SECTION 2 – ENERGY MARKET, PART 1

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

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

Table 2-1 The Energy Market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Effective**

- The aggregate market structure was evaluated as competitive because the calculations for hourly HHI (Herfindahl-Hirschman Index) indicate that by the FERC standards, the PJM Energy Market during 2010 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1185 with a minimum of 942 and a maximum of 1599 in 2010.

- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints. The results of the three pivotal supplier test, used to test local market structure, indicates the existence of market power in a number of local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for local market power, PJM's application of the three pivotal supplier test mitigated local market power and forced competitive offers, correcting for structural issues created by local transmission constraints.

- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets.

- Market performance was evaluated as competitive because market results in the Energy Market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both Day-Ahead and Real-Time

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

Energy Markets. In 2010, the markup component of the PJM real-time, load-weighted, average LMP was $0.31 per MWh, or 0.6 percent.

- Market design was evaluated as effective because the analysis shows that the PJM Energy Market resulted in competitive market outcomes, with prices reflecting, on average, the marginal cost to produce energy. In aggregate, PJM's Energy Market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the markup design mitigates market power and causes the market to provide competitive market outcomes.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[2] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs only in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[3]

Highlights and New Analysis

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

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

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

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

---

2 OATT Attachment M

3 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.

4 The MMU's fuel cost adjusted LMP analysis reflects both fuel and emission cost differences over the periods in question. It could also be characterized as input cost adjusted LMP analysis.

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

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

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

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

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

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

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

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

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

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

Summary Recommendations

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

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

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

Overview

Market Structure

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

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

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

- **Local Market Structure and Offer Capping.** A noncompetitive local market structure is the trigger for offer capping. PJM continued to apply a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in 2010. PJM offer caps units only when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer-capping levels have historically been low in PJM. In the Day-Ahead Energy Market offer-capped unit hours increased from 0.1 percent in 2009 to 0.2 percent in 2010. In the Real-Time Energy Market offer-capped unit hours increased from 0.4 percent in 2009 to 1.2 percent in 2010.

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

5 Calculated values shown in Section 2, "Energy Market, Part 1," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.
6 For the purpose of the *2010 State of the Market Report for PJM*, all hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2010 State of the Market Report for PJM*, Appendix G, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

- **Local Market Structure.** In 2010, the AECO, AEP, AP, BGE, ComEd, DLCO, Dominion, DPL, Met-Ed, PENELEC, PPL and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 100 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.[7]

Market Performance: Markup, Load and Locational Marginal Price

- **Markup.** The markup conduct of individual owners and units has an impact on market prices. The MMU calculates explicit measures of the impact of marginal unit markups on LMP. The LMP impact is a measure of market power. The price impact of markup must be interpreted carefully. The price impact is not based on a full redispatch of the system, as such a full redispatch is practically impossible because it would require reconsideration of all dispatch decisions and unit commitments. The markup impact includes the maximum impact of the identified markup conduct on a unit by unit basis, but the inclusion of negative markup impacts has an offsetting effect. The markup analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval. The markup analysis is a more general measure of the competitiveness of the Energy Market.

  The markup component of the overall PJM real-time, load-weighted, average LMP in 2010 was $0.31 per MWh, or 0.6 percent. Coal steam units contributed -$0.99 to the total markup component of LMP. Combustion turbine units that use natural gas as their primary fuel source contributed $0.34 to the total markup component of LMP. Combined cycle units that use gas as their primary fuel source contributed $0.77 to the total markup component of LMP. The markup was $1.63 per MWh during peak hours and -$1.11 per MWh during off-peak hours.

  The markup component of the overall PJM day-ahead, load-weighted, average LMP was -$0.60 per MWh, or -1.3 percent. Coal steam units contributed -$0.68 to the total markup component of LMP. Natural gas steam units contributed $0.05 to the total markup component of LMP. The markup was $0.03 per MWh during peak hours and -$1.27 per MWh during off-peak hours.

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

- **Load.** On average, PJM real-time load increased in 2010 by 4.7 percent from 2009, rising from 76,035 MW to 79,611 MW. PJM day-ahead load increased in 2010 by 2.6 percent from 2009, rising from 88,707 MW to 90,985 MW.

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

7 See the *2010 State of the Market Report for PJM*, Volume II, Appendix D, "Local Energy Market Structure: TPS Results" for detailed results of the TPS test.

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

PJM Day-Ahead Energy Market prices increased in 2010 compared to 2009. The system simple average LMP was 20.5 percent higher in 2010 than in the 2009, $44.57 per MWh versus $37.00 per MWh. The load-weighted LMP was 22.7 percent higher in 2010 than in 2009, $47.65 per MWh versus $38.82 per MWh.

- **Load and Spot Market.** Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In 2010, 4.9 percent of real-time load was supplied by bilateral contracts, 19.3 percent by spot market purchases and 75.8 percent by self-supply. Compared with 2009, reliance on bilateral contracts decreased by 1.1 percentage points; reliance on spot supply increased by 3.2 percentage points; and reliance on self-supply decreased by 2.1 percentage points in 2010.

Demand-Side Response

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

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

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

8 The MMU's fuel cost adjusted LMP analysis reflects both fuel and emission cost differences over the periods in question. It could also be characterized as input cost adjusted LMP analysis.

