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 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 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.

Overview

Market Structure

- **Supply.** During the June to September 2009 summer period, the PJM Energy Market received an hourly average of 153,520 MW in supply offers including hydroelectric generation.[3] The summer 2009 average daily offered supply was 1,439 MW lower than the summer 2008 average daily offered supply of 154,959 MW. An extended outage at a nuclear power plant was the primary cause of the decrease. Lower fuel prices in the 2009 summer period resulted in a shift down of the 2009 summer period supply curve.

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

2 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment M: Market Monitoring Plan," First Revised Sheet No. 448.05 (Effective June 29, 2009).

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.

- **Demand.** The PJM system peak load in 2009 was 126,805 MW in the hour ended 1700 EPT on August 10, 2009, while the PJM peak load in 2008 was 130,100 MW in the hour ended 1700 EPT on June 9, 2008.[4] The 2009 peak load was 3,295 MW, or 2.5 percent, lower than the 2008 peak load. This is the lowest annual peak load since the last transmission system integration.

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

- **Local Market Structure and Offer Capping.** Noncompetitive local market structure is the trigger for offer capping. PJM applied a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in 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 in 2009, lower from 0.2 percent in 2008. In the Real-Time Energy Market offer-capped unit hours fell from 1.0 percent in 2008 to 0.4 percent in 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 100 or more hours during calendar year 2009. In 2009, the AECO, AEP, AP, BGE, ComEd, DLCO, Dominion, PECO, PENELEC, Pepco and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 100 or more hours. The analysis of the application of the three pivotal supplier test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.

4 For the purpose of Volume I and Volume II of the *2009 State of the Market Report for PJM*, all hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See Appendix N, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

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 -$2.38 per MWh, or -6.1 percent. Coal steam units contributed -$2.54, or 106.7 percent, to the total markup component of LMP. Combined cycle units that use gas as their primary fuel source contributed -$0.00 or 0.2 percent to the total markup component of LMP. The markup was -$1.67 per MWh during peak hours and -$3.15 per MWh during off-peak hours.

  The markup component of the overall PJM day-ahead, load-weighted, average LMP was -$1.65 per MWh, or -4.2 percent. Coal steam units contributed -$1.53 or 93.0 percent to the total markup component of LMP. Natural gas steam units contributed -$0.12 or 7.4 percent to the total markup component of LMP. The markup was -$1.12 per MWh during peak hours and -$2.22 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 2009 by 4.4 percent from 2008, falling from 79,515 MW to 76,035 MW. PJM day-ahead load decreased in 2009 by 7.1 percent from 2008, falling from 95,522 MW to 88,707 MW.

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

  PJM Real-Time Energy Market prices decreased in 2009 compared to 2008. The system simple average LMP was 44.1 percent lower in 2009 than in 2008, $37.08 per MWh versus $66.40 per MWh. The load-weighted LMP was 45.1 percent lower in 2009 than 2008, $39.05 per MWh versus $71.13 per MWh. The real-time fuel cost adjusted, load-weighted, average LMP was 10.5 percent lower in 2009 than the load-weighted, average LMP in 2008, $63.66 per MWh compared to $71.13 per MWh. In other words, if fuel costs for 2009 had been the same as 2008, the 2009 load-weighted LMP would have been higher, $63.66 per MWh, instead of the observed $39.05 per MWh, and 10.5 percent lower than the load-weighted average LMP for 2008. Fuel costs and lower loads in 2009 contributed to downward pressure on LMP.

PJM Day-Ahead Energy Market prices decreased in 2009 compared to 2008. The system simple average LMP was 44.0 percent lower in 2009 than in 2008, $37.00 per MWh versus $66.12 per MWh. The load-weighted LMP was 44.7 percent lower in 2009 than in 2008, $38.82 per MWh versus $70.25 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 could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In 2009, 12.9 percent of real-time load was supplied by bilateral contracts, 17.0 percent by spot market purchases and 70.1 percent by self-supply. Compared with 2008, reliance on bilateral contracts decreased by 1.8 percentage points; reliance on spot supply decreased by 3.1 percentage points; and reliance on self-supply increased by 4.9 percentage points in 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.

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

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

- **Demand-Side Response Activity.** In 2009, in the Economic Program, participation decreased compared to 2008. There were decreases in a range of activity metrics including registrations, settlements submitted, settled MWh and credits. There were many factors contributing to lower levels of participation and lower revenues in the Economic Program, including lower price levels in 2009, lower load levels and improved measurement and verification. On the peak load day, August 10, 2009, there were 2,486.6 MW in the Economic Load Response Program.

  In 2009, the Emergency Program, specifically, the Load Management (LM) Program, participation increased compared to 2008. For the 2009/2010 delivery year, there were 7,294.3 MW registered in the LM Program, compared to 4498.2 MW registered in the 2008/2009 delivery year.

Since the introduction of the capacity market on June 1, 2007 the capacity market has been the source of growth in total demand side revenues and demand side revenues from the capacity market were the only significant source of revenue in 2009. In 2009, payments from the Economic Program decreased from 2008 by $26 million or 96 percent, from $27.7 million to $1.2 million, while capacity revenue increased from 2008 by $161 million or 114 percent, from $141 million to $303 million since 2008. Synchronized Reserve credits decreased by $1.1 million, from $5.1 million to $4.0 million from 2008 to 2009.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance for the year 2009, including aggregate supply and demand, concentration ratios, local market concentration ratios, price-cost markup, offer capping, participation in demand-side response programs, loads and prices in this section of the report. The next section continues the analysis of the PJM Energy Market including additional measures of market performance.

Aggregate supply decreased by about 1,439 MW when comparing the summer months of 2009 to the summer months of 2008 while aggregate peak load decreased by 3,295 MW, modifying the general supply demand balance from 2008 with a corresponding impact on Energy Market prices. Overall load was also lower than in 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 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 2009 was $39.05, or 45.1 percent lower than the load-weighted, average LMP for 2008, which was $71.13. The real-time fuel cost adjusted, load-weighted, average LMP was 10.5 percent lower in 2009 than the load-weighted, average LMP in 2008, $63.66 per MWh compared to $71.13 per MWh. In other words, if fuel costs for 2009 had been the same as 2008, the 2009 load-weighted LMP would have been higher, $63.66 per MWh, instead of the observed $39.05 per MWh, and 10.5 percent lower than the load-weighted average LMP for 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 2009.

Market Structure

Supply

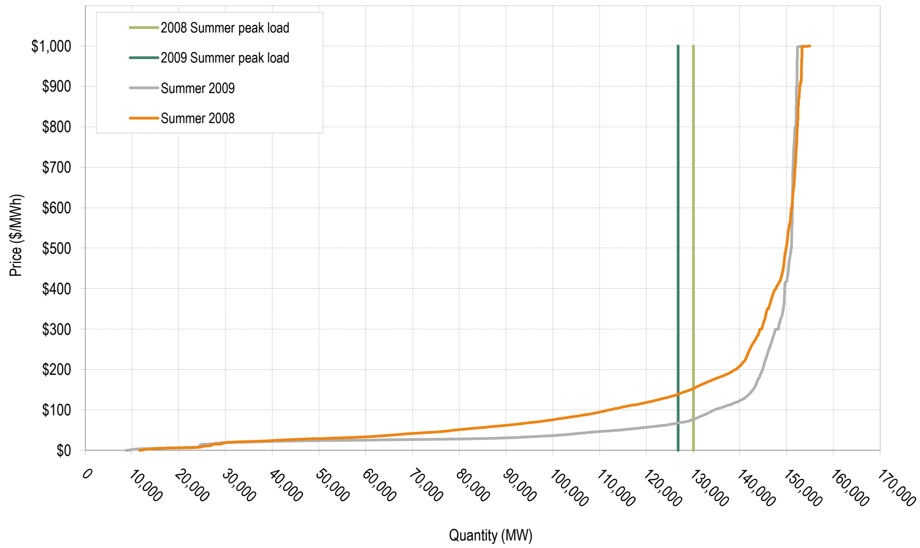
During the June to September 2009 summer period, the PJM Energy Market received a daily average of 153,520 MW in total supply offers including hydroelectric generation. The summer 2009 average daily offered supply was 1,439 MW lower than the summer 2008 average daily offered supply of 154,959 MW. An extended outage at a nuclear power plant was the primary cause of the decrease. American Electric Power’s Cook Nuclear Plant Unit 1, for example, was on a full outage for the entire summer.[5] Other outages, mainly of coal units in the western PJM region, contributed to the decreases in offered supply. The 2009 summer period outages were partially offset by the addition of 1,881.5 MW (full capacity) of wind generation.

During the summer of 2009, the peak demand was 3,295 MW, or 2.5 percent, lower than the 2008 peak, which, when combined with the shift down of the 2009 supply curve, resulted in a lower price level at the intersection of supply and demand. (See Figure 2-1)

5 “AEP´s Cook Nuclear Unit 1 Reaches Full Reactor Power.” AEP press release, December 23, 2009. <http://www.aep.com/newsroom/newsreleases/?id=1582>.

Supply offer prices for the summer of 2009 were lower than those in 2008 primarily due to a decline in fuel costs in the PJM region. All fuel types experienced price decreases, including a 33.2 percent decrease in coal prices, a 65.9 percent decrease in natural gas prices, and a 45.8 percent decrease in oil-related commodity prices.[6]

Figure 2-1 Average PJM aggregate supply curves: Summers 2008 and 2009



Total internal capacity in the RPM auction for the 2008/2009 delivery year increased 350.2 MW from 156,968.0 MW on June 1, 2008, to 157,318.2 MW on June 1, 2009.[7] This increase was the result of 439.2 MW of new generation, 74.1 MW of generation uprates, and 220.6 MW of demand resource (DR) mods, offset in part by 383.7 MW from higher EFORds. In the 2008/2009 auction, 15 more generating resources made offers than in the 2007/2008 RPM Auction. The increase included five new wind resources (66.1 MW), three new diesel resources (23.3 MW) and two resources (112.6 MW) which came out of retirement while the remaining five resources were the result of a reclassification of external resources. In 2009, 1,881.5 MW of non-derated wind capacity also entered service in PJM, which is not accounted for in the RPM auction. There were no unit retirements in 2009.

The net result of these factors was that the summer 2009 average aggregate supply curve shifted down.

Demand

Table 2-1 shows the actual coincident summer peak loads for the years 1999 through 2009. The 2009 actual summer peak load of 126,805 was 3,295 MW less than the 2008 summer peak load of 130,100 MW and was the lowest peak demand since 2005, the year of the last transmission

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

7 Unless otherwise specified, all volumes are in terms of UCAP.

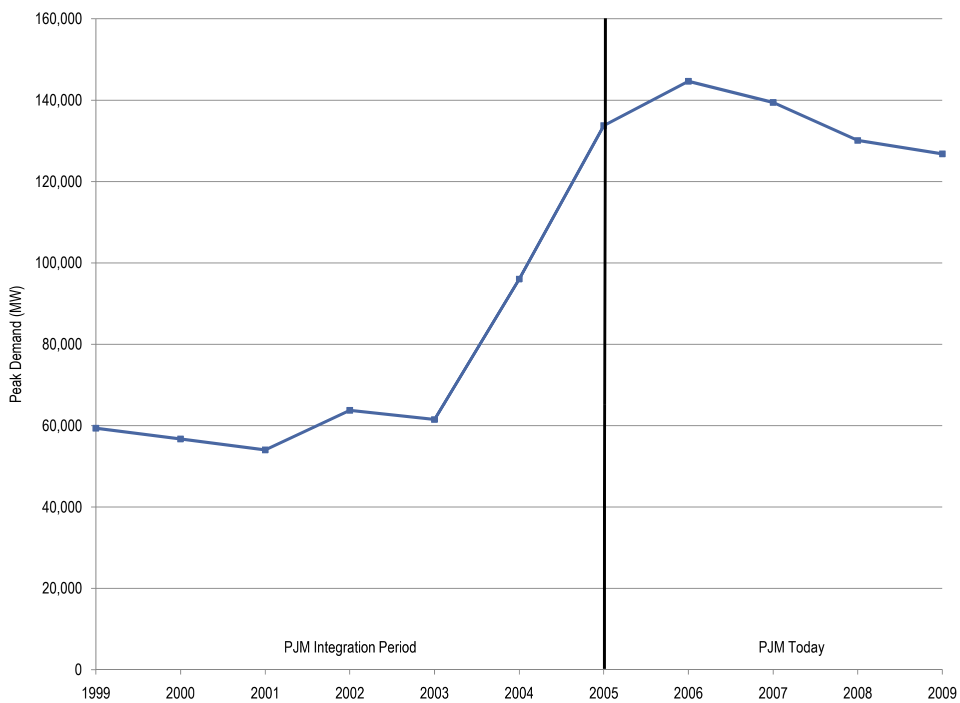
system integrations (Duquesne Light and Dominion) into PJM. This measure of peak load is the total amount of generation output and net energy imports required to meet the peak demand on the system, including losses, rather than the actual load served.[8]

Table 2-1 Actual PJM footprint summer peak loads: 1999 to 2009

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Difference (MW)	Difference (%)
1999	Jul 6, 1999	1400	59,365	NA	NA
2000	Jun 26, 2000	1600	56,727	(2,638)	(4.4%)
2001	Aug 9, 2001	1500	54,015	(2,712)	(4.8%)
2002	Aug 14, 2002	1600	63,762	9,747	18.0%
2003	Aug 22, 2003	1600	61,499	(2,263)	(3.5%)
2004	Dec 20, 2004	1900	96,016	34,517	56.1%
2005	Jul 26, 2005	1600	133,761	37,746	39.3%
2006	Aug 2, 2006	1700	144,644	10,883	8.1%
2007	Aug 8, 2007	1600	139,428	(5,216)	(3.6%)
2008	Jun 9, 2008	1700	130,100	(9,328)	(6.7%)
2009	Aug 10, 2009	1700	126,805	(3,295)	(2.5%)

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

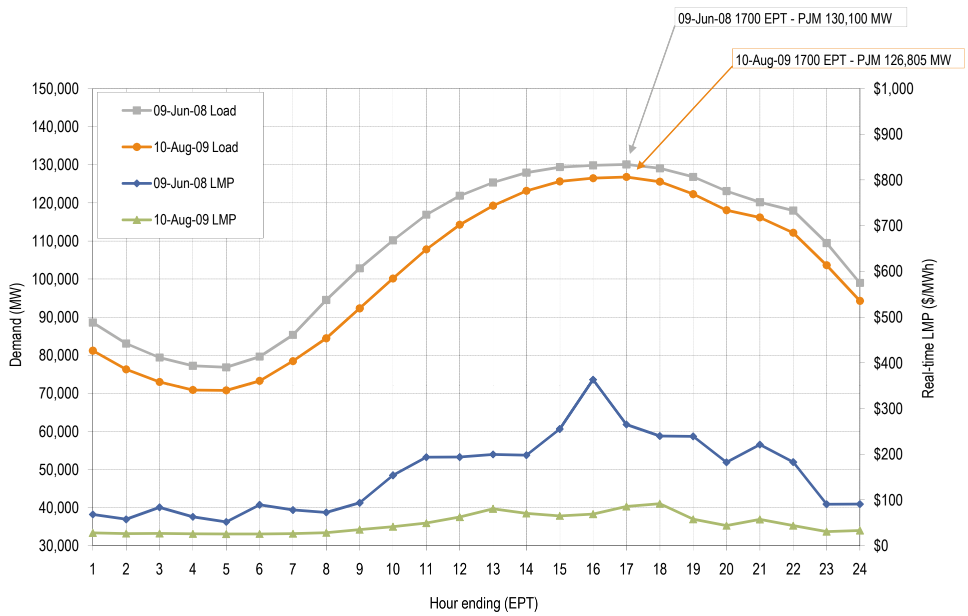
Figure 2-2 Actual PJM footprint summer peak loads: 1999 to 2009



8 Peak loads shown are eMTR load. See the *2009 State of the Market Report for PJM*, Volume II, Appendix I, "Load Definitions," for detailed definitions of load.

The hourly load and average PJM LMP for the 2009 and 2008 summer peak days are shown in Figure 2-3. The peak for 2009 occurred on August 10, at hour ending 1700. The hourly integrated LMP for this hour was $85.64 per MWh. The peak for 2008 occurred on June 9, at hour ending 1700. The hourly integrated LMP for this hour was $265.19 per MWh.

Figure 2-3 PJM summer peak-load comparison: Monday, August 10, 2009, and Monday, June 9, 2008



Market Concentration

During 2009, concentration in the PJM Energy Market was moderate overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.[9] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal during high demand periods. When transmission constraints exist, local markets are created with ownership that is typically significantly more concentrated than the overall Energy Market. PJM offer-capping rules that limit the exercise of local market power and generation owners' obligations to serve load were effective in most cases in preventing the exercise of market power in these areas during 2009. If those obligations were to change or the rules were to change, however, the market power related incentives and impacts would change as a result.

Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate that comparatively small numbers of sellers dominate a market; low concentration ratios mean larger numbers of sellers split market sales more equally. The best tests of market competitiveness are direct tests of the conduct of individual participants and their

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

impact on price. The direct examination of offer behavior by individual market participants is one such test. Low aggregate market concentration ratios establish neither that a market is competitive nor that participants are unable to exercise market power. High concentration ratios do, however, indicate an increased potential for participants to exercise market power.

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

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

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

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

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

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during 2009 was moderately concentrated. (See Table 2-2). Based on the hourly Energy Market measure, average HHI was 1242 with a minimum of 935 and a maximum of 1628 in 2009. The highest hourly market share was 32 percent and the highest average market share for 2009 was 22 percent.

10 77 FERC ¶ 61,263, "Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement," Order No. 592, pp. 64-70.

Table 2-2 PJM hourly Energy Market HHI: Calendar year 2009[11]

	Hourly Market HHI
Average	1242
Minimum	935
Maximum	1628
Highest market share (One hour)	32%
Highest market share (All hours)	22%
# Hours	8760
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

Table 2-3 includes 2009 HHI values by supply curve segment, including base, intermediate and peaking plants. The hourly measure indicates that, on average, intermediate and peaking segments of the supply curve are highly concentrated, while the baseload segment is moderately concentrated.

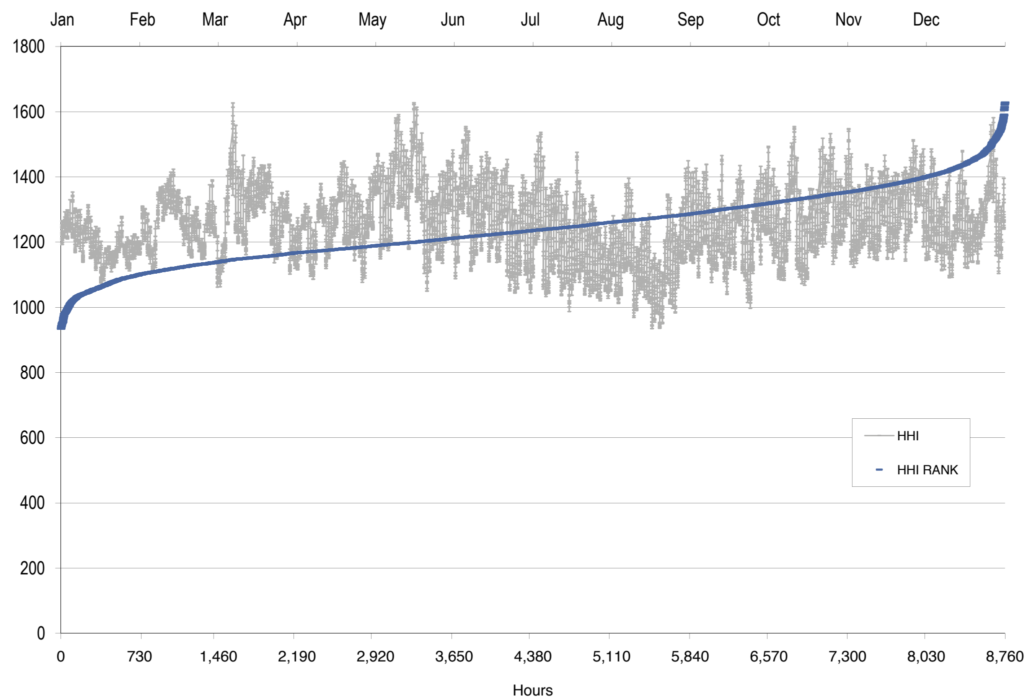
Table 2-3 PJM hourly Energy Market HHI (By segment): Calendar year 2009

	Minimum	Average	Maximum
Base	1117	1273	1616
Intermediate	872	1954	7176
Peak	669	5644	10000

Figure 2-4 presents the 2009 hourly HHI values in chronological order and an HHI duration curve that shows 2009 HHI values in ascending order of magnitude. The HHI values were in the unconcentrated range for 0.8 percent of the hours while HHI values were in the moderately concentrated range in the remaining 99.2 percent of hours, with a maximum value of 1628, as shown in Table 2-2.

11 This analysis includes all hours of 2009, regardless of congestion.

Figure 2-4 PJM hourly Energy Market HHI: Calendar year 2009



Local Market Structure and Offer Capping

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

PJM has clear rules limiting the exercise of local market power.[12] The rules provide for offer capping when conditions on the transmission system create a structurally noncompetitive local market (as measured by the three pivotal supplier test), when units in that local market have made noncompetitive offers and when such offers would set the price above the competitive level in the absence of mitigation. Offer caps are set at the level of a competitive offer. Offer-capped units receive the higher of the market price or their offer cap. Thus, if broader market conditions lead to a price greater than the offer cap, the unit receives the higher market price. The rules governing the exercise of local market power recognize that units in certain areas of the system would be in a position to extract monopoly profits, but for these rules. The offer-capping rules exempted certain units from offer capping based on the date of their construction. Such exempt units could, and

12 See "Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.," Schedule 1, Section 6.4.2. (February 1, 2010).

did, exercise market power, at times, that would not have been permitted if the units had not been exempt. The FERC eliminated the exemption effective May 17, 2008.[13]

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

PJM's three pivotal supplier test represents the practical application of the FERC market power tests in real time.[14] The three pivotal supplier test is passed if no three generation suppliers in a load pocket are jointly pivotal. Stated another way, if the incremental output of the three largest suppliers in a load pocket is removed and enough incremental generation remains available to solve the incremental demand for constraint relief, where the relevant competitive supply includes all incremental MW at a cost less than, or equal, to 1.5 times the clearing price, then offer capping is suspended.

Levels of offer capping have historically been low in PJM, as shown in Table 2-4.

Table 2-4 Annual offer-capping statistics: Calendar years 2005 to 2009

	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	0.4%	0.1%	0.1%	0.0%

Table 2-5 presents data on the frequency with which units were offer capped in 2009. Table 2-5 shows the number of generating units that met the specified criteria for total offer-capped run hours and percentage of total run hours that were offer-capped for 2009. For example, in 2009, only 1 unit was offer-capped for greater than, or equal to, 80 percent of its run hours and had 200 or more offer-capped run hours.

13 123 FERC ¶ 61,169 (2008).
14 See the *2009 State of the Market Report for PJM*, Volume II, Appendix L, "Three Pivotal Supplier Test."

Table 2-5 Offer-capped unit statistics: Calendar year 2009

	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	6
80% and < 90%	0	0	0	1	2	13
75% and < 80%	0	0	0	1	0	6
70% and < 75%	0	0	0	1	1	9
60% and < 70%	0	0	0	0	1	21
50% and < 60%	0	0	0	0	1	19
25% and < 50%	0	1	1	2	3	56
10% and < 25%	1	0	0	0	6	53

Table 2-5 shows that a small number of units are offer capped for a significant number of hours or for a significant proportion of their run hours. For example, only 8 units (about 0.6 percent of all units) that had offer-capped run hours of at least 200 hours (about 2.3 percent of all hours) in 2009 were offer capped for 10 percent or more of their run hours. Only 2 units (or about 0.2 percent of all units) that had greater than, or equal to, 400 offer-capped run hours were offer capped for 10 percent or more of their run hours.

When compared to the 2008 offer-capped statistics, 8.3 percent of the categories show an increase in the number of units; 39.6 percent of the categories show no change and 52.1 percent of the categories show a decrease in the number of units.[15]

When compared to the 2007 offer-capped statistics, 29.2 percent of the categories show an increase in the number of units; 33.3 percent of the categories show no change and 37.5 percent of the categories show a decrease in the number of units.[16]

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

Local Market Structure

In 2009, the AECO, AEP, AP, BGE, ComEd, DLCO, Dominion, PECO, PENELEC, Pepco and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 100 or more hours. Using the three pivotal supplier results for calendar year 2009, actual competitive conditions associated with each of these frequently binding constraints were analyzed in real time.[17] The DAY, DPL, JCPL, Met-Ed, PPL and RECO Control Zones were not affected by constraints binding for 100 or more hours.

15 See the *2009 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market" Table C-23 for 2008 data.
16 See the *2009 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market" Table C-22 for 2007 data.
17 See the *2009 State of the Market Report for PJM*, Volume II, Appendix L, "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test.

The three pivotal supplier test is applied by PJM on an ongoing basis in order to determine whether offer capping is required to prevent the exercise of local market power for any constraint not exempt from offer capping. The FERC eliminated the exemption of interfaces effective May 17, 2008.[18] The MMU analyzed the results of the three pivotal supplier tests conducted by PJM for the Real-Time Energy Market for the period January 1, 2009, through December 31, 2009.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and does not result in offer capping when that is not the case. Local markets are noncompetitive when there is a small number of suppliers. The number of hours in which one or more suppliers pass the three pivotal supplier test and are not subject to offer capping increases as the number of suppliers in the local market increases. For example, the regional constraints have a larger number of suppliers and more than 54 percent of the three pivotal supplier tests have one or more passing owners. In contrast, more local constraints like the Tiltonsville – Windsor 138 kV line in the AP Control Zone have only two suppliers and therefore are always structurally noncompetitive.

The fact that some constraints never had any generation resources that failed the three pivotal supplier test during the period analyzed does not lead to the conclusion that such constraints should never have offer capping for local market power. The same logic applies to interface constraints which were exempt from offer capping prior to May 17, 2008. Even if no generation resources associated with any of the previously exempt interface constraints failed the three pivotal suppler test during the period analyzed, that does not mean that such interfaces should always be exempt from offer capping for local market power. The fact that one or more generation resources, required to resolve these interfaces, did fail the three pivotal supplier test at times simply reinforces the point. If the generation resources associated with these interfaces always pass the three pivotal supplier test, there will be no offer capping; and conversely if such resources at times fail the three pivotal supplier test, appropriate offer capping will be applied.

Information is provided for each constraint including the number of tests applied and the number of tests in which one or more owners passed and/or failed the three pivotal supplier test.[19] Additional information is provided for each constraint including the average MW required to relieve a constraint, the average supply available, the average number of owners included in each test and the average number of owners that passed or failed each test.

- **Regional 500 kV Constraints.** In 2009, several regional transmission constraints occurred for more than 100 hours. The Kammer 765/500 kV transformer, along with two interface constraints (5004/5005 and AP South) all experienced more than 100 hours of congestion, while the Bedington – Black Oak Interface constraint occurred for 73 hours in 2009.[20] The three pivotal supplier test was applied to all of these constraints. The AP South is one of the four interfaces for which generation owners were exempt from offer capping prior to May 17, 2008.

18 123 FERC ¶ 61,169 (2008).

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

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

Table 2-6 includes information on the three pivotal supplier test results for the two regional constraints (the Kammer 765/500 kV transformer and the 5004/5005 Interface) that were never exempt from offer capping.[21] The percentage of tested intervals resulting in one or more owners passing ranged from 87 percent to 97 percent while 7 percent to 26 percent of the tests show one or more owners failing.

For the AP South Interface, which was exempt from offer capping prior to May 17, 2008, the percentage of tested intervals resulting in one or more owners passing ranged from 54 percent to 57 percent while 64 percent to 68 percent of the tests show one or more owners failing in 2009.

Table 2-6 Three pivotal supplier results summary for regional constraints: Calendar year 2009

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	714	691	97%	49	7%
	Off Peak	216	206	95%	26	12%
AP South	Peak	1,777	1,012	57%	1,134	64%
	Off Peak	951	518	54%	642	68%
Kammer	Peak	3,786	3,508	93%	624	16%
	Off Peak	4,145	3,619	87%	1,064	26%

Table 2-7 shows that, on average, during 2009 peak periods, the local markets created by the 5004/5005 Interface and the Kammer transformer had 19 owners with available supply and 21 owners with available supply, respectively. Of those owners, an average of 19 passed the test for the 5004/5005 Interface and an average of 19 passed the test for the Kammer transformer.[22] During off-peak periods, on average, the 5004/5005 Interface and the Kammer transformer had 18 owners with available supply and 17 owners with available supply. Of those owners, an average of 17 passed the test for the 5004/5005 Interface and an average of 14 passed the test for the Kammer transformer. For AP South, on average, 6 out of 12 owners passed the test during both on-peak and off-peak periods in 2009.

