%
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 September 2009 (See 2007 SOM, Figure 2-4)

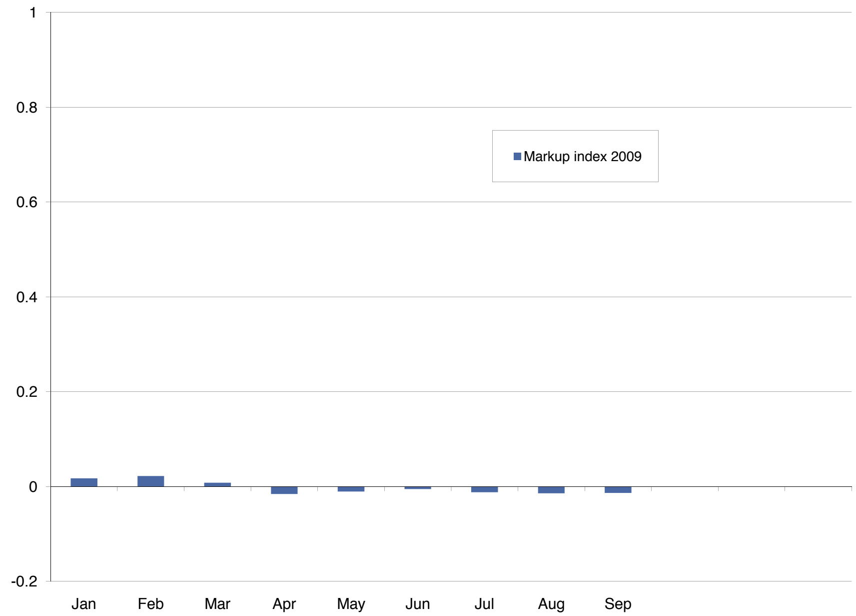


Table 2-40 Average, day-ahead marginal unit markup index (By price category): January through September 2009 (See 2007 SOM, Table 2-34)

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.04)	($2.54)
$25 to $50	0.04	$0.40
$50 to $75	0.09	$5.26
$75 to $100	0.09	$7.98
$100 to $125	0.31	$33.95
$125 to $150	(0.04)	($8.16)
> $150	0.00	$0.00

Table 2-41 The markup component of the overall PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through September 2009 (New Table)

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($0.52)	103.5%
Gas	CC	($0.03)	6.9%
Gas	CT	$0.01	(1.9%)
Gas	Diesel	$0.00	(0.0%)
Gas	Steam	$0.01	(1.4%)
Municipal Waste	Steam	($0.00)	0.2%
Oil	Diesel	($0.00)	0.0%
Oil	Steam	$0.02	(3.9%)
Wind	Wind	$0.02	(3.2%)
Total		($0.50)	100.0%

Table 2-42 Monthly markup components of day-ahead, load-weighted LMP: January through September 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)
Jul	($1.10)	($0.55)	($1.80)
Aug	($1.63)	($0.75)	($2.57)
Sep	($1.31)	($0.69)	($2.00)
2009 (Jan - Sep)	($0.50)	$0.31	($1.39)

Table 2-43 Day-ahead, average, zonal markup component: January through September 2009 (See 2007 SOM, Table 2-36)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($0.04)	$0.78	($0.96)
AEP	($1.22)	($0.17)	($2.35)
AP	$0.40	$1.21	($0.48)
BGE	($0.22)	$0.60	($1.12)
ComEd	($0.71)	$0.02	($1.48)
DAY	($1.38)	($0.33)	($2.56)
DLCO	($1.17)	($0.22)	($2.21)
Dominion	($0.68)	$0.01	($1.41)
DPL	($0.10)	$0.60	($0.85)
JCPL	$0.00	$0.82	($0.95)
Met-Ed	$0.01	$0.74	($0.82)
PECO	($0.05)	$0.76	($0.95)
PENELEC	($0.09)	$0.65	($0.95)
Pepco	($0.51)	$0.18	($1.31)
PPL	$0.01	$0.77	($0.83)
PSEG	($0.12)	$0.62	($0.97)
RECO	($0.09)	$0.65	($1.02)

Table 2-44 Average, day-ahead markup (By price category): January through September 2009 (See 2007 SOM, Table 2-37)

	Average Markup Component	Frequency
Below $20	($1.63)	5%
$20 to $40	($1.68)	62%
$40 to $60	$1.01	26%
$60 to $80	$2.00	5%
$80 to $100	$2.70	2%
$100 to $120	$4.26	0%
$120 to $140	$1.43	0%
Above $160	$0.00	0%

Frequently Mitigated Unit and Associated Unit Adders – Component of Price

Table 2-45 Frequently mitigated units and associated units (By month): January through September 2009 (See 2008 SOM, Table 2-42)

	FMUs and AUs			Total Eligible for Any Adder
	Tier 1	Tier 2	Tier 3	
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
July	27	32	75	134
August	27	37	64	128
September	40	23	56	119

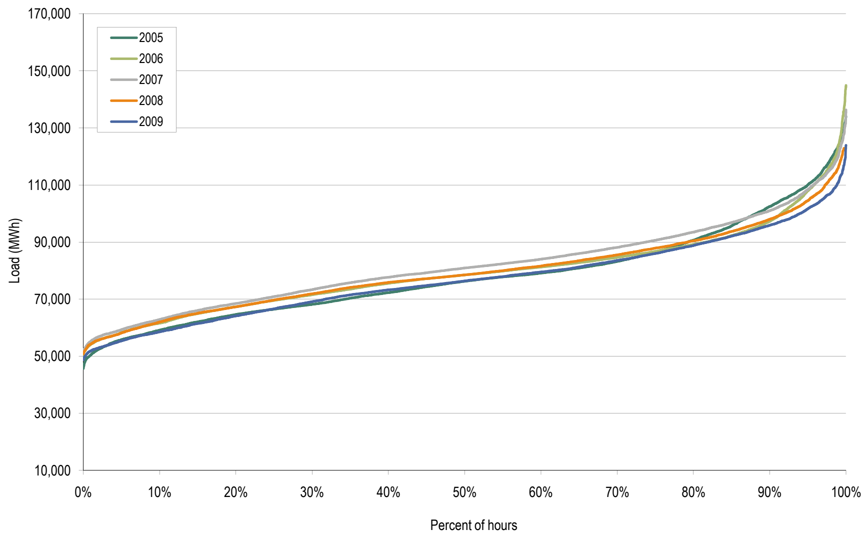
Market Performance: Load and LMP

Load

Real-Time Load

PJM Real-Time Load Duration

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



PJM Real-Time, Annual Average Load

Table 2-46 PJM real-time average load: Calendar years 2000 through September 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	76,956	76,355	13,879	(3.2%)	(2.7%)	0.9%

PJM Real-Time, Monthly Average Load

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

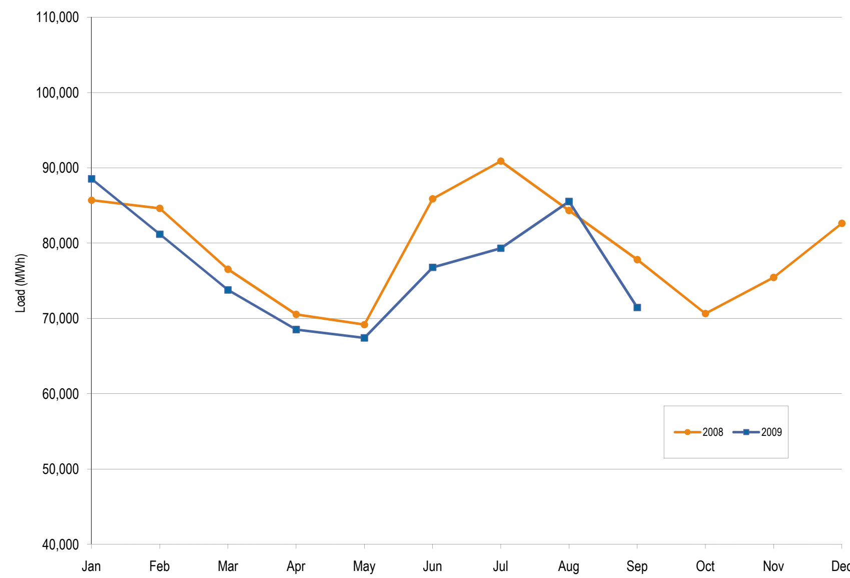


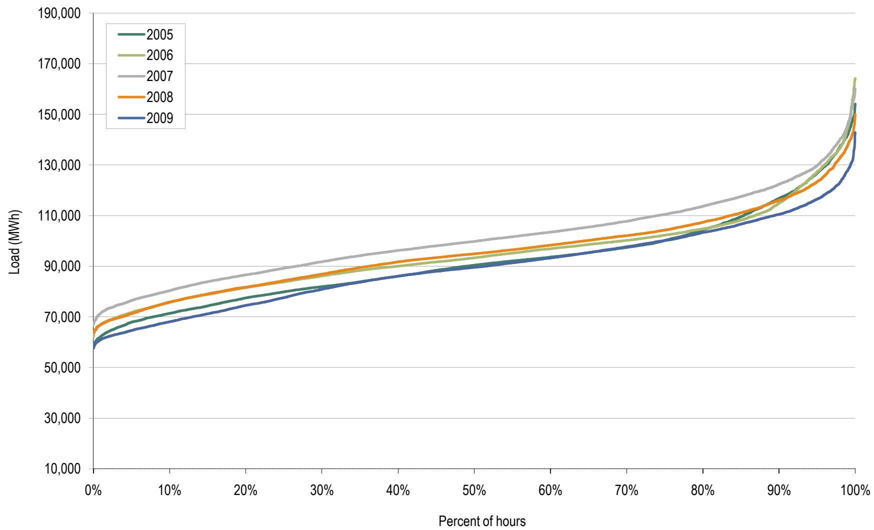
Table 2-47 Monthly minimum, average and maximum of PJM hourly THI: Cooling periods of 2008 and 2009 (See 2008 SOM, Table 2-45)