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

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

  That PJM may require subzonal Load Management events while CSPs may aggregate customers on a zonal basis and, in some cases, are assessed compliance on a zonal basis, is a broader issue that needs to be addressed. More precise locational deployment of Load Management improves efficiency while reducing the ability of a CSP to aggregate customers.

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

  Since the implementation of the RPM design on June 1, 2007, capacity revenue has become the primary source of revenue to participants in PJM demand side programs. In 2010, Economic Program revenues increased by $1.5 Million or 111 percent, from $1.4 million to $2.9 million. In 2010, Load Management (LM) Program revenues increased by $209 million or 69 percent, from $303 million to $512 million. Synchronized Reserve credits increased by $1.3 million, from approximately $4.0 million to $5.3 million from 2009 to 2010. In 2009, since there were no Load Management Events, no emergency energy revenues were eligible. However, in 2010, there were six Load Management Events resulting in $13.8 million in emergency energy revenues.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in 2010, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, price-cost markup, offer capping, participation in demand-side response programs, loads and prices in this section of the report. The next section continues the analysis of the PJM Energy Market including additional measures of market performance.

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

Aggregate hourly supply offered increased by about 554 MWh when comparing the summer of 2010 to the summer of 2009, while aggregate peak load increased by 9,667 MW, modifying the general supply demand balance from the summer of 2009 with a corresponding impact on Energy Market prices. Average load in 2010 also increased from 2009, rising from 76,035 MW to 79,611 MW. Market concentration levels remained moderate and average markup was slightly positive. This relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive for most hours.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load. LMP is a broader indicator of the level of competition. While PJM has experienced price spikes, these have been limited in duration and, in general, prices in PJM have been well below the marginal cost of the highest cost unit installed on the system. The significant price spikes in PJM have been directly related to supply and demand fundamentals. In PJM, prices tend to increase as the market approaches scarcity conditions as a result of generator offers and the associated shape of the aggregate supply curve. The pattern of prices within days and across months and years illustrates how prices are directly related to demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints. This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. A generation owner or group of generation owners is pivotal for a local market if the output of the owners' generation facilities is required in order to relieve a transmission constraint. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests. The result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and specific owners had structural market power. The analysis of the application of the three pivotal supplier test demonstrates that it is working successfully to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive.[10]

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

10 See the *2010 State of the Market Report for PJM*, Volume II, Appendix D, "Local Energy Market Structure: TPS Results" for detailed results of the TPS test.

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

Detailed Recommendations

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

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

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

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

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

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

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

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

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

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

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

Market Structure

Supply

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

During the summer of 2010, the peak demand was 9,667 MW, or 7.6 percent, higher than the 2009 peak, which, when combined with the shift up and to the right of the 2010 supply curve, resulted in a higher price level at the intersection of supply and demand (Figure 2-1). The summer 2010 point of supply and demand intersection was approximately $116, a 70.6 percent increase over the summer 2009 point of supply and demand intersection of $68.

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

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

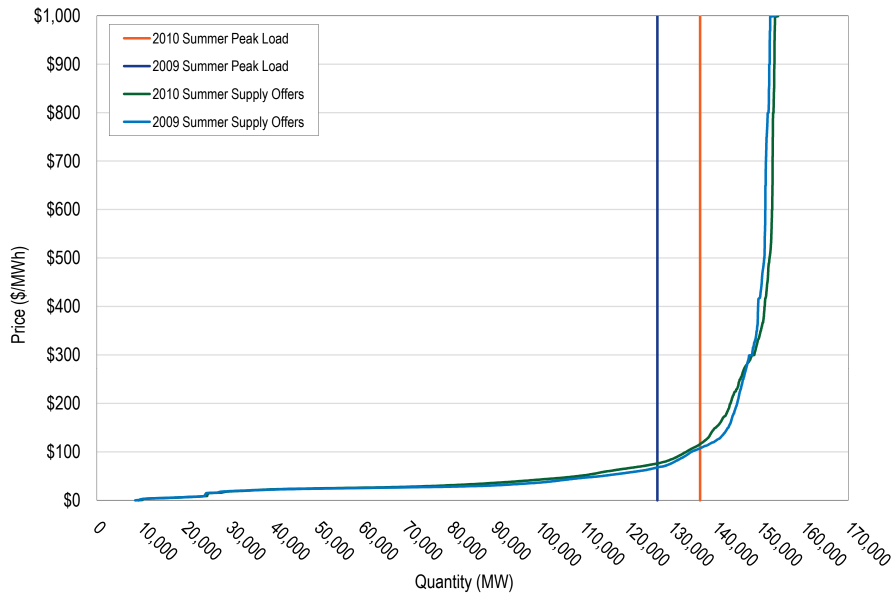


Table 2-2 shows unit deactivations for 2010.[13] A total of 741.0 MW was retired in 2010, including 299.0 MW from Edison Mission Group, 189.0 MW from American Municipal Power-Ohio, Inc., 137.0 MW from Dominion Resources, Inc., 89.0 MW from NRG Energy, Inc., 17.0 MW from City of Vineland, 6.6 MW from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

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

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

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

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

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

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

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

Range	All Offers	Pool-Scheduled Share of All Offers	Self-Scheduled Share of All Offers
($200) - $0	9.5%	21.2%	78.8%
$0 - $200	60.8%	88.6%	11.4%
$200 - $400	19.8%	98.7%	1.3%
$400 - $600	5.2%	98.2%	1.8%
$600 - $800	1.1%	91.1%	8.9%
$800 - $1,000	3.6%	92.1%	7.9%