Table 2-7 Three pivotal supplier test details for three regional constraints: Calendar year 2009

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	59	316	18	17	1
AP South	Peak	92	278	12	6	6
	Off Peak	100	290	12	6	6
Kammer	Peak	51	249	21	19	2
	Off Peak	52	221	17	14	3

21 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.

22 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.

- **Central, East and West Interfaces.** The remaining three interfaces that were exempt until May 2008, the Central, East and West Interface constraints occurred for fewer than 100 hours. The East Interface did not constrain in 2009, while the Central and West Interface constraints occurred for 8 hours and 87 hours in 2009. Table 2-8 shows that in 2009, the percentage of tested intervals resulting in one or more owners passing ranged from 97 percent to 100 percent while no more than 9 percent of the tests showed one or more owners failing. No tests were applied to the East Interface in 2009.

Table 2-8 Three pivotal supplier results summary for the Central, East and West Interfaces: Calendar year 2009

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	23	23	100%	0	0%
	Off Peak	9	9	100%	0	0%
East	Peak	0	NA	NA	NA	NA
	Off Peak	0	NA	NA	NA	NA
West	Peak	332	321	97%	30	9%
	Off Peak	65	65	100%	0	0%

Table 2-9 shows that the local market created by the Central Interface had 18 owners during on-peak periods and 19 owners during off-peak periods and all passed the test in 2009. The local market created by the West Interface, on average, had 18 owners during off-peak periods and all passed the test. During on-peak periods, 21 of 22 passed the test for the West Interface.

Table 2-9 Three pivotal supplier test details for the Central, East and West interfaces: Calendar year 2009

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Central	Peak	54	514	18	18	0
	Off Peak	84	884	19	19	0
East	Peak	NA	NA	NA	NA	NA
	Off Peak	NA	NA	NA	NA	NA
West	Peak	125	627	22	21	1
	Off Peak	118	717	18	18	0

- **AECO Control Zone Constraints.** In 2009, there was only one constraint in the AECO Control Zone that occurred for more than 100 hours. Table 2-10 and Table 2-11 show the results of the three pivotal supplier test applied to this constraint. The average number of owners with available supply was one on peak and one off peak for the Absecon – Lewis 69 kV line. The three pivotal supplier test results reflect this, as all tests were failed.

Table 2-10 Three pivotal supplier results summary for constraints located in the AECO Control Zone: Calendar year 2009

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 2-11 Three pivotal supplier test details for constraints located in the AECO Control Zone: Calendar year 2009

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

- **AEP Control Zone Constraints.** In 2009, there were five constraints that occurred for more than 100 hours in the AEP Control Zone. Table 2-12 and Table 2-13 show the results of the three pivotal supplier tests applied to the constraints in the AEP Control Zone. For four of the five constraints, the average number of owners with available supply was one. The three pivotal supplier test results reflect this, as the average number of owners that passed is significant only for the Cloverdale – Lexington 500 kV line with the largest number of owners, on average. The Cloverdale – Lexington 500 kV line had more owners and more effective supply and thus a higher percentage of tests with one or more owners that passed.

Table 2-12 Three pivotal supplier results summary for constraints located in the AEP Control Zone: Calendar year 2009

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	425	252	59%	278	65%
	Off Peak	1,841	1,024	56%	1,244	68%
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	300	0	0%	300	100%
Poston - Postel Tap	Peak	461	0	0%	461	100%
	Off Peak	39	0	0%	39	100%
Ruth - Turner	Peak	1,397	0	0%	1,397	100%
	Off Peak	1,847	0	0%	1,847	100%

Table 2-13 Three pivotal supplier test details for constraints located in the AEP Control Zone: Calendar year 2009

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Cloverdale - Lexington	Peak	72	212	15	8	8
	Off Peak	68	183	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	4	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	21	2	1	0	1

- **AP Control Zone Constraints.** In 2009, there were seven constraints that occurred for more than 100 hours in the AP Control Zone. Table 2-14 and Table 2-15 show the results of the three pivotal supplier tests applied to the constraints in the AP Control Zone. For three of the seven constraints, the average number of owners with available supply was four or less. The three pivotal supplier test results reflect this, as the average number of owners that passed is significant only for the four constraints with a larger number of owners, on average. Four constraints, the Elrama – Mitchell 138 kV line, the Mount Storm – Pruntytown 500 kV line, the Sammis – Wylie Ridge 345 kV line and the Wylie Ridge transformer had more owners and more effective supply and thus a higher percentage of tests with one or more owners that passed.

Table 2-14 Three pivotal supplier results summary for constraints located in the AP Control Zone: Calendar year 2009

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%
Doubs	Peak	844	39	5%	830	98%
	Off Peak	245	10	4%	244	100%
Elrama - Mitchell	Peak	770	385	50%	488	63%
	Off Peak	328	189	58%	173	53%
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	657	467	71%	319	49%
Tiltonsville - Windsor	Peak	1,470	1	0%	1,469	100%
	Off Peak	405	0	0%	405	100%
Wylie Ridge	Peak	695	577	83%	182	26%
	Off Peak	945	653	69%	378	40%

Table 2-15 Three pivotal supplier test details for constraints located in the AP Control Zone: Calendar year 2009

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
Doubs	Peak	15	12	4	0	4
	Off Peak	18	14	4	0	4
Elrama - Mitchell	Peak	19	59	11	7	4
	Off Peak	16	57	11	8	3
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	51	127	17	11	6
Tiltonsville - Windsor	Peak	10	5	2	0	2
	Off Peak	8	5	2	0	2
Wylie Ridge	Peak	36	147	17	15	2
	Off Peak	37	141	14	12	2

- **BGE Control Zone Constraints.** In 2009, the Graceton – Raphael 230 kV line was the only constraint in the BGE Control Zone to occur for more than 100 hours. Table 2-16 and Table 2-17 show the results of the three pivotal supplier test applied to this constraint. The average number of owners with available supply was 19 on peak and 20 off peak. In 2009, 90 percent of the tests during on-peak periods and 86 percent of the tests during off-peak periods showed one or more owners passing.

Table 2-16 Three pivotal supplier results summary for constraints located in the BGE Control Zone: Calendar year 2009

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	531	478	90%	93	18%
	Off Peak	342	294	86%	94	27%

Table 2-17 Three pivotal supplier test details for constraints located in the BGE Control Zone: Calendar year 2009

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	31	115	19	17	2
	Off Peak	41	141	20	17	3

- **ComEd Control Zone Constraints.** In 2009, there were three constraints that occurred for more than 100 hours in the ComEd Control Zone. Table 2-18 and Table 2-19 show the results of the three pivotal supplier tests applied to the constraints in the ComEd Control Zone. The average number of owners with available supply was three or less for the Pleasant Valley – Belvidere 138 kV line and the Electric Jct – Nelson 345 kV line and five for the Crete – East Frankfurt 345 kV line during on-peak periods. The three pivotal supplier test results reflect this, as the average number of owners that passed is significant only for the Crete – East Frankfurt 345 kV line during on-peak periods.

Table 2-18 Three pivotal supplier results summary for constraints located in the ComEd Control Zone: Calendar year 2009

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	320	33	10%	313	98%
	Off Peak	3,538	86	2%	3,508	99%
Electric Jct - Nelson	Peak	262	5	2%	261	100%
	Off Peak	740	1	0%	740	100%
Pleasant Valley - Belvidere	Peak	528	0	0%	528	100%
	Off Peak	1,560	0	0%	1,560	100%

Table 2-19 Three pivotal supplier test details for constraints located in the ComEd Control Zone: Calendar year 2009

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	30	104	5	0	4
	Off Peak	32	44	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	10	0	1	0	1

- **DLCO Control Zone Constraints.** In 2009, only one constraint in the DLCO Control Zone experienced more than 100 hours of congestion. Table 2-20 and Table 2-21 show the results of the three pivotal supplier test applied to this constraint. The average number of owners with available supply was one on peak and one off peak for the Logans Ferry – Universal 138 kV line. The three pivotal supplier test results reflect this, as all tests were failed.

Table 2-20 Three pivotal supplier results summary for constraints located in the DLCO Control Zone: Calendar year 2009

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 2-21 Three pivotal supplier test details for constraints located in the DLCO Control Zone: Calendar year 2009

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

- **Dominion Control Zone Constraints.** In 2009, there was only one constraint in the Dominion Control Zone that occurred for more than 100 hours. Table 2-22 and Table 2-23 show the results of the three pivotal supplier test applied to this constraint. The average number of owners with available supply was one on peak and one off peak for the Beechwood – Kerr Dam 115 kV line. The three pivotal supplier test results reflect this, as all tests were failed.

Table 2-22 Three pivotal supplier results summary for constraints located in the Dominion Control Zone: Calendar year 2009

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	928	0	0%	928	100%
	Off Peak	125	0	0%	125	100%

Table 2-23 Three pivotal supplier test details for constraints located in the Dominion Control Zone: Calendar year 2009

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

- **PECO Control Zone Constraints.** In 2009, the Emilie transformer was the only constraint in the PECO Control Zone to occur for more than 100 hours. Table 2-24 and Table 2-25 show the results of the three pivotal supplier test applied to this constraint. The average number of owners with available supply was four on peak and four off peak. The three pivotal supplier test results reflect this, as nearly all tests were failed.

Table 2-24 Three pivotal supplier results summary for constraints located in the PECO Control Zone: Calendar year 2009

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 2-25 Three pivotal supplier test details for constraints located in the PECO Control Zone: Calendar year 2009

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

- **PENELEC Control Zone Constraints.** In 2009, there was only one constraint in the PENELEC Control Zone that occurred for more than 100 hours. Table 2-26 and Table 2-27 show the results of the three pivotal supplier tests applied to this constraint. The average number of owners with available supply was four on peak and five off peak for the Homer City – Shelocta 230 kV line. The three pivotal supplier test results reflect this, as nearly all tests were failed.

Table 2-26 Three pivotal supplier results summary for constraints located in the PENELEC Control Zone: Calendar year 2009

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	685	24	4%	674	98%
	Off Peak	149	3	2%	149	100%

Table 2-27 Three pivotal supplier test details for constraints located in the PENELEC Control Zone: Calendar year 2009

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	24	57	4	0	4
	Off Peak	40	54	5	0	5

- **Pepco Control Zone Constraints.** In 2009, the Buzzard – Ritchie 230 kV line was the only constraint in the Pepco Control Zone to occur for more than 100 hours. Table 2-28 and Table 2-29 show the results of the three pivotal supplier test applied to this constraint. The average number of owners with available supply was two on peak and no tests were applied to this constraint during off-peak periods. The three pivotal supplier test results reflect this, as all tests were failed.

Table 2-28 Three pivotal supplier results summary for constraints located in the Pepco Control Zone: Calendar year 2009

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 2-29 Three pivotal supplier test details for constraints located in the Pepco Control Zone: Calendar year 2009

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

- **PSEG Control Zone Constraints.** In 2009, two constraints in the PSEG Control Zone occurred for more than 100 hours. Table 2-30 and Table 2-31 show the results of the three pivotal supplier tests applied to these constraints. For both of the constraints, the average number of owners with available supply was three or less. The three pivotal supplier test results reflect this, as nearly all tests were failed.

Table 2-30 Three pivotal supplier results summary for constraints located in the PSEG Control Zone: Calendar year 2009

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%
Plainsboro - Trenton	Peak	592	0	0%	592	100%
	Off Peak	13	0	0%	13	100%

Table 2-31 Three pivotal supplier test details for constraints located in the PSEG Control Zone: Calendar year 2009

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
Plainsboro - Trenton	Peak	9	122	1	0	1
	Off Peak	7	141	1	0	1

Market Performance: Markup

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

The MMU calculates the impact on system prices of marginal unit price-cost markup, based on analysis using sensitivity factors. The calculation shows the markup component of price based on a comparison between the price-based offer and the cost-based offer of each actual marginal unit on the system.[23]

The price impact of markup must be interpreted carefully. The markup calculation is not based on a full redispatch of the system to determine the marginal units and their marginal costs that would have occurred if all units had made all offers at marginal cost. Thus the results do not reflect a

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

counterfactual market outcome based on the assumption that all units made all offers at marginal cost. It is important to note that a full redispatch analysis is practically impossible and a limited redispatch analysis would not be dispositive. Nonetheless, such a hypothetical counterfactual analysis would reveal the extent to which the actual system dispatch is less than competitive if it showed a difference between dispatch based on marginal cost and actual dispatch. It is possible that the unit-specific markup, based on a redispatch analysis, would be lower than the markup component of price if the reference point were an inframarginal unit with a lower price and a higher cost than the actual marginal unit. If the actual marginal unit has marginal costs that would cause it to be inframarginal, a new unit would be marginal. If the offer of that new unit were greater than the cost of the original marginal unit, the markup impact would be lower than the MMU measure. If the newly marginal unit is on a price-based schedule, the analysis would have to capture the markup impact of that unit as well.

The MMU calculates an explicit measure of the impact of marginal unit markups on LMP. The markup impact includes the maximum impact of the identified markup conduct on a unit by unit basis, but the inclusion of negative markup impacts has an offsetting effect. The markup analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval. The markup analysis is a more general measure of the competitiveness of the Energy Market.

Real-Time Markup

Ownership of Marginal Resources

Table 2-32 shows the contribution to PJM real-time, annual, load-weighted LMP by individual marginal resource owner, utilizing generator sensitivity factors.[24] The contribution of each marginal resource to price at each load bus is calculated for the year and summed by the company that offers the marginal resource into the Real-Time Energy Market. The results show that, during calendar year 2009, the offers of one company contributed 17 percent of the real-time, annual, load-weighted PJM system LMP and that the offers of the top four companies contributed 48 percent of the real-time, annual, load-weighted, average PJM system LMP.

Table 2-32 Marginal unit contribution to PJM real-time, annual, load-weighted LMP (By parent company): Calendar year 2009

Company	Percent of Price
1	17%
2	14%
3	9%
4	8%
5	7%
6	6%
7	5%
8	4%
9	3%
Other (57 companies)	27%

24 See the *2009 State of the Market Report for PJM*, Volume II, Appendix K, "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

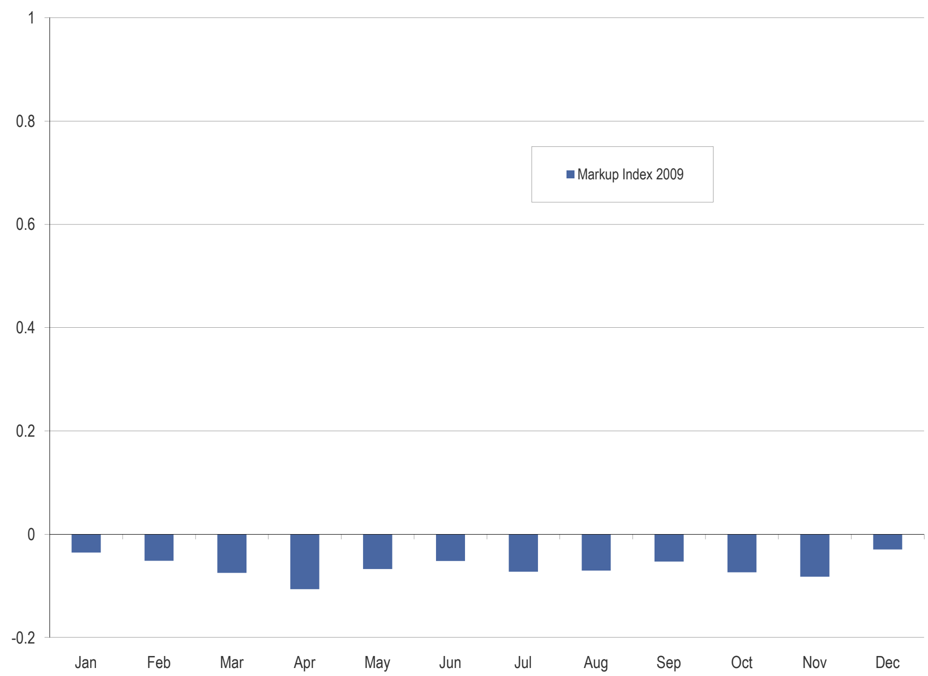
Table 2-33 shows the type of fuel used by marginal resources. In 2009, coal units were 74 percent of marginal resources and natural gas units were 22 percent of marginal resources.

Table 2-33 Type of fuel used (By real-time marginal units): Calendar year 2009

Fuel Type	2009
Coal	74%
Natural Gas	22%
Petroleum	3%
Landfill Gas	1%
Interface	0%
Misc	0%

Figure 2-5 shows the real-time, load-weighted, unit markup index. The markup index for each marginal unit is calculated as (Price – Cost)/Price. The markup index is normalized and can vary from -1.00 when the offer price is less than marginal cost, to 1.00 when the offer price is higher than marginal cost.[25] This index calculation method weights the impact of individual unit markups using sensitivity factors. In 2009, the annual average markup index was -0.06 with a maximum of -0.03 in December and a minimum of -0.11 in April.

Figure 2-5 Real-time, LMP contribution and load-weighted, unit markup index: Calendar year 2009



25 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. Also the markup index was weighted by the percentage of the LMP of each type of marginal resources.

Unit Markup Characteristics

In order to contribute to a more complete description of markup behavior, this section includes information on markup index by unit and fuel type and by offer price category.

Table 2-34 shows the annual average unit markup index for marginal units, by unit type and primary fuel.

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

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($2.54)	106.7%
Gas	CC	($0.00)	0.2%
Gas	CT	$0.11	(4.5%)
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	($0.01)	0.3%
Oil	CT	$0.02	(0.9%)
Oil	Diesel	($0.00)	0.2%
Oil	Steam	$0.05	(2.2%)
Uranium	Steam	($0.00)	0.0%
Water	Hydro	$0.00	0.0%
Wind	Wind	$0.00	(0.0%)
Total		($2.38)	100.0%

Table 2-35 shows the average markup index of marginal units in the Real-Time Market, by offer price category. A unit is assigned to a price category for each interval in which it was marginal, based on its offer price at that time.

Table 2-35 Average, real-time marginal unit markup index (By price category): Calendar year 2009

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.06)	($2.35)
$25 to $50	(0.09)	($4.17)
$50 to $75	(0.01)	($1.14)
$75 to $100	0.04	$2.75
$100 to $125	0.09	$9.78
$125 to $150	0.08	$10.17
> $150	0.04	$8.14

Markup Component of System Price

The price component measure uses real-time, load-weighted, price-based LMP and real-time, load-weighted LMP computed using cost-based offers for all marginal units in the Real-Time Market. The price component of markup is computed by calculating the system price, based on the price-based offers of the marginal units and comparing that to the system price, based on the cost-based offers of the marginal units. Both results are compared to the actual system price to determine how much of the LMP can be attributed to markup.

Table 2-36 shows the markup component of average prices and of average monthly on-peak and off-peak prices. In 2009, -$2.38 per MWh of the PJM real-time, load-weighted average LMP was attributable to markup. In 2009, the markup component of LMP was -$3.15 per MWh off peak and -$1.67 per MWh on peak.

Table 2-36 Monthly markup components of real-time load-weighted LMP: Calendar year 2009

	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	($1.22)	($0.05)	($2.33)
Feb	($1.09)	($0.42)	($1.80)
Mar	($3.03)	($3.14)	($2.92)
Apr	($4.50)	($3.62)	($5.53)
May	($2.78)	($2.35)	($3.19)
Jun	($1.84)	($0.79)	($3.15)
Jul	($1.93)	($1.34)	($2.70)
Aug	($3.14)	($1.43)	($4.97)
Sep	($2.62)	($2.08)	($3.22)
Oct	($2.86)	($2.14)	($3.64)
Nov	($3.15)	($2.86)	($3.43)
Dec	($1.07)	($0.70)	($1.45)
2009	($2.38)	($1.67)	($3.15)

Markup Component of Real-Time Zonal Prices

The annual average real-time price component of unit markup is shown for each zone in Table 2-37. The smallest zonal all hours' annual average markup component was in the DLCO Control Zone, -$3.62 per MWh, while the highest all hours' annual average zonal markup component was in the DPL Control Zone, -$1.55 per MWh. On peak, the smallest annual average zonal markup was in the DLCO Control Zone, -$3.05 per MWh, while the highest annual average zonal markup was in the Pepco Control Zone, -$0.60 per MWh. Off peak, the smallest annual average zonal markup was in the DAY Control Zone, -$4.26 per MWh, while the highest annual average zonal markup was in the DPL Control Zone, -$1.99 per MWh.

Table 2-37 Average real-time zonal markup component: Calendar year 2009

	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	($2.13)	($1.34)	($2.97)
AEP	($3.25)	($2.55)	($4.00)
AP	($2.10)	($1.27)	($2.98)
BGE	($1.84)	($0.91)	($2.81)
ComEd	($2.86)	($2.51)	($3.24)
DAY	($3.42)	($2.67)	($4.26)
DLCO	($3.62)	($3.05)	($4.24)
Dominion	($1.67)	($0.84)	($2.54)
DPL	($1.55)	($1.13)	($1.99)
JCPL	($1.99)	($1.12)	($2.96)
Met-Ed	($1.79)	($1.23)	($2.40)
PECO	($2.06)	($1.35)	($2.83)
PENELEC	($2.47)	($1.74)	($3.26)
Pepco	($1.58)	($0.60)	($2.65)
PPL	($2.05)	($1.28)	($2.90)
PSEG	($2.11)	($1.28)	($3.04)
RECO	($2.16)	($1.28)	($3.21)

Markup by Real-Time System Price Levels

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

Table 2-38 shows the average markup component of observed price when the PJM system LMP was in the identified price range.

Table 2-38 Average real-time markup component (By price category): Calendar year 2009

	Average Markup Component	Frequency
Below $20	($1.58)	3.8%
$20 to $40	($4.11)	67.6%
$40 to $60	($1.24)	20.8%
$60 to $80	$2.18	4.9%
$80 to $100	$8.25	1.8%
$100 to $120	$5.49	0.6%
$120 to $140	$37.62	0.3%
$140 to $160	$16.44	0.1%
Above $160	$47.88	0.1%

Day-Ahead Markup

Ownership of Marginal Resources

Table 2-39 shows the contribution to PJM day-ahead, annual, load-weighted LMP by individual marginal resource owner, utilizing generator sensitivity factors.[26] The contribution of each marginal resource to price at each load bus is calculated for the year and summed by the company that offers the marginal resource into the Day-Ahead Energy Market. The results show that, during calendar year 2009, the offers of one company contributed 32 percent of the day-ahead, annual, load-weighted PJM system LMP and that the offers of the top four companies contributed 52 percent of the day-ahead, annual, load-weighted, average PJM system LMP.

Table 2-39 Marginal unit contribution to PJM day-ahead, annual, load-weighted LMP (By parent company): Calendar year 2009

Company	Percent of Price
1	32%
2	8%
3	6%
4	6%
5	5%
6	4%
7	3%
8	3%
9	3%
Other (119 companies)	30%

Table 2-40 shows the type of fuel used by marginal resources. In 2009, the transactions that were on the margin accounted for 33 percent of marginal resources and the decrement bids that were on the margin accounted for 30 percent of all marginal resources.

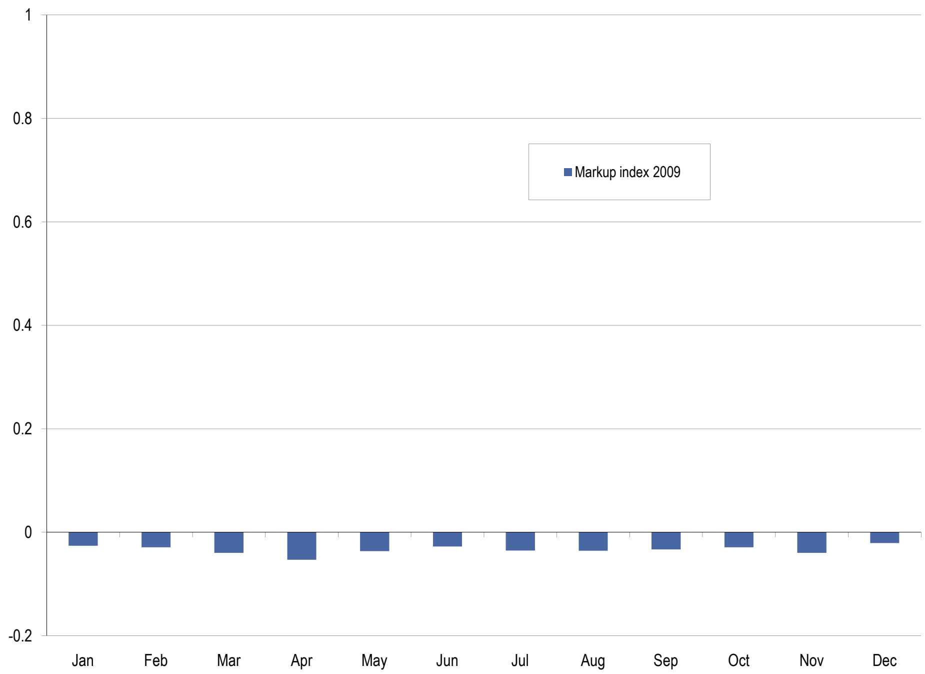
Table 2-40 Day-ahead marginal resources by type/fuel: Calendar year 2009

Type/Fuel	2009
Transaction	33%
DEC	30%
INC	21%
Coal	12%
Natural gas	3%
Price sensitive demand	1%
Oil	0%
Wind	0%
Municipal waste	0%
Diesel	0%

26 See the *2009 State of the Market Report for PJM*, Volume II, Appendix K, "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Figure 2-6 shows the day-ahead, load-weighted, unit markup index. The markup index for each marginal unit is calculated as (Price – Cost)/Price. The markup index is normalized and can vary from -1.00 when the offer price is less than marginal cost, to 1.00 when the offer price is higher than marginal cost.[27] This index calculation method weights the impact of individual unit markups using sensitivity factors. In 2009, the annual average markup index was -0.03 with a maximum of -0.02 in December and a minimum of -0.05 in April.

Figure 2-6 Day-ahead, LMP contribution and load-weighted unit markup index: Calendar year 2009



27 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. Also the markup index was weighted by the percentage of the LMP of each type of marginal resources. The markup index of transaction marginal resources, INC marginal resources and DEC marginal resources was zero.

Unit Markup Characteristics

In order to contribute to a more complete description of markup behavior, this section includes information on markup index by unit and fuel type and by offer price category.

Table 2-41 shows the annual average unit markup index for marginal units, by unit type and primary fuel.

Table 2-41 Average, day-ahead marginal unit markup index (By primary fuel and unit type): Calendar year 2009

Fuel Type	Unit Type	Average Markup Index	Average Dollar Markup
Coal	Steam	(0.08)	($3.71)
Diesel	Diesel	(0.07)	($5.34)
Municipal waste	Steam	(0.05)	($1.43)
Natural gas	CT	0.05	$2.81
Natural gas	Diesel	(0.04)	($2.60)
Natural gas	Steam	0.01	($0.15)
Oil	Steam	0.01	$1.15
Wind	Wind	1.00	$52.11

Table 2-42 shows the average markup index of marginal units in Day-Ahead Market, by offer price category. A unit is assigned to a price category for each interval in which it was marginal, based on its offer price at that time.

Table 2-42 Average marginal unit markup index (By price category): Calendar year 2009

Price Category	Average Markup Index	Average Dollar Markup
< $25	($0.05)	($1.93)
$25 to $50	($0.08)	($3.73)
$50 to $75	($0.02)	($1.60)
$75 to $100	$0.01	($0.24)
$100 to $125	($0.01)	($2.01)
$125 to $150	($0.03)	($4.30)
> $150	$0.00	$0.00

Markup Component of System Price

The price component measure uses day-ahead, load-weighted, price-based LMP and day-ahead, load-weighted LMP computed using cost-based offers for all marginal units in Day-Ahead Market. The price component of markup is computed by calculating the system price, based on the price-based offers of the marginal units and comparing that to the system price, based on the cost-based offers of the marginal units. Both results are compared to the actual system price to determine how much of the LMP can be attributed to markup.