	2008			2009			Difference		
	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max
Jun	54.94	70.16	81.30	52.48	67.85	77.91	(4.5%)	(3.3%)	(4.2%)
Jul	62.02	72.23	80.34	58.65	69.52	78.11	(5.4%)	(3.8%)	(2.8%)
Aug	59.82	69.67	78.55	57.45	71.63	81.01	(4.0%)	2.8%	3.1%

Day-Ahead Load

PJM Day-Ahead Load Duration

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



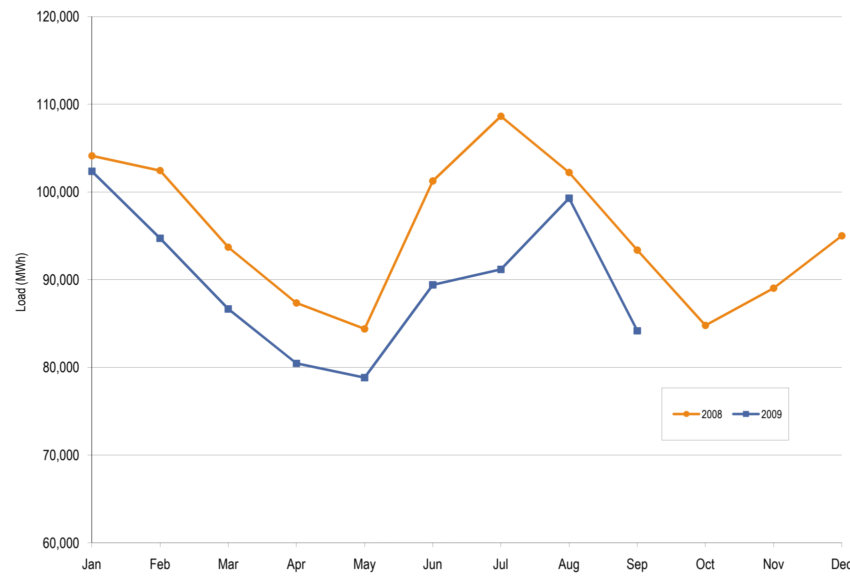
PJM Day-Ahead, Annual Average Load

Table 2-48 PJM day-ahead average load: Calendar years 2005 through September 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	89,680	89,515	15,756	(6.1%)	(5.7%)	2.1%

PJM Day-Ahead, Monthly Average Load

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

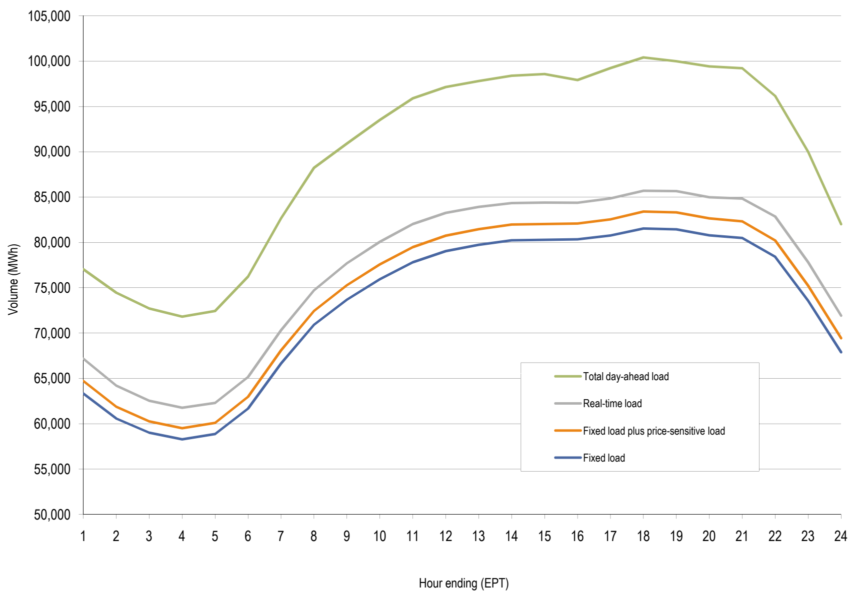


Real-Time and Day-Ahead Load

Table 2-49 Cleared day-ahead and real-time load (MWh): January through September 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	72,973	1,603	15,104	89,680	76,956	12,724	(2,380)
Median	72,358	1,609	15,369	89,515	76,355	13,160	(2,209)
Standard deviation	13,129	458	2,660	15,756	13,879	1,877	(783)

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

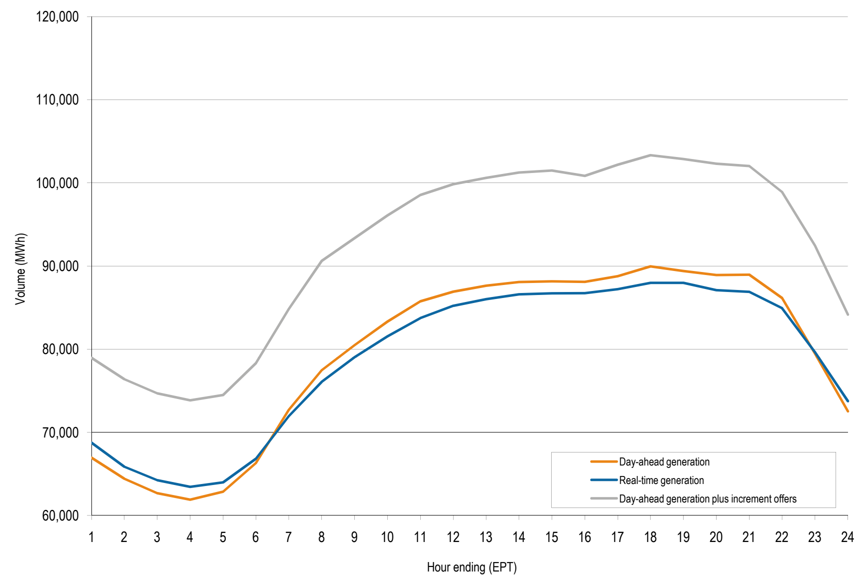


Real-Time and Day-Ahead Generation

Table 2-50 Day-ahead and real-time generation (MWh): January through September 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	79,502	12,684	92,186	78,850	652	13,336
Median	79,455	12,553	92,109	78,316	1,139	13,793
Standard deviation	15,458	1,615	16,220	14,242	1,216	1,978

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



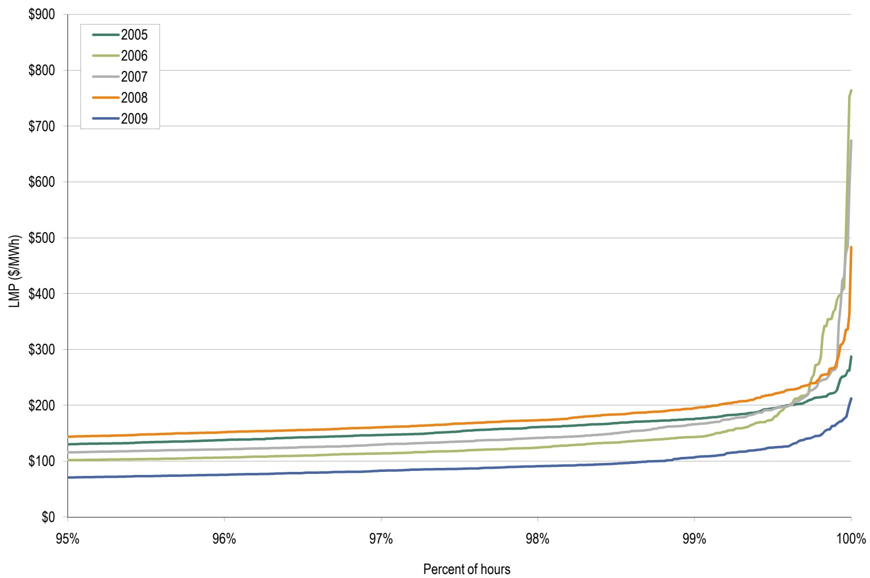
Locational Marginal Price (LMP)

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 September 2009 (See 2008 SOM, Figure 2-10)



PJM Real-Time, Annual Average LMP

Table 2-51 PJM real-time, simple average LMP (Dollars per MWh): Calendar years 2000 through September 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	$37.42	$33.00	$17.92	(43.6%)	(40.6%)	(53.6%)

Zonal Real-Time, Annual Average LMP

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

	2008 (Jan - Sep)	2009 (Jan - Sep)	Difference	Difference as Percent of 2008
AECO	$88.73	$41.33	($47.40)	(53.4%)
AEP	$56.49	$33.81	($22.68)	(40.2%)
AP	$70.91	$38.89	($32.02)	(45.2%)
BGE	$87.55	$42.04	($45.51)	(52.0%)
ComEd	$53.10	$28.78	($24.32)	(45.8%)
DAY	$56.89	$33.56	($23.33)	(41.0%)
DLCO	$52.23	$32.47	($19.76)	(37.8%)
Dominion	$83.17	$40.55	($42.62)	(51.2%)
DPL	$84.20	$42.02	($42.18)	(50.1%)
JCPL	$86.31	$41.39	($44.92)	(52.0%)
Met-Ed	$81.33	$40.40	($40.94)	(50.3%)
PECO	$81.47	$40.51	($40.96)	(50.3%)
PENELEC	$67.83	$37.13	($30.70)	(45.3%)
Pepco	$87.88	$42.26	($45.62)	(51.9%)
PPL	$79.70	$39.87	($39.82)	(50.0%)
PSEG	$86.38	$41.88	($44.50)	(51.5%)
RECO	$84.50	$40.85	($43.65)	(51.7%)