Demand

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

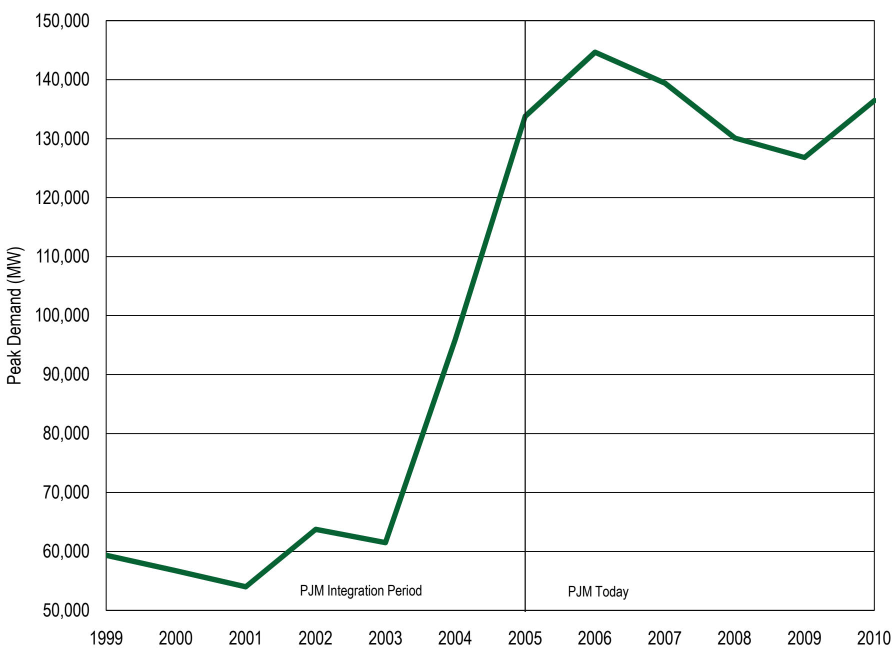
139,428 MW. This measure of peak load is the total amount of generation output and net energy imports required to meet the peak demand on the system, including losses, rather than the actual load served.[14]

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

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

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

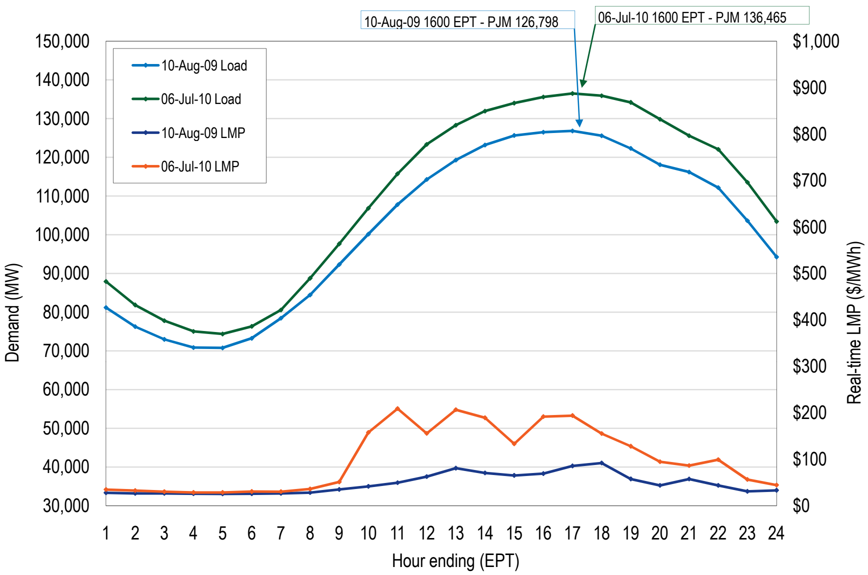
Figure 2-2 Actual PJM footprint peak loads: 1999 to 2010



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

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

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



Market Concentration

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

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

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

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

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

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

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

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

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

PJM HHI Results

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

16 HHI and market share are commonly used, but potentially misleading metrics for structural market power. Traditional HHI and market share analyses tend to assume homogeneity in the costs of suppliers. It is often assumed, for example, that small suppliers have the highest costs and that the largest suppliers have the lowest costs. This assumption leads to the conclusion that small suppliers compete among themselves at the margin, and therefore participants with small market share do not have market power. The three pivotal supplier test provides a more accurate metric for structural market power because it measures, for the relevant time period, the relationship between demand in a given market and the relative importance of individual suppliers in meeting that demand. The MMU uses the results of the three pivotal supplier tests, not HHI or market share measures, as the basis for conclusions regarding structural market power.

17 See the *2010 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part 1," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI). Consistent with common application, the market share and HHI calculations presented in the SOM are based on supply that is cleared in the market in every hour, not on measures of available capacity.