Table 2-43 shows the markup component of average prices and of average monthly on-peak and off-peak prices. In 2009, -$1.65 per MWh of the PJM day-ahead, load-weighted average LMP was attributable to markup. In 2009, the markup component of LMP was -$2.22 per MWh off peak and -$1.12 per MWh on peak.

Table 2-43 Monthly markup components of day-ahead, load-weighted LMP: Calendar year 2009

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($2.07)	($1.32)	($2.79)
Feb	($1.84)	($0.83)	($2.90)
Mar	($2.01)	($1.48)	($2.59)
Apr	($2.49)	($2.06)	($3.00)
May	($1.52)	($0.79)	($2.22)
Jun	($1.13)	($0.43)	($2.00)
Jul	($1.65)	($1.37)	($2.01)
Aug	($1.78)	($1.73)	($1.84)
Sep	($1.34)	($1.07)	($1.65)
Oct	($1.29)	($0.85)	($1.78)
Nov	($1.59)	($0.91)	($2.25)
Dec	($1.03)	($0.51)	($1.56)
Annual	($1.65)	($1.12)	($2.22)

Markup Component of Zonal Prices

The annual average price component of unit markup is shown for each zone in Table 2-44. The smallest zonal all hours' markup component was in the DAY Control Zone, -$2.72 per MWh, while the highest all hours' zonal markup component was in the BGE Control Zone, -$1.02 per MWh. On peak, the smallest zonal markup was in the DAY Control Zone, -$2.01 per MWh, while the highest markup was in the BGE Control Zone, -$0.44 per MWh. Off peak, the smallest zonal markup was in the DAY Control Zone, -$3.52 per MWh, while the highest markup was in the Pepco Control Zone, -$1.59 per MWh.

Table 2-44 Day-ahead, average, zonal markup component: Calendar year 2009

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($1.29)	($0.73)	($1.90)
AEP	($2.60)	($1.87)	($3.37)
AP	($1.44)	($0.92)	($1.99)
BGE	($1.02)	($0.44)	($1.64)
ComEd	($1.77)	($1.53)	($2.02)
DAY	($2.72)	($2.01)	($3.52)
DLCO	($2.62)	($1.98)	($3.31)
Dominion	($1.26)	($0.89)	($1.65)
DPL	($1.24)	($0.65)	($1.86)
JCPL	($1.35)	($0.72)	($2.06)
Met-Ed	($1.20)	($0.63)	($1.84)
PECO	($1.25)	($0.64)	($1.91)
PENELEC	($1.60)	($1.02)	($2.25)
Pepco	($1.03)	($0.53)	($1.59)
PPL	($1.32)	($0.73)	($1.95)
PSEG	($1.32)	($0.79)	($1.92)
RECO	($1.40)	($0.88)	($2.05)

Markup by System Price Levels

The annual average markup component of the identified price range and its frequency are shown in Table 2-45.

Table 2-45 shows the average markup component of observed price when the PJM day-ahead, system LMP was in the identified price range.

Table 2-45 Average, day-ahead markup (By price category): Calendar year 2009

	Average Markup Component	Frequency
Below $20	($0.49)	4%
$20 to $40	($2.37)	64%
$40 to $60	($0.68)	26%
$60 to $80	($0.93)	4%
$80 to $100	$0.30	1%
$100 to $120	$0.08	0%
$120 to $140	($0.76)	0%
Above $160	$0.00	0%

Markup Component by Fuel, Unit Type

The markup component of the overall PJM day-ahead, load-weighted average LMP by primary fuel and unit type is shown in Table 2-46. The coal steam units accounted for 93.0 percent of the markup component of overall PJM day-ahead, load-weighted average LMP. The natural gas steam units accounted for 7.4 percent.

Table 2-46 The markup component of the overall PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: Calendar year 2009

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($1.53)	93.0%
Diesel	Diesel	($0.00)	0.1%
Municipal waste	Steam	($0.00)	0.0%
Natural gas	CT	$0.00	(0.1%)
Natural gas	Diesel	($0.00)	0.1%
Natural gas	Steam	($0.12)	7.4%
Oil	Steam	($0.01)	0.3%
Wind	Wind	$0.01	(0.7%)
Total		($1.65)	100.0%

Frequently Mitigated Unit and Associated Unit Adders – Component of Price

On January 25, 2005, the FERC ordered that frequently offer-capped units be provided additional compensation as a form of scarcity pricing, consistent with a recommendation of the MMU.[28] A frequently mitigated unit (FMU) was defined to be a unit that was offer capped for 80 percent or more of its run hours during the prior calendar year. FMUs were allowed either a $40 adder to their cost-based offers in place of the 10 percent adder, or the unit-specific, going-forward costs of the affected unit as a cost-based offer.

In the second half of 2005, discussions were held regarding scarcity pricing and local market power mitigation that led to a settlement agreement accepted by the FERC on January 27, 2006.[29] The settlement agreement revised the definition of FMUs to provide for a set of graduated adders associated with increasing levels of offer capping.[30] Units capped for 60 percent or more of their run hours and less than 70 percent are entitled to an adder of either 10 percent of their cost-based offer or $20 per MWh. Units capped 70 percent or more of their run hours and less than 80 percent are entitled to an adder of either 15 percent of their cost-based offer (not to exceed $40) or $30 per MWh. Units capped 80 percent or more of their run hours are entitled to an adder of $40 per MWh or the unit-specific, going-forward costs of the affected unit as a cost-based offer.[31] These categories are designated Tier 1, Tier 2 and Tier 3, respectively.

The settlement agreement further amended the OA to designate associated units (AUs), also at the recommendation of the MMU. An AU is a unit that is electrically and economically identical to an FMU, but does not qualify for the same adder. The settlement agreement provides for monthly designation of FMUs and AUs, where a unit's capping percentage is based on a rolling 12-month average, effective with a one-month lag.[32]

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

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

28 110 FERC ¶ 61,053 (2005).
29 114 FERC ¶ 61, 076 (2006).
30 *PJM Interconnection, L.L.C.*, Settlement Agreement, Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).
31 OA, Fifth Revised Sheet No. 131B (Effective July 3, 2007).
32 OA, Fifth Revised Sheet No. 132 (Effective July 3, 2007). In 2007, the FERC approved OA revisions to clarify the AU criteria.

Table 2-47 shows the number of FMUs and AUs in each month of 2009. For example, in December 2009, there were 43 FMUs and AUs in Tier 1, 24 FMUs and AUs in Tier 2, and 29 FMUs and AUs in Tier 3.

Table 2-47 Frequently mitigated units and associated units (By month): Calendar year 2009

	FMUs and AUs			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	26	56	55	137
February	46	46	36	128
March	31	48	54	133
April	33	41	63	137
May	32	43	61	136
June	40	42	62	144
July	27	32	75	134
August	27	37	64	128
September	40	23	56	119
October	31	49	38	118
November	38	31	27	96
December	43	24	29	96

Table 2-48 shows the number of months FMUs and AUS were eligible for any adder (Tier 1, Tier 2 or Tier 3) during 2009. Of the 186 units eligible in at least one month during 2009, 88 units (47 percent) were FMUs or AUs for more than eight months. Approximately one third of the units (61 units or 33 percent) were eligible every month during the year. This demonstrates that the group of FMUs and AUs is fairly stable, although units may move between the tier levels, month-to-month.

Table 2-48 Frequently mitigated units and associated units total months eligible: Calendar year 2009

Months Adder-Eligible	FMU & AU Count
1	16
2	18
3	6
4	2
5	6
6	3
7	20
8	17
9	8
10	19
11	10
12	61
Total	186

FMU and AU adders contributed $0.17 per MWh to system average LMP in 2009, out of a real-time, load weighted LMP of $39.05 per MWh.

Market Performance: Load and LMP

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

Load

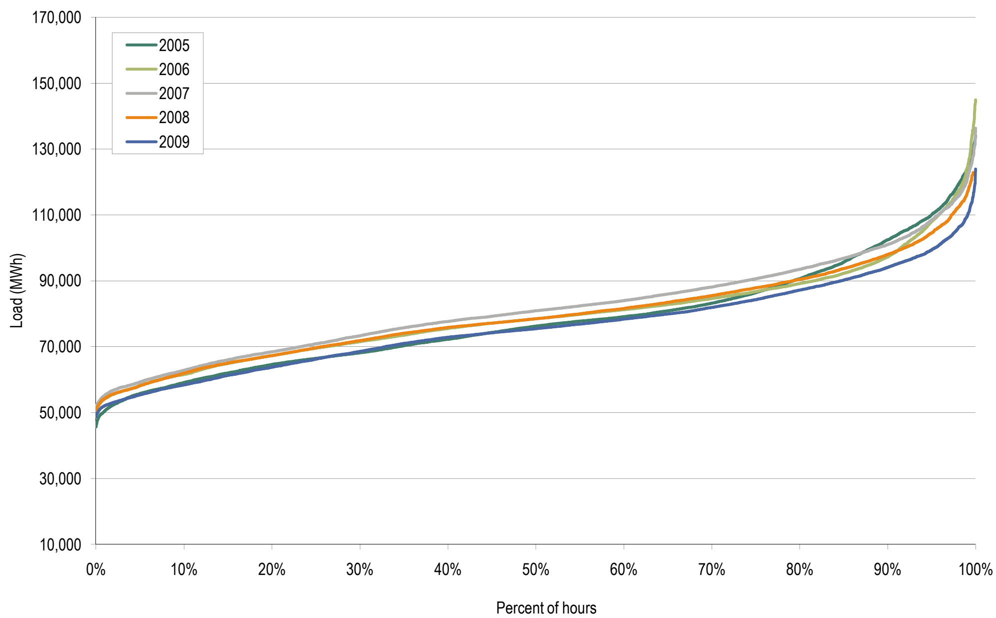
Real-Time Load

PJM real-time load is the total hourly accounting load in real time.[33]

PJM Real-Time Load Duration

Figure 2-7 shows PJM real-time load duration curves from 2005 to 2009. A load duration curve shows the percent of hours that load was at, or below, a given level for the year.

Figure 2-7 PJM real-time load duration curves: Calendar years 2005 to 2009



PJM Real-Time, Annual Average Load

Table 2-49 presents summary real-time load statistics for the 12-year period 1998 to 2009. The average load of 76,035 MWh in 2009 was 4.4 percent lower than the 2008 annual average hourly

33 All real-time load data in Section 2, "Energy Market, Part 1," "Market Performance: Load and LMP" are based on PJM accounting load. See the *2009 State of the Market Report for PJM*, Volume II, Appendix I, "Load Definitions," for detailed definitions of accounting load.

load. This average load was based on the PJM hourly accounting load. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load because of the implementation of marginal loss pricing.[34]

Table 2-49 PJM real-time average load: Calendar years 1998 to 2009

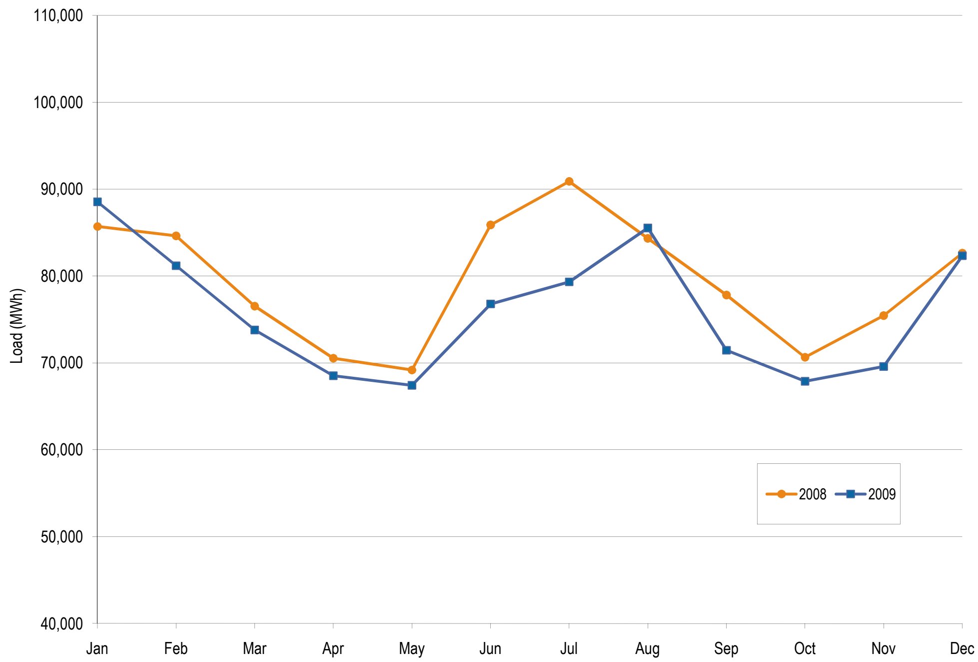
	PJM Real-Time Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	28,578	28,653	5,511	NA	NA	NA
1999	29,641	29,341	5,956	3.7%	2.4%	8.1%
2000	30,113	30,170	5,529	1.6%	2.8%	(7.2%)
2001	30,297	30,219	5,873	0.6%	0.2%	6.2%
2002	35,731	34,746	8,013	17.9%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

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

PJM Real-Time, Monthly Average Load

Figure 2-8 compares the real-time, monthly average hourly loads of 2009 with those of 2008.

Figure 2-8 PJM real-time average load: Calendar years 2008 to 2009



PJM real-time load is significantly affected by temperature. PJM uses the Temperature-Humidity Index (THI), the Winter Weather Parameter (WWP) and the average temperature as the weather variables in the PJM load forecast model for different seasons. THI is a measure of effective temperature using temperature and relative humidity for the cooling season (June, July and August).[35] Table 2-50 shows the monthly minimum, average and maximum of the PJM hourly THI for the cooling months in 2008 and 2009. When comparing 2009 to 2008, changes in THI were mixed, consistent with the changes in load. For the cooling months of 2009, the average THI was 69.64, 1.5 percent lower than the average 70.71 THI for 2008. The maximum THI (80.82) and minimum THI (52.61) in 2009 were 0.6 percent lower and 4.2 percent lower, respectively, than the maximum THI (81.30) and minimum THI (54.94) in 2008 during the cooling months.

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

Table 2-50 Monthly minimum, average and maximum of PJM hourly THI: Cooling periods of 2008 and 2009

	2008			2009			Difference		
	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max
Jun	54.94	70.16	81.30	52.61	67.83	77.92	(4.2%)	(3.3%)	(4.2%)
Jul	62.00	72.25	80.34	58.57	69.48	78.10	(5.5%)	(3.8%)	(2.8%)
Aug	59.89	69.70	78.62	57.21	71.57	80.82	(4.5%)	2.7%	2.8%

WWP is the wind-adjusted temperature for the heating season (January, February and December). The average temperatures are used for the months not covered by the THI or WWP. Table 2-51 shows the load weighted THI, WWP and average temperature for heating, cooling and shoulder seasons.[36]

Table 2-51 PJM annual Summer THI, Winter WWP and average temperature: cooling, heating and shoulder months of 2005 through 2009

	Summer THI	Winter WWP	Shoulder Average Temperature
2005	76.64	26.56	54.26
2006	75.59	31.67	54.62
2007	75.45	27.10	56.55
2008	75.35	27.52	54.10
2009	74.23	25.56	55.09

Day-Ahead Load

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

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

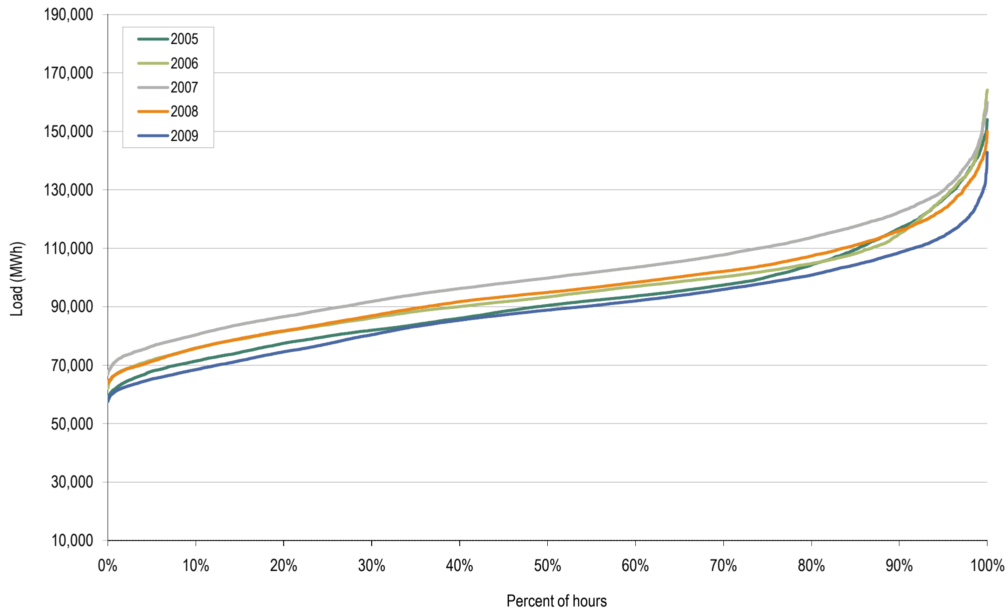
PJM day-ahead load is the hourly total of the above three types of cleared demand bids.

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

PJM Day-Ahead Load Duration

Figure 2-9 shows PJM day-ahead load duration curves from 2005 to 2009.

Figure 2-9 PJM day-ahead load duration curves: Calendar years 2005 to 2009



PJM Day-Ahead, Annual Average Load

Table 2-52 presents summary day-ahead load statistics for the 10 year period 2000 to 2009. The average load of 88,707 MWh in 2009 was 7.1 percent lower than the 2008 annual average load. The cleared fixed demand accounted for 81.2 percent, the cleared decrement bids accounted for 17.1 percent and the cleared price sensitive demand accounted for 1.7 percent of average load in 2009. The cleared decrement bids, fixed demand and price-sensitive demand in 2009 were 18.5 percent, 4.1 percent and 18.8 percent lower than in 2008. The cleared decrement bids in 2009 dropped to 15,136 MWh from 18,561 MWh in 2008, the cleared fixed demand in 2009 dropped to 72,073 MWh from 75,115 MWh, and the price-sensitive demand in 2009 dropped to 1,498 MWh from 1,846 MWh in 2008.

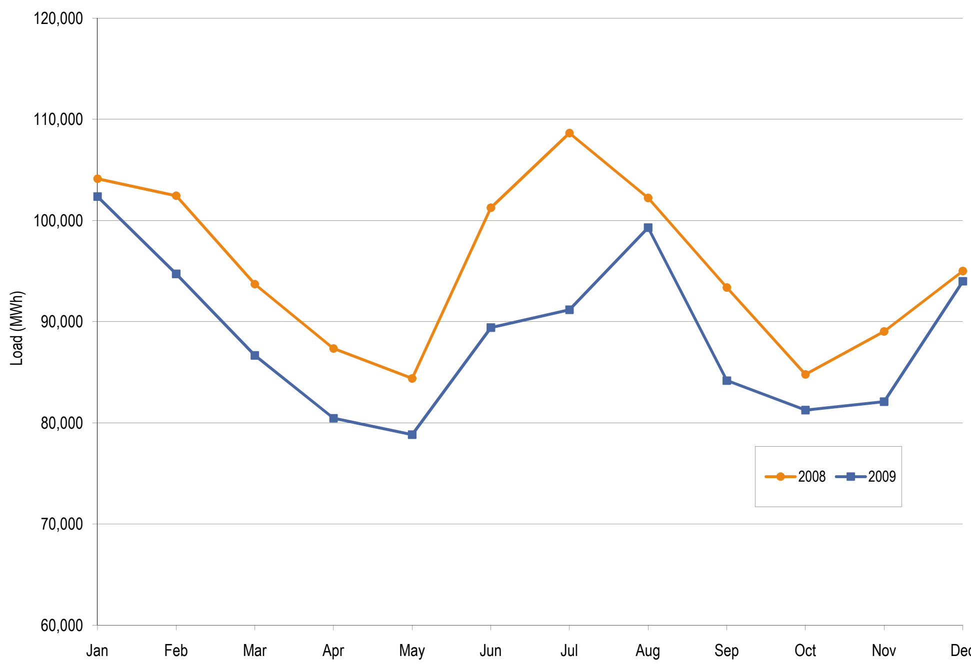
Table 2-52 PJM day-ahead average load: Calendar years 2000 to 2009

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

PJM Day-Ahead, Monthly Average Load

Figure 2-10 compares the day-ahead, monthly average loads of 2009 with those of 2008.

Figure 2-10 PJM day-ahead average load: Calendar years 2008 to 2009



Real-Time and Day-Ahead Load

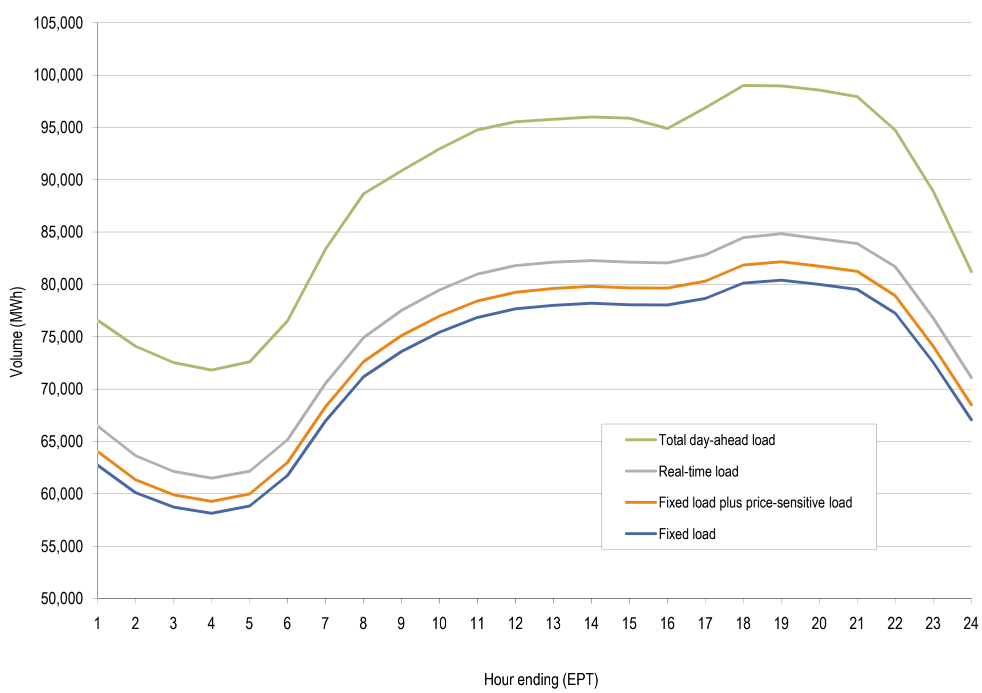
Table 2-53 presents summary statistics for the 2009 day-ahead and real-time loads and the average difference between them. The sum of day-ahead cleared fixed demand and price-sensitive demand averaged 2,464 MWh less than real-time average load. Total day-ahead load (the sum of the three types of cleared demand bids) averaged 12,672 MWh more than real-time load. Table 2-53 shows that, at 81.2 percent, fixed demand was the largest component of day-ahead load. At 1.7 percent, price-sensitive load was the smallest component, with cleared decrement bids accounting for the remaining 17.1 percent of day-ahead load.

Table 2-53 Cleared day-ahead and real-time load (MWh): Calendar year 2009

	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	72,073	1,498	15,136	88,707	76,035	12,672	(2,464)
Median	71,649	1,448	15,246	88,833	75,471	13,362	(1,884)
Standard deviation	12,515	451	2,624	14,896	13,260	1,636	(988)

Figure 2-11 shows the average 2009 hourly cleared volumes of fixed-demand bids, the sum of cleared fixed-demand and price-sensitive bids, total day-ahead load and real-time load. During 2009, real-time, hourly average load was higher than cleared fixed-demand load plus cleared price-sensitive load in the Day-Ahead Energy Market, although the reverse was true for 4.5 percent of the hours. When cleared decrement bids are included, day-ahead load always exceeded real-time load.

Figure 2-11 Day-ahead and real-time loads (Average hourly volumes): Calendar year 2009



Real-Time and Day-Ahead Generation

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

In the Day-Ahead Energy Market, three types of financially binding generation offers are made and cleared:[37]

- **Self-Scheduled.** Offer to supply a fixed block of MWh that must run from a specific unit, or as a minimum amount of MWh that must run on a specific unit that also has a dispatchable component above the minimum.[38]

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

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

Table 2-54 presents summary statistics for 2009 day-ahead and real-time generation and the average differences between them. Day-ahead cleared generation from physical units averaged 468 MWh higher than real-time generation. Day-ahead cleared generation plus cleared INC offers averaged 13,128 MWh more than real-time generation. Table 2-54 also shows that cleared generation and INC offers accounted for 86.1 percent and 13.9 percent of day-ahead supply, respectively.

Table 2-54 Day-ahead and real-time generation (MWh): Calendar year 2009

	Day Ahead			Real Time	Average Difference	
	Cleared Generation	Cleared INC Offer	Cleared Generation Plus INC Offer	Generation	Cleared Generation	Cleared Generation Plus INC Offer
Average	78,494	12,660	91,154	78,026	468	13,128
Median	78,667	12,505	91,318	77,639	1,028	13,679
Standard deviation	14,820	1,661	15,406	13,647	1,173	1,759

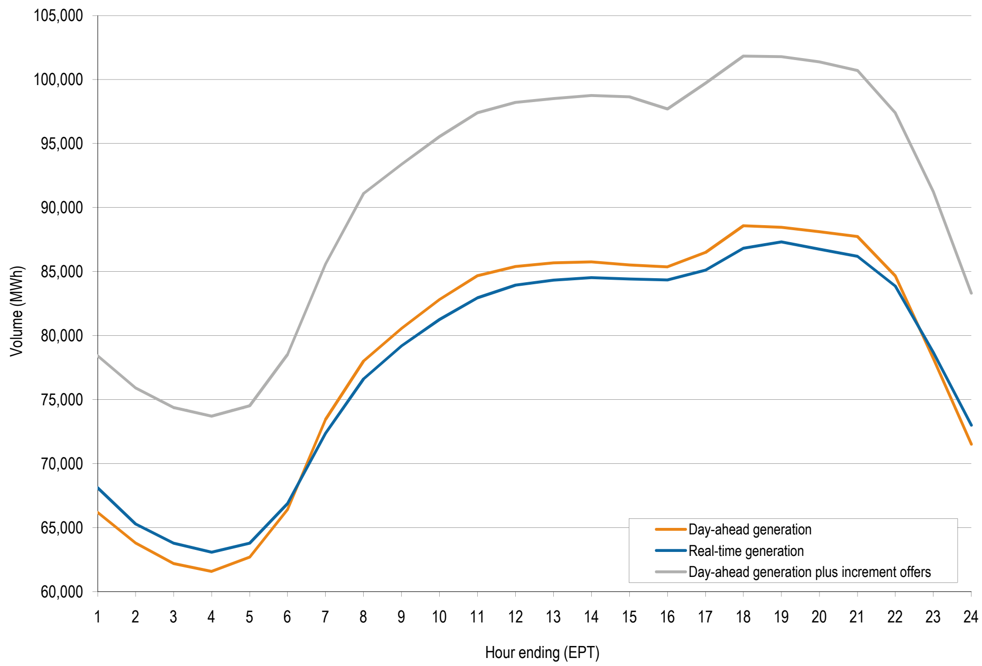
Figure 2-12 shows average hourly cleared volumes of day-ahead generation, day-ahead generation plus increment offers and real-time generation for 2009.[39] Day-ahead generation is all the self-scheduled and generator offers cleared in the Day-Ahead Energy Market. Real-time hourly average generation was lower than day-ahead generation from physical units 57.5 percent of the hours in 2009. Overall, day-ahead generation from physical units was higher than real-time generation on an hourly average basis. However, on an hourly average basis, real-time generation did exceed day-ahead generation from physical units between hours ending 1 and 6, and during hours ending 23 and 24. When cleared increment offers are included, average hourly total day-ahead cleared MW offers exceeded real-time generation.

37 All references to day-ahead generation and increment offers are presented in cleared MWh in the "Real-Time and Day-Ahead Generation" portion of the *2009 State of the Market Report for PJM,* Volume II, Section 2, "Energy Market, Part 1."