Real-Time, Annual Average LMP by Jurisdiction

Table 2-53 Jurisdiction real-time, simple average LMP (Dollars per MWh): January through September 2008 and 2009 (See 2008 SOM, Table 2-51)

	2008 (Jan - Sep)	2009 (Jan - Sep)	Difference	Difference as Percent of 2008
Delaware	$83.06	$41.56	($41.50)	(50.0%)
Illinois	$53.10	$28.78	($24.32)	(45.8%)
Indiana	$56.19	$33.26	($22.93)	(40.8%)
Kentucky	$56.91	$33.63	($23.29)	(40.9%)
Maryland	$87.25	$42.03	($45.22)	(51.8%)
Michigan	$57.27	$34.48	($22.80)	(39.8%)
New Jersey	$86.71	$41.65	($45.05)	(52.0%)
North Carolina	$78.14	$39.56	($38.57)	(49.4%)
Ohio	$55.66	$33.33	($22.33)	(40.1%)
Pennsylvania	$74.55	$38.86	($35.69)	(47.9%)
Tennessee	$57.72	$33.69	($24.03)	(41.6%)
Virginia	$80.02	$39.83	($40.19)	(50.2%)
West Virginia	$58.18	$35.00	($23.18)	(39.8%)
District of Columbia	$87.91	$43.74	($44.17)	(50.2%)

Hub Real-Time, Annual Average LMP

Table 2-54 Hub real-time, simple average LMP (Dollars per MWh): January through September 2008 and 2009 (See 2008 SOM, Table 2-52)

	2008 (Jan - Sep)	2009 (Jan - Sep)	Difference	Difference as Percent of 2008
AEP Gen Hub	$53.11	$31.90	($21.22)	(39.9%)
AEP-DAY Hub	$56.14	$33.39	($22.75)	(40.5%)
Chicago Gen Hub	$52.24	$27.98	($24.25)	(46.4%)
Chicago Hub	$53.17	$28.98	($24.19)	(45.5%)
Dominion Hub	$80.83	$39.88	($40.95)	(50.7%)
Eastern Hub	$84.10	$41.97	($42.13)	(50.1%)
N Illinois Hub	$52.68	$28.60	($24.08)	(45.7%)
New Jersey Hub	$86.40	$41.61	($44.79)	(51.8%)
Ohio Hub	$56.24	$33.39	($22.84)	(40.6%)
West Interface Hub	$62.82	$34.73	($28.09)	(44.7%)
Western Hub	$73.86	$38.64	($35.23)	(47.7%)

Real-Time, Load-Weighted, Average LMP

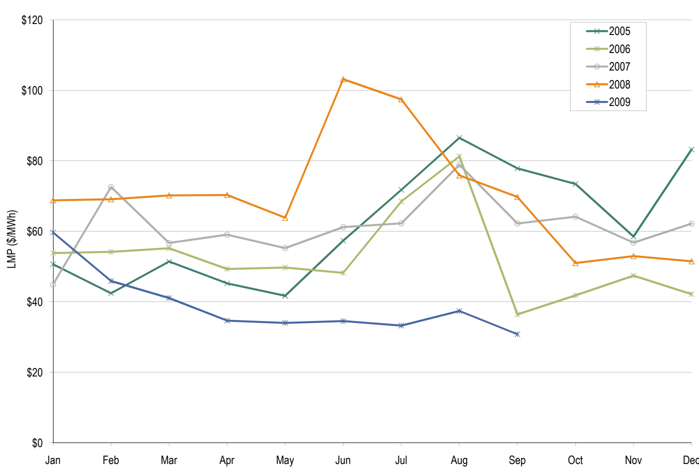
PJM Real-Time, Annual, Load-Weighted, Average LMP

Table 2-55 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 2000 through September 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	$39.57	$34.57	$19.04	(44.4%)	(41.9%)	(53.5%)

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

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



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

Table 2-56 Zonal real-time, annual, load-weighted, average LMP (Dollars per MWh): January through September 2008 and 2009 (See 2008 SOM, Table 2-54)

	2008 (Jan - Sep)	2009 (Jan - Sep)	Difference	Difference as Percent of 2008
AECO	$99.86	$43.27	($56.59)	(56.7%)
AEP	$60.18	$35.56	($24.62)	(40.9%)
AP	$75.57	$41.49	($34.07)	(45.1%)
BGE	$95.51	$44.83	($50.68)	(53.1%)
ComEd	$57.78	$30.60	($27.19)	(47.0%)
DAY	$61.59	$35.30	($26.28)	(42.7%)
DLCO	$56.30	$33.65	($22.65)	(40.2%)
Dominion	$91.15	$43.46	($47.69)	(52.3%)
DPL	$91.73	$45.13	($46.59)	(50.8%)
JCPL	$94.68	$43.78	($50.90)	(53.8%)
Met-Ed	$87.05	$43.01	($44.03)	(50.6%)
PECO	$87.85	$42.69	($45.15)	(51.4%)
PENELEC	$71.33	$39.03	($32.30)	(45.3%)
Pepco	$96.23	$45.10	($51.13)	(53.1%)
PPL	$84.84	$42.83	($42.01)	(49.5%)
PSEG	$93.34	$43.74	($49.60)	(53.1%)
RECO	$92.92	$42.91	($50.01)	(53.8%)

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

Table 2-57 Jurisdiction real-time, annual, load-weighted, average LMP (Dollars per MWh): January through September 2008 and 2009 (See 2008 SOM, Table 2-55)

	2008 (Jan - Sep)	2009 (Jan - Sep)	Difference	Difference as Percent of 2008
Delaware	$89.73	$44.21	($45.52)	(50.7%)
Illinois	$57.78	$30.60	($27.19)	(47.0%)
Indiana	$59.40	$34.42	($24.99)	(42.1%)
Kentucky	$61.40	$36.18	($25.22)	(41.1%)
Maryland	$95.61	$45.12	($50.49)	(52.8%)
Michigan	$61.71	$35.78	($25.93)	(42.0%)
New Jersey	$94.62	$43.67	($50.95)	(53.8%)
North Carolina	$87.14	$42.10	($45.04)	(51.7%)
Ohio	$59.49	$34.92	($24.58)	(41.3%)
Pennsylvania	$79.41	$41.12	($38.30)	(48.2%)
Tennessee	$60.38	$35.88	($24.50)	(40.6%)
Virginia	$87.45	$42.78	($44.67)	(51.1%)
West Virginia	$61.65	$37.21	($24.44)	(39.6%)
District of Columbia	$94.44	$46.29	($48.15)	(51.0%)

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

Fuel Cost

Table 2-58 PJM real-time, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): January through September 2009, year-over-year method (See 2008 SOM, Table 2-56)

	2008 (Jan - Sep) Load-Weighted LMP	2009 (Jan - Sep) Fuel-Cost-Adjusted, Load-Weighed LMP	Change
Average	$77.27	$68.61	(11.2%)

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

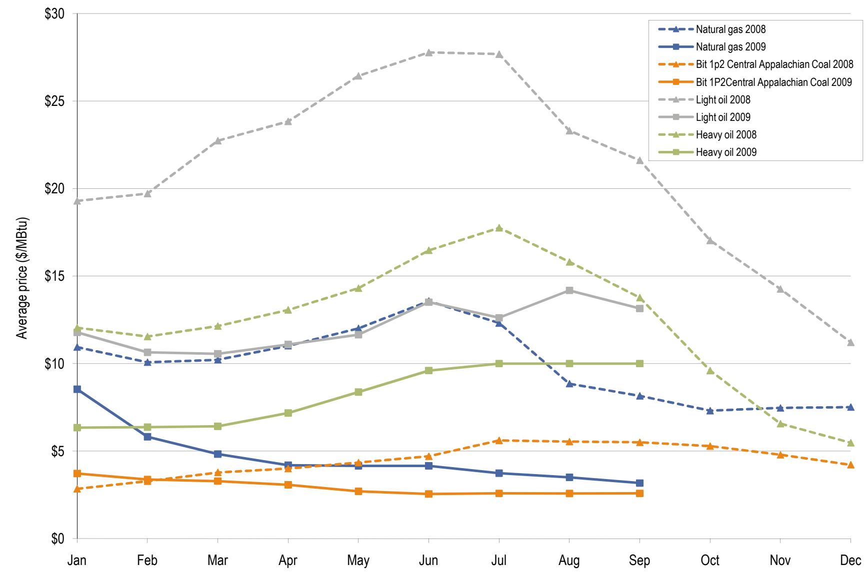
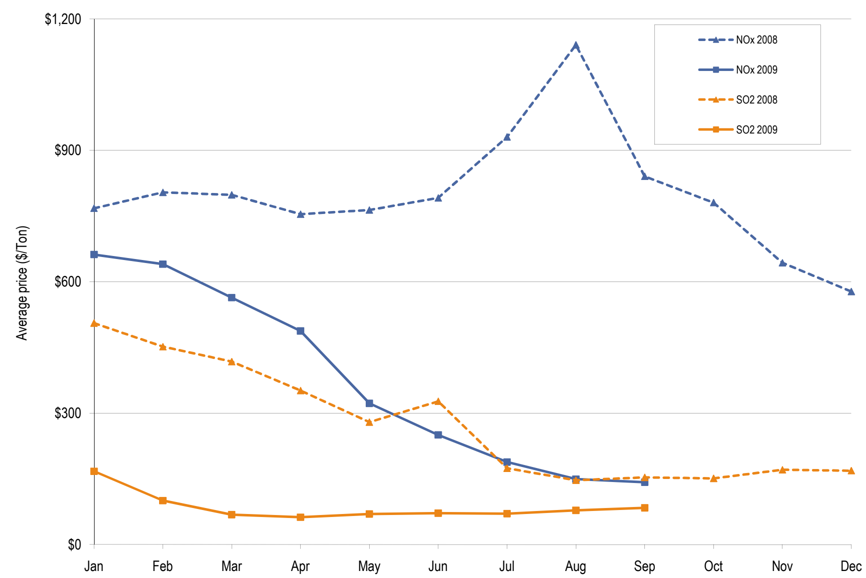