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

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

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

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

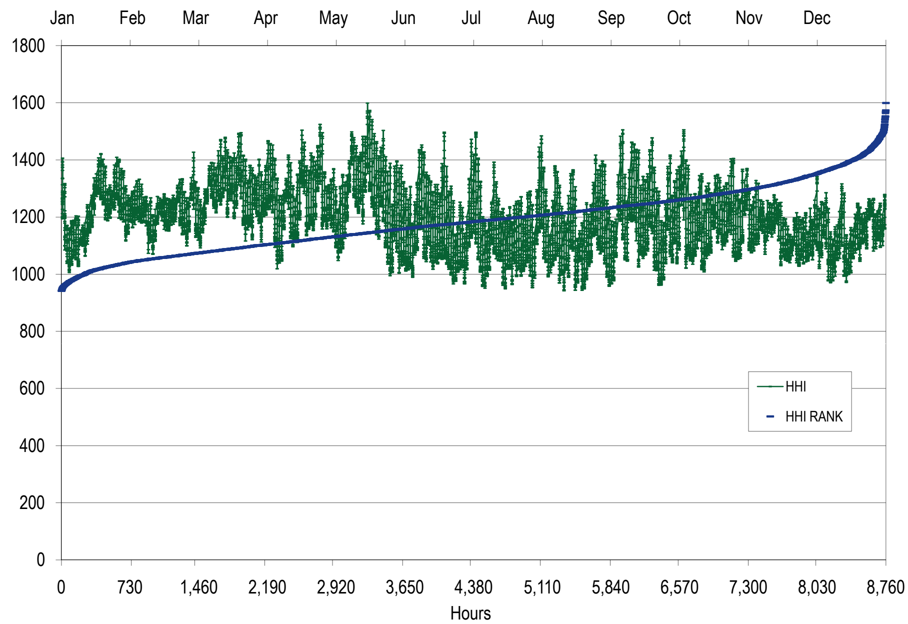
Table 2-6 PJM hourly Energy Market HHI (By segment): Calendar year 2010

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

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

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

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



Local Market Structure and Offer Capping

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

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

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

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

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

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

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

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2006	1.0%	0.2%	0.4%	0.1%
2007	1.1%	0.2%	0.2%	0.0%
2008	1.0%	0.2%	0.2%	0.1%
2009	0.4%	0.1%	0.1%	0.0%
2010	1.2%	0.4%	0.2%	0.1%

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

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

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

	2010 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2	0	0	0	1	13
80% and < 90%	0	2	1	7	8	13
75% and < 80%	0	0	0	0	3	7
70% and < 75%	3	0	0	0	4	13
60% and < 70%	0	1	1	1	0	34
50% and < 60%	1	0	0	5	0	22
25% and < 50%	4	2	4	9	17	41
10% and < 25%	2	0	0	4	2	37

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

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

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

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

Local Market Structure

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

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

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

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

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

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

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

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

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

26 See the *2010 State of the Market Report for PJM*, Volume II, Appendix D, "Local Energy Market Structure: TPS Results" for detailed results of the TPS test.

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

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

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

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

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
5004/5005 Interface	Peak	6,489	1,745	27%	5,191	80%
	Off Peak	3,242	1,542	48%	1,981	61%
AP South	Peak	13,037	827	6%	12,617	97%
	Off Peak	6,849	684	10%	6,464	94%
Bedington - Black Oak	Peak	4,228	746	18%	4,080	96%
	Off Peak	2,303	555	24%	2,165	94%
Central	Peak	67	35	52%	37	55%
	Off Peak	45	13	29%	35	78%
East	Peak	22	9	41%	16	73%
	Off Peak	37	11	30%	30	81%
Harrison - Pruntytown	Peak	3,343	386	12%	3,129	94%
	Off Peak	3,315	402	12%	3,042	92%
West	Peak	687	489	71%	320	47%
	Off Peak	271	262	97%	22	8%

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

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

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005 Interface	Peak	319	1,760	18	5	13
	Off Peak	220	1,150	16	8	8
AP South	Peak	298	812	8	1	7
	Off Peak	327	800	8	1	7
Bedington - Black Oak	Peak	214	673	10	1	9
	Off Peak	179	732	8	1	7
Central	Peak	401	2,680	19	9	10
	Off Peak	574	3,228	15	5	10
East	Peak	301	2,671	15	7	9
	Off Peak	354	1,836	11	4	8
Harrison - Pruntytown	Peak	417	1,870	16	2	15
	Off Peak	441	1,840	16	2	14
West	Peak	467	2,577	19	12	6
	Off Peak	143	1,055	20	19	1

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

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

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
5004/5005 Interface	Peak	6,489	709	11%	349	5%	49%
	Off Peak	3,242	176	5%	38	1%	22%
AP South	Peak	13,037	342	3%	154	1%	45%
	Off Peak	6,849	147	2%	45	1%	31%
Bedington - Black Oak	Peak	4,228	57	1%	26	1%	46%
	Off Peak	2,303	38	2%	6	0%	16%
Central	Peak	67	7	10%	0	0%	0%
	Off Peak	45	12	27%	3	7%	25%
East	Peak	22	4	18%	1	5%	25%
	Off Peak	37	2	5%	0	0%	0%
Harrison - Pruntytown	Peak	3,343	337	10%	151	5%	45%
	Off Peak	3,315	154	5%	70	2%	45%
West	Peak	687	84	12%	15	2%	18%
	Off Peak	271	18	7%	1	0%	6%