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

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

Figure 2-12 Day-ahead and real-time generation (Average hourly volumes): Calendar year 2009



Locational Marginal Price (LMP)

The conduct of individual market entities within a market structure is reflected in market prices. The overall level of prices is a good general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them.[40]

Real-Time LMP

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

Real-Time Average LMP

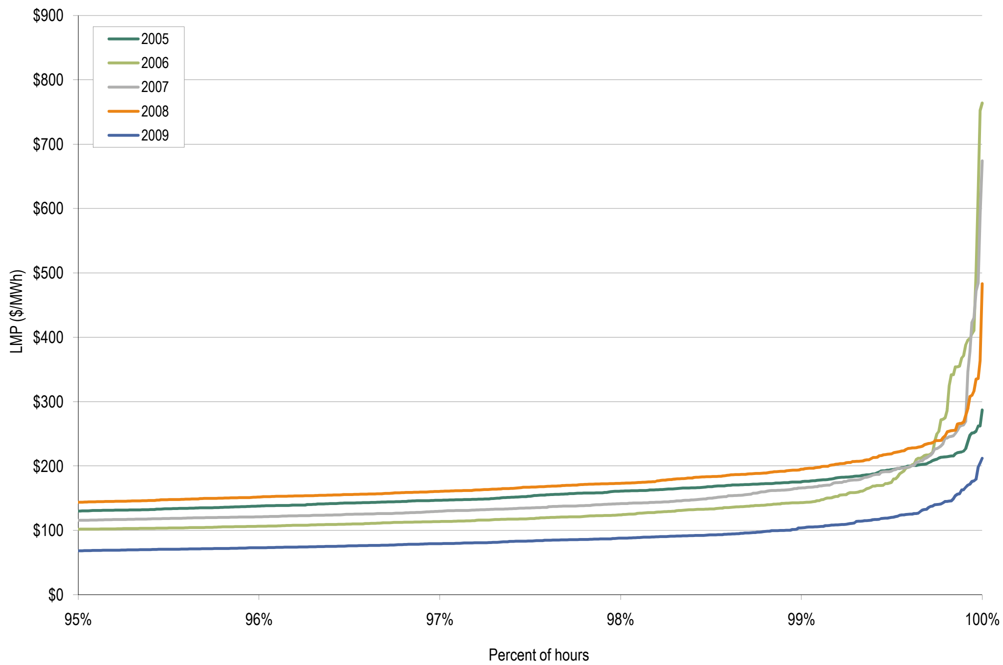
PJM Real-Time LMP Duration

A price duration curve shows the percent of hours when LMP is at, or below, a given price for the year. Figure 2-13 presents price duration curves for hours above the 95th percentile from 2005 to 2009. As Figure 2-13 shows, LMPs were less than $100 per MWh during 95 percent or more of the

40 See the *2009 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market," for methodological background, detailed price data and comparisons and Appendix H, "Calculating Locational Marginal Price" for more information on how bus LMPs are aggregated to system LMPs.

hours for the year 2009 and less than $150 during 95 percent or more of the hours for the years 2005 to 2008.[41]

Figure 2-13 Price duration curves for the PJM Real-Time Energy Market during hours above the 95th percentile: Calendar years 2005 to 2009



PJM Real-Time, Annual Average LMP

Table 2-55 shows the PJM real-time, annual, simple average LMP for the 12-year period 1998 to 2009.[42] The system simple average LMP for 2009 was 44.1 percent lower than the 2008 annual average, $37.08 per MWh versus $66.40 per MWh. The PJM real-time, annual, simple average LMP in 2009 was lower than the average LMP in every year since 2003.

41 See the *2009 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

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

Table 2-55 PJM real-time, simple average LMP (Dollars per MWh): Calendar years 1998 to 2009

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

Zonal Real-Time, Annual Average LMP

Table 2-56 shows PJM zonal real-time, simple average LMP for 2008 and 2009. The largest zonal decrease was in the AECO Control Zone which experienced a $40.03, or 49.6 percent decrease from 2008 and the smallest decrease was in the DLCO Control Zone which experienced a $16.08 decrease, or 33.0 percent, from 2008.

Table 2-56 Zonal real-time, simple average LMP (Dollars per MWh): Calendar years 2008 to 2009

	2008	2009	Difference	Difference as Percent of 2008
AECO	$80.70	$40.68	($40.03)	(49.6%)
AEP	$53.42	$33.63	($19.79)	(37.0%)
AP	$65.85	$38.29	($27.56)	(41.9%)
BGE	$80.05	$41.71	($38.33)	(47.9%)
ComEd	$49.38	$29.05	($20.33)	(41.2%)
DAY	$53.68	$33.49	($20.19)	(37.6%)
DLCO	$48.81	$32.73	($16.08)	(33.0%)
Dominion	$75.87	$40.00	($35.87)	(47.3%)
DPL	$77.20	$41.23	($35.96)	(46.6%)
JCPL	$78.80	$40.93	($37.87)	(48.1%)
Met-Ed	$74.70	$39.94	($34.77)	(46.5%)
PECO	$75.07	$40.00	($35.07)	(46.7%)
PENELEC	$63.37	$36.85	($26.52)	(41.9%)
Pepco	$80.45	$41.88	($38.57)	(47.9%)
PPL	$73.35	$39.44	($33.91)	(46.2%)
PSEG	$79.14	$41.27	($37.87)	(47.9%)
RECO	$77.46	$40.36	($37.10)	(47.9%)

Real-Time, Annual Average LMP by Jurisdiction

Table 2-57 shows the real-time, simple average LMP for all or part of the jurisdictions within the PJM footprint during 2008 and 2009. The largest decrease was in New Jersey which experienced a $38.19, or 48.2 percent decrease from 2008, and the smallest decrease was in Ohio which experienced a $19.39, or 36.8 percent, decrease from 2008.

Table 2-57 Jurisdiction real-time, simple average LMP (Dollars per MWh): Calendar years 2008 to 2009

	2008	2009	Difference	Difference as Percent of 2008
Delaware	$76.26	$40.80	($35.47)	(46.5%)
Illinois	$49.38	$29.05	($20.33)	(41.2%)
Indiana	$53.01	$33.08	($19.93)	(37.6%)
Kentucky	$53.80	$33.48	($20.32)	(37.8%)
Maryland	$79.75	$41.66	($38.09)	(47.8%)
Michigan	$54.07	$34.09	($19.98)	(36.9%)
New Jersey	$79.27	$41.08	($38.19)	(48.2%)
North Carolina	$71.69	$38.92	($32.77)	(45.7%)
Ohio	$52.64	$33.25	($19.39)	(36.8%)
Pennsylvania	$68.98	$38.47	($30.50)	(44.2%)
Tennessee	$54.36	$33.54	($20.82)	(38.3%)
Virginia	$73.20	$39.29	($33.91)	(46.3%)
West Virginia	$55.02	$34.60	($20.42)	(37.1%)
District of Columbia	$80.57	$42.98	($37.59)	(46.7%)

Hub Real-Time, Annual Average LMP

Table 2-58 shows the real-time, simple average LMPs at the PJM hubs for 2008 and 2009. Hub prices are average LMPs across a defined set of buses, created to provide market participants with trading points that exhibit greater price stability than individual buses. The largest price decrease was for the New Jersey Hub which experienced a $37.98, or 48.1 percent decrease from 2008, and the smallest decrease was for the AEP Gen Hub which experienced a $18.52, or 36.8 percent, decrease from 2008.

Table 2-58 Hub real-time, simple average LMP (Dollars per MWh): Calendar years 2008 to 2009

	2008	2009	Difference	Difference as Percent of 2008
AEP Gen Hub	$50.35	$31.83	($18.52)	(36.8%)
AEP-DAY Hub	$53.05	$33.23	($19.82)	(37.4%)
Chicago Gen Hub	$48.60	$28.28	($20.32)	(41.8%)
Chicago Hub	$49.43	$29.25	($20.18)	(40.8%)
Dominion Hub	$73.89	$39.27	($34.63)	(46.9%)
Eastern Hub	$77.15	$41.23	($35.92)	(46.6%)
N Illinois Hub	$48.99	$28.85	($20.14)	(41.1%)
New Jersey Hub	$79.02	$41.04	($37.98)	(48.1%)
Ohio Hub	$53.09	$33.24	($19.85)	(37.4%)
West Interface Hub	$58.40	$34.66	($23.74)	(40.7%)
Western Hub	$68.53	$38.30	($30.22)	(44.1%)

Real-Time, Load-Weighted, Average LMP

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

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

Table 2-59 shows the PJM real-time, annual, load-weighted, average LMP for the 12-year period 1998 to 2009. The load-weighted, average system LMP for 2009 was 45.1 percent lower than the 2008 annual, load-weighted, average, $39.05 per MWh versus $71.13 per MWh. The real-time, annual, load-weighted, average LMP in 2009 was lower than the load-weighted, average LMP in every year since 2003.

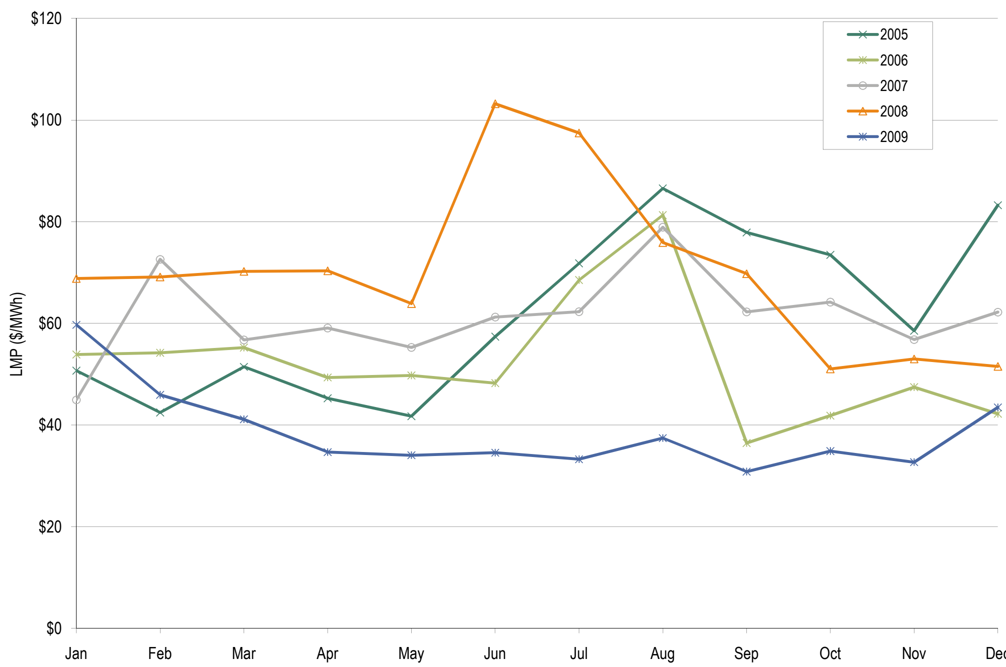
Table 2-59 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 1998 to 2009

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

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

Figure 2-14 shows the PJM real-time, monthly, load-weighted LMP from 2005 through 2009.

Figure 2-14 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2005 to 2009



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

Table 2-60 shows PJM zonal real-time, load-weighted, average LMP for 2008 and 2009. The largest zonal decrease was in the AECO Control Zone which experienced a $48.00, or 53.0 percent, decrease from 2008, and the smallest decrease was in the DLCO Control Zone which experienced a $18.59, or 35.4 percent, decrease from 2008.

Table 2-60 Zonal real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 2008 to 2009

	2008	2009	Difference	Difference as Percent of 2008
AECO	$90.55	$42.55	($48.00)	(53.0%)
AEP	$56.65	$35.20	($21.45)	(37.9%)
AP	$69.88	$40.59	($29.29)	(41.9%)
BGE	$87.11	$44.28	($42.83)	(49.2%)
ComEd	$53.63	$30.69	($22.94)	(42.8%)
DAY	$57.81	$35.11	($22.70)	(39.3%)
DLCO	$52.45	$33.86	($18.59)	(35.4%)
Dominion	$82.88	$42.67	($40.21)	(48.5%)
DPL	$83.88	$44.05	($39.83)	(47.5%)
JCPL	$86.43	$43.26	($43.17)	(50.0%)
Met-Ed	$79.81	$42.32	($37.49)	(47.0%)
PECO	$80.76	$42.03	($38.72)	(48.0%)
PENELEC	$66.47	$38.57	($27.91)	(42.0%)
Pepco	$87.89	$44.50	($43.39)	(49.4%)
PPL	$77.79	$42.10	($35.69)	(45.9%)
PSEG	$85.54	$43.08	($42.46)	(49.6%)
RECO	$85.26	$42.41	($42.85)	(50.3%)

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

Table 2-61 shows the real-time, load-weighted, average LMPs for all or part of the jurisdictions within the PJM footprint during 2008 and 2009[43]. The largest decrease was in New Jersey which experienced a $43.43, or 50.2 percent, decrease from 2008, and the smallest decrease was in Ohio which experienced a $21.19, or 37.9 percent, decrease from 2008.

Table 2-61 Jurisdiction real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 2008 to 2009

	2008	2009	Difference	Difference as Percent of 2008
Delaware	$82.25	$43.20	($39.05)	(47.5%)
Illinois	$53.63	$30.69	($22.94)	(42.8%)
Indiana	$55.98	$34.15	($21.83)	(39.0%)
Kentucky	$57.45	$35.72	($21.73)	(37.8%)
Maryland	$87.10	$44.48	($42.62)	(48.9%)
Michigan	$58.07	$35.35	($22.72)	(39.1%)
New Jersey	$86.48	$43.05	($43.43)	(50.2%)
North Carolina	$80.28	$41.24	($39.04)	(48.6%)
Ohio	$55.90	$34.71	($21.19)	(37.9%)
Pennsylvania	$73.29	$40.54	($32.75)	(44.7%)
Tennessee	$56.67	$35.47	($21.21)	(37.4%)
Virginia	$79.65	$41.97	($37.68)	(47.3%)
West Virginia	$58.21	$36.52	($21.69)	(37.3%)
District of Columbia	$86.68	$45.35	($41.33)	(47.7%)

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

Fuel Cost

Changes in LMP can result from changes in the marginal costs of marginal units, the units setting LMP. In general, fuel costs make up between 80 percent and 90 percent of marginal cost depending on generating technology, unit efficiency, unit age and other factors. The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs.[44] Changes in emission allowance costs are another contributor to changes in the marginal cost of marginal units. To account for the changes in fuel and allowance costs between 2008 and 2009, the 2009 load-weighted LMP was adjusted to reflect the change in the daily price of fuels and emission allowances used by marginal units and the change in the amount of load affected by marginal units, using sensitivity factors.[45]

43 The PJM footprint includes 17 control zones. Each control zone is in one or more states or the District of Columbia, but such jurisdictions generally are not entirely covered by PJM control zones. The term jurisdiction is used here to refer to the states in which one or more of these control zones are located. For maps showing the PJM footprint and its control zones, see the *2009 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

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

45 For more information, see the *2009 State of the Market Report for PJM*, Volume II, Appendix K, "Calculation and Use of Generator Sensitivity Factors."

The prices of the primary fuel types used in the PJM footprint, including coal, natural gas and oil, all decreased in price in 2009. In 2009, for example, the price of 1.2 percent sulfur content Central Appalachian coal was 42.6 percent lower than in 2008. The Western Rail Powder River Basin coal price was 22.1 percent lower than in 2008. Natural gas prices were 53.8 percent lower in 2009 than in 2008. No. 2 (light) oil prices were 31.9 percent lower and No. 6 (heavy) oil prices were 27.0 percent lower in 2009 than in 2008. Figure 2-15 shows spot average fuel prices for 2008 and 2009.[46]

Figure 2-15 Spot average fuel price comparison: Calendar years 2008 to 2009

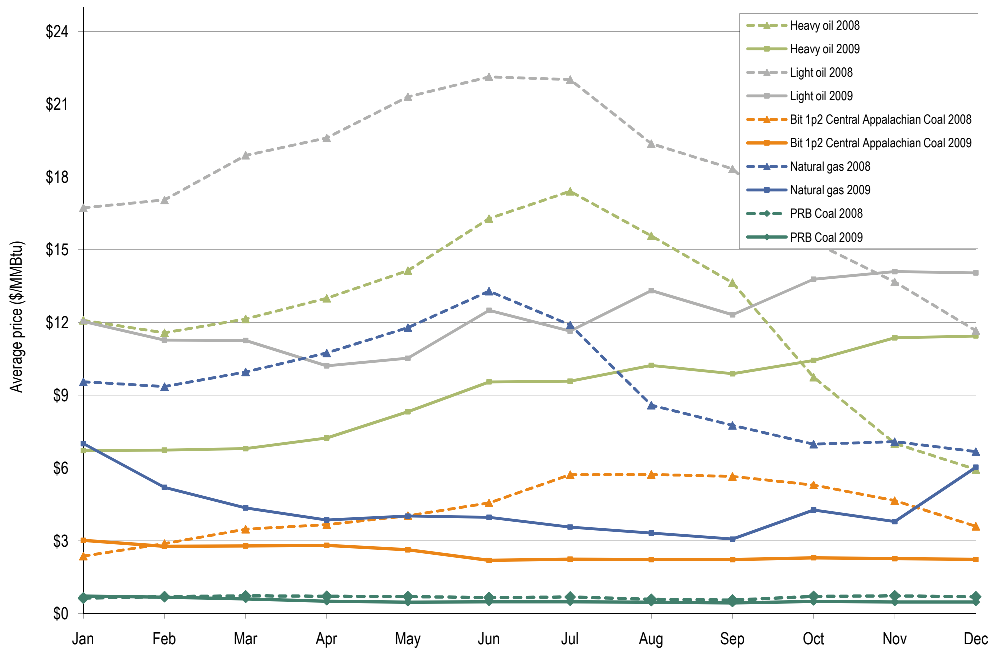
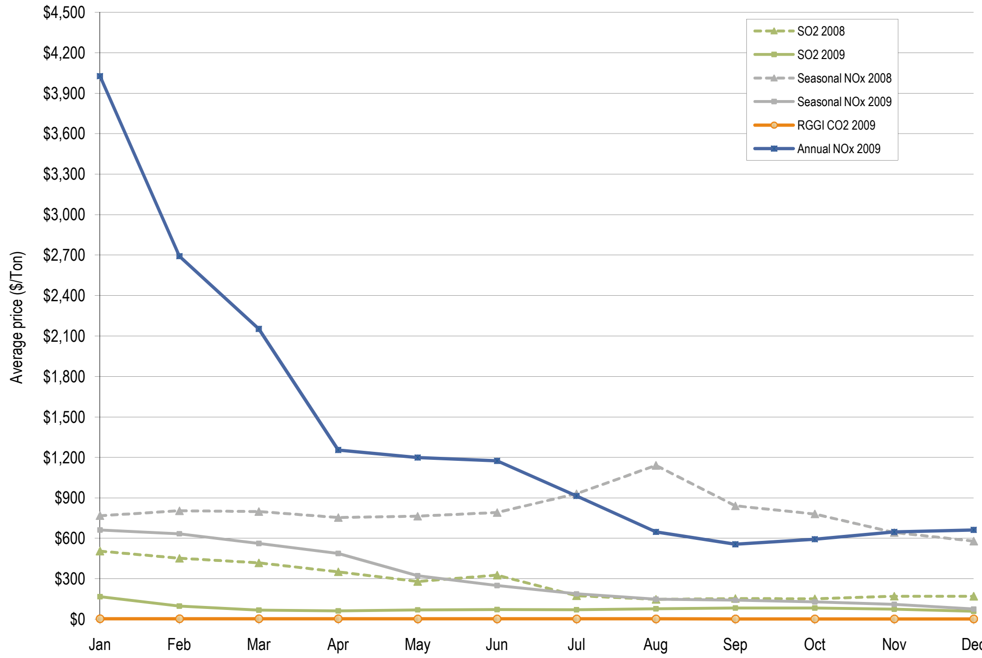


Figure 2-16 shows average, daily settled prices for NO_x and SO_2 emission within PJM. In 2009, seasonal NO_x prices were 61.6 percent lower than in 2008. SO_2 prices were 70.1 percent lower in 2009 than in 2008. Figure 2-10 also shows the average, daily settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances. RGGI allowances are required by generation in participating RGGI states. This includes PJM generation located in Delaware, Maryland, and New Jersey.

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

Figure 2-16 Spot average emission price comparison: Calendar years 2008 to 2009



The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities. Under RGGI, each state has its own CO_2 Budget Trading Program that has been implemented through state regulations based on a common set of reciprocal rules that allow the ten individual state programs to function as a single regional compliance market for CO_2 allowances. Starting in 2009, the RGGI rules require that qualifying power generators hold allowances sufficient to cover their total CO_2 emissions over each three year compliance period. Qualifying power generators can purchase their allowances for the compliance period directly from the quarterly auctions held before and during the compliance period, or from holders of allowances from previous auctions. Additional allowances can be made available via RGGI state approved qualifying offset projects, although offset allowances can make up only a limited portion of a regulated power plant's compliance obligation. The current maximum allowable contribution of CO_2 offset allowances to a power generation facility's compliance obligation is 3.3 percent of emissions per compliance period. The cap on the contribution of CO_2 offset allowances can be raised to 5 percent or to 10 percent if the calendar year average price of CO_2 allowances exceeds annual Consumer Price Index (CPI) adjusted stage 1 ($7) or stage 2 ($10) trigger prices, respectively.

Since September 25, 2008, a total of six auctions have been held for 2009- 2011 compliance period allowances, and four auctions have been held for 2012-2014 compliance period allowances. Table 2-62 shows the RGGI CO_2 auction clearing prices and quantities for the six 2009-2011 compliance period auctions held as of the end of calendar year 2009. The weighted average allowance auction price for the 2009-2011 compliance period auctions held from September 2008 through the 2009 calendar year was $2.91. Auction prices within the 2009 calendar year for the 2009-2011 compliance period peaked at $3.51 in March 18, 2009. Subsequent 2009 calendar year auctions for the 2009-2011 compliance period saw the clearing price fall, with the last auction of the year, the December 2, 2009 auction, providing the lowest auction price of the year at $2.05 an allowance. The monthly average 2009 spot price for a 2009-2011 compliance period allowance was $3.06 per ton. Monthly average spot prices for the 2009-2011 compliance period varied during the year, peaking in March at $3.80 per ton and declining to $2.16 per ton by December.

Table 2-62 RGGI CO_2 allowance auction prices and quantities: 2009-2011 Compliance Period

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

The first phase of the Environmental Protection Agency's (EPA) Clean Air Interstate Rule (CAIR) went into effect across the 28 eastern states and the District of Columbia on January 1, 2009, mandating emissions cuts of NO_x. CAIR requires upwind states to implement control measures to reduce emissions of NO_x and SO_2 and created an optional interstate cap and trade program for these pollutants. Mandates for SO_2 emissions will commence on January 1, 2010. The EPA expects that CAIR, when fully implemented, will reduce SO_2 emissions in these states by over 70 percent and NO_x emissions by over 60 percent from 2003 levels. During this period, the EPA must, consistent with court action on CAIR, develop a replacement rule, but it is unclear at this time what practical effect this might have on the substance of the EPA's program.[47]

Table 2-63 compares the 2009 PJM fuel-cost-adjusted, load-weighted, average LMP to the 2008 load-weighted, average LMP. The load-weighted, average LMP for 2009 was 45.1 percent lower than the load-weighted, average LMP for 2008. The real-time fuel-cost-adjusted, load-weighted, average LMP in 2009 was 10.5 percent lower than the load-weighted LMP in 2008. If fuel costs for the year 2009 had been the same as for 2008, the 2009 load-weighted LMP would have been higher, $63.66 per MWh instead of the observed $39.05 per MWh. Lower coal, gas and oil prices in 2009 resulted in lower prices in 2009 than would have occurred if fuel prices had remained at their 2008 levels. Net fuel cost decreases were the primary reason for the lower LMPs in 2009. Lower loads also contributed to lower LMPs.

Table 2-63 PJM annual, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Year-over-year method

	2008 Load-Weighted LMP	2009 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$71.13	$63.66	(10.5%)

47 See North Carolina v. Environmental Protection Agency, et al., 531 F.3d 896 (D.C. Circuit 2008).

Components of Real-Time, Load-Weighted LMP

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

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

Table 2-64 shows that 52.6 percent of the annual, load-weighted LMP was the result of coal costs; 31.0 percent was the result of gas costs and 5.6 percent was the result of the cost of emission allowances. Markup was -6.1 percent of LMP. The fuel-related components of LMP reflect the impact of the cost of the identified fuel on LMP rather than all of the components of the offers of units burning that fuel on LMP.

As a result of the way in which LMP is calculated, there are differences between the components of LMP associated with individual unit characteristics, e.g. fuel costs and VOM, and observed LMP. This total net difference in 2009 was -$0.67 per MWh. (Numbers in parentheses in the table are negative.) The components of this difference are listed in Table 2-64.[48]

Table 2-64 Components of PJM real-time, annual, load-weighted, average LMP: Calendar year 2009

Element	Contribution to LMP	Percent
Coal	$20.53	52.6%
Natural Gas	$12.10	31.0%
10% Cost Adder	$3.73	9.6%
VOM	$2.50	6.4%
Oil	$0.88	2.3%
NO_x	$0.80	2.1%
SO_2	$0.76	1.9%
CO_2	$0.61	1.6%
FMU Adder	$0.17	0.4%
Offline CT Adder	$0.03	0.1%
Municipal Waste	$0.02	0.0%
NA	$0.01	0.0%
Unit LMP Differential	$0.00	0.0%
Shadow Price Limit Adder	($0.01)	(0.0%)
M2M Adder	($0.14)	(0.3%)
Dispatch Differential	($0.15)	(0.4%)
UDS Override Differential	($0.43)	(1.1%)
Markup	($2.38)	(6.1%)
LMP	$39.05	100.0%

48 These components are explained in the *2009 State of the Market Report for PJM,* Volume II, Appendix K, "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Day-Ahead LMP

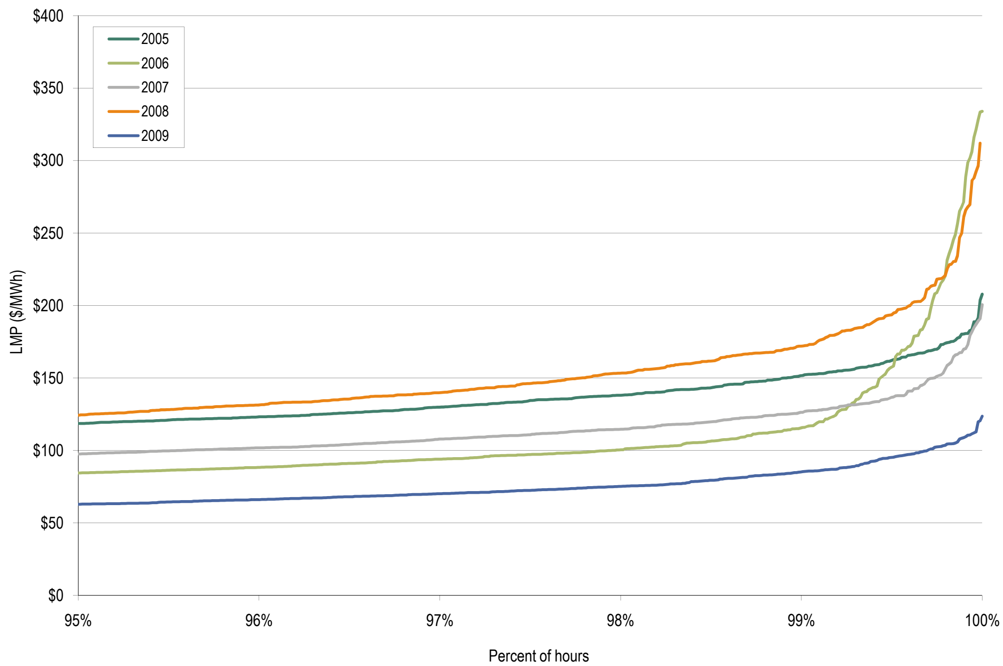
Day-ahead LMP is the hourly LMP for the PJM Day-Ahead Energy Market.

Day-Ahead Average LMP

PJM Day-Ahead LMP Duration

A price duration curve shows the percent of hours when LMP is at, or below, a given price for the year. Figure 2-17 presents day-ahead price duration curves for hours above the 95th percentile from 2005 to 2009. As Figure 2-11 shows, day-ahead LMP was less than \$100 per MWh during 95 percent or more of the hours for the years 2006, 2007 and 2009 and less than \$150 during 95 percent or more of the hours for 2005 and 2008.