Figure 2-14 Spot average emission price comparison: Calendar years 2008 through September 2009 (See 2008 SOM, Figure 2-13)



Components of Real-Time, Load-Weighted LMP

Table 2-59 Components of PJM annual, load-weighted, average LMP: January through September 2009 (See 2008 SOM, Table 2-57)

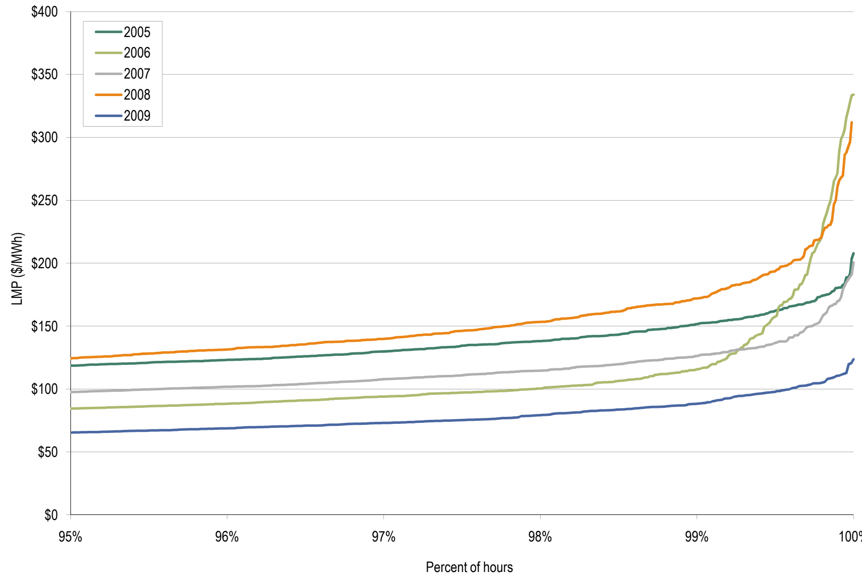
Element	Contribution to LMP	Percent
Coal	$22.06	55.8%
Gas	$12.10	30.6%
Oil	$3.26	8.2%
Uranium	$0.00	0.0%
Municipal Waste	$0.02	0.0%
FMU Adder	$0.19	0.5%
SO2	$1.33	3.4%
NOX	$0.49	1.2%
VOM	$4.40	11.1%
Markup	($3.67)	(9.3%)
Offline CT Adder	$0.05	0.1%
UDS Override Differential	($0.38)	(1.0%)
Dispatch Differential	($0.21)	(0.5%)
M2M Adder	($0.18)	(0.5%)
Flow violation Adjustment	($0.01)	(0.0%)
Unit LMP Differential	($0.00)	(0.0%)
NA	$0.12	0.3%
LMP	$39.57	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 September 2009 (See 2008 SOM, Figure 2-14)



PJM Day-Ahead, Annual Average LMP

Table 2-60 PJM day-ahead, simple average LMP (Dollars per MWh): Calendar years 2005 through September 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	$37.35	$35.29	$14.32	(43.5%)	(40.1%)	(53.6%)

Zonal Day-Ahead, Annual Average LMP

Table 2-61 Zonal day-ahead, simple average LMP (Dollars per MWh): January through September 2008 and 2009 (See 2008 SOM, Table 2-62)

	2008 (Jan - Sep)	2009 (Jan - Sep)	Difference	Difference as Percent of 2008
AECO	$85.95	$42.15	($43.80)	(51.0%)
AEP	$56.89	$33.70	($23.19)	(40.8%)
AP	$70.23	$38.37	($31.86)	(45.4%)
BGE	$87.81	$42.75	($45.06)	(51.3%)
ComEd	$54.22	$28.80	($25.42)	(46.9%)
DAY	$56.96	$33.07	($23.90)	(42.0%)
DLCO	$54.88	$32.25	($22.63)	(41.2%)
Dominion	$82.35	$41.07	($41.28)	(50.1%)
DPL	$84.64	$42.43	($42.21)	(49.9%)
JCPL	$86.90	$41.99	($44.90)	(51.7%)
Met-Ed	$81.95	$40.87	($41.08)	(50.1%)
PECO	$82.47	$41.37	($41.09)	(49.8%)
PENELEC	$70.04	$37.46	($32.58)	(46.5%)
Pepco	$88.50	$42.91	($45.59)	(51.5%)
PPL	$80.45	$40.45	($40.00)	(49.7%)
PSEG	$86.72	$42.56	($44.16)	(50.9%)
RECO	$84.94	$41.51	($43.44)	(51.1%)

Day-Ahead, Annual Average LMP by Jurisdiction

Table 2-62 Day-ahead, simple average LMP (Dollars per MWh) by jurisdiction: January through September 2008 and 2009 (See 2008 SOM, Table 2-63)

	2008 (Jan - Sep)	2009 (Jan - Sep)	Difference	Difference as Percent of 2008
Delaware	$83.38	$41.81	($41.57)	(49.9%)
Illinois	$54.22	$28.80	($25.42)	(46.9%)
Indiana	$57.10	$33.14	($23.95)	(41.9%)
Kentucky	$56.47	$33.41	($23.05)	(40.8%)
Maryland	$87.12	$42.64	($44.48)	(51.1%)
Michigan	$58.00	$34.41	($23.59)	(40.7%)
New Jersey	$86.71	$42.33	($44.38)	(51.2%)
North Carolina	$77.70	$40.03	($37.68)	(48.5%)
Ohio	$56.21	$33.00	($23.21)	(41.3%)
Pennsylvania	$75.69	$39.29	($36.40)	(48.1%)
Tennessee	$57.49	$33.90	($23.59)	(41.0%)
Virginia	$79.32	$40.37	($38.95)	(49.1%)
West Virginia	$57.98	$34.79	($23.19)	(40.0%)
District of Columbia	$88.21	$44.06	($44.15)	(50.1%)

Day-Ahead, Load-Weighted, Average LMP

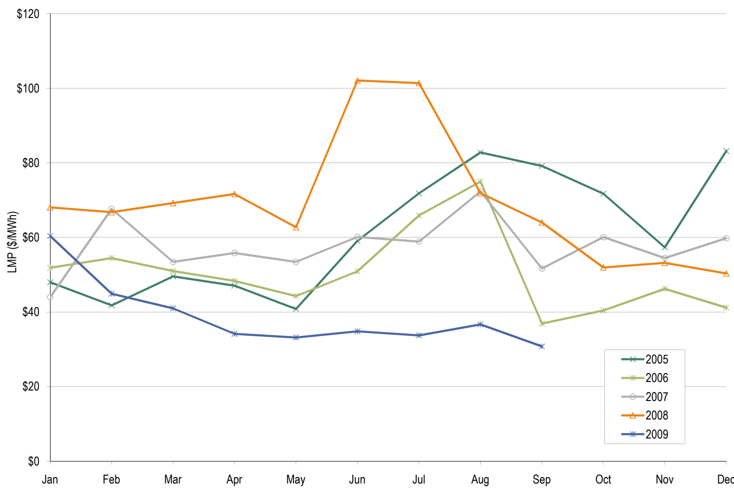
PJM Day-Ahead, Annual, Load-Weighted, Average LMP

Table 2-63 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2005 through September 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	$39.35	$36.92	$14.98	(44.0%)	(41.3%)	(54.8%)

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

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



Zonal Day-Ahead, Annual, Load-Weighted LMP

Table 2-64 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): January through September 2008 and 2009 (See 2008 SOM, Table 2-65)

	2008 (Jan - Sep)	2009 (Jan - Sep)	Difference	Difference as Percent of 2008
AECO	$96.75	$44.48	($52.27)	(54.0%)
AEP	$60.23	$35.37	($24.86)	(41.3%)
AP	$73.22	$40.77	($32.45)	(44.3%)
BGE	$95.41	$45.38	($50.03)	(52.4%)
ComEd	$57.63	$30.11	($27.52)	(47.8%)
DAY	$60.93	$34.63	($26.31)	(43.2%)
DLCO	$58.72	$33.33	($25.39)	(43.2%)
Dominion	$89.53	$43.87	($45.66)	(51.0%)
DPL	$91.81	$45.11	($46.69)	(50.9%)
JCPL	$94.43	$44.22	($50.21)	(53.2%)
Met-Ed	$86.79	$43.54	($43.25)	(49.8%)
PECO	$88.34	$43.49	($44.85)	(50.8%)
PENELEC	$72.64	$39.06	($33.57)	(46.2%)
Pepco	$94.03	$45.43	($48.60)	(51.7%)
PPL	$84.92	$43.14	($41.79)	(49.2%)
PSEG	$93.15	$44.48	($48.67)	(52.2%)
RECO	$92.61	$43.93	($48.68)	(52.6%)

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

Table 2-65 Jurisdiction day-ahead, load weighted LMP (Dollars per MWh): January through September 2008 and 2009 (See 2008 SOM, Table 2-66)