Ownership of Marginal Resources

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

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

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

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

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

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

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

Fuel Type of Marginal Units

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

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

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

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

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

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

Market Conduct: Markup

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

Real-Time Markup Conduct

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

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

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

Day-Ahead Markup Conduct

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

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

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

Market Performance

Markup

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

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

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

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

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

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

Real-Time Markup

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

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

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

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

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

Markup Component of Real-Time System Price

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

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

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

Markup Component of Real-Time Zonal Prices

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

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

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

Markup by Real-Time System Price Levels

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

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

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

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

Day-Ahead Markup

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

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

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

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

Markup Component of Day-Ahead System Price

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

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

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

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

Markup Component of Day-Ahead Zonal Prices

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

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

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

Markup by Day-Ahead System Price Levels

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

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

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

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

Frequently Mitigated Unit and Associated Unit Adders

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

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

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

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

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

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

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

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

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

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

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

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

Energy Market Opportunity Cost

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

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

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

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

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

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

The result is an hourly LMP estimate for each generator bus, a daily fuel cost estimate for each generator bus and therefore an hourly margin for each bus. (The net margin also accounts for emissions costs, the ten percent adder, VOM and FMU adders.) The hourly LMP and the fuel costs are the result of using the historical ratios multiplied by the forward curve data. The margins which result from comparing these hourly LMP and fuel cost data reflects the forward data, adjusted using historical data, to the specific generator bus. The only purpose of using the historical data is to translate the forward curve data to specific hours and buses.

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

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

Market Performance: Load and LMP

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

Load

Real-Time Load

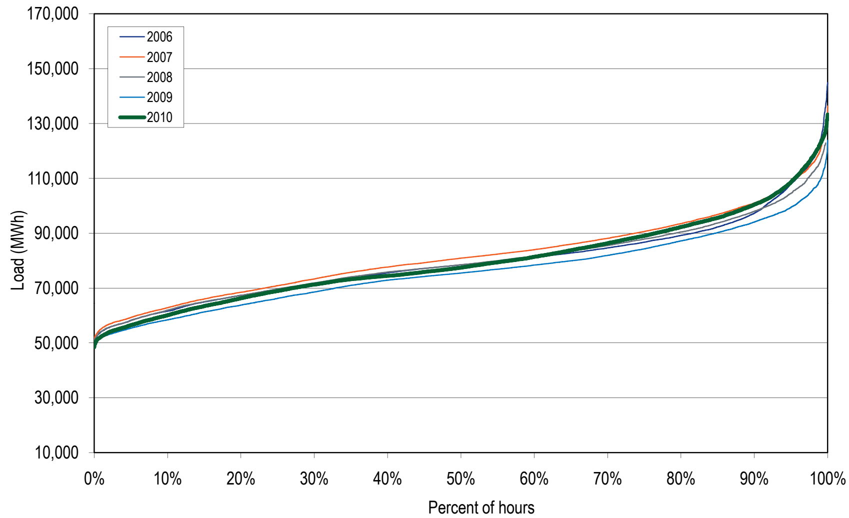
PJM real-time load is the total hourly accounting load in real time.[38]

PJM Real-Time Load Duration

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

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

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



PJM Real-Time, Annual Average Load

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

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

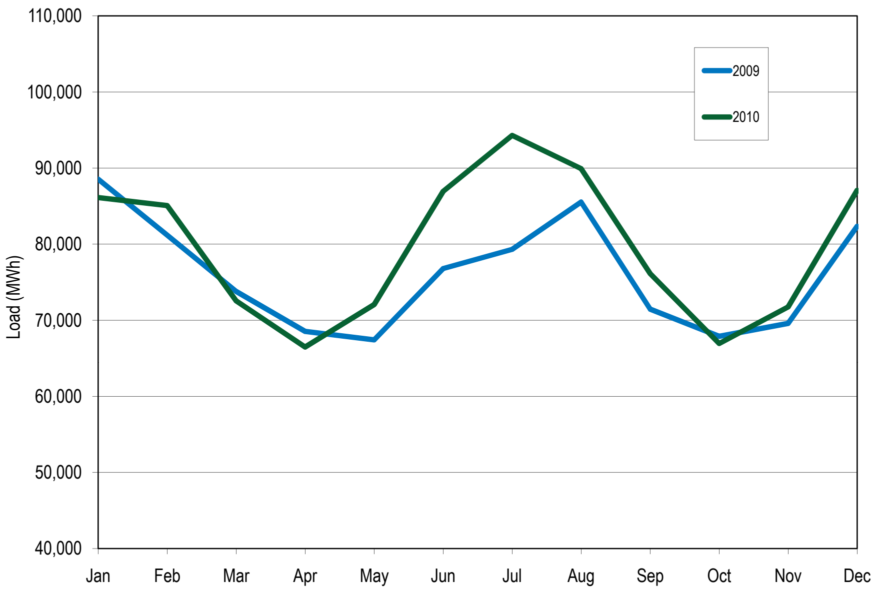
	PJM Real-Time Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	28,578	28,653	5,511	NA	NA	NA
1999	29,641	29,341	5,956	3.7%	2.4%	8.1%
2000	30,113	30,170	5,529	1.6%	2.8%	(7.2%)
2001	30,297	30,219	5,873	0.6%	0.2%	6.2%
2002	35,731	34,746	8,013	17.9%	15.0%	36.5%
2003	37,398	37,031	6,832	4.7%	6.6%	(14.7%)
2004	49,963	48,103	13,004	33.6%	29.9%	90.3%
2005	78,150	76,247	16,296	56.4%	58.5%	25.3%
2006	79,471	78,473	14,534	1.7%	2.9%	(10.8%)
2007	81,681	80,914	14,618	2.8%	3.1%	0.6%
2008	79,515	78,481	13,758	(2.7%)	(3.0%)	(5.9%)
2009	76,035	75,471	13,260	(4.4%)	(3.8%)	(3.6%)
2010	79,611	77,430	15,504	4.7%	2.6%	16.9%