Figure 2-17 Price duration curves for the PJM Day-Ahead Energy Market during hours above the 95th percentile: Calendar years 2005 to 2009



PJM Day-Ahead, Annual Average LMP

Table 2-65 shows the PJM day-ahead annual, simple average LMP for the 10 year period 2000 to 2009. The system simple average LMP for 2009 was 44.0 percent lower than the 2008 annual average, $37.00 per MWh versus $66.12 per MWh. The PJM day-ahead annual, simple average LMP in 2009 was lower than every prior year since 2003.

Table 2-65 PJM day-ahead, simple average LMP (Dollars per MWh): Calendar years 2000 to 2009

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

Zonal Day-Ahead, Annual Average LMP

Table 2-66 shows PJM zonal day-ahead, simple average LMP for 2008 and 2009. The largest zonal decrease was in the Pepco Control Zone which experienced a $38.72, or 47.6 percent, decrease from 2008 and the smallest decrease was in the DLCO Control Zone which experienced a $18.59, or 36.5 percent, decrease from 2008.

Table 2-66 Zonal day-ahead, simple average LMP (Dollars per MWh): Calendar years 2008 to 2009

	2008	2009	Difference	Difference as Percent of 2008
AECO	$78.99	$41.44	($37.54)	(47.5%)
AEP	$53.61	$33.44	($20.17)	(37.6%)
AP	$65.09	$37.80	($27.29)	(41.9%)
BGE	$80.70	$42.57	($38.13)	(47.3%)
ComEd	$50.50	$28.94	($21.55)	(42.7%)
DAY	$53.53	$32.94	($20.59)	(38.5%)
DLCO	$50.92	$32.33	($18.59)	(36.5%)
Dominion	$75.60	$40.58	($35.02)	(46.3%)
DPL	$77.95	$41.73	($36.22)	(46.5%)
JCPL	$79.74	$41.36	($38.38)	(48.1%)
Met-Ed	$75.54	$40.35	($35.19)	(46.6%)
PECO	$76.23	$40.79	($35.44)	(46.5%)
PENELEC	$65.11	$37.09	($28.02)	(43.0%)
Pepco	$81.26	$42.54	($38.72)	(47.6%)
PPL	$74.25	$39.90	($34.35)	(46.3%)
PSEG	$79.77	$41.84	($37.93)	(47.6%)
RECO	$78.08	$40.92	($37.16)	(47.6%)

Day-Ahead, Annual Average LMP by Jurisdiction

Table 2-67 shows PJM's day-ahead, simple average LMPs for 2008 and 2009, by jurisdiction. The largest decrease was in New Jersey which experienced a $38.05, or 47.7 percent, decrease from 2008, and the smallest decrease was in Ohio which experienced a $20.02, or 37.9 percent, decrease from 2008.

Table 2-67 Jurisdiction day-ahead, simple average LMP (Dollars per MWh): Calendar years 2008 to 2009

	2008	2009	Difference	Difference as Percent of 2008
Delaware	$76.88	$41.15	($35.73)	(46.5%)
Illinois	$50.50	$28.94	($21.55)	(42.7%)
Indiana	$53.58	$32.87	($20.71)	(38.7%)
Kentucky	$53.36	$33.22	($20.14)	(37.7%)
Maryland	$80.01	$42.38	($37.63)	(47.0%)
Michigan	$54.48	$33.94	($20.53)	(37.7%)
New Jersey	$79.68	$41.64	($38.05)	(47.7%)
North Carolina	$71.66	$39.50	($32.16)	(44.9%)
Ohio	$52.85	$32.83	($20.02)	(37.9%)
Pennsylvania	$70.04	$38.80	($31.24)	(44.6%)
Tennessee	$54.24	$33.66	($20.58)	(37.9%)
Virginia	$73.01	$39.88	($33.13)	(45.4%)
West Virginia	$54.67	$34.34	($20.33)	(37.2%)
District of Columbia	$81.04	$43.38	($37.66)	(46.5%)

Day-Ahead, Load-Weighted, Average LMP

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

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

Table 2-68 shows the PJM day-ahead, annual, load-weighted, average LMP for the 10-year period 2000 to 2009. The day-ahead, load-weighted, average LMP for 2009 was 44.7 percent lower than the 2008 annual, load-weighted, average, at $38.82 per MWh versus $70.25 per MWh. The day-ahead, load-weighted, average LMP for 2009 was lower than in every prior year since 2003.

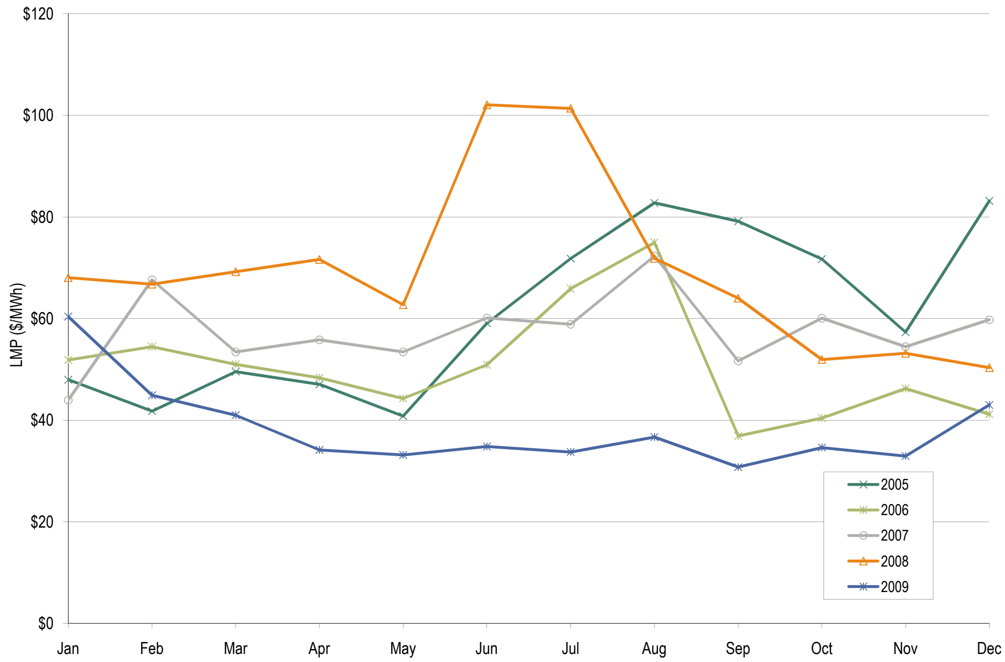
Table 2-68 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2000 to 2009

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

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

Figure 2-18 shows the PJM day-ahead, monthly, load-weighted LMP from 2005 through 2009.

Figure 2-18 Day-ahead, monthly, load-weighted, average LMP: Calendar years 2005 to 2009



Zonal Day-Ahead, Annual, Load-Weighted LMP

Table 2-69 shows PJM's zonal day-ahead, load-weighted, average LMPs for 2008 and 2009. The largest zonal decrease was in the AECO Control Zone which experienced a $45.23, or 51.0 percent, decrease from 2008, and the smallest decrease was in the DLCO Control Zone which experienced a $20.95, or 38.6 percent, decrease from 2008.

Table 2-69 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2008 to 2009

	2008	2009	Difference	Difference as Percent of 2008
AECO	$88.77	$43.54	($45.23)	(51.0%)
AEP	$56.48	$34.92	($21.56)	(38.2%)
AP	$67.94	$39.97	($27.97)	(41.2%)
BGE	$87.50	$44.94	($42.56)	(48.6%)
ComEd	$53.83	$30.09	($23.74)	(44.1%)
DAY	$57.04	$34.38	($22.66)	(39.7%)
DLCO	$54.33	$33.37	($20.95)	(38.6%)
Dominion	$81.98	$43.16	($38.82)	(47.3%)
DPL	$84.24	$44.15	($40.09)	(47.6%)
JCPL	$86.65	$43.51	($43.14)	(49.8%)
Met-Ed	$79.88	$42.72	($37.16)	(46.5%)
PECO	$81.44	$42.80	($38.64)	(47.4%)
PENELEC	$67.56	$38.50	($29.06)	(43.0%)
Pepco	$86.36	$44.83	($41.53)	(48.1%)
PPL	$78.08	$42.32	($35.76)	(45.8%)
PSEG	$85.82	$43.70	($42.12)	(49.1%)
RECO	$84.73	$43.24	($41.49)	(49.0%)

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

Table 2-70 shows PJM's day-ahead, load-weighted, average LMP for 2008 and 2009 by jurisdiction. The largest decrease was in New Jersey which experienced a $42.79, or 49.5 percent, decrease from 2008, and the smallest decrease was in Kentucky which experienced a $20.77, or 37.1 percent, decrease from 2008.

Table 2-70 Jurisdiction day-ahead, load weighted LMP (Dollars per MWh): Calendar years 2008 to 2009

	2008	2009	Difference	Difference as Percent of 2008
Delaware	$82.99	$43.36	($39.62)	(47.7%)
Illinois	$53.83	$30.09	($23.74)	(44.1%)
Indiana	$56.53	$33.89	($22.64)	(40.0%)
Kentucky	$56.02	$35.25	($20.77)	(37.1%)
Maryland	$85.98	$44.90	($41.08)	(47.8%)
Michigan	$57.83	$35.08	($22.75)	(39.3%)
New Jersey	$86.39	$43.60	($42.79)	(49.5%)
North Carolina	$78.13	$41.93	($36.19)	(46.3%)
Ohio	$55.72	$34.22	($21.50)	(38.6%)
Pennsylvania	$73.58	$40.69	($32.89)	(44.7%)
Tennessee	$56.50	$35.51	($20.99)	(37.1%)
Virginia	$78.63	$42.40	($36.23)	(46.1%)
West Virginia	$57.56	$36.04	($21.52)	(37.4%)
District of Columbia	$85.66	$45.86	($39.80)	(46.5%)

Components of Day-Ahead, Load-Weighted LMP

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

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

Table 2-71 Components of PJM day-ahead, annual, load-weighted, average LMP (Dollars per MWh): Calendar year 2009

Element	Contribution to LMP	Percent
DEC	$11.97	30.8%
INC	$11.65	30.0%
Coal	$8.73	22.5%
Natural Gas	$2.82	7.3%
Price Sensitive Demand	$1.38	3.6%
10% Cost Adder	$1.34	3.4%
VOM	$0.88	2.3%
Transaction	$0.81	2.1%
NO_x	$0.32	0.8%
SO_2	$0.30	0.8%
CO_2	$0.19	0.5%
Oil	$0.13	0.3%
Diesel	$0.00	0.0%
Constrained Off	$0.00	0.0%
FMU Adder	$0.00	0.0%
NA	($0.05)	(0.1%)
Markup	($1.65)	(4.2%)
Total	$38.82	100.0%

Marginal Losses

Marginal losses are the incremental change in system real power losses caused by changes in the system load and generation patterns.[49] Before June 1, 2007, the PJM economic dispatch and LMP models did not include marginal losses. The losses were treated as a static component of load, and the physical nature and location of power system losses were ignored. The PJM Tariff required implementation of marginal loss modeling when required technical systems became available. On June 1, 2007, PJM began including marginal losses in economic dispatch and LMP models.[50] The primary benefit of a marginal loss mechanism is that it more accurately models the physical reality of power system losses. More accurate models permit increased efficiency and optimize asset utilization. One characteristic of marginal loss modeling is that it creates a separate marginal loss price for every location on the power grid.

Table 2-72 shows the PJM real-time, simple average LMP components, including the loss component, for calendar years 2006 to 2009. As of June 1, 2007, PJM changed from a single node reference bus to a distributed load reference bus. While there is no effect on the total LMP, the components of LMP change with a shift in the reference bus. With a distributed load reference bus, the energy component is now a load-weighted system price. In turn, this means that there is no congestion

49 For additional information, see the *2009 State of the Market Report for PJM*, Volume II, Appendix J, “Marginal Losses.”

50 For additional information, see PJM. “Open Access Transmission Tariff” (December 10, 2007), Section 3.4, Original Sheet No. 388G.

or losses included at the PJM price, unlike the case with a single node reference bus. The energy price equals the PJM price in a given hour and on a yearly average basis. Table 2-72 shows a $0.03 loss component included at the PJM price. The PJM price is weighted with accounting load, which differs from the state-estimated load used in determination of the energy component. The $0.03 loss component of the average PJM system price results from these different weights. The $2.08 and $1.00 congestion component of the average PJM system price for 2006 and 2007 respectively, resulted from the fact that the distributed load reference bus did not go into effect until June 1, 2007.

Table 2-72 PJM real-time, simple average LMP components (Dollars per MWh): Calendar years 2006 to 2009

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

Table 2-73 shows the zonal real-time, simple average LMP components, including the loss component, for calendar years 2008 and 2009.

Table 2-73 Zonal real-time, simple average LMP components (Dollars per MWh): Calendar years 2008 to 2009

	2008				2009			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$80.70	$66.29	$10.77	$3.64	$40.68	$37.01	$1.83	$1.84
AEP	$53.42	$66.29	($10.46)	($2.42)	$33.63	$37.01	($2.16)	($1.22)
AP	$65.85	$66.29	$0.29	($0.73)	$38.29	$37.01	$1.32	($0.03)
BGE	$80.05	$66.29	$11.06	$2.69	$41.71	$37.01	$3.04	$1.67
ComEd	$49.38	$66.29	($13.46)	($3.46)	$29.05	$37.01	($5.61)	($2.35)
DAY	$53.68	$66.29	($11.18)	($1.43)	$33.49	$37.01	($2.72)	($0.79)
DLCO	$48.81	$66.29	($14.47)	($3.01)	$32.73	$37.01	($3.02)	($1.26)
Dominion	$75.87	$66.29	$8.76	$0.82	$40.00	$37.01	$2.37	$0.62
DPL	$77.20	$66.29	$7.69	$3.21	$41.23	$37.01	$2.32	$1.91
JCPL	$78.80	$66.29	$8.64	$3.87	$40.93	$37.01	$2.01	$1.91
Met-Ed	$74.70	$66.29	$6.51	$1.90	$39.94	$37.01	$2.03	$0.90
PECO	$75.07	$66.29	$6.11	$2.67	$40.00	$37.01	$1.71	$1.28
PENELEC	$63.37	$66.29	($2.33)	($0.59)	$36.85	$37.01	($0.06)	($0.09)
Pepco	$80.45	$66.29	$12.40	$1.76	$41.88	$37.01	$3.74	$1.13
PPL	$73.35	$66.29	$5.50	$1.55	$39.44	$37.01	$1.75	$0.68
PSEG	$79.14	$66.29	$8.92	$3.92	$41.27	$37.01	$2.27	$2.00
RECO	$77.46	$66.29	$7.62	$3.54	$40.36	$37.01	$1.55	$1.80

Table 2-74 shows the real-time, annual, simple average LMP loss component at the PJM hubs for 2009, for each hub in PJM.

Table 2-74 Hub real-time, simple average LMP components (Dollars per MWh): Calendar year 2009

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$31.83	$37.01	($2.82)	($2.35)
AEP-DAY Hub	$33.23	$37.01	($2.40)	($1.38)
Chicago Gen Hub	$28.28	$37.01	($5.90)	($2.82)
Chicago Hub	$29.25	$37.01	($5.43)	($2.33)
Dominion Hub	$39.27	$37.01	$2.00	$0.26
Eastern Hub	$41.23	$37.01	$2.14	$2.08
N Illinois Hub	$28.85	$37.01	($5.62)	($2.53)
New Jersey Hub	$41.04	$37.01	$2.12	$1.91
Ohio Hub	$33.24	$37.01	($2.42)	($1.34)
West Interface Hub	$34.66	$37.01	($1.20)	($1.15)
Western Hub	$38.30	$37.01	$1.42	($0.12)

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

Table 2-75 shows the real-time, annual, load-weighted, average LMP components, for PJM and its 17 control zones for 2009.

Table 2-75 Zonal and PJM real-time, annual, load-weighted, average LMP components (Dollars per MWh): Calendar year 2009

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$42.55	$38.60	$1.98	$1.97
AEP	$35.20	$39.03	($2.53)	($1.30)
AP	$40.59	$39.24	$1.41	($0.06)
BGE	$44.28	$39.07	$3.43	$1.78
ComEd	$30.69	$38.59	($5.50)	($2.40)
DAY	$35.11	$39.02	($3.12)	($0.79)
DLCO	$33.86	$38.59	($3.38)	($1.35)
Dominion	$42.67	$39.24	$2.78	$0.65
DPL	$44.05	$39.25	$2.71	$2.09
JCPL	$43.26	$39.02	$2.18	$2.06
Met-Ed	$42.32	$39.08	$2.27	$0.97
PECO	$42.03	$38.80	$1.87	$1.36
PENELEC	$38.57	$38.87	($0.18)	($0.11)
Pepco	$44.50	$38.96	$4.36	$1.18
PPL	$42.10	$39.31	$2.02	$0.77
PSEG	$43.08	$38.57	$2.41	$2.10
RECO	$42.41	$38.82	$1.68	$1.91
PJM	$39.05	$38.97	$0.05	$0.03

Table 2-76 shows the PJM day-ahead, simple average LMP components, including the loss component, for calendar years 2006 through 2009. As of June 1, 2007, PJM changed from a single node reference bus to a distributed load reference bus. While there is no effect on the total LMP, the components of LMP change with a shift in the reference bus. With a distributed load reference bus, the energy component is now a load-weighted system price. In turn, this means that there is no congestion or losses included at the PJM price, unlike the case with a single node reference bus. The energy price equals the PJM price in a given hour and on a yearly average basis. In the Day-Ahead Energy Market, the distributed load reference bus is weighted with fixed-demand bids only and the day-ahead energy component is, therefore, a system fixed-demand-weighted price. The day-ahead system price calculation uses all types of demand, including fixed, price-sensitive and decrement bids. In the Real-Time Energy Market, the energy component equals the system load-weighted price; however, in the Day-Ahead Energy Market the energy component and the PJM system price are not equal, but the loss component and the congestion component have only a small effect. This is due to the use of all types of demand to weight the PJM price and not fixed demand only.

Table 2-76 PJM day-ahead, simple average LMP components (Dollars per MWh): Calendar years 2006 to 2009

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

Table 2-77 shows the zonal day-ahead, simple average LMP components, including the loss component, for calendar years 2008 and 2009.[51]

Table 2-77 Zonal day-ahead, simple average LMP components (Dollars per MWh): Calendar years 2008 to 2009.

	2008				2009			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$78.99	$66.43	$7.93	$4.63	$41.44	$37.15	$2.03	$2.26
AEP	$53.61	$66.43	($9.56)	($3.26)	$33.44	$37.15	($2.12)	($1.59)
AP	$65.09	$66.43	($0.50)	($0.84)	$37.80	$37.15	$0.62	$0.03
BGE	$80.70	$66.43	$10.96	$3.31	$42.57	$37.15	$3.33	$2.08
ComEd	$50.50	$66.43	($11.37)	($4.56)	$28.94	$37.15	($5.09)	($3.12)
DAY	$53.53	$66.43	($10.04)	($2.86)	$32.94	$37.15	($2.77)	($1.45)
DLCO	$50.92	$66.43	($11.77)	($3.73)	$32.33	$37.15	($3.37)	($1.46)
Dominion	$75.60	$66.43	$8.07	$1.10	$40.58	$37.15	$2.47	$0.96
DPL	$77.95	$66.43	$7.63	$3.90	$41.73	$37.15	$2.25	$2.33
JCPL	$79.74	$66.43	$7.92	$5.39	$41.36	$37.15	$1.82	$2.39
Met-Ed	$75.54	$66.43	$6.59	$2.53	$40.35	$37.15	$2.10	$1.10
PECO	$76.23	$66.43	$5.93	$3.87	$40.79	$37.15	$1.87	$1.78
PENELEC	$65.11	$66.43	($0.91)	($0.41)	$37.09	$37.15	($0.10)	$0.03
Pepco	$81.26	$66.43	$12.28	$2.55	$42.54	$37.15	$3.75	$1.64
PPL	$74.25	$66.43	$5.62	$2.20	$39.90	$37.15	$1.88	$0.86
PSEG	$79.77	$66.43	$7.76	$5.58	$41.84	$37.15	$2.12	$2.57
RECO	$78.08	$66.43	$6.55	$5.10	$40.92	$37.15	$1.47	$2.30

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

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

Table 2-78 shows zonal and PJM day-ahead, annual, load-weighted, average LMP components for calendar year 2009.

Table 2-78 Zonal and PJM day-ahead, load-weighted, average LMP components (Dollars per MWh): Calendar year 2009

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$43.54	$38.85	$2.26	$2.43
AEP	$34.92	$39.15	($2.53)	($1.70)
AP	$39.97	$39.44	$0.51	$0.02
BGE	$44.94	$39.01	$3.71	$2.22
ComEd	$30.09	$38.38	($5.09)	($3.20)
DAY	$34.38	$39.11	($3.20)	($1.52)
DLCO	$33.37	$38.62	($3.69)	($1.55)
Dominion	$43.16	$39.27	$2.87	$1.03
DPL	$44.15	$39.10	$2.56	$2.49
JCPL	$43.51	$38.99	$1.99	$2.52
Met-Ed	$42.72	$39.16	$2.38	$1.18
PECO	$42.80	$38.87	$2.05	$1.88
PENELEC	$38.50	$38.64	($0.19)	$0.04
Pepco	$44.83	$38.80	$4.29	$1.73
PPL	$42.32	$39.21	$2.14	$0.96
PSEG	$43.70	$38.75	$2.26	$2.69
RECO	$43.24	$39.21	$1.60	$2.44
PJM	$38.82	$38.96	($0.04)	($0.09)

Marginal Loss Accounting

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

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

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

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

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

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

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

Monthly Marginal Loss Costs

Table 2-79 shows a monthly summary of marginal loss costs by type for 2009. Marginal loss costs totaled $1.268 billion. The highest monthly loss cost was in January and totaled $207.3 million or 16.3 percent of the total. The majority of the marginal loss costs was in the Day-Ahead Energy Market and totaled $1.293 billion. The day-ahead costs were offset, in part, by a total of -$24.5 million in the balancing market. The overcollected portion of transmission losses that was credited back to load plus exports as of December 31, 2009, was $639.7 million or 50.8 percent of the total losses. In determining the overcollected loss amount, PJM accumulates the day-ahead and balancing transmission loss charges paid by all customer accounts each hour, subtracts the spot market energy value of the actual transmission loss MWh during that hour, and allocates this amount as transmission loss credits each hour.[52]

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

Table 2-79 Marginal loss costs by type (Dollars (Millions)): Calendar year 2009

	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
Oct	$14.4	($51.8)	$3.8	$69.9	($0.5)	($0.5)	($3.0)	($2.9)	$67.0
Nov	$22.0	($53.8)	$3.7	$79.6	$0.0	($0.7)	($1.7)	($1.0)	$78.6
Dec	$31.9	($93.3)	$4.8	$129.9	($0.1)	($1.7)	($1.7)	($0.1)	$129.8
Total	$319.9	($907.3)	$65.4	$1,292.6	($4.1)	($13.0)	($33.5)	($24.5)	$1,268.1

Zonal Marginal Loss Costs

Table 2-80 shows the marginal loss costs by type in each control zone in 2009. The ComEd, AEP and Dominion control zones had the highest marginal loss costs in 2009, with $264.6 million, $214.8 million and $132.9 million, respectively. Energy flows in PJM are generally from west to east, reflecting the fact that less expensive generation in the western portion of PJM is dispatched to assist in meeting the demand of load centers located in the eastern portion of PJM. Generation supplied from western resources to satisfy eastern load generally results in increased west-to-east transmission flow and increased losses. As may be seen in Table 2-80, the marginal loss generation credits in the western zones are generally greaeter in magnitude than those of the eastern zones. The characteristics of the marginal loss component of LMP are analogous to those of the congestion component of LMP, or CLMP. Generation congestion credits are generally negative for units located on the unconstrained side of a transmission element, indicating that an increase in output tends to increase the flow of energy across the constrained element. Analogously, the generation marginal loss credits are generally negative for units for which an increase in output tends to increase system losses.

Table 2-80 Marginal loss costs by control zone and type (Dollars (Millions)): Calendar year 2009

	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	$25.9	$5.2	$0.2	$21.0	$0.3	($0.2)	$0.1	$0.5	$21.5
AEP	($49.5)	($247.3)	$18.7	$216.6	($0.6)	($0.5)	($1.6)	($1.7)	$214.8
AP	$2.8	($79.2)	$6.9	$88.8	$2.6	$3.8	($2.7)	($3.9)	$84.9
BGE	$57.9	$13.9	$1.7	$45.7	$2.8	($1.9)	($1.3)	$3.3	$49.0
ComEd	($157.3)	($419.4)	($0.3)	$261.8	$0.2	($2.1)	$0.4	$2.8	$264.6
DAY	($4.4)	($56.1)	$1.3	$53.0	($0.3)	$2.4	$0.1	($2.6)	$50.4
DLCO	($21.3)	($41.9)	$0.1	$20.7	($2.2)	$0.1	($0.0)	($2.3)	$18.4
DPL	$49.7	$11.0	$0.5	$39.1	($2.6)	($1.4)	($0.3)	($1.5)	$37.6
Dominion	$84.7	($41.8)	$4.2	$130.7	$2.1	($1.9)	($1.8)	$2.2	$132.9
JCPL	$59.2	$21.8	$0.2	$37.5	$0.2	($2.2)	($0.2)	$2.2	$39.7
Met-Ed	$18.2	$3.5	$0.2	$14.9	$0.1	($0.5)	($0.1)	$0.5	$15.4
PECO	$59.0	$12.9	$0.0	$46.1	($0.5)	($0.7)	($0.0)	$0.2	$46.3
PENELEC	($13.1)	($77.8)	$0.4	$65.0	($2.3)	($0.3)	($0.1)	($2.0)	$63.0
Pepco	$81.2	$35.5	$2.4	$48.1	($2.2)	($2.5)	($1.7)	($1.4)	$46.8
PJM	($7.6)	($42.8)	$21.6	$56.8	($0.5)	($11.7)	($19.4)	($8.2)	$48.6
PPL	$36.7	($23.0)	$1.4	$61.1	($0.1)	$1.0	$0.2	($0.9)	$60.2
PSEG	$94.3	$18.2	$5.9	$82.1	($1.0)	$5.6	($5.0)	($11.6)	$70.5
RECO	$3.4	$0.1	$0.1	$3.5	$0.1	($0.1)	($0.1)	$0.0	$3.5
Total	$319.9	($907.3)	$65.4	$1,292.6	($4.1)	($13.0)	($33.5)	($24.5)	$1,268.1

Table 2-81 shows the monthly marginal loss cost, by control zone in 2009.