	2008 (Jan - Sep)	2009 (Jan - Sep)	Difference	Difference as Percent of 2008
Delaware	$90.25	$44.31	($45.94)	(50.9%)
Illinois	$57.63	$30.11	($27.52)	(47.8%)
Indiana	$60.44	$34.23	($26.21)	(43.4%)
Kentucky	$59.67	$35.77	($23.89)	(40.0%)
Maryland	$93.78	$45.41	($48.37)	(51.6%)
Michigan	$61.53	$35.58	($25.95)	(42.2%)
New Jersey	$93.93	$44.38	($49.55)	(52.8%)
North Carolina	$85.12	$42.71	($42.41)	(49.8%)
Ohio	$59.62	$34.56	($25.06)	(42.0%)
Pennsylvania	$79.64	$41.36	($38.28)	(48.1%)
Tennessee	$60.41	$35.96	($24.46)	(40.5%)
Virginia	$85.70	$43.12	($42.58)	(49.7%)
West Virginia	$61.14	$36.71	($24.43)	(40.0%)
District of Columbia	$93.03	$46.86	($46.17)	(49.6%)

Components of Day-Ahead, Load-Weighted LMP

Table 2-66 Components of PJM day-ahead, annual, load-weighted, average LMP: January through September 2009 (See 2008 SOM, Table 2-57)

Element	Contribution to LMP	Percent
DEC	$12.40	31.5%
INC	$11.63	29.6%
Coal	$9.15	23.3%
Gas	$2.41	6.1%
Price sensitive demand	$1.37	3.5%
VOM	$0.90	2.3%
Transaction	$0.87	2.2%
Oil	$0.74	1.9%
SO2	$0.29	0.7%
NOx	$0.10	0.2%
Misc	$0.00	0.0%
Constrained off	$0.00	0.0%
FMU adder	$0.00	0.0%
NA	($0.00)	(0.0%)
Markup	($0.50)	(1.3%)
LMP	$39.35	100.0%

Marginal Losses

Table 2-67 PJM real-time, simple average LMP components (Dollars per MWh): Calendar years 2006 through September 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	$37.42	$37.35	$0.05	$0.03

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

	2008 (Jan - Sep)				2009 (Jan - Sep)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$88.73	$71.83	$12.91	$3.99	$41.33	$37.35	$2.13	$1.85
AEP	$56.49	$71.83	($12.66)	($2.68)	$33.81	$37.35	($2.32)	($1.23)
AP	$70.91	$71.83	($0.04)	($0.88)	$38.89	$37.35	$1.62	($0.08)
BGE	$87.55	$71.83	$12.82	$2.90	$42.04	$37.35	$3.05	$1.65
ComEd	$53.10	$71.83	($15.07)	($3.66)	$28.78	$37.35	($6.24)	($2.33)
DAY	$56.89	$71.83	($13.36)	($1.57)	$33.56	$37.35	($2.99)	($0.80)
DLCO	$52.23	$71.83	($16.33)	($3.27)	$32.47	$37.35	($3.53)	($1.35)
Dominion	$83.17	$71.83	$10.47	$0.87	$40.55	$37.35	$2.60	$0.60
DPL	$84.20	$71.83	$8.88	$3.50	$42.02	$37.35	$2.67	$2.00
JCPL	$86.31	$71.83	$10.32	$4.17	$41.39	$37.35	$2.11	$1.93
Met-Ed	$81.33	$71.83	$7.44	$2.06	$40.40	$37.35	$2.21	$0.83
PECO	$81.47	$71.83	$6.78	$2.86	$40.51	$37.35	$1.88	$1.28
PENELEC	$67.83	$71.83	($3.27)	($0.72)	$37.13	$37.35	($0.04)	($0.17)
Pepco	$87.88	$71.83	$14.16	$1.89	$42.26	$37.35	$3.82	$1.09
PPL	$79.70	$71.83	$6.20	$1.67	$39.87	$37.35	$1.90	$0.63
PSEG	$86.38	$71.83	$10.35	$4.20	$41.88	$37.35	$2.53	$2.01
RECO	$84.50	$71.83	$8.90	$3.77	$40.85	$37.35	$1.73	$1.77

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

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$31.90	$37.35	($3.08)	($2.37)
AEP-DAY Hub	$33.39	$37.35	($2.57)	($1.38)
Chicago Gen Hub	$27.98	$37.35	($6.55)	($2.82)
Chicago Hub	$28.98	$37.35	($6.06)	($2.31)
Dominion Hub	$39.88	$37.35	$2.29	$0.24
Eastern Hub	$41.97	$37.35	$2.45	$2.17
N Illinois Hub	$28.60	$37.35	($6.24)	($2.51)
New Jersey Hub	$41.61	$37.35	$2.33	$1.93
Ohio Hub	$33.39	$37.35	($2.61)	($1.35)
West Interface Hub	$34.73	$37.35	($1.40)	($1.23)
Western Hub	$38.64	$37.35	$1.46	($0.18)

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

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

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$43.27	$38.98	$2.29	$1.99
AEP	$35.56	$39.65	($2.77)	($1.32)
AP	$41.49	$39.85	$1.76	($0.11)
BGE	$44.83	$39.58	$3.48	$1.77
ComEd	$30.60	$39.06	($6.09)	($2.38)
DAY	$35.30	$39.57	($3.47)	($0.81)
DLCO	$33.65	$39.05	($3.96)	($1.44)
Dominion	$43.46	$39.77	$3.04	$0.64
DPL	$45.13	$39.79	$3.14	$2.20
JCPL	$43.78	$39.46	$2.25	$2.07
Met-Ed	$43.01	$39.61	$2.49	$0.91
PECO	$42.69	$39.26	$2.06	$1.37
PENELEC	$39.03	$39.41	($0.18)	($0.20)
Pepco	$45.10	$39.43	$4.52	$1.15
PPL	$42.83	$39.89	$2.22	$0.72
PSEG	$43.74	$38.97	$2.66	$2.11
RECO	$42.91	$39.23	$1.81	$1.88
PJM	$39.57	$39.49	$0.04	$0.03

Table 2-71 PJM day-ahead, simple average LMP components (Dollars per MWh): 2006 through September 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	$37.35	$37.52	($0.07)	($0.10)

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

	2008 (Jan - Sep)				2009 (Jan - Sep)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$85.95	$71.78	$9.05	$5.12	$42.15	$37.52	$2.35	$2.29
AEP	$56.89	$71.78	($11.24)	($3.65)	$33.70	$37.52	($2.24)	($1.58)
AP	$70.23	$71.78	($0.47)	($1.08)	$38.37	$37.52	$0.83	$0.03
BGE	$87.81	$71.78	$12.50	$3.52	$42.75	$37.52	$3.24	$2.00
ComEd	$54.22	$71.78	($12.82)	($4.74)	$28.80	$37.52	($5.61)	($3.11)
DAY	$56.96	$71.78	($11.68)	($3.14)	$33.07	$37.52	($3.01)	($1.44)
DLCO	$54.88	$71.78	($12.84)	($4.06)	$32.25	$37.52	($3.73)	($1.54)
Dominion	$82.35	$71.78	$9.51	$1.07	$41.07	$37.52	$2.59	$0.97
DPL	$84.64	$71.78	$8.60	$4.27	$42.43	$37.52	$2.58	$2.33
JCPL	$86.90	$71.78	$9.18	$5.93	$41.99	$37.52	$2.07	$2.41
Met-Ed	$81.95	$71.78	$7.39	$2.78	$40.87	$37.52	$2.33	$1.03
PECO	$82.47	$71.78	$6.46	$4.23	$41.37	$37.52	$2.10	$1.76
PENELEC	$70.04	$71.78	($1.22)	($0.52)	$37.46	$37.52	$0.01	($0.06)
Pepco	$88.50	$71.78	$14.06	$2.66	$42.91	$37.52	$3.78	$1.61
PPL	$80.45	$71.78	$6.23	$2.45	$40.45	$37.52	$2.12	$0.81
PSEG	$86.72	$71.78	$8.84	$6.10	$42.56	$37.52	$2.45	$2.59
RECO	$84.94	$71.78	$7.62	$5.55	$41.51	$37.52	$1.69	$2.30

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

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

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$44.48	$39.38	$2.63	$2.47
AEP	$35.37	$39.80	($2.72)	($1.71)
AP	$40.77	$40.03	$0.72	$0.01
BGE	$45.38	$39.57	$3.66	$2.15
ComEd	$30.11	$38.88	($5.58)	($3.20)
DAY	$34.63	$39.66	($3.51)	($1.52)
DLCO	$33.33	$39.06	($4.10)	($1.64)
Dominion	$43.87	$39.81	$3.02	$1.05
DPL	$45.11	$39.66	$2.95	$2.51
JCPL	$44.22	$39.44	$2.23	$2.55
Met-Ed	$43.54	$39.75	$2.67	$1.12
PECO	$43.49	$39.32	$2.30	$1.87
PENELEC	$39.06	$39.22	($0.10)	($0.06)
Pepco	$45.43	$39.30	$4.40	$1.73
PPL	$43.14	$39.78	$2.44	$0.92
PSEG	$44.48	$39.19	$2.59	$2.71
RECO	$43.93	$39.67	$1.80	$2.45
PJM	$39.35	$39.50	($0.05)	($0.10)

Monthly Marginal Loss Costs

Table 2-74 Marginal loss costs by type (Dollars (Millions)): January through September 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	$22.8	($70.4)	$3.1	$96.3	($0.1)	($1.6)	($0.8)	$0.8	$97.0
Aug	$27.4	($87.0)	$3.3	$117.7	($0.1)	($0.9)	($1.2)	($0.3)	$117.4
Sep	$17.1	($55.6)	$2.2	$74.9	($1.0)	($0.5)	($1.2)	($1.7)	$73.2
Total	$251.6	($708.5)	$53.2	$1,013.2	($3.5)	($10.2)	($27.1)	($20.4)	$992.8