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

PJM Real-Time, Monthly Average Load

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

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



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

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

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

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

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

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

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

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

Day-Ahead Load

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

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

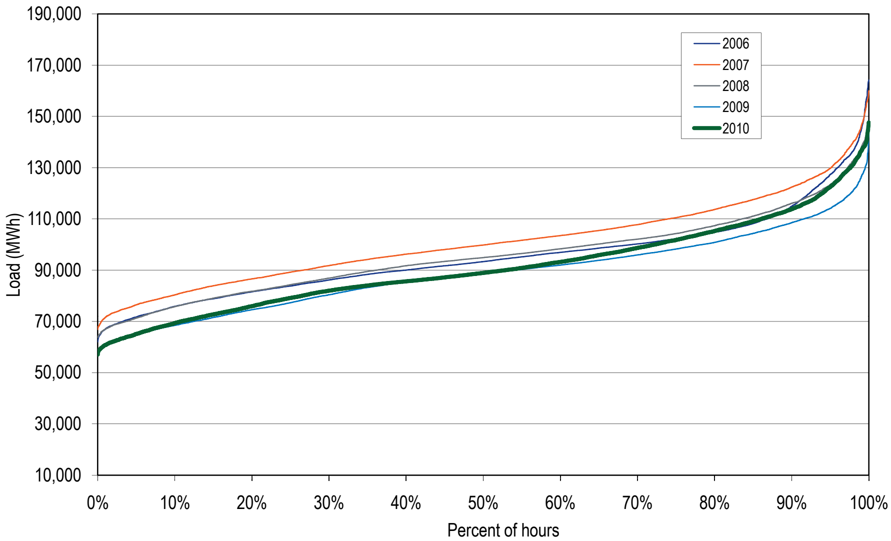
PJM day-ahead load is the hourly total of the above three types of cleared demand bids.

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

PJM Day-Ahead Load Duration

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

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



PJM Day-Ahead, Annual Average Load

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

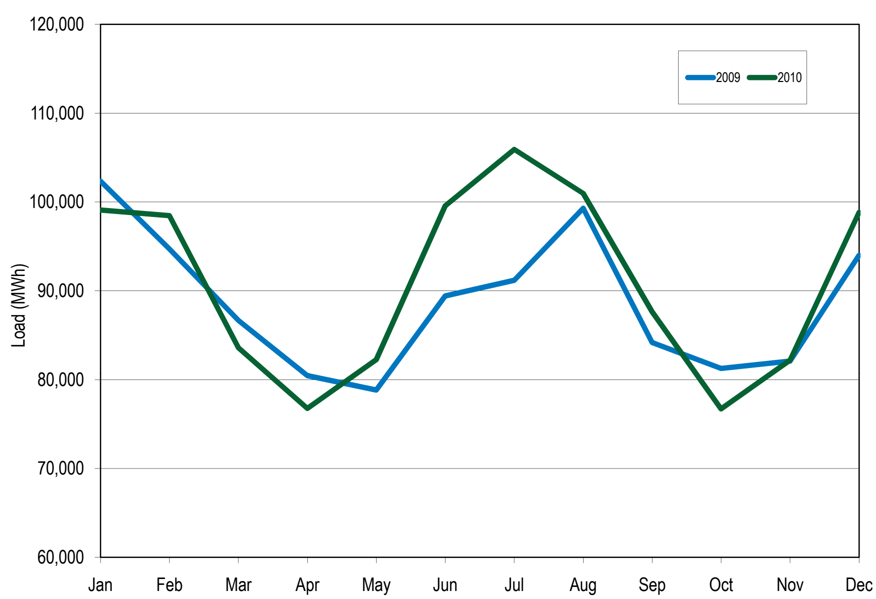
Table 2-31 PJM day-ahead average load: Calendar years 2000 to 2010

	PJM Day-Ahead Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	33,045	33,217	6,850	NA	NA	NA
2001	33,318	32,812	6,489	0.8%	(1.2%)	(5.3%)
2002	42,131	40,720	10,130	26.4%	24.1%	56.1%
2003	44,340	44,368	7,883	5.2%	9.0%	(22.2%)
2004	61,034	58,544	16,318	37.7%	32.0%	107.0%
2005	92,002	90,424	17,381	50.7%	54.5%	6.5%
2006	94,793	93,331	16,048	3.0%	3.2%	(7.7%)
2007	100,912	99,799	16,190	6.5%	6.9%	0.9%
2008	95,522	94,886	15,439	(5.3%)	(4.9%)	(4.6%)
2009	88,707	88,833	14,896	(7.1%)	(6.4%)	(3.5%)
2010	90,985	88,925	17,014	2.6%	0.1%	14.2%