Table 2-81 Monthly marginal loss costs by control zone (Dollars (Millions)): Calendar year 2009

	Marginal Loss Costs by Control Zone (Millions)												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
AECO	$3.4	$2.0	$1.7	$1.7	$1.2	$1.3	$2.0	$2.7	$1.2	$0.9	$1.3	$2.1	$21.5
AEP	$32.6	$22.9	$18.6	$13.1	$11.7	$17.5	$15.0	$21.9	$13.4	$11.0	$12.9	$24.1	$214.8
AP	$18.0	$9.4	$8.4	$6.2	$4.8	$5.4	$5.0	$7.5	$3.3	$3.6	$4.7	$8.7	$84.9
BGE	$7.0	$4.4	$4.2	$2.6	$2.8	$3.4	$4.1	$5.2	$3.4	$2.8	$3.8	$5.2	$49.0
ComEd	$36.3	$26.1	$28.0	$19.4	$16.9	$18.4	$19.3	$21.2	$16.1	$17.1	$19.4	$26.4	$264.6
DAY	$7.8	$4.6	$4.5	$3.3	$2.2	$3.7	$3.9	$4.4	$3.5	$3.9	$4.6	$4.1	$50.4
DLCO	$3.5	$1.9	$2.1	$1.2	$0.7	$1.6	$1.6	$1.4	$1.3	$0.3	$0.6	$2.2	$18.4
DPL	$6.8	$4.3	$4.0	$2.9	$2.4	$2.2	$3.0	$3.4	$2.1	$1.4	$1.8	$3.2	$37.6
Dominion	$20.2	$11.8	$11.1	$7.0	$8.2	$11.5	$12.2	$14.3	$8.2	$6.8	$7.6	$13.7	$132.9
JCPL	$8.3	$5.6	$3.7	$2.4	$2.1	$1.8	$2.5	$3.3	$1.4	$1.5	$2.0	$5.1	$39.7
Met-Ed	$2.4	$1.4	$1.2	$0.9	$0.8	$1.4	$1.4	$1.6	$1.1	$0.9	$0.6	$1.8	$15.4
PECO	$8.0	$4.3	$3.5	$2.6	$2.9	$4.1	$4.1	$5.6	$3.4	$2.3	$2.0	$3.6	$46.3
PENELEC	$12.1	$5.6	$4.3	$4.1	$5.0	$5.6	$5.9	$6.0	$3.2	$3.1	$2.8	$5.4	$63.0
Pepco	$6.0	$3.6	$4.3	$3.1	$2.8	$3.7	$4.1	$5.0	$3.2	$2.9	$3.5	$4.5	$46.8
PJM	$14.1	$6.0	$4.8	$2.0	$3.2	$1.3	$2.6	$2.2	$0.8	$1.2	$3.1	$7.4	$48.6
PPL	$10.1	$6.5	$5.5	$3.8	$3.0	$4.5	$4.9	$5.1	$3.6	$3.6	$3.6	$6.1	$60.2
PSEG	$10.1	$8.8	$7.1	$6.0	$5.1	$4.9	$5.3	$6.1	$4.0	$3.4	$4.1	$5.7	$70.5
RECO	$0.6	$0.4	$0.3	$0.3	$0.2	$0.2	$0.2	$0.3	$0.2	$0.2	$0.2	$0.4	$3.5
Total	$207.3	$129.7	$117.2	$82.6	$76.0	$92.3	$97.0	$117.4	$73.2	$67.0	$78.6	$129.8	$1,268.1

Virtual Offers and Bids

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

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

Any market participant in the PJM Day-Ahead Energy Market can use increment offers and decrement bids as financial instruments that do not require physical generation or load. Increment offers and decrement bids may be submitted at any hub, transmission zone, aggregate, or single bus for which LMP is calculated. Table 2-82 shows the average volume of trading in virtual bids per hour, as well as the average total MW values of all virtual bids per hour.

Table 2-82 Monthly volume of cleared and submitted INCs, DECs: Calendar year 2009

	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	22,449	459	993	16,736	23,285	480	957
Oct	13,178	26,649	467	1,246	15,705	26,058	364	1,041
Nov	12,914	22,725	366	903	14,976	22,266	289	726
Dec	11,679	23,958	275	850	14,998	26,715	270	862
Annual	12,873	21,233	405	847	15,322	22,881	444	804

Table 2-83 shows the frequency with which generation offers, import or export transactions, decrement bids, increment offers and price-sensitive demand are marginal for each month in 2009.[53] Together, increment offers and decrement bids represented 51.4 percent of the marginal bids or offers in 2009.

Table 2-83 Type of day-ahead marginal units: Calendar year 2009

	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%
Oct	9.3%	32.8%	22.7%	34.6%	0.6%
Nov	16.3%	28.8%	27.0%	27.4%	0.6%
Dec	16.2%	20.6%	43.1%	19.0%	1.1%
Annual	14.7%	33.2%	30.1%	21.3%	0.7%

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

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

Table 2-84 shows virtual bids by the type of bid parent organization: financial or physical player.

Table 2-84 PJM virtual bids by type of bid parent organization (MW): Calendar year 2009

	Category	Total Virtual Bids MW	Percentage
2009	Financial	106,470,151	31.8%
2009	Physical	228,583,038	68.2%
2009	Total	335,053,190	100%

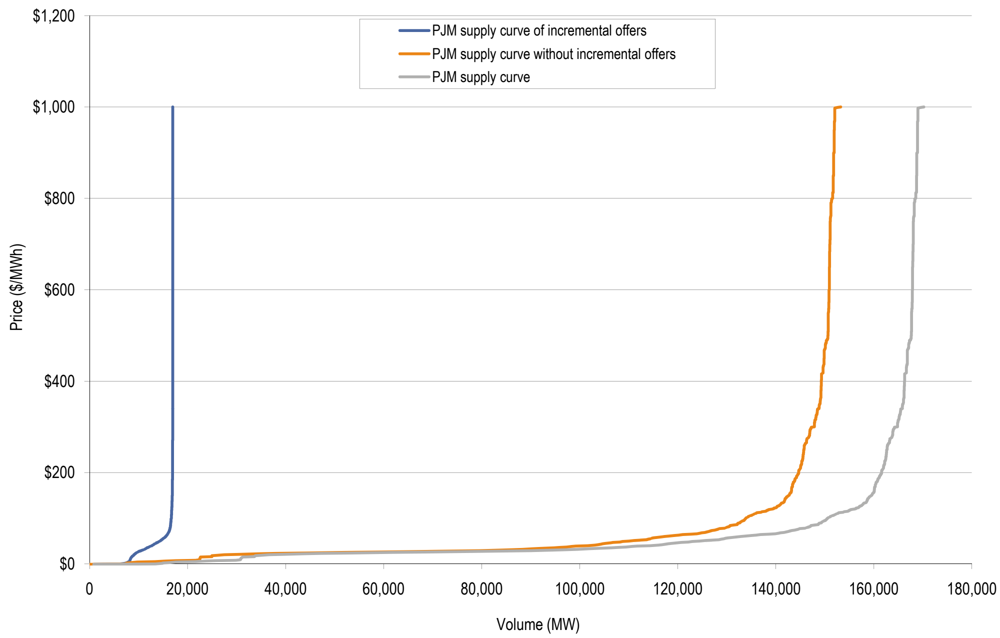
Table 2-85 shows virtual bids bid by top ten aggregates.

Table 2-85 PJM virtual bids by top ten aggregates (MW): Calendar year 2009

Aggregate Name	Aggregate Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	6,670,457	7,825,323	14,495,780
N ILLINOIS HUB	HUB	3,348,214	1,896,015	5,244,229
AEP-DAYTON HUB	HUB	1,161,223	1,546,752	2,707,976
ComEd	ZONE	214,326	1,240,075	1,454,401
PSEG	ZONE	238,864	1,120,509	1,359,373
MISO	INTERFACE	499,015	594,096	1,093,112
JCPL	ZONE	415,840	564,987	980,828
SOUTHIMP	INTERFACE	843,985	0	843,985
IMO	INTERFACE	805,834	12,185	818,019
NYIS	INTERFACE	184,642	491,293	675,935

Figure 2-19 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve without increment offers and the system aggregate supply curve with increment offers for an example day in May 2009. There were average hourly increment offers of 16,981 MW and average hourly total offers of 170,202 MW for the example day.

Figure 2-19 PJM day-ahead aggregate supply curves: 2009 example day



Price Convergence

When the PJM Day-Ahead Energy Market was introduced, it was expected that competition, exercised substantially through the use of virtual offers and bids, would tend to cause prices in the Day-Ahead and Real-Time Energy Markets to converge. But price convergence does not necessarily mean a zero or even a very small difference in prices between Day-Ahead and Real-Time Energy Markets. There may be factors, from operating reserve charges to risk that result in a competitive, market-based differential. In addition, convergence in the sense that Day-Ahead and Real-Time prices are equal at individual buses or aggregates is not a realistic expectation. PJM markets do not provide a mechanism that could result in convergence within any individual day as there is at least a one-day lag after any change in system conditions. As a general matter, virtual offers and bids are based on expectations about both Day-Ahead and Real-Time Market conditions and reflect the uncertainty about conditions in both markets and the fact that these conditions change hourly and daily. Substantial, virtual trading activity does not guarantee that market power cannot be exercised in the Day-Ahead Energy Market. Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. (See Figure 2-20) There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis. (See Figure 2-21)

As Table 2-86 shows, day-ahead and real-time prices were relatively close, on average, during 2009. The simple annual average LMP in the Real-Time Energy Market was $0.08 per MWh or 0.2 percent higher than the simple annual average LMP in the Day-Ahead Energy Market during 2009.

Table 2-86 Day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar year 2009

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
Average	$37.00	$37.08	$0.08	0.2%
Median	$35.16	$32.71	($2.45)	(7.5%)
Standard deviation	$13.39	$17.12	$3.73	21.8%

The price difference between the Real-Time and the Day-Ahead Energy Markets results, in part, from volatility in the Real-Time Energy Market that is difficult, or impossible, to anticipate in the Day-Ahead Energy Market. In 2009, the real-time, load-weighted, hourly LMPs were higher than day-ahead, load-weighted, hourly LMPs by more than $50 per MWh for 46 hours, more than $100 per MWh for 5 hours and more than $150 per MWh for 0 hours. Although real-time prices were higher than day-ahead prices on average in 2009, real-time prices were lower than day-ahead prices for 58.3 percent of the hours. During hours when real-time prices were higher than day-ahead prices, the average positive difference between them was $7.33 per MWh, which is much greater than the difference, $0.08, when all hours are included. During hours when real-time prices were less than day-ahead prices, the average negative difference was -$5.09 per MWh.

Table 2-87 shows the difference between the Real-Time and the Day-Ahead Energy Market Prices from 2000 to 2009. From 2000 to 2003, the real-time simple annual average LMP was lower than the day-ahead simple annual average LMP. Since 2004, the real-time simple annual average LMP has been higher than the day-ahead simple annual average LMP.[54]

Table 2-87 Day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar years 2000 to 2009

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

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

Table 2-88 provides frequency distributions of the differences between PJM real-time load-weighted hourly LMP and PJM day-ahead load-weighted hourly LMP for calendar years 2005 through 2009. The table shows the number of hours (frequency) and the cumulative percent of hours (cumulative percent) when the hourly LMP difference was within a given $50 per MWh price interval. From calendar year 2005 to calendar year 2009, LMP differences occurred predominantly in the range between -$50 per MWh and $50 per MWh. The largest PJM real-time and day-ahead load-weighted hourly LMP difference occurred in the calendar year of 2006 where an hourly price difference was greater than $500 per MWh. In 2007, the PJM real-time and day-ahead load-weighted hourly LMP differences are less than $150 per MWh in all but 14 hours. In 2008, the PJM real-time and day-ahead load-weighted hourly LMP differences are less than $150 per MWh in all but 7 hours. In 2009, the PJM real-time and day-ahead load-weighted hourly LMP differences were less than $100 per MWh in all but 5 hours.

Table 2-88 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): Calendar years 2005 to 2009

	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	0.03%
($50) to $0	5,015	57.99%	5,205	59.54%	4,600	52.89%	5,120	59.30%	5,108	58.34%
$0 to $50	3,471	97.61%	3,372	98.04%	3,827	96.58%	3,247	96.27%	3,603	99.47%
$50 to $100	190	99.78%	152	99.77%	255	99.49%	284	99.50%	41	99.94%
$100 to $150	17	99.98%	9	99.87%	31	99.84%	37	99.92%	5	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 2-20 shows the hourly differences between day-ahead and real-time load-weighted hourly LMP in 2009. Although the average difference between the Day-Ahead and Real-Time Energy Market was $0.08 per MWh for the entire year, Figure 2-20 demonstrates the considerable variation, both positive and negative, between day-ahead and real-time prices. The highest difference between real-time and day-ahead load-weighted hourly LMP was $136.14 per MWh for the hour ended 1800 on November 1, 2009, when the real-time load-weighted hourly LMP was $176.74 and the day-ahead load-weighted hourly LMP was $40.60.

Figure 2-20 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: Calendar year 2009

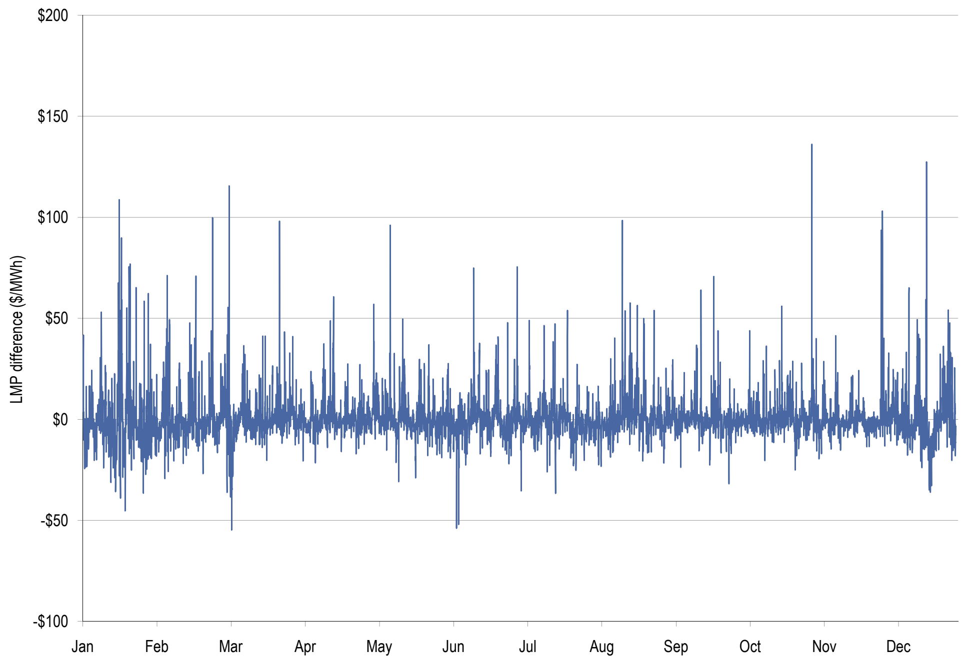


Figure 2-21 shows the monthly simple average differences between the day-ahead and real-time LMP in 2009. The highest monthly difference was in May.

Figure 2-21 Monthly simple average of real-time minus day-ahead LMP: Calendar year 2009

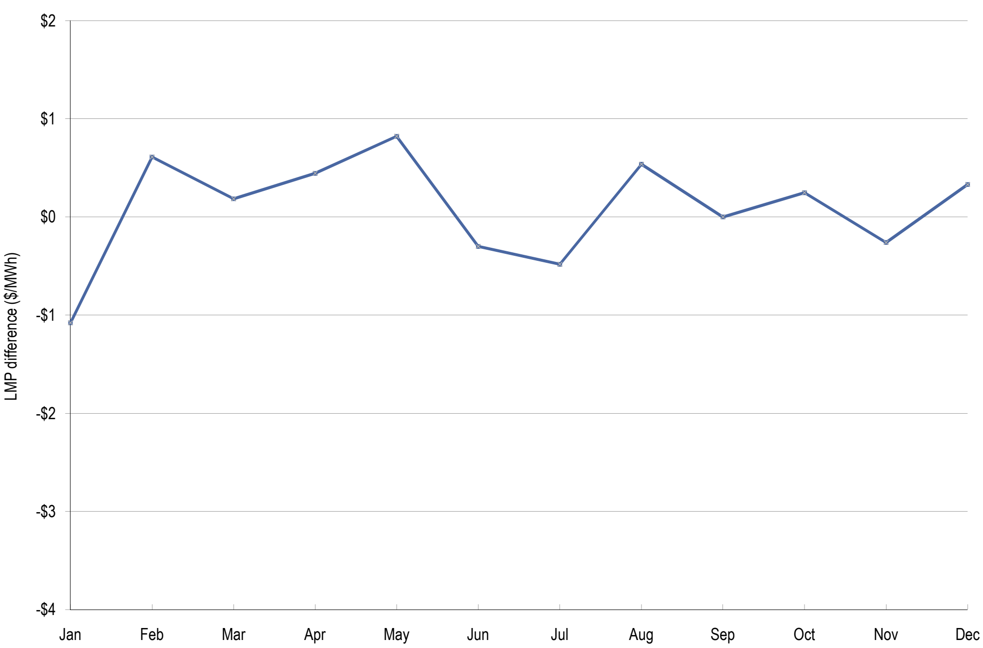
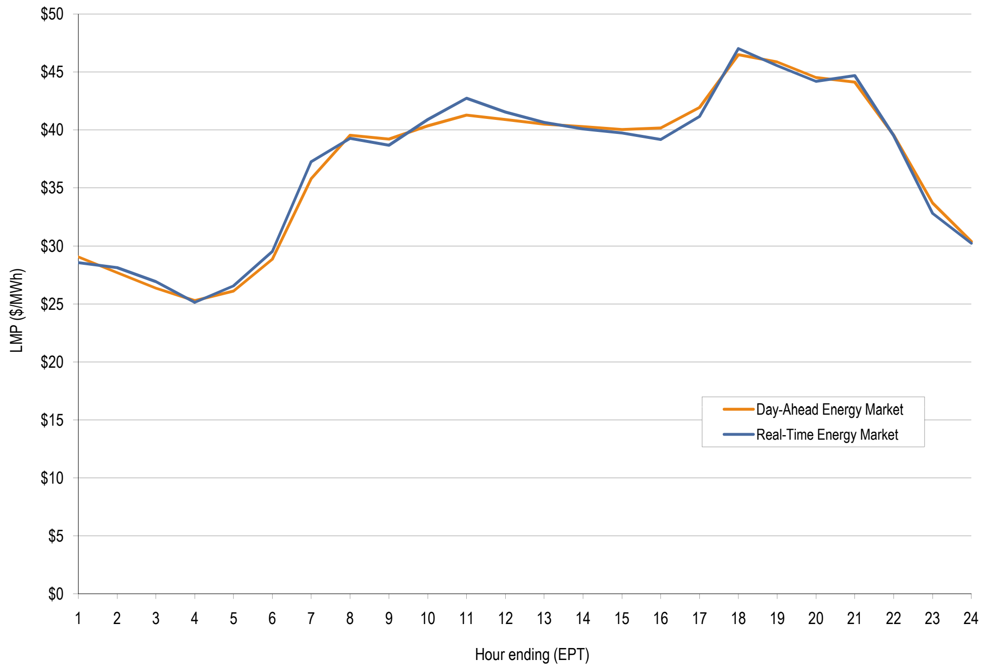


Figure 2-22 shows simple day-ahead and real-time LMP on an average hourly basis. Real-time simple average LMP was greater than day-ahead simple average LMP for 11 out of 24 hours.[55]

Figure 2-22 PJM system simple hourly average LMP: Calendar year 2009



55 See the *2009 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market," for more details on the frequency distribution of prices.

Zonal Price Convergence

Table 2-89 shows 2009 zonal day-ahead and real-time simple annual average LMP. The difference between zonal day-ahead and real-time simple annual average LMP ranged from $0.86 in the BGE Control Zone, where the day-ahead simple annual average LMP was higher than the real-time simple annual average LMP, to $0.56 in the DAY Control Zone, where the day-ahead simple annual average LMP was lower than the real-time simple annual average LMP.

Table 2-89 Zonal day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar year 2009

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$41.44	$40.68	($0.77)	(1.9%)
AEP	$33.44	$33.63	$0.19	0.6%
AP	$37.80	$38.29	$0.49	1.3%
BGE	$42.57	$41.71	($0.86)	(2.1%)
ComEd	$28.94	$29.05	$0.10	0.4%
DAY	$32.94	$33.49	$0.56	1.7%
DLCO	$32.33	$32.73	$0.39	1.2%
Dominion	$40.58	$40.00	($0.58)	(1.5%)
DPL	$41.73	$41.23	($0.50)	(1.2%)
JCPL	$41.36	$40.93	($0.43)	(1.1%)
Met-Ed	$40.35	$39.94	($0.41)	(1.0%)
PECO	$40.79	$40.00	($0.80)	(2.0%)
PENELEC	$37.09	$36.85	($0.24)	(0.7%)
Pepco	$42.54	$41.88	($0.66)	(1.6%)
PPL	$39.90	$39.44	($0.46)	(1.2%)
PSEG	$41.84	$41.27	($0.57)	(1.4%)
RECO	$40.92	$40.36	($0.56)	(1.4%)

Price Convergence by Jurisdiction

Table 2-90 shows the 2009 day-ahead and real-time simple annual average LMPs by jurisdiction. The difference between day-ahead and real-time simple annual average LMP ranged from $0.72 in Maryland, where the day-ahead simple annual average LMP was higher than the real-time simple annual average LMP, to $0.42 in Ohio, where the day-ahead simple annual average LMP was lower than the real-time simple annual average LMP.

Table 2-90 Jurisdiction day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar year 2009

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Delaware	$41.15	$40.80	($0.35)	(0.9%)
Illinois	$28.94	$29.05	$0.10	0.4%
Indiana	$32.87	$33.08	$0.20	0.6%
Kentucky	$33.22	$33.48	$0.26	0.8%
Maryland	$42.38	$41.66	($0.72)	(1.7%)
Michigan	$33.94	$34.09	$0.15	0.4%
New Jersey	$41.64	$41.08	($0.56)	(1.4%)
North Carolina	$39.50	$38.92	($0.58)	(1.5%)
Ohio	$32.83	$33.25	$0.42	1.3%
Pennsylvania	$38.80	$38.47	($0.33)	(0.9%)
Tennessee	$33.66	$33.54	($0.13)	(0.4%)
Virginia	$39.88	$39.29	($0.58)	(1.5%)
West Virginia	$34.34	$34.60	$0.26	0.7%
District of Columbia	$43.38	$42.98	($0.40)	(0.9%)

Load and Spot Market

Real-Time Load and Spot Market[56]

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

56 The analysis here differs from that presented in the *2007 State of the Market Report* in several respects. The billing organization analysis is not included here because it is not a meaningful representation of the ways in which load is served in PJM. Rather, billing organization data reflects decisions by parent organizations about where to incorporate the load serving obligation. In addition, the transfer of load serving obligations via eSchedule bilateral contracts is treated as a transfer of load serving obligation rather than as a bilateral to serve load.

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

The PJM system's reliance on self-supply, bilateral contracts and spot purchases to meet real-time load is calculated by summing across all PJM parent companies that serve load in the Real-Time Energy Market for each hour. Table 2-91 shows the monthly average share of real-time load served by self-supply, bilateral contract and spot purchase in 2008 and 2009 based on parent company. For 2009, 12.9 percent of real-time load was supplied by bilateral contracts, 17.0 percent by spot market purchase and 70.1 percent by self-supply. Compared with 2008, reliance on bilateral contracts decreased 1.8 percentage points, reliance on spot supply decreased by 3.1 percentage points and reliance on self-supply increased by 4.9 percentage points.

Table 2-91 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: Calendar years 2008 to 2009

	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%	13.0%	19.8%	67.2%	(2.1%)	(2.9%)	5.0%
Nov	14.8%	22.9%	62.3%	13.2%	19.0%	67.8%	(1.7%)	(4.0%)	5.6%
Dec	12.1%	20.5%	67.4%	11.7%	16.8%	71.5%	(0.4%)	(3.7%)	4.1%
Annual	14.6%	20.1%	65.2%	12.9%	17.0%	70.1%	(1.8%)	(3.1%)	4.9%

Day-Ahead Load and Spot Market

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

The PJM system's reliance on self-supply, bilateral contracts, and spot purchases to meet day-ahead load (cleared fixed-demand, price-sensitive load and decrement bids) is calculated by summing across all the parent companies of PJM billing organizations that serve load in the Day-Ahead Energy Market for each hour. Table 2-92 shows the monthly average share of day-ahead load served by self-supply, bilateral contracts and spot purchases in 2008 and 2009, based on parent companies. For 2009, 4.9 percent of day-ahead load was supplied by bilateral contracts, 14.9 percent by spot market purchases, and 80.2 percent by self-supply. Compared with 2008, reliance on bilateral contracts decreased by 0.2 percentage points, reliance on spot supply decreased by 3.6 percentage points, and reliance on self-supply increased by 3.7 percentage points.

Table 2-92 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: Calendar Years 2008 to 2009

	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%	13.7%	81.9%	0.2%	(1.9%)	1.6%
Feb	4.5%	16.0%	79.5%	4.5%	12.3%	83.2%	(0.1%)	(3.7%)	3.7%
Mar	4.7%	16.0%	79.3%	4.3%	12.8%	82.9%	(0.4%)	(3.3%)	3.6%
Apr	5.0%	16.8%	78.2%	4.4%	13.8%	81.7%	(0.5%)	(3.0%)	3.5%
May	5.0%	18.2%	76.8%	4.6%	15.6%	79.8%	(0.4%)	(2.6%)	3.0%
Jun	5.5%	20.2%	74.3%	4.7%	13.9%	81.4%	(0.8%)	(6.3%)	7.2%
Jul	5.6%	20.4%	74.0%	5.6%	16.0%	78.4%	0.0%	(4.4%)	4.4%
Aug	4.9%	20.2%	75.0%	5.2%	15.3%	79.5%	0.3%	(4.9%)	4.6%
Sep	5.4%	19.3%	75.3%	4.8%	16.1%	79.2%	(0.7%)	(3.2%)	3.8%
Oct	5.4%	20.3%	74.3%	5.0%	17.8%	77.2%	(0.4%)	(2.5%)	2.9%
Nov	5.6%	18.9%	75.5%	5.8%	15.9%	78.3%	0.2%	(3.0%)	2.8%
Dec	4.6%	19.1%	76.3%	5.2%	15.6%	79.2%	0.6%	(3.5%)	2.9%
Annual	5.0%	18.4%	76.5%	4.9%	14.9%	80.2%	(0.2%)	(3.6%)	3.7%

Demand-Side Response (DSR)

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

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

Today, most end use customers do not face the market price of energy, that is the locational marginal price of energy (LMP), or the market price of capacity, the locational capacity market clearing price. This results in a market failure because when customers do not know the market price and do not pay the market price, the behavior of those customers is inconsistent with the market value of electricity. When customers pay a price less than the market price, customers will tend to consume more than if they faced the market price and when customers pay a price greater than the market price, customers will tend to consume less than they would if they faced the market price. This market failure is relevant to the wholesale power market because the power used by customers is generated and sold in the wholesale power market. The transition to a more functional demand side requires that the default energy price for all customers be the day ahead or real time hourly locational marginal price (LMP) and the locational clearing price of capacity.

PJM's Economic Load Response Program is designed to address this market failure by attempting to replicate the price signal to customers that would exist if customers were exposed to the real time wholesale price of energy and by providing settlement services to facilitate the participation of third party Curtailment Service Providers (CSPs) in the market. PJM's Load Management (LM) Program in the RPM market also attempts to replicate the price signal to customers that would exist if customers were exposed to the locational market price of capacity. The PJM market design also creates the opportunity for demand resources to participate in ancillary services markets.[57]

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

57 See the *2009 State of the Market Report for PJM*, Volume II, "Ancillary Service Markets."

PJM Load Response Programs Overview

All load response programs in PJM can be grouped into the Economic and the Emergency Programs. Table 2-93 provides an overview of the key features of PJM load response programs.

Table 2-93 Overview of Demand Side Programs

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

Economic Load Response

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

History

On March 15, 2002, PJM submitted filing amendments to the OATT and to the OA to establish a multiyear Economic Load-Response Program (the Economic Program).[58] On May 31, 2002, the FERC accepted the Economic Program, effective June 1, 2002, but with a December 1, 2004, sunset provision.[59] On October 29, 2004, the FERC extended the Economic Program until December 31, 2007.[60] On February 24, 2006, the FERC approved changes to the PJM Tariff to permit demand-side resources to provide ancillary services and to make the Economic Program

58 *PJM Interconnection, L.L.C.*, Tariff Amendments, Docket No. ER02-1326-000 (March 15, 2002).
59 99 FERC ¶ 61,227 (2002).
60 *PJM Interconnection, L.L.C.*, Letter Order, Docket No. ER04-1193-000 (October 29, 2004).

permanent.[61,62] The same order permitted an increase in the limit on the combined total MW in the Economic and Emergency Programs from 100 MW to 500 MW in the Pilot Program for resources with non-hourly integrated metering.

On November 20, 2007, the PJM Industrial Customer Coalition (PJMICC) filed a complaint with the FERC requesting continuation of Economic Load-Response subsidy payments that, under the existing PJM Tariff, would expire on December 31, 2007.[63] The Commission denied the complaint, stating that, "Even without the subsidy payments, the Economic Program provides customers within PJM the incentive to reduce load based on the wholesale rates they confront."[64,65] On December 31, 2007, the Economic Program incentive payment provisions expired per the PJM OA.