Zonal Marginal Loss Costs

Table 2-75 Marginal loss costs by control zone and type (Dollars (Millions)): January through September 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	$20.3	$3.9	$0.2	$16.6	$0.3	($0.1)	$0.1	$0.5	$17.2
AEP	($37.0)	($190.3)	$14.3	$167.6	$0.2	($0.2)	($1.2)	($0.8)	$166.8
AP	$1.8	($63.3)	$6.9	$71.9	$2.1	$3.2	($2.9)	($4.0)	$68.0
BGE	$42.4	$8.7	$0.7	$34.4	$2.1	($1.3)	($0.6)	$2.8	$37.3
ComEd	($115.7)	($314.3)	$0.2	$198.8	$0.0	($2.8)	$0.0	$2.8	$201.7
DAY	($3.3)	($42.0)	$1.0	$39.6	($0.2)	$1.7	$0.1	($1.8)	$37.9
DLCO	($16.5)	($33.7)	$0.1	$17.3	($1.9)	$0.1	($0.0)	($2.0)	$15.3
Dominion	$66.2	($33.8)	$3.0	$103.0	$1.5	($1.2)	($1.0)	$1.7	$104.7
DPL	$39.0	$6.4	$0.4	$33.0	($2.4)	($0.8)	($0.2)	($1.8)	$31.2
JCPL	$46.2	$16.9	$0.2	$29.5	$0.0	($1.7)	($0.1)	$1.6	$31.1
Met-Ed	$12.9	$1.2	$0.2	$12.0	($0.0)	($0.3)	($0.1)	$0.1	$12.1
PECO	$46.4	$8.2	$0.0	$38.3	($0.5)	($0.7)	($0.0)	$0.2	$38.4
PENELEC	($11.0)	($64.8)	$0.4	$54.2	($1.7)	$0.6	($0.1)	($2.4)	$51.7
PEPCO	$61.4	$26.7	$1.8	$36.4	($1.7)	($2.2)	($1.2)	($0.6)	$35.8
PJM	($4.3)	($31.0)	$18.4	$45.2	($0.6)	($8.4)	($16.2)	($8.3)	$36.8
PPL	$27.3	($19.3)	$1.1	$47.7	($0.3)	$0.7	$0.1	($0.8)	$46.9
PSEG	$72.7	$12.1	$4.3	$64.9	($0.6)	$3.4	($3.6)	($7.6)	$57.3
RECO	$2.7	$0.0	$0.1	$2.7	$0.0	($0.0)	($0.1)	($0.0)	$2.7
Total	$251.6	($708.5)	$53.2	$1,013.2	($3.5)	($10.2)	($27.1)	($20.4)	$992.8

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

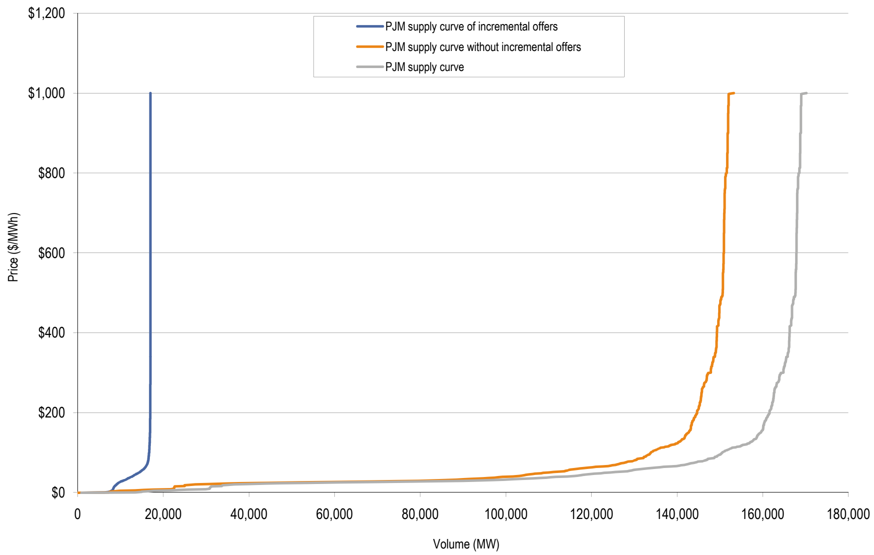
	Marginal Loss Costs by Control Zone (Millions)									
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Grand Total
AECO	$3.4	$2.0	$1.7	$1.7	$1.2	$1.3	$2.0	$2.7	$1.2	$17.2
AEP	$32.6	$22.9	$18.6	$13.1	$11.7	$17.5	$15.0	$21.9	$13.4	$166.8
AP	$18.0	$9.4	$8.4	$6.2	$4.8	$5.4	$5.0	$7.5	$3.3	$68.0
BGE	$7.0	$4.4	$4.2	$2.6	$2.8	$3.4	$4.1	$5.2	$3.4	$37.3
ComEd	$36.3	$26.1	$28.0	$19.4	$16.9	$18.4	$19.3	$21.2	$16.1	$201.7
DAY	$7.8	$4.6	$4.5	$3.3	$2.2	$3.7	$3.9	$4.4	$3.5	$37.9
DLCO	$3.5	$1.9	$2.1	$1.2	$0.7	$1.6	$1.6	$1.4	$1.3	$15.3
Dominion	$20.2	$11.8	$11.1	$7.0	$8.2	$11.5	$12.2	$14.3	$8.2	$104.7
DPL	$6.8	$4.3	$4.0	$2.9	$2.4	$2.2	$3.0	$3.4	$2.1	$31.2
JCPL	$8.3	$5.6	$3.7	$2.4	$2.1	$1.8	$2.5	$3.3	$1.4	$31.1
Met-Ed	$2.4	$1.4	$1.2	$0.9	$0.8	$1.4	$1.4	$1.6	$1.1	$12.1
PECO	$8.0	$4.3	$3.5	$2.6	$2.9	$4.1	$4.1	$5.6	$3.4	$38.4
PENELEC	$12.1	$5.6	$4.3	$4.1	$5.0	$5.6	$5.9	$6.0	$3.2	$51.7
PEPCO	$6.0	$3.6	$4.3	$3.1	$2.8	$3.7	$4.1	$5.0	$3.2	$35.8
PJM	$14.1	$6.0	$4.8	$2.0	$3.2	$1.3	$2.6	$2.2	$0.8	$36.8
PPL	$10.1	$6.5	$5.5	$3.8	$3.0	$4.5	$4.9	$5.1	$3.6	$46.9
PSEG	$10.1	$8.8	$7.1	$6.0	$5.1	$4.9	$5.3	$6.1	$4.0	$57.3
RECO	$0.6	$0.4	$0.3	$0.3	$0.2	$0.2	$0.2	$0.3	$0.2	$2.7
Total	$207.3	$129.7	$117.2	$82.6	$76.0	$92.3	$97.0	$117.4	$73.2	$992.8

Virtual Offers and Bids

Table 2-77 Type of day-ahead marginal units: January through September 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%
Jul	12.4%	34.8%	31.2%	20.9%	0.7%
Aug	11.5%	29.4%	36.5%	22.2%	0.4%
Sep	12.8%	33.3%	25.7%	27.5%	0.6%
Annual	15.0%	35.1%	29.8%	19.4%	0.7%

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



Price Convergence

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

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
Average	$37.35	$37.42	$0.08	0.2%
Median	$35.29	$33.00	($2.29)	(7.0%)
Standard deviation	$14.32	$17.92	$3.60	20.1%

Table 2-79 Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): Calendar years 2000 through September 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	$37.35	$37.42	$0.08	0.2%

Table 2-80 Frequency distribution by hours of PJM real-time and day-ahead LMP difference (Dollars per MWh): 2005 through September 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	0.05%
($50) to $0	5,015	57.99%	5,205	59.54%	4,600	52.89%	5,120	59.30%	3,776	57.69%
$0 to $50	3,471	97.61%	3,372	98.04%	3,827	96.58%	3,247	96.27%	2,736	99.45%
$50 to $100	190	99.78%	152	99.77%	255	99.49%	284	99.50%	34	99.97%
$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 September 2009 (See 2008 SOM, Figure 2-17)

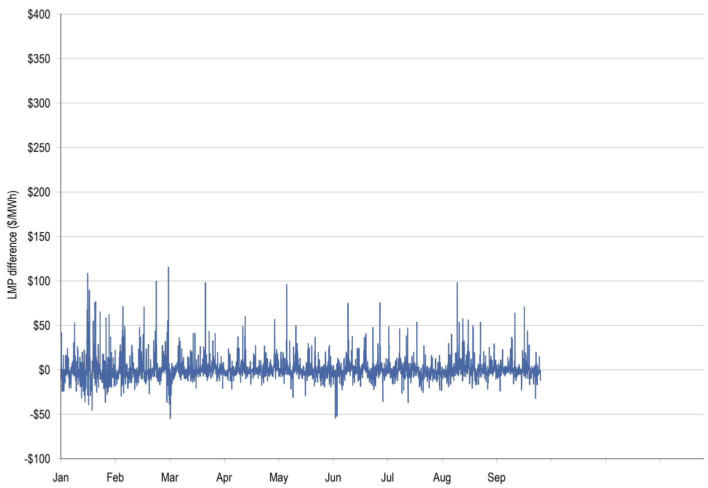


Figure 2-19 Monthly average of real-time minus day-ahead LMP: January through September 2009 (See 2008 SOM, Figure 2-18)