PJM Day-Ahead, Monthly Average Load

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

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



Real-Time and Day-Ahead Load

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

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

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

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

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

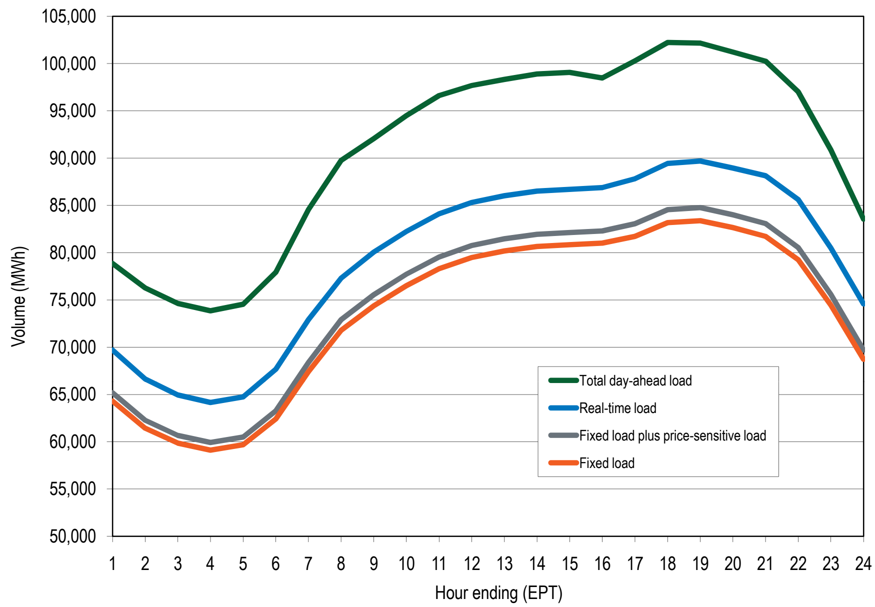
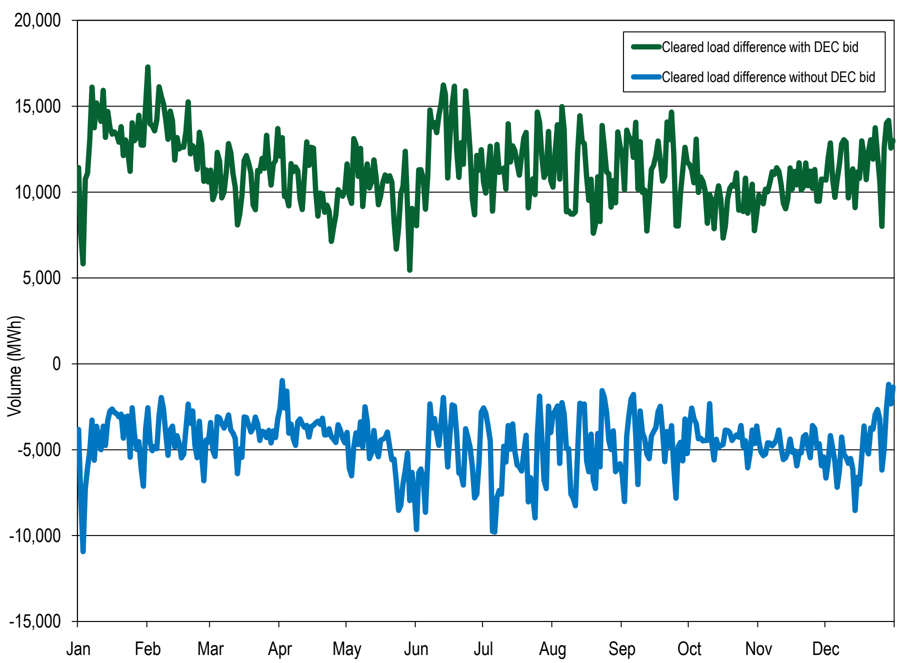


Figure 2-10 Difference between day-ahead and real-time loads (Average daily volumes): Calendar year 2010