PJM stakeholders continued to discuss the incentive issue during the first half of 2009, but no proposal obtained majority backing. On June 29, 2009, a statement issued on behalf of the PJM Board explained the Board's long term objective to develop the demand side of the market and its short term support for an incentive program, and indicated that PJM would file its own proposal.[66]

On August 24, 2009, PJM filed a proposal. The proposal provided for compensating fixed price demand response customers at LMP less the generation portion of their retail rates (LMP – G) rather than both the generation and transmission portions (LMP - G - T).[67] PJM explained that this change is intended to "(i) alleviate underpayment to the Fixed Price Customer, (ii) result in similar compensation for Fixed Price Customers and LMP-based Customers[footnote omitted] that reduce demand, and (iii) provide Fixed Price Customers the same incentives as LMP-based Customers to reduce demand…"[68] The proposal subjects to debit payments a participant who (i) self-schedules demand reductions or is dispatched for reductions in the Real-Time Energy Market when settlement of its daily activity shows that the participant's credits accumulated for reducing demand are less than accumulated debits for failure to reduce, or (ii) who self-schedules reductions when the applicable zonal LMP drops below the applicable generation charge in the customer's retail rate.[69] PJM proposed to re-introduce incentive payments that would apply to reduced consumption in the nine percent of hours when LMP is at its highest levels and would sunset when there are 1,000 MW of additional price responsive demand capability for small and medium-sized end-use customers.[70]

Numerous stakeholders intervened, many filing protests. Certain intervenors opposed PJM's proposal to pay participants in the Economic Load Response Program LMP – G, arguing instead that participants should be paid full LMP.[71] The MMU filed an answer responding that payment of full LMP was "inconsistent with … fundamental economics" and over compensatory, would "degrade

61 114 FERC ¶ 61,201 (February 24, 2006).

62 See PJM. "Amended and Restated Operating Agreement (OA)," Schedule 1, Section 3.3.A (December 10, 2007).

63 Complaint of the PJM Industrial Coalition in Docket EL08-12-000.

64 121 FERC ¶ 61,315 at P 26 (December 31, 2007).

65 For a discussion of subsidy payments under PJM's Economic Load-Response Program, see "MMU White Paper: PJM Demand Side Response Program" (December 4, 2007) <http://monitoringanalytics.com/reports/Reports/2007/20071204-dsr-whitepaper.pdf> (115 KB).

66 Statement of Terry Boston, President and CEO, on behalf of the PJM Board of Managers (June 26, 2009), which is posted on PJM's website at: <http://www.pjm.com/~/media/about-pjm/newsroom/2009-releases/20090626-pjm-board-statement-regarding-dr-in-pjm-markets.ashx> (104 KB).

67 Supplemental Report and Submittal of PJM Interconnection, L.L.C. in Support of Further Commission Action on Rehearing, initially filed in EL08-12. The FERC determined to initiate a new proceeding with this filing, docketed as EL09-68-000.

68 *Id*. at 6.

69 *Id*.

70 *Id*. at 5–6.

71 Such comments include those filed in Comments and Protest of Demand Response Supporters, including: Comverge, Inc.; EnergyConnect, Inc.; EnerNOC, Inc.; the PJM Industrial Customer Coalition; Viridity Energy, Inc.; Wal‑Mart Stores East, L.P.; Protest of the New Jersey Board of Public Utilities and the District of Columbia Public Service Commission ("BPU/DCPSC"); and Comments of the Public Service Commission of Maryland.

the efficient operation of the markets," and "provide no offsetting social benefit.[72] Commission action in this proceeding is pending.

Other proceedings active in 2009 concerning PJM's demand response programs involved approval and measurement of participation.

On July 28, 2009, PJM filed revisions to the metering requirements in PJM's Economic and Emergency Load Response Programs intended to clarify the responsibilities of Curtailment Service Providers (CSPs) in connection with program participants' metering equipment, to account for metering data requirements, to provide uniform terminology and requirements, and to revise certain out-dated requirements included in the Emergency Load Response Program.[73] The Commission approved these revisions, effective September 28, 2009.[74]

In two interrelated proceedings, PJM and the Commission addressed the role of relevant electric retail regulatory authorities (or RERRAs) in approving participation in its Economic and Emergency Load Response Programs.[75] PJM submitted a filing to address the issue, and the Commission concurrently took up the issue in its rulemaking proceeding concerning reform of the organized markets.[76]

On November 20, 2009, PJM submitted a compliance filing pursuant to orders issued in both of these interrelated proceedings.[77] The proposed revisions address the mandate in Order 719-A that RTOs not accept bids from aggregators of retail customers (ARCs) that aggregate the demand response of: (i) the customers of utilities that distributed more than four million MWh in the previous fiscal year, unless the RERRA prohibits an ARC from bidding such customers' demand response, or (ii) the customers of utilities that distributed four million MWh or less in the previous fiscal year, unless the RERRA affirmatively permits an ARC to bid such customers' demand response. Additionally, per the direction in Order 719-A, PJM's proposed revisions describe the mechanism for notifying an affected electric distribution company (EDC) and Load Serving Entity (LSE) when load served by that entity is enrolled to participate in its programs, either individually or through an ARC. The proposed revisions addressed the requirements of the September 14th Order to: (i) recognize a RERRA's ability to condition eligibility to participate in PJM's Demand Side Response Programs; (ii) update obsolete references to "Active Load Management"; (iii) address how RERRA prohibitions will affect existing demand response resource registrations and/or commitments; (iv) clarify that PJM will effectuate such RERRA policies prospectively by precluding affected resources from offering capacity in RPM auctions that are conducted subsequent to the effective date of those policies; (v) clarify that registrations of Economic Load Response Participants will be promptly terminated upon receipt by PJM of evidence of a conflicting prohibition or unsatisfied condition of a RERRA, and that participants will be permitted to submit settlements for the curtailment service already provided; and (vi) commit to posting on PJM's website a list of RERRAs that prohibit or condition retail participation in PJM's programs, and providing annual updates on those programs to PJM's Markets and Reliability Committee. PJM requested that the Commission accept the proposed tariff changes for both proceedings together, and grant a retroactive effective date of August 28, 2009, the effective date of Order 719-A.[78] This filing is currently pending before the Commission.

72 Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM, EL09-68-000 at 1–2 (October 16, 2009).
73 PJM filing in Docket No. ER09-1508.
74 Letter order in Docket No. ER09-1508-000 (September 9, 2009).
75 Dockets Nos. ER09-701-000 and RM07-19-000.
76 *Id.*
77 PJM compliance filing in Dockets Nos. ER09-701-000 & RM07-19-000 (November 20th Filing); 128 FERC ¶ 61,059 (July 16, 2009) ("Order No. 719-A"); 128 FERC ¶ 61,238 (September 14, 2010) ("September 14th Order").
78 November 20th Filing at 12.

Current State

The fundamental purpose of PJM's Economic Load Response Program is, or should be, to address a specific market failure, which is that many retail customers do not pay the market price or LMP. Based on this purpose, the design goal of the Economic Program incentives should be to replicate the price signal to customers that would exist if customers were exposed to the real-time wholesale price. The real-time hourly LMP is the appropriate price signal as it reflects the incremental value of each MWh consumed.[79]

Retail customers pay retail rates including components that reflect the cost of generation (or power purchased from the grid), the cost of transmission and the cost of distribution. Under a rate design consistent with the purpose of the demand-side program, the hourly LMP would replace only the generation component of retail rates in order to provide the appropriate wholesale market price signal to customers. Accordingly, the load reductions in the Economic Program are appropriately compensated at LMP less the generation component of the applicable retail rate per MWh.

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

The PJM Economic Load-Response Program is a PJM-managed accounting mechanism that provides for payment of the savings that result from load reductions to the load-reducing customer. Such a mechanism is required because of the complex interaction between the wholesale market and the retail incentive and regulatory structures faced by both LSEs and customers. The broader goal of the Economic Program is a transition to a structure where customers do not require mandated payments, but where customers see and react to market prices or enter into contracts with intermediaries to provide that service. Even as currently structured, however, and even with the reintroduction of the defined subsidies, if they exclude previously identified inappropriate components, the Economic Program represents a minimal and relatively efficient intervention into the market.[80]

Emergency Load Response

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

History

On February 14, 2002, the PJM Members Committee approved a permanent Emergency Load-Response Program.[81] On March 1, 2002, PJM filed amendments to the OATT and to the OA to

79 This does not mean that every retail customer should be required to pay the real-time LMP, regardless of their risk preferences. However, it would provide the appropriate price signal if every retail customer were obligated to pay the real-time LMP as a default. That risk could be hedged via a contract with an intermediary.
80 One such inappropriate component was the payment of subsidies to customers who were already exposed to hourly LMP pricing.
81 *PJM Interconnection, L.L.C.*, Tariff Amendments, Docket No. ER02-1205-000 (March 1, 2002).

establish a permanent Emergency Load-Response Program (the Emergency Program).[82] By order dated April 30, 2002, the FERC approved the Emergency Program effective June 1, 2002. Like the Economic Program, a sunset date for it was set for December 1, 2004.[83] On October 29, 2004, the FERC extended the program until December 31, 2007, thereby making it coterminous with the Economic Program.[84] On February 24, 2006, the FERC approved changes to the PJM Tariff to make the Emergency Program permanent, including energy only and full emergency options.[85] The Emergency Program was modified in June 2006 to include an Emergency-Capacity Only option.

As a result of Reliability Pricing Model (RPM) implementation on June 1, 2007, the Load Management (LM) Program was introduced as the mechanism for Emergency Program customers and other DR providers to participate in RPM. Customers in the Emergency-Full and Emergency-Capacity Only options of the Emergency Program are committed capacity resources, which receive RPM capacity payments and which are subject to RPM penalties for noncompliance during emergency events. Emergency-Full customers are also eligible for energy payments for reductions during emergency events.[86]

On March 4, 2009, PJM filed with the Commission revisions to the Emergency Load Response Program. The proposed revisions defined Capacity Only resources, revised the way in which actual load reductions by Full Program Option and Capacity Only resources are added back for the purpose of calculating peak load for capacity, and prevented double counting of MWs in the calculation of peak load and normalized peak demand.[87] By order issued May 7, 2009, the Commission accepted PJM's proposed revisions, effective June 1, 2009.[88]

Current State

There are three options for Emergency Load Response registration and participation: energy only; capacity only; and capacity plus energy.

Energy Only

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

82 *PJM Interconnection, L.L.C.*, Tariff Amendments, Docket No. ER02-1205-000 (March 1, 2002).
83 99 FERC ¶ 61,139 (2002).
84 *PJM Interconnection, L.L.C.*, Letter Order, Docket No. ER04-1193-000 (October 29, 2004).
85 114 FERC ¶ 61,201 (February 24, 2006).
86 For additional information on RPM provisions for customers in the Emergency Load Response Program, see PJM, "Manual 18: PJM Capacity Market", Revision 8 (January 1, 2010).
87 PJM filing in Docket No. ER09-797-000 (March 4, 2009).
88 Letter Order in ER09-797-000 (May 7, 2010).

Capacity Only

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

Energy and Capacity (Full Emergency Option)

Similar to the Energy Only option, participants in the Full Emergency option submit minimum dispatch prices associated with reductions during emergency events. In addition, they are considered committed capacity resources and receive capacity payments. Participation during an emergency event or capacity testing is mandatory and failure to reduce will result in a compliance test failure charge as well as a daily capacity deficiency charge.

Minimum Dispatch Price

During an emergency event, participants registered in the Full Emergency option and the Emergency Energy Only option will be paid the higher of the submitted minimum dispatch price or the zonal real-time LMP for emergency reductions. The minimum dispatch price, which is submitted by the participant, acts as a floor for energy compensation during an emergency event. Given the current program rules, market participants have an incentive to submit a minimum dispatch price at the maximum threshold for energy bids of $1,000/MWh. For the 2009/2010 delivery year, approximately 88 percent of registered sites representing 71 percent of registered MW in the Emergency Full Capacity option submitted a minimum dispatch price of either $999 or $1,000 per MWh.

There is no relationship between the minimum dispatch price and the locational price of energy or the participant's costs associated with not consuming energy. The minimum dispatch price is also not a meaningful signal from the participant about its willingness to curtail. In the Emergency Full option, end use participants are already contractually obligated to curtail during an emergency event because they are capacity resources and receive capacity payments. Thus, the ability to submit a minimum dispatch price is a guarantee of an energy payment for resources that are already required to curtail, regardless of their minimum dispatch price. The appropriate energy payment for a load reduction during an emergency event is the hourly LMP less any generation component of their retail rate. For customers on a real-time LMP contract, no energy payment is necessary because the customer saves the hourly LMP by not consuming during an emergency event. Any energy payment in excess of the real-time LMP net of generation costs results in an unnecessary and inappropriate subsidy.[89]

89 Energy Only participants are also paid the higher of the real-time LMP and the submitted minimum dispatch price. However, there are currently no participants registered under this option.

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

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

Load Management

As part of the transition to RPM, effective June 1, 2007, the PJM active load management (ALM) program was changed to the load management (LM) program.[90] Load Management generally refers to the integration of load response resources into RPM. It includes the Full and Capacity Only options of the Emergency Load Response Program.

The LM program was, from its inception in June 2007, comprised of two types of resources: Interruptible Load for Reliability (ILR) resources and Demand Resources (DR). Customers offering DR resources submit a capacity sell bid into an RPM Auction and are paid the clearing price. Interruptible load for reliability (ILR) resources must be certified at least three months prior to the delivery year and are paid the final zonal ILR price. The ILR option was eliminated on March 26, 2009 for the delivery year beginning June 1, 2012.[91]

Every DR resource is required to register under the Emergency-Full option of the Emergency Program, and it receives energy payments for load reductions during emergency events equal to the higher of LMP or a submitted minimum dispatch price. It also may be registered in the Economic Program simultaneously. If a customer is determined to be reducing economically during an emergency event, energy payments are paid in accordance with the Economic Load Response Program (ELRP) rules.

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

90 An LM program continues to have three types of products: Direct Load Control, Firm Service Level or Guaranteed Load Drop. Each of the products continues to have two notification periods: short-lead time and long-lead time.

91 126 FERC ¶ 61,275 (2009).

For all RPM Auctions run prior to October 29, 2009, under PJM's interpretation of the tariff, all existing Demand Resources were mitigated to an offer of $0 per MW-day if their sell offer would otherwise affect the Capacity Market clearing price. On September 1, 2009, PJM filed to exempt Demand Resources from market power mitigation provisions in the RPM Auctions, subject to ongoing monitoring, with the support of the MMU and market participants.[92] It was approved by the Commission on October 29, 2009.[93]

Participation

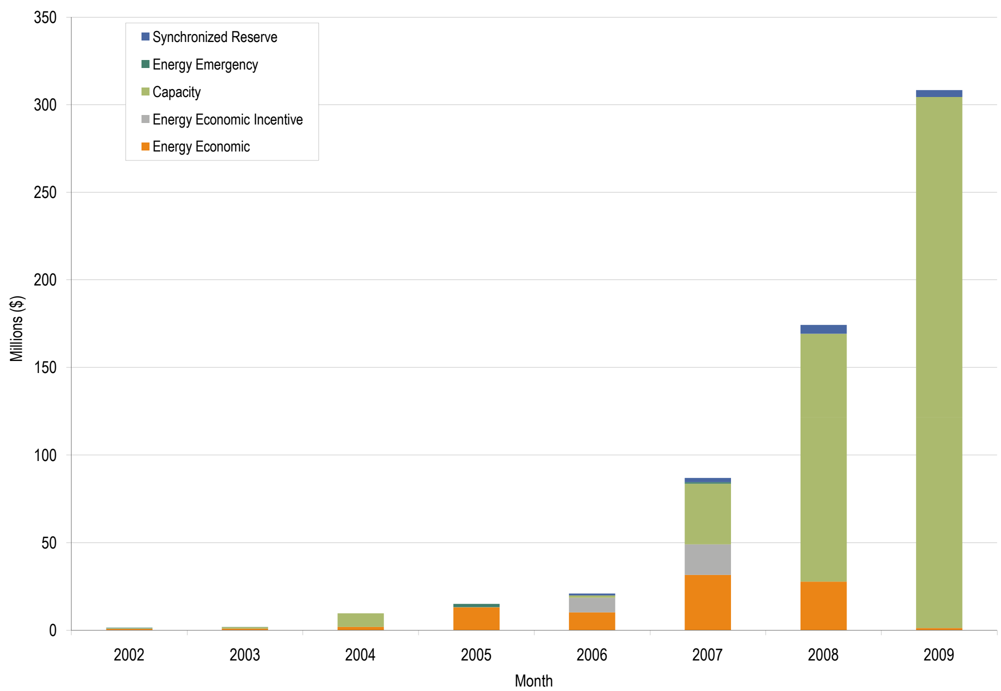
In 2009, in the Economic Program, participation decreased compared to 2008. There were decreases in a range of activity metrics including registrations, settlements submitted, settled MWh and credits. There were many factors contributing to lower levels of participation and lower revenues in the Economic Program, including lower price levels in 2009, lower load levels and improved measurement and verification.

In 2009, the Emergency Program, specifically, the LM Program, participation increased compared to 2008. For the 2009/2010 delivery year, there were 7,294.3 MW registered in the LM Program, compared to 4,498.2 MW registered in the 2008/2009 delivery year.

Figure 2-23 shows all revenue from PJM Demand Side Response Programs by market for the period 2002 through 2009. Since the implementation of the RPM design on June 1, 2007, capacity revenue has become the primary source of revenue to DSR participants. Economic Program revenues declined in 2008 while capacity revenue increased significantly. In 2009, payments from the Economic Program were significantly lower than 2008, decreasing by $26 million or 96 percent, from $27.7 million to $1.2 million, while capacity revenue increased significantly, rising by $161 million or 114 percent, from $141 million to $303 million since 2008. Synchronized Reserve credits decreased by $1.1 million, from approximately $5.1 million to $4.0 million from 2008 to 2009.

92 PJM filing initiating Docket No. ER09-1673-000.
93 129 FERC ¶ 61,081 (2009).

Figure 2-23 Demand Response revenue by market: Calendar years 2002 through 2009



Economic Program

Table 2-94 shows the number of registered sites and MW per peak load day for calendar years 2002 through 2009.[94] On August 10th, 2009, there were 2,486.6 MW registered in the Economic Program compared to the 2,294.7 MW on June 9, 2008, an 8.4 percent increase in peak load day capability. Program totals are subject to monthly and seasonal variation, as registrations begin, expire and renew. Table 2-95 shows registered sites and MW for the last day of each month for the period calendar years 2007 through 2009. Registered sites and MW have generally decreased from the same time period in 2008 since May.[95] Registration in the Economic Program means that customers have been signed up and can participate if they choose. Thus, registrations represent the maximum level of potential participation.

94 Table 2-94 and Table 2-95 reflect distinct registration counts. They do not reflect the number of distinct sites registered for the Economic Program, as multiple sites may be aggregated within a single registration.

95 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.

Table 2-94 Economic Program registration: Within 2002 to 2009

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

Table 2-95 Economic Program registrations on the last day of the month: January 2007 through December 2009

	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	1,875	2,730
Nov	4,897	2,948	4,851	3,271	1,874	2,730
Dec	4,898	2,944	4,851	3,290	1,853	2,627
Avg.	2,684	2,408	4,727	3,185	2,508	2,852

Table 2-96 shows the zonal distribution of capability in the Economic Program on August 10, 2009. The ComEd Control Zone includes 318 sites or 24 percent of sites and 9 percent of registered MW in the Economic Program. The BGE Control Zone includes 139 sites or 10 percent of sites and 26 percent of registered MW in the Economic Program.

Table 2-96 Distinct registrations and sites in the Economic Program: August 10, 2009[96]

	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

The total MWh of load reduction and the associated payments under the Economic Program are shown in Table 2-97.[97] Load reduction levels decreased by 425,500 MWh, from 477,212 in 2008 to 51,684 MWh in calendar year 2009, an 89 percent decrease.[98] Total payments in the Economic Program fell $26.5 million, from $27.7 million in 2008 to $1.2 million in 2009, a 96 percent decrease. Payments per MWh were $24 in 2009 compared to $58 in 2008. The Economic Program's actual load reduction per peak-day, registered MW decreased to 20.8 MWh for calendar year 2009, a decrease of 90 percent from 2008.[99] In the calendar year 2009, the maximum hourly load reduction attributable to the Economic Program was 142.3 MW on January 16.

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

97 The "Total MWh" and "Total Payments" for the Economic Program shown here are also subject to subsequent settlement adjustments in 2009.

98 The Economic Program payments and MWh presented in this report do not include all settlement adjustments for 2008 and 2009. The data are provided by PJM's DSR department; Economic Program payments and MWh reductions are based on the January, 2010, PJM billing information and are subject to adjustments.

99 The "Total MWh" and "Total Payments" for calendar year 2008 are different from those reported in the *2008 State of the Market Report for PJM,* as a result of adjusted settlements. The "Total MWh" increased by 24,990 MWh and the "Total Payments" increased by $633,080.

Table 2-97 Performance of PJM Economic Program participants

	Total MWh	Total Payments	$/MWh	Total MWh per Peak-Day, Registered MW
2002	6,727	$801,119	$119	20.1
2003	19,518	$833,530	$43	30.0
2004	58,352	$1,917,202	$33	66.6
2005	157,421	$13,036,482	$83	71.2
2006	258,468	$18,584,013	$72	234.8
2007	714,148	$49,033,576	$74	285.9
2008	477,212	$27,720,575	$58	208.0
2009	51,684	$1,236,416	$24	20.8

Total Payments in Table 2-97 include incentive payments in the Economic Program for the years 2006 and 2007. The economic incentive program expired in November of 2007.[100] Table 2-98 shows total MWh reductions and payments less incentive payments for the years 2002 through 2009.[101]

Table 2-98 Performance of PJM Economic Program participants without incentive payments

	Total MWh	Total Payments	$/MWh	Total MWh per Peak-Day, Registered MW
2002	6,727	$801,119	$119	20.1
2003	19,518	$833,530	$43	30.0
2004	58,352	$1,917,202	$33	66.6
2005	157,421	$13,036,482	$83	71.2
2006	258,468	$10,213,828	$40	234.8
2007	714,148	$31,600,046	$44	285.9
2008	477,212	$27,720,575	$58	208.0
2009	51,684	$1,236,416	$24	20.8

Figure 2-24 shows monthly economic program payments, excluding incentive payments, for 2007 through 2009. Economic Program credits consistently declined in 2008 after June. In 2009, payments were down significantly in every month compared to the same time period in 2007 and 2008.[102] While there are a number of factors that could explain this reduction, declining price levels for energy are the single biggest factor. Energy prices declined significantly in 2008 and again in 2009. Lower prices mean reduced incentives to reduce load and fewer hours eligible for load reductions, given a fixed rate contract. The reduction was also the result in part of the revisions to the Customer Baseline Load (CBL) calculation effective June 12, 2008 and the newly implemented activity review process effective November 3, 2008.

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

101 Settlement data for 2008 and 2009 including reductions, credits and incentive payments data received from PJM DSR group February 26, 2010.

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

Figure 2-24 Economic Program payments: Calendar years 2007 (without incentive payments), 2008 and 2009

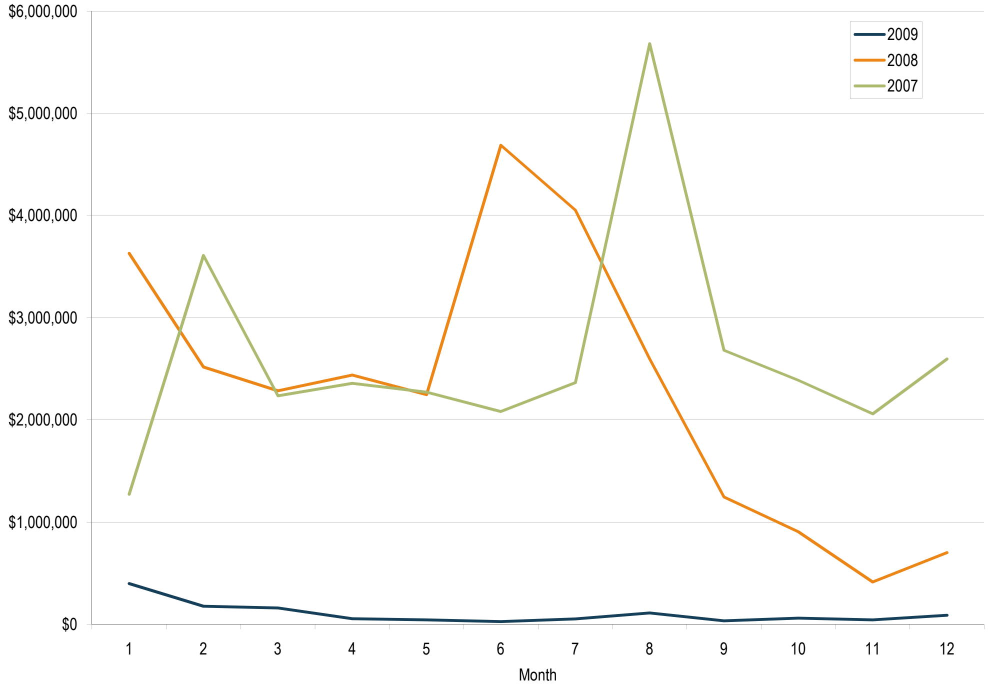


Table 2-99 shows 2009 performance in the Economic Program by control zone and participation type. The total number of curtailed hours for the Economic Program was 31,516 and the total payment amount was $1,236,416.[103] Overall, approximately 90 percent of the MWh reductions, 90 percent of payments and 90 percent of curtailed hours resulted from the real-time, self scheduled option of the Economic Program. Approximately 7 percent of the MWh reductions, 7 percent of payments and 1 percent of curtailed hours resulted from the day-ahead option.[104] Approximately 3 percent of the MWh reductions, 3 percent of the payments and 9 percent of the curtailed hours resulted from the dispatched in real time option of the program. (See Table 2-99) The PPL Control Zone accounted for $480,596 or 39 percent of all Economic Program credits, associated with 18,829 or 36 percent of total program MWh reductions.

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

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

Table 2-99 PJM Economic Program by zonal reduction: Calendar year 2009

	Real Time			Day Ahead			Dispatched in Real Time			Totals		
	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours
AECO	42	$729	144				4	$117	15	46	$846	159
AEP	3,897	$41,796	248	1,317	$23,063	22				5,214	$64,858	270
AP	2,140	$38,555	526				10	$562	11	2,150	$39,117	537
BGE	58	$2,461	210							58	$2,461	210
ComEd	260	$316	102				700	$4,474	806	960	$4,790	908
DAY	3	$104	1							3	$104	1
DLCO	6	$178	13							6	$178	13
Dominion	5,653	$243,316	865	74	$1,549	44	263	$7,257	155	5,989	$252,122	1,064
DPL	15	$557	258							15	$557	258
JCPL	0	$17	1				11	$178	33	11	$195	34
Met-Ed	81	$3,516	135				5	$255	15	86	$3,771	150
PECO	15,005	$280,076	19,347				260	$10,919	1,222	15,265	$290,995	20,569
PENELEC	163	$6,741	52				2	$47	6	166	$6,788	58
Pepco	132	$4,349	88				50	$1,941	89	182	$6,289	177
PPL	18,829	$480,596	6,057	2,182	$66,057	365	209	$11,924	373	21,220	$558,577	6,795
PSEG	304	$4,598	257				5	$158	32	309	$4,756	289
RECO	1	$12	24							1	$12	24
Total	46,589	$1,107,915	28,328	3,573	$90,668	431	1,519	$37,833	2,757	51,681	$1,236,416	31,516
Max	18,829	$480,596	19,347	2,182	$66,057	365	700	$11,924	1,222	21,220	$558,577	20,569
Avg	2,741	$65,171	1,666	1,191	$30,223	144	138	$3,439	251	3,040	$72,730	1,854

Table 2-100 shows total settlements submitted by month for calendar years 2007 through 2009. For January through July of 2008, total monthly settlements were higher than the monthly totals for 2007, despite the recent expiration of the incentive program. In October of 2008, settlement submissions dropped significantly from the prior month and from the same month in 2007, a trend that continued through early 2009. This drop in participation corresponds with the implementation of the PJM daily review process, as well as the lower overall price levels in PJM. April of 2009 showed the lowest level of settlements submitted in the three year period, after which, settlements began to show steady growth. By June of 2009, settlement activity showed signs of stabilization.

Table 2-100 Settlement days submitted by month in the Economic Program: 2007 through 2009

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	2,361
Nov	2,842	1,105	2,321
Dec	2,675	986	1,240
Total	26,423	32,990	21,605

Table 2-101 shows the number of distinct Curtailment Service Providers (CSPs) and distinct customers actively submitting settlements by month for the period 2007 through 2009. The number of active customers per month decreased in early 2009, reaching a three year low in April. Since then, monthly customer counts vary significantly. However, the number of active customers in calendar year 2009 has increased by 225, or 43 percent, over calendar year 2008.