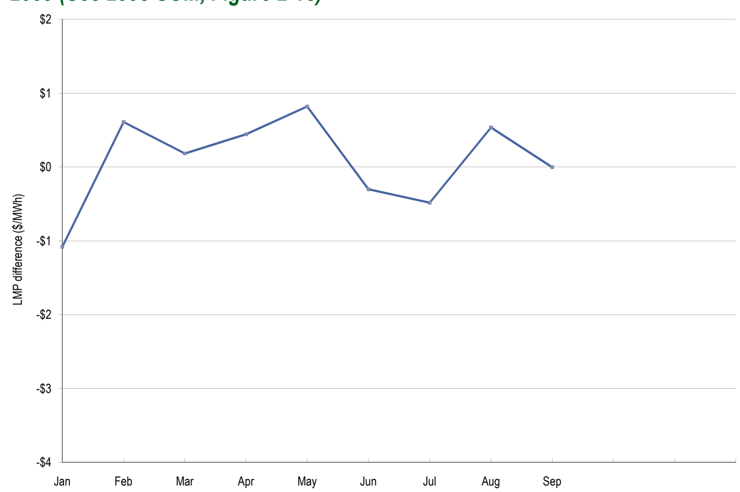
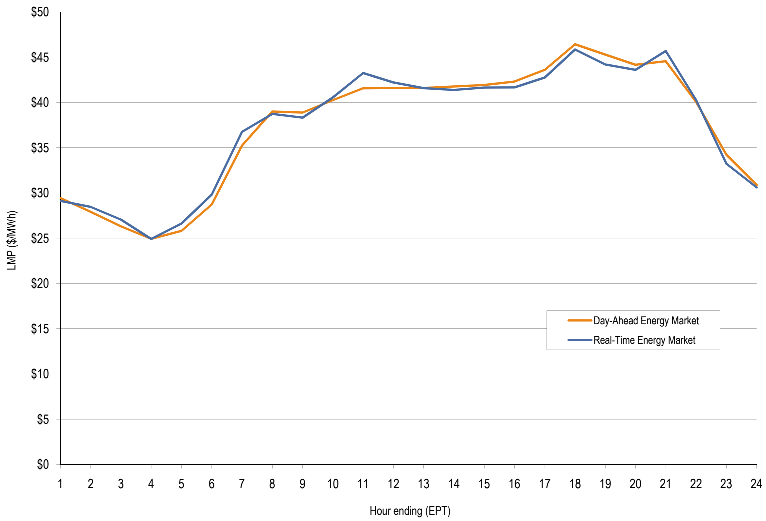


Figure 2-20 PJM system hourly average LMP: January through September 2009 (See 2008 SOM, Figure 2-19)



Zonal Price Convergence

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

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$42.15	$41.33	($0.82)	(2.0%)
AEP	$33.70	$33.81	$0.11	0.3%
AP	$38.37	$38.89	$0.52	1.3%
BGE	$42.75	$42.04	($0.71)	(1.7%)
ComEd	$28.80	$28.78	($0.02)	(0.1%)
DAY	$33.07	$33.56	$0.49	1.5%
DLCO	$32.25	$32.47	$0.22	0.7%
Dominion	$41.07	$40.55	($0.52)	(1.3%)
DPL	$42.43	$42.02	($0.41)	(1.0%)
JCPL	$41.99	$41.39	($0.60)	(1.4%)
Met-Ed	$40.87	$40.40	($0.48)	(1.2%)
PECO	$41.37	$40.51	($0.86)	(2.1%)
PENELEC	$37.46	$37.13	($0.33)	(0.9%)
Pepco	$42.91	$42.26	($0.65)	(1.5%)
PPL	$40.45	$39.87	($0.58)	(1.5%)
PSEG	$42.56	$41.88	($0.67)	(1.6%)
RECO	$41.51	$40.85	($0.66)	(1.6%)

Price Convergence by Jurisdiction

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

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Delaware	$41.81	$41.56	($0.25)	(0.6%)
Illinois	$28.80	$28.78	($0.02)	(0.1%)
Indiana	$33.14	$33.26	$0.11	0.3%
Kentucky	$33.41	$33.63	$0.21	0.6%
Maryland	$42.64	$42.03	($0.61)	(1.5%)
Michigan	$34.41	$34.48	$0.06	0.2%
New Jersey	$42.33	$41.65	($0.67)	(1.6%)
North Carolina	$40.03	$39.56	($0.46)	(1.2%)
Ohio	$33.00	$33.33	$0.33	1.0%
Pennsylvania	$39.29	$38.86	($0.42)	(1.1%)
Tennessee	$33.90	$33.69	($0.22)	(0.6%)
Virginia	$40.37	$39.83	($0.54)	(1.3%)
West Virginia	$34.79	$35.00	$0.22	0.6%
District of Columbia	$44.06	$43.74	($0.32)	(0.7%)

Load and Spot Market

Real-Time Load and Spot Market

Table 2-83 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: 2008 through September 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%	12.6%	16.9%	70.5%	(1.2%)	(3.7%)	4.8%
Aug	14.9%	22.6%	62.4%	11.7%	16.0%	72.3%	(3.2%)	(6.6%)	9.9%
Sep	14.7%	23.0%	62.2%	12.5%	18.1%	69.4%	(2.3%)	(4.9%)	7.2%
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%	13.0%	16.6%	70.4%	(1.7%)	(3.5%)	5.2%

Day-Ahead Load and Spot Market

Table 2-84 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: 2008 through September 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%	5.6%	16.3%	78.2%	(0.0%)	(4.2%)	4.2%
Aug	4.9%	20.2%	75.0%	5.1%	15.5%	79.3%	0.3%	(4.6%)	4.4%
Sep	5.4%	19.3%	75.3%	4.7%	16.3%	78.9%	(0.7%)	(2.9%)	3.6%
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%	4.7%	14.5%	80.8%	(0.3%)	(4.0%)	4.3%

Virtual Markets

Increment Offers and Decrement Bids

Table 2-85 Monthly volume of cleared and submitted INCs, DECs: January through September 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	12,187	17,654	314	821	14,554	19,322	483	808
Aug	12,347	22,931	433	1,020	16,626	23,788	641	1,069
Sep	13,936	22,417	459	993	16,736	23,268	480	957
Oct								
Nov								
Dec								
Annual	12,873	20,145	416	796	15,353	22,150	491	778

Demand-Side Response (DSR)

Emergency Program

Table 2-86 Zonal capability in the Emergency Program for the 2009 peak day through September (By option): August 10, 2009 (See 2008 SOM, Table 2-86)

	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	445	473.4	46	40.6
DPL	0	0.0	168	123.0	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

Table 2-87 Zonal monthly capacity credits: January through September 2009 (See 2008 SOM, Table 2-87)

Zone	January	February	March	April	May	June	July	August	September
AECO	$154,551	$139,595	$154,551	$149,566	$154,551	$375,086	$387,589	$387,589	$375,086
AEP	$2,578,133	$2,328,636	$2,578,133	$2,494,967	$2,578,133	$3,746,728	$3,871,619	$3,871,619	$3,746,728
APS	$966,835	$873,270	$966,835	$935,647	$966,835	$2,982,596	$3,082,016	$3,082,016	$2,982,596
BGE	$2,882,161	$2,603,243	$2,882,161	$2,789,189	$2,882,161	$4,464,694	$4,613,517	$4,613,517	$4,464,694
ComEd	$3,294,602	$2,975,769	$3,294,602	$3,188,324	$3,294,602	$4,217,299	$4,357,876	$4,357,876	$4,217,299
DAY	$258,904	$233,849	$258,904	$250,552	$258,904	$646,419	$667,966	$667,966	$646,419
DLCO	$258,489	$233,474	$258,489	$250,151	$258,489	$375,138	$1,655,820	$1,655,820	$375,138
Dominion	$296,319	$267,643	$296,319	$286,760	$296,319	$1,602,407	$1,004,045	$1,004,045	$1,602,407
DPL	$665,561	$601,152	$665,561	$644,091	$665,561	$971,656	$387,642	$387,642	$971,656
JCPL	$554,279	$500,639	$554,279	$536,399	$554,279	$868,932	$897,896	$897,896	$868,932
Met-Ed	$681,734	$615,760	$681,734	$659,743	$681,734	$1,313,605	$1,357,392	$1,357,392	$1,313,605
PECO	$1,375,581	$1,242,460	$1,375,581	$1,331,207	$1,375,581	$2,052,483	$2,120,899	$2,120,899	$2,052,483
PENELEC	$283,241	$255,831	$283,241	$274,105	$283,241	$1,282,941	$1,324,705	$1,324,705	$1,282,941
Pepco	$572,160	$516,789	$572,160	$553,703	$572,160	$788,433	$814,714	$814,714	$788,433
PPL	$1,200,552	$1,084,370	$1,200,552	$1,161,825	$1,200,552	$3,500,850	$3,617,545	$3,617,545	$3,500,850
PSEG	$922,290	$833,036	$922,290	$892,538	$922,290	$1,720,276	$1,777,619	$1,777,619	$1,720,276
RECO	$10,219	$9,230	$10,219	$9,890	$10,219	$17,897	$18,494	$18,494	$17,897
Total	$16,955,611	$15,314,746	$16,955,611	$16,408,656	$16,955,611	$30,927,439	$31,957,354	$31,957,354	$30,927,439

Economic Program

Table 2-88 Economic Program registration on the last day of the month: January 2007 through September 2009[10,11] (New Table)