Table 2-101 Distinct customers and CSPs submitting settlements in the Economic Program by month: Calendar years 2007 through 2009

	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	11	93
Nov	10	204	14	208	9	143
Dec	11	243	13	193	10	160
Total Distinct Active	21	405	24	522	25	747

Table 2-102 shows a frequency distribution of MWh reductions and credits at each hour for calendar year 2009. The period from hour ending 0800 EPT to 2300 EPT accounts for 85 percent of MWh reductions and 86 percent of credits.

Table 2-102 Hourly frequency distribution of Economic Program MWh reductions and credits: Calendar year 2009

	MWh Reductions				Program Credits			
Hour Ending	MWh Reductions	Percent	Cumulative Frequency	Cumulative Percent	Credits	Percent	Cumulative Frequency	Cumulative Percent
1	667	1.29%	667	1.29%	$7,678	0.62%	$7,678	0.62%
2	674	1.30%	1,341	2.59%	$7,930	0.64%	$15,608	1.26%
3	729	1.41%	2,069	4.00%	$9,297	0.75%	$24,904	2.01%
4	818	1.58%	2,887	5.59%	$9,424	0.76%	$34,328	2.78%
5	833	1.61%	3,720	7.20%	$10,249	0.83%	$44,577	3.61%
6	887	1.72%	4,606	8.91%	$14,975	1.21%	$59,552	4.82%
7	2,100	4.06%	6,706	12.98%	$94,378	7.63%	$153,930	12.45%
8	2,603	5.04%	9,310	18.01%	$115,366	9.33%	$269,295	21.78%
9	2,648	5.12%	11,958	23.14%	$76,388	6.18%	$345,684	27.96%
10	2,476	4.79%	14,435	27.93%	$66,820	5.40%	$412,503	33.36%
11	2,517	4.87%	16,952	32.80%	$68,721	5.56%	$481,224	38.92%
12	2,477	4.79%	19,429	37.59%	$54,170	4.38%	$535,394	43.30%
13	2,474	4.79%	21,903	42.38%	$49,943	4.04%	$585,336	47.34%
14	2,717	5.26%	24,620	47.64%	$52,595	4.25%	$637,931	51.60%
15	2,629	5.09%	27,249	52.72%	$49,714	4.02%	$687,646	55.62%
16	2,826	5.47%	30,075	58.19%	$48,496	3.92%	$736,141	59.54%
17	3,185	6.16%	33,260	64.35%	$62,960	5.09%	$799,101	64.63%
18	3,484	6.74%	36,744	71.09%	$106,428	8.61%	$905,530	73.24%
19	3,353	6.49%	40,096	77.58%	$89,845	7.27%	$995,375	80.50%
20	3,428	6.63%	43,524	84.21%	$82,600	6.68%	$1,077,975	87.19%
21	2,936	5.68%	46,460	89.89%	$82,642	6.68%	$1,160,617	93.87%
22	2,259	4.37%	48,719	94.26%	$41,770	3.38%	$1,202,387	97.25%
23	1,684	3.26%	50,402	97.52%	$20,561	1.66%	$1,222,948	98.91%
24	1,281	2.48%	51,684	100.00%	$13,468	1.09%	$1,236,416	100.00%

Table 2-103 shows the frequency distribution of Economic Program MWh reductions and credits by real-time zonal, load-weighted, average LMP in various price ranges. Reductions occurred primarily when zonal, load-weighted, average LMP was between $25 and $100 per MWh. Approximately 91 percent of MWh reductions and 66 percent of program credits are associated with hours when the applicable zonal LMP was less than or equal to $100.

Table 2-103 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): Calendar year 2009

	MWh Reductions				Program Credits			
LMP	MWh Reductions	Percent	Cumulative Frequency	Cumulative Percent	Credits	Percent	Cumulative Frequency	Cumulative Percent
$0 to $25	723	1.40%	723	1.40%	$511	0.04%	$511	0.04%
$25 to $50	30,468	58.95%	31,191	60.35%	$318,633	25.77%	$319,143	25.81%
$50 to $75	10,891	21.07%	42,082	81.43%	$276,135	22.33%	$595,278	48.15%
$75 to $100	4,877	9.44%	46,958	90.86%	$223,239	18.06%	$818,517	66.20%
$100 to $125	2,227	4.31%	49,185	95.17%	$144,874	11.72%	$963,391	77.92%
$125 to $150	1,287	2.49%	50,472	97.66%	$108,610	8.78%	$1,072,001	86.70%
$150 to $200	813	1.57%	51,285	99.23%	$92,181	7.46%	$1,164,182	94.16%
$200 to $250	326	0.63%	51,611	99.87%	$52,867	4.28%	$1,217,050	98.43%
$250 to $300	11	0.02%	51,622	99.89%	$2,276	0.18%	$1,219,325	98.62%
> $300	59	0.11%	51,681	100.00%	$17,091	1.38%	$1,236,416	100.00%

Emergency Program

The zonal distribution of DSR capability in the Emergency Program option is shown in Table 2-104 by program option. On August 10, 2009, the peak-load day for the year, there were no available resources in the Emergency-Energy Only option of the Emergency Program.[105] There were 6,007 sites accounting for 5,129.8 MW registered in the Emergency Full option and 1,410 sites accounting for 2,164.5 MW registered in Emergency Capacity Only option. The ComEd Control Zone showed the highest number of registered sites in Emergency-Full option at 805 or 13%, while the AEP Control Zone showed the highest MW capability with 1,259.9 MW registered, or 25 percent of MW registered in the option. The ComEd Control Zone showed the highest participation in the Capacity Only option of the Emergency Program with 526 sites, or 37 percent of total sites, and 697.1 MW, or 32 percent of total MW registered in the option. In 2009, there were no days with emergency activity.

105 The number of registered sites and MW levels are measured as a one-day snapshot. The one-day snapshot is used because retail customers may change curtailment service providers (CSP) multiple times within a year and each such change would require a registration. When switching occurs, an annual total of registered sites would count the same sites and MW multiple times.

Table 2-104 Registered sites and MW in the Emergency Program (By zone and option): August 10, 2009

	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

Load Management Program

The increase in registrations in the Emergency Program for peak periods in 2009 compared to 2008 is due to increased participation in the Load Management (LM) Program, or increased load response participation in RPM. Table 2-105 shows registered MW in the Load Management Program by program type for delivery years 2007/2008 through 2009/2010.

Table 2-105 Registered MW in the Load Management Program by program type: Delivery years 2007 through 2009

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

Table 2-106 shows zonal monthly capacity credits that were paid during the calendar year 2009 to ILR and DR resources. Credits from January to May are associated with participation in the 2008/2009 RPM delivery year, while credits from June to December are associated with participation in the 2009/2010 RPM delivery year. The increase in capacity credits after May is the result of a significant increase in both DR and ILR participation in RPM delivery year 2009/2010, as well as increases in RPM clearing prices.

Table 2-106 Zonal monthly capacity credits: January 1, 2009, through December 31, 2009

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Total
AECO	$154,551	$139,595	$154,551	$149,566	$154,551	$375,086	$387,589	$387,589	$375,086	$387,589	$375,086	$387,589	$3,428,428
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	$3,871,619	$3,746,728	$3,871,619	$39,284,662
APS	$966,835	$873,270	$966,835	$935,647	$966,835	$2,982,596	$3,082,016	$3,082,016	$2,982,596	$3,082,016	$2,982,596	$3,082,016	$25,985,273
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	$4,613,517	$4,464,694	$4,613,517	$45,887,067
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	$4,357,876	$4,217,299	$4,357,876	$46,131,297
DAY	$258,904	$233,849	$258,904	$250,552	$258,904	$646,419	$667,966	$667,966	$646,419	$667,966	$646,419	$667,966	$5,872,235
DLCO	$258,489	$233,474	$258,489	$250,151	$258,489	$375,138	$387,642	$387,642	$375,138	$387,642	$375,138	$387,642	$3,935,073
Dominion	$296,319	$267,643	$296,319	$286,760	$296,319	$1,602,407	$1,655,820	$1,655,820	$1,602,407	$1,655,820	$1,602,407	$1,655,820	$12,873,861
DPL	$665,561	$601,152	$665,561	$644,091	$665,561	$971,656	$1,004,045	$1,004,045	$971,656	$1,004,045	$971,656	$1,004,045	$10,173,074
JCPL	$554,279	$500,639	$554,279	$536,399	$554,279	$868,932	$897,896	$897,896	$868,932	$897,896	$868,932	$897,896	$8,898,256
Met-Ed	$681,734	$615,760	$681,734	$659,743	$681,734	$1,313,605	$1,357,392	$1,357,392	$1,313,605	$1,357,392	$1,313,605	$1,357,392	$12,691,086
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	$2,120,899	$2,052,483	$2,120,899	$21,341,456
PENELEC	$283,241	$255,831	$283,241	$274,105	$283,241	$1,282,941	$1,325,705	$1,325,705	$1,282,941	$1,325,705	$1,282,941	$1,325,705	$10,531,303
Pepco	$572,160	$516,789	$572,160	$553,703	$572,160	$788,433	$814,714	$814,714	$788,433	$814,714	$788,433	$814,714	$8,411,124
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	$3,617,545	$3,500,850	$3,617,545	$30,820,581
PSEG	$922,290	$833,036	$922,290	$892,538	$922,290	$1,720,276	$1,777,619	$1,777,619	$1,720,276	$1,777,619	$1,720,276	$1,777,619	$16,763,747
RECO	$10,219	$9,230	$10,219	$9,890	$10,219	$17,897	$18,494	$18,494	$17,897	$18,494	$17,897	$18,494	$177,443
Total	$16,955,611	$15,314,746	$16,955,611	$16,408,656	$16,955,611	$30,927,439	$31,958,354	$31,958,354	$30,927,439	$31,958,354	$30,927,439	$31,958,354	$303,205,966

With the elimination of the ILR option on March 26, 2009, effective for the 2012/2013 RPM delivery year, load response participation in RPM will be limited to DR.[106] Table 2-107 shows the amount of DR offered and cleared in each Base Residual Auction (BRA) from delivery year 2007/2008 through 2012/2013. The first auction since the elimination of ILR, for delivery year 2012/2013, showed a significant increase in the amount of DR offered and cleared compared to all prior delivery years.

Table 2-107 Demand Response (DR) offered and cleared in RPM Base Residual Auction: Delivery years 2007/2008 through 2012/2013

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	6,824.3

106 126 FERC ¶ 61,275 (2009).

Load Management Testing

For the 2007/2008 and the 2008/2009 delivery years, Load Management (LM) compliance was assessed only for actual PJM declared events. If no event was declared, no capacity testing was required. On December 12, 2008, PJM filed amendments to the tariff providing for LM testing if no emergency event is called by August 15 of the delivery year. These amendments were approved by the Commission on March 26, 2009 and effective in the 2009/2010 delivery year.[107]

Since there were no emergency events called in the 2009/2010 delivery year, all committed DR and certified ILR resources were required to submit test results. All of a provider's committed DR and certified ILR resources in the same zone are required to test at the same time for a one hour period between 12:00 PM EPT to 8:00 PM EPT on a non-holiday weekday between June 1 and September 30.[108] The resource provider must notify PJM of the intent to test 48 hours in advance.

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

Results from the 2009/2010 Load Management testing results are shown in Table 2-108. The first column shows the nominal value which represents the reduction capability indicated by the participant at registration. The second column shows Load Management MW commitments, which are used to assess RPM compliance. Differences between these two columns may reflect differences between MW offered and cleared for any partially cleared DR resource. In addition, RPM Commitments consider any RPM transactions, such as capacity replacement sales or purchases for Demand Resources, while the nominal ICAP does not. Overall, test results showed 1,298.5 MW available over RPM Commitments, or 118 percent test compliance. The DPL control zone showed the highest percentage of compliance, with load reductions at 147 percent of RPM Commitments, while the AEP control zone showed the highest level of MW reduction in testing, with load reductions at 1,995.3 MW, or 400.5 MW over RPM Commitments. The DAY control zone showed the lowest level of test compliance, with load reductions at 99 percent of RPM Commitments.

107 126 FERC ¶ 61,275 (2009).

108 For more information, see Manual 18, "PJM Capacity Market", Revision 8 (January 1, 2010), Section 8.6.

Table 2-108 Load Management test results and compliance by zone for the 2009/2010 delivery year

Zone	Nominal ICAP	Committed MW	Load Reduction Test Results	Over/Under Compliance	Percent Test Compliance	Percent of Nominal ICAP
AECO	61.5	61.4	76.0	14.5	124%	123%
AEP	1,764.2	1,594.8	1,995.3	400.5	125%	113%
AP	497.2	495.0	645.7	150.7	130%	130%
BGE	641.9	640.0	666.5	26.5	104%	104%
ComEd	1,343.7	1,342.6	1,552.9	210.3	116%	116%
DAY	204.7	204.4	203.4	(1.1)	99%	99%
DLCO	514.0	507.7	554.7	47.0	109%	108%
Dominion	162.4	160.2	184.6	24.4	115%	114%
DPL	120.4	120.2	177.2	57.0	147%	147%
JCPL	146.7	146.3	184.3	38.0	126%	126%
Met-Ed	224.5	221.5	244.0	22.4	110%	109%
PECO	351.8	351.3	441.6	90.3	126%	126%
PENELEC	220.2	218.4	270.2	51.8	124%	123%
Pepco	117.7	109.9	144.2	34.3	131%	123%
PPL	607.1	601.0	662.3	61.2	110%	109%
PSEG	312.9	310.8	381.4	70.5	123%	122%
RECO	3.5	3.1	3.2	0.1	104%	91%
Total	7,294.3	7,088.8	8,387.4	1,298.5	118%	115%

Load Management test results are submitted by CSPs directly to PJM. The test results consist of metered load data provided by the CSP which are compared to some baseline consumption level or firm service level determined by LM participation type.[109] There is no physical or technical oversight or verification by PJM or by the relevant LSE of actual testing. PJM screens the data for unreasonable test results, but relies on the CSP to submit accurate metered load data for the testing period with no verification.

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

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

Measurement and Verification

Economic Program

Participants in the Economic Program are paid based upon the reductions in MWh usage that can be attributed to demand side actions and measures. Most participants in the Economic Program measure their reductions by comparing metered load against an estimate of what metered load would have been absent the reduction.[110] The general methodology is to create a base line usage level by calculating the average usage for a set of days that are intended to be representative of a retail customer's typical usage, including separate calculations for weekends/holidays. The extent to which the DSR Program can accurately quantify and compensate actual load reductions is dependent on the Program's ability to establish what a customer's metered load would have been absent any load reduction. This is a very difficult task and the methods used to date have been flawed, resulting in payments for reductions in usage that did not occur.

Customer Base Line (CBL) - History

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

Prior to recent process revisions, the EDC or LSE was responsible for reviewing a customer's CBL data and could object to the calculations. When an EDC or LSE objected, customers had time to resubmit the data, which were also subject to review. From the beginning of the Economic Program, there were multiple settlement disputes in which an EDC or LSE did not approve CBL calculations and CSPs requested PJM involvement. These disputes were among the factors that led to the creation of the Customer Base Line Subcommittee (CBLS) in January 2007. The subcommittee's mission was to "Evaluate current methodology for PJM economic load response used to determine load reductions done through deliberate customer actions in response to expected day ahead and/or real time prices…[and] propose enhancements and/or changes that will improve the transparency and accuracy of the results which will also help to reduce the number of unanticipated settlement rejections."[111]

In December 2007, proposals to modify CBL business rules were presented to the PJM Market Implementation Committee with a focus on two major issues: the permissible period for selecting a comparable day and the number of days to be used for the CBL calculation; and the definition of

110 On-site generation meter data is the other method used to determine the load reduction, if used only for economic load reduction.
111 "Customer Baseline Committee Charter," February 27, 2007, <http://www.pjm.com/~/media/committees-groups/subcommittees/cbls/postings/20070223-final-charter.ashx> (22.7 KB).

a demand-side curtailment. The key criteria considered by the CBLS were empirical performance, simplicity, eliminating gaming/free-ridership, and overall cost to implement and administer.

On April 14, 2008, PJM filed with the FERC revisions to the Tariff and Operating Agreement to improve the Economic Program.[112] The filing included provisions to: (1) improve the method of establishing CBLs; (2) clarify that eligibility is limited to demand reductions in response to price; (3) establish objective criteria to assist with the identification of inappropriate market activity; and (4) provide PJM the authority to deny participation in the Program. Revisions were approved June 12, 2008.[113]

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

Prior to the revisions, the standard weekday CBL included the highest five weekdays of the most recent 10 weekdays, with no limit on how current CBL days must be. In addition, low usage days were defined as load less than 25 percent of average usage. Submitted settlement days were considered event days in CBL calculations even if they were eventually denied. Saturdays, Sundays and holidays were all considered “like days”.

The effect of the revisions approved June 12, 2008 was to provide for CBL calculations based on more recent and comparable data, which has made CBL calculations more representative of retail customers’ load absent any reduction activities. Additionally, the provision clarifying that participation is limited to reductions in response to real time prices and the establishment of PJM’s authority to deny participation were necessary program changes that are essential components of a rational verification process.

CBL Issues

Even after the revisions, the CBL is still a simple, generic formula applied to nearly every customer’s usage and, as such, is not adequate to serve as the sole or primary basis for determining if an intentional load reduction took place. There are no mandatory CBL enhancements for customers with highly volatile load patterns. If a customer normally has lower load on one particular weekday, that day will appear as a reduction eligible for payment under the current CBL methodology although no deliberate load reducing actions were taken in response to real time price signals. There are no mandatory adjustments to the standard CBL for load levels that are a function of weather. In a mild week following a week of extreme temperatures and high load levels, a customer can submit settlements without taking any load reducing action and it will appear as a reduction eligible for payment because metered load is below CBL. A customer’s CBL calculation is only reviewed in the Economic Program registration process and the review criteria are unclear. In the registration

112 *PJM Interconnection, L.L.C.,* Tariff Amendments, Docket No. ER08-824-000 (April 14, 2008).
113 123 FERC ¶ 61,257 (2008).

process, an alternative CBL may be proposed by the CSP or the relevant LSE/EDC.[114] PJM has developed thirteen alternative CBL calculations, three of which include a weather sensitivity adjustment. While the weather adjusted alternative CBL calculations likely provide a more accurate baseline for all customer consumption, an alternative CBL is an optional program feature rather than a required one, and, as a result, the majority of settlements submitted use an unadjusted standard CBL. Since the implementation of the Load Response System (eLRS) on June 1, there were 17,791 settlements submitted and processed for CBL calculations for calendar year 2009. Of those 17,357 CBL calculations, 14,383 or 83 percent utilized the standard, unadjusted CBL, and 1,468 or 8 percent utilized an alternative CBL adjusted for weather sensitivity.

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

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

The MMU has analyzed all settlement data submitted in the Economic Load Response Program from the period January 1 through December 31, 2009, to further assess the revised CBL calculation.[115] While the revised CBL showed significant improvements in representing load patterns, the revised CBL methodology is still inadequate as a basis for defining and determining load reductions which are compensated under the PJM demand side programs. The tariff changes effective June 13, 2008, provide for a thirty day period to review activity in the Economic Load Response Program, after which, "[t]he Office of the Interconnection may refer the matter to the PJM MMU and/or the FERC Office of Enforcement if the review indicates the relevant Economic Load Response Participant and/or relevant electric distribution company or LSE is engaging in activity that is inconsistent with the PJM Interchange Energy Market rules governing Economic Load Response Participants."[116] PJM has not referred any participants or registrations to the MMU.

Analysis of Settlements

The MMU only has access to meter data submitted as part of a settlement day. The revised PJM settlement review process includes screens that result in reduced submissions of excess settlement data.[117] While this is a positive change for the program, it limits the hourly metered load data provided to PJM and thus limits the ability of PJM and the MMU to assess whether a customer's CBL is representative.

114 If, however, agreement cannot be reached, then PJM will determine the alternative CBL.
115 Since behind the meter generation customers do not require a CBL, they were excluded from this analysis.
116 OA Schedule 1 § 3.3A.7(b).
117 Specifically, the normal operations screen and the requirement that notification hours match settlement hours have resulted in a reduction of the submission of excess settlement data.

In the *2008 State of the Market Report for PJM*, the MMU reported that a large number of consecutive hours showing a metered load less than CBL maybe an indication that the CBL is not an adequate method to determine load reductions. If a CBL is accurately modeling load patterns, then a CBL greater than real time load indicates load reducing actions are taking place. If, for any settlement, the number of consecutive hours showing load reduction is beyond a reasonable window for load reducing actions in response to price, it should initiate a CBL review and warrant further substantiation from the customer and CSP.

The MMU screened all settlements submitted for January 1 through December 31, 2009 for any settlement that showed 24 consecutive hours of load reduction. Table 2-109 shows the proportion of 24 hour reduction settlements to total settlements submitted, as well as the proportion of credits associated with these settlements. Table 2-110 shows the same information for July 1, 2008 through December 31, 2008. The proportion of settlements showing 24 hours of reduction has dropped significantly from 19.8 percent in 2008 to 1.5 percent in 2009. The proportion of total credits associated with these settlements has dropped significantly from 40.6 percent to 22.4 percent. However, in 2009, these 314 settlement days still accounts for a disproportionally large percent of total credits for the time period.

Table 2-109 Settlements showing consecutive 24 hour reductions as a percent of total settlements submitted for the period January 1, 2009 through December 31, 2009

	Settlement Days	Percent of Total Settlements	CSP Credits	Percent of Total Credit
24 consecutive hours CBL > metered load	314	1.5%	$273,356	22.4%
All other settlements	20,589	97.4%	$944,544	77.6%
Total	21,133	100.0%	$1,217,900	100.0%

Table 2-110 Settlements showing consecutive 24 hour reductions as a percent of total settlements submitted for the period July 1, 2008 through December 31, 2008

	Settlement Days	Percent of Total Settlements	CSP Credits	Percent of Total Credit
24 consecutive hours CBL > metered load	2,812	19.8%	$3,955,865	40.6%
All other settlements	11,416	80.2%	$5,789,988	59.4%
Total	14,228	100.0%	$9,745,853	100.0%

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

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

Activity Review Process

Effective November 3, 2008, PJM began a new Activity Review Process for settlements in the Economic Demand Side Response Program.[118] The Activity Review Process includes a daily screen of settlements as well as an ongoing "normal operations" registration review process for identifying inappropriate behavior. The daily settlement screens define specific criteria for the automatic denial of daily settlements. The "normal operations" review process requires identified participants to submit documentation on load reducing actions associated with settlements submitted. With the implementation of the activity review process, PJM specifically defines the acceptable criteria for LSE/EDC denial of settlements. LSE/EDCs can no longer deny settlements based on whether the customer's CBL calculations reasonably represent load or on a determination that a load reduction action was not in response to price. While it is reasonable to limit the authority of LSE/EDCs in the review of demand side settlements as the LSE/EDCs have economic incentives to deny settlements, the MMU recommends that LSE/EDCs should be able to initiate PJM settlement reviews.

The daily screen provides that PJM will deny a daily settlement when any of the following criteria are met: (1) no advanced notification for settlements; (2) settlement hours do not match notification hours; (3) settlement is worth less than $5 in value; or (4) 75 percent or more of settlement hours show a retail generation and transmission rate higher than LMP.

The daily screen does indirectly address an issue with the CBL calculation, the ineligibility of "event days" for inclusion in CBL. When a high CBL results from high load days, a customer or CSP could submit settlements on daily basis to block lower load days from CBL eligibility, creating an upward bias in measured CBL. When a customer submits low value settlements for the purpose of blocking the inclusion of low load days from the CBL, the daily review process will deny them if they fail one of the four identified screens. But, PJM does not review daily settlements to assess responsiveness to price or accuracy of the CBL.

PJM's "normal operations" screen involves a review of all participation when a customer submits settlements for 70 percent (21 days) of available days in a rolling 30 weekday period. The review includes: (1) analysis of notifications and settlements; (2) review of registration contract; (3) required CSP submission of detailed description of load reduction activities; (4) written verification from end-use customer regarding DSR activity on specific days; and (5) optional on-site review. During this review, all new settlement requests will be denied pending the outcome of the review. Depending on the conclusion of the activity review, the registration may be terminated and the CSP may be referred to the FERC Office of Enforcement and/or the MMU, pursuant to the tariff.

118 See PJM. "Economic Demand Side Response: Activity review process and PJM actions" <http://www.pjm.com/~/media/committees-groups/committees/drsc/20081031/20081031-item-04-dsr-activity-review-proc.ashx>

Load Management Program

There are three forms of participation in the Load Management (LM) Program distinguished by their measurement and verification protocol: (1) Direct Load Control (DLC), (2) Firm Service Level (FSL), and (3) Guaranteed Load Drop (GLD). The DLC option accounts for 7 percent of registered MW in the LM Program, while the FSL option accounts for 47 percent and the GLD option accounts for 47 percent.

The DLC method is used for customers in the Pilot Program for non-hourly metered customers. For DLC customers, a CSP will interface directly with customer equipment, sending a communication to cycle when PJM has declared an event. Load reductions are estimated through PJM reported or site surveyed impact studies.

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

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

The prior section addresses shortfalls of the standard CBL calculation used in the Economic Program, including the potential for an upward bias based on prior days with warmer temperatures. The potential for an upward bias during an actual Emergency Event is minimal, since Emergency Events coincide with peak load conditions in PJM which are highly correlated with peak temperatures. However, this design flaw is an issue when applied to Load Management testing as participants have discretion as to when testing will take place. It is possible for a GLD customer or a group of GLD customers to perform testing directly following a week of high temperatures and higher overall load levels and to show a greater level of reduction capability than would be possible during an emergency event.

The MMU recommends that regression analysis capturing the effect of ambient temperature be incorporated in any GLD testing that estimates unrestricted load consumption based on a comparable day or a comparable set of days.

Conclusions: Demand Side

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

Emergency Program

In the 2009/2010 delivery year, all participants in the Emergency Program were capacity resources, integrated into RPM through the Load Management Program. The purpose of the Load Management Program is to provide a mechanism for end-use customers to avoid paying the Capacity Market clearing price in return for agreeing to not use capacity when it is needed by customers who have paid for capacity. The fact that customers in the Load Management Program only have to agree to interrupt ten times per year represents a flaw in the design of the program. There is no reason to believe that the customers who pay for capacity will need the capacity used by participating LM customers only ten times per year. In fact, it can be expected that the probability of needing that capacity will increase with the amount of MW that participating LM customers clear in the RPM auctions.

Under the Emergency Energy Only option and the Emergency Full option, participants are made whole to a minimum strike price offer regardless of the hourly LMP. There is no economic reason to compensate load reductions up to $1,000/MWh during an emergency event regardless of the hourly LMP. Compensation in the Emergency Program should be directly aligned with the RPM market clearing price. The appropriate energy market price signal for load reduction in any hour is the hourly LMP. This means that the appropriate compensation in any PJM Program is the LMP less the generation component of a fixed retail rate, which is already made available through participation in the Economic Program. There is no need for energy payments through the Emergency Program. The current design of the Emergency Program incents resources to seek overcompensation through Emergency Energy payments equal to the greater of LMP or a submitted minimum dispatch price, which, in most cases is set at $1,000/MWh.

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

While the introduction of Load Management testing for any delivery year without an emergency event is an improvement to the Program, the current state of testing does not constitute an adequate measurement and verification protocol to ensure that demand side capacity resources can reliably reduce during a system emergency. The MMU recommends that the testing program be modified to require verification of test methods and results. In addition, the MMU recommends that when used to determine compliance in Load Management testing for GLD customers, the CBL calculation should include statistical analysis that captures the effect of ambient conditions.

Economic Program

In PJM's Economic Load Response Program, the primary tool used to establish what unrestricted load would have been is the standard CBL. The modifications to the CBL calculations effective June, 2008, and the new review process, effective November, 2008, represent significant improvements to the Economic Program, but the review process is not yet adequate to ensure that other customers are receiving the benefit of actual demand reductions when payments are made under the program. The new review process is not yet developed to the point that it can establish that load reductions are the result of identifiable load reducing actions taken in response to price. There is no explicit or implicit screening mechanism in place to verify that CBL calculations are representative of customer load.

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

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

The definition of the standard or default CBL should continue to be refined to ensure that it reflects the actual normal use of individual customers including normal daily and hourly fluctuations in usage and usage that is a function of measurable weather conditions.

While it is reasonable to limit the authority of LSE/EDCs in the review of demand side settlements as the LSE/EDCs have economic incentives to deny settlements, the MMU recommends that LSE/EDCs should be able to initiate PJM settlement reviews.

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