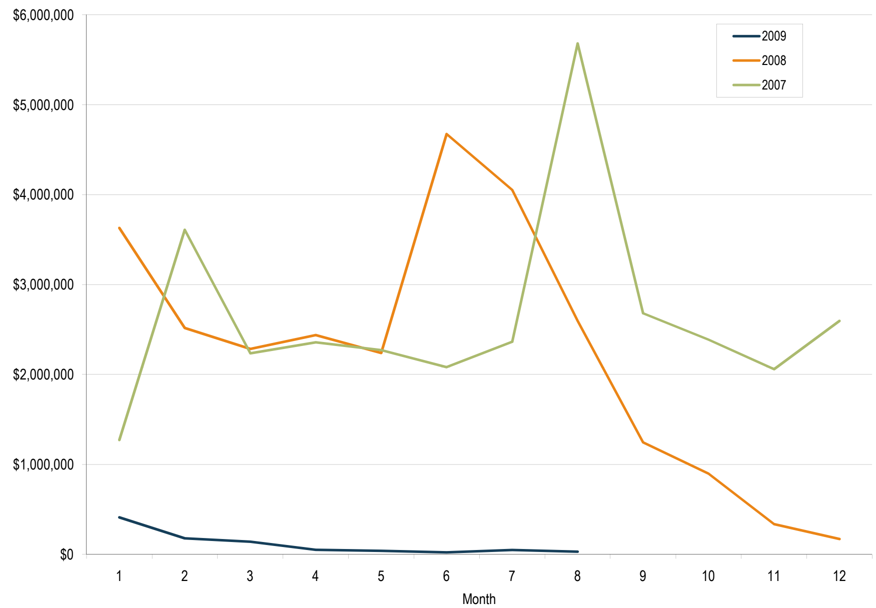
	2007		2008		2009	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	508	1,530	4,906	2,959	4,862	3,303
Feb	953	1,567	4,902	2,961	4,869	3,219
Mar	959	1,578	4,972	3,012	4,867	3,227
Apr	980	1,648	5,016	3,197	2,582	3,242
May	996	3,674	5,069	3,588	1,250	2,860
Jun	2,490	2,168	3,112	3,014	1,265	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		
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	2,721	2,904

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 Table 2-88 reflects distinct registration counts. It does not reflect the number of distinct sites registered for the Economic Program, as multiple sites may be aggregated within a single registration.

Table 2-89 Distinct Registrations and Sites in the Economic Program: August 10, 2009[12] (See 2008 SOM, Table 2-89)

	Registrations	Sites	MW
AECO	38	38	17.7
AEP	15	15	201.7
AP	88	88	212.3
BGE	139	139	645.3
ComEd	318	318	276.4
DAY	5	5	10.6
DLCO	28	28	226.2
Dominion	93	93	131.2
DPL	67	67	71.1
JCPL	38	41	101.3
Met-Ed	41	41	60.9
PECO	160	160	147.0
PENELEC	39	39	31.2
Pepco	22	23	20.3
PPL	136	142	266.6
PSEG	91	92	65.8
RECO	3	3	1.0
Total	1,321	1,332	2,486.6

Figure 2-21 Economic Program Payments: Calendar years 2007 (without incentive payments), 2008 and January through September of 2009[13,14] (See 2008 SOM, Figure 2-20)



12 Effective July 1, 2009, PJM implemented a new eSuite application, Load Response System (eLRS) to serve as the interface for collecting and storing customer registration and settlement data. With the implementation of the LRS system, more detail is available on customer registrations and, as a result, there is an enhanced ability to capture multiple distinct locations aggregated to a single registration. The second column of Table 2-89 reflects the number of registered end-user sites, including sites that are aggregated to a single registration.

13 All August and September 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.

14 In the September billing cycle, PJM Market Settlements encountered an error in which prior settled amounts in the Economic Load Response Program were paid again for several CSPs. PJM Market Settlements notified all affected CSPs of the billing error and made the appropriate adjustments in the October 2009 bill. All Economic Load Response credit and reduction data in this report were provided by PJM as of October 13, 2009. Data in this report reflect the corrected amounts.

Table 2-90 PJM Economic Program by zonal reduction: January through September 2009[15] (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	38	$1,149	144				4	$117	15	43	$1,266	159
AEP	3,895	$53,692	247	1,317	$25,038	22				5,212	$78,730	269
AP	1,322	$27,046	251				10	$562	11	1,332	$27,608	262
BGE	49	$2,291	208							49	$2,291	208
ComEd	336	$316	146				723	$4,369	822	1,059	$4,684	968
DAY												
DLCO												
Dominion	4,597	$205,728	824	74	$674	44	155	$6,094	137	4,825	$212,496	1,005
DPL	10	$414	246							10	$414	246
JCPL							9	$248	30	9	$248	30
Met-Ed	66	$3,218	96				5	$255	17	72	$3,474	113
PECO	7,207	$153,200	12,332				213	$14,254	1,104	7,420	$167,454	13,436
PENELEC	863	$6,661	116				2	$47	6	865	$6,708	122
Pepco	131	$4,341	83				39	$1,753	71	170	$6,094	154
PPL	9,568	$319,582	3,586	2,182	$65,196	365	172	$14,954	336	11,922	$399,733	4,287
PSEG	296	$4,139	266				5	$177	32	301	$4,316	298
RECO	1	$12	24							1	$12	24
Total	28,381	$781,790	18,569	3,573	$90,909	431	1,337	$42,832	2,581	33,290	$915,530	21,581
Max	9,568	$319,582	12,332	2,182	$65,196	365	723	$14,954	1,104	11,922	$399,733	13,436
Avg	2,027	$55,842	1,326	1,191	$30,303	144	122	$3,894	235	2,219	$61,035	1,439

Table 2-91 Settlement days submitted by month in the Economic Program: 2007, 2008 and January through September 2009 (New Table)

Month	2007	2008	2009
Jan	937	2,916	1,264
Feb	1,170	2,811	654
Mar	1,255	2,818	574
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	
Nov	2,842	1,105	
Dec	2,675	986	
Total	26,423	32,316	15,683

15 While total credits in Table 2-90 for the period January through September 2009 match the Demand Response Steering Committee (DRSC) October 13, 2009 report, the number of MWh and the amount of credits identified as Real-Time Self-Scheduled, Real-Time Dispatch, and Day Ahead activities do not agree. Monitoring Analytics has requested that PJM verify results.

Table 2-92 Distinct customers and CSPs submitting settlements in the Economic Program by month: Calendar years 2007, 2008 and January through September 2009 (New Table)

	2007		2008		2009	
Month	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers
Jan	11	72	13	261	17	257
Feb	10	89	13	243	12	129
Mar	9	87	11	216	11	149
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		
Nov	10	204	14	208		
Dec	11	243	13	193		
Total Distinct Active	21	405	24	522	25	747

Table 2-93 Hourly frequency distribution of Economic Program MWh reductions and credits: January through September 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	450	1.35%	450	1.35%	$6,262	0.68%	$6,262	0.68%
2	462	1.39%	912	2.74%	$6,312	0.69%	$12,574	1.37%
3	492	1.48%	1,404	4.22%	$7,725	0.84%	$20,299	2.22%
4	518	1.56%	1,922	5.77%	$7,922	0.87%	$28,222	3.08%
5	535	1.61%	2,457	7.38%	$8,607	0.94%	$36,828	4.02%
6	565	1.70%	3,022	9.08%	$11,974	1.31%	$48,803	5.33%
7	1,691	5.08%	4,713	14.16%	$86,917	9.49%	$135,719	14.82%
8	2,073	6.23%	6,786	20.39%	$104,820	11.45%	$240,540	26.27%
9	1,944	5.84%	8,730	26.23%	$68,294	7.46%	$308,834	33.73%
10	1,661	4.99%	10,391	31.21%	$55,288	6.04%	$364,122	39.77%
11	1,561	4.69%	11,952	35.90%	$51,343	5.61%	$415,465	45.38%
12	1,483	4.45%	13,435	40.36%	$36,595	4.00%	$452,060	49.38%
13	1,527	4.59%	14,962	44.94%	$33,076	3.61%	$485,136	52.99%
14	1,719	5.16%	16,680	50.11%	$33,879	3.70%	$519,015	56.69%
15	1,643	4.94%	18,323	55.04%	$30,866	3.37%	$549,880	60.06%
16	1,714	5.15%	20,037	60.19%	$28,436	3.11%	$578,316	63.17%
17	1,996	6.00%	22,033	66.18%	$39,447	4.31%	$617,763	67.48%
18	2,233	6.71%	24,266	72.89%	$59,268	6.47%	$677,031	73.95%
19	2,153	6.47%	26,419	79.36%	$62,739	6.85%	$739,770	80.80%
20	2,089	6.28%	28,509	85.64%	$59,315	6.48%	$799,085	87.28%
21	1,901	5.71%	30,410	91.35%	$65,079	7.11%	$864,164	94.39%
22	1,298	3.90%	31,708	95.25%	$29,106	3.18%	$893,270	97.57%
23	868	2.61%	32,576	97.86%	$13,511	1.48%	$906,780	99.04%
24	714	2.14%	33,290	100.00%	$8,750	0.96%	$915,530	100.00%

Table 2-94 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): January through September 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	487	1.46%	487	1.46%	$300	0.03%	$300	0.03%
$25 to $50	17,241	51.79%	17,728	53.25%	$203,256	22.20%	$203,555	22.23%
$50 to $75	7,303	21.94%	25,031	75.19%	$163,412	17.85%	$366,967	40.08%
$75 to $100	3,949	11.86%	28,980	87.05%	$162,043	17.70%	$529,010	57.78%
$100 to $125	1,917	5.76%	30,896	92.81%	$116,528	12.73%	$645,538	70.51%
$125 to $150	1,162	3.49%	32,058	96.30%	$97,590	10.66%	$743,128	81.17%
$150 to $200	829	2.49%	32,887	98.79%	$98,745	10.79%	$841,872	91.95%
$200 to $250	334	1.00%	33,221	99.79%	$54,219	5.92%	$896,091	97.88%
$250 to $300	10	0.03%	33,231	99.82%	$2,248	0.25%	$898,339	98.12%
> $300	59	0.18%	33,290	100.00%	$17,192	1.88%	$915,530	100.00%

Load Management (LM)

Table 2-95 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	999.4	6,295.0	7,294.9

Table 2-96 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	518.5
2009/2010	906.9	865.2
2010/2011	935.6	908.1
2011/2012	1,597.3	1,319.5
2012/2013	9,535.4	6,824.1