Real-Time and Day-Ahead Generation

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

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

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

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

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

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

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

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

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

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

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

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

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

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

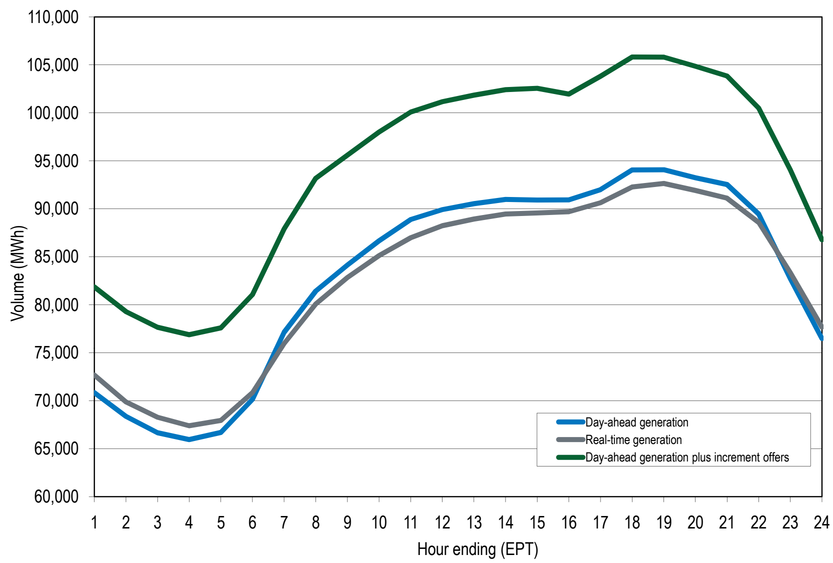
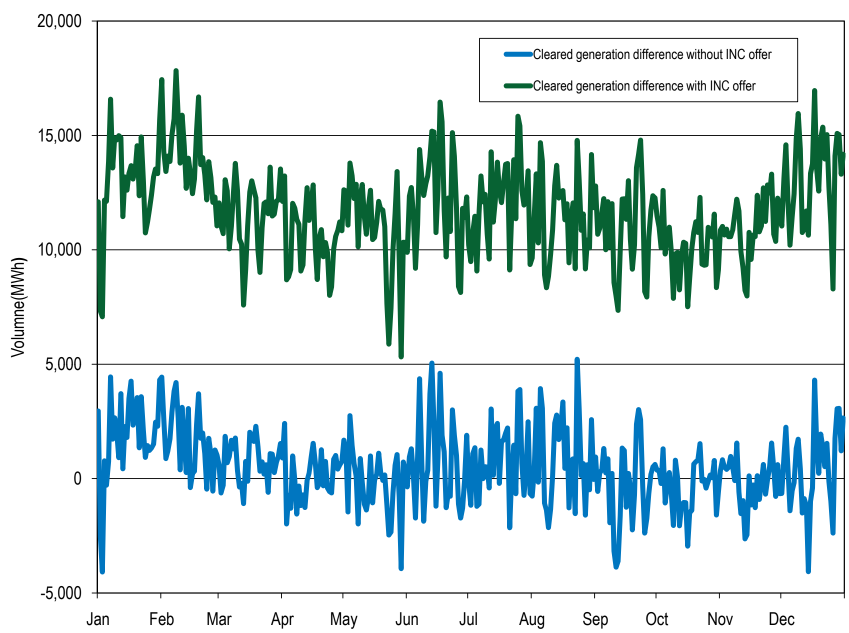


Figure 2-12 Difference between day-ahead and real-time generation (Average daily volumes): Calendar year 2010



Locational Marginal Price (LMP)

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

Real-Time LMP

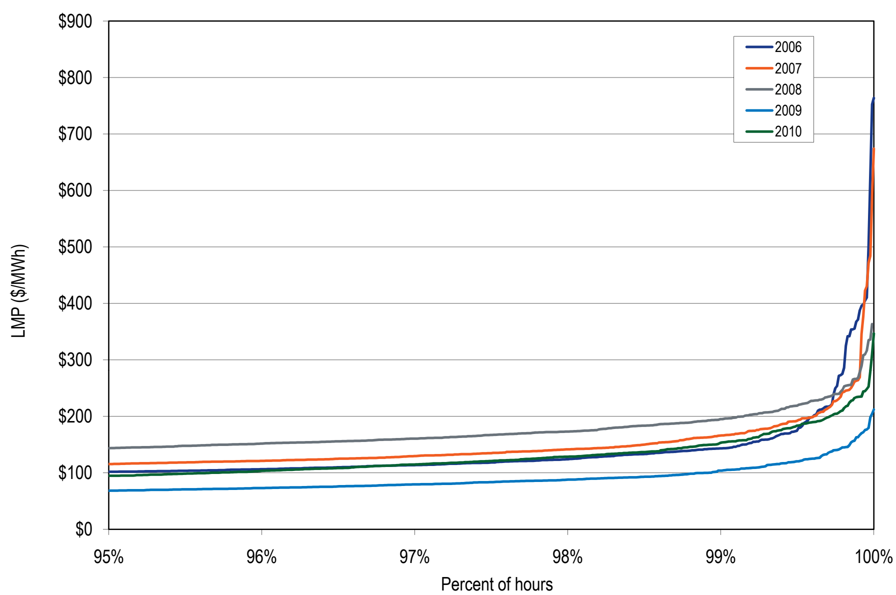
Real-time LMP is the hourly LMP for the PJM Real-Time Energy Market.

Real-Time Average LMP

PJM Real-Time LMP Duration

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

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



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

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

PJM Real-Time, Annual Average LMP

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

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

	Real-Time LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.72	$16.60	$31.45	NA	NA	NA
1999	$28.32	$17.88	$72.42	30.4%	7.7%	130.3%
2000	$28.14	$19.11	$25.69	(0.6%)	6.9%	(64.5%)
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.41	(12.6%)	(8.3%)	(50.2%)
2003	$38.28	$30.79	$24.71	35.2%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	(15.2%)	(12.1%)	(8.9%)
2007	$57.58	$49.92	$34.60	16.9%	20.4%	5.8%
2008	$66.40	$55.53	$38.62	15.3%	11.2%	11.6%
2009	$37.08	$32.71	$17.12	(44.1%)	(41.1%)	(55.7%)
2010	$44.83	$36.88	$26.20	20.9%	12.7%	53.1%

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

Zonal Real-Time, Annual Average LMP

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

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

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

Real-Time, Annual Average LMP by Jurisdiction

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

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

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

Hub Real-Time, Annual Average LMP

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

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

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

Real-Time, Load-Weighted, Average LMP

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

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

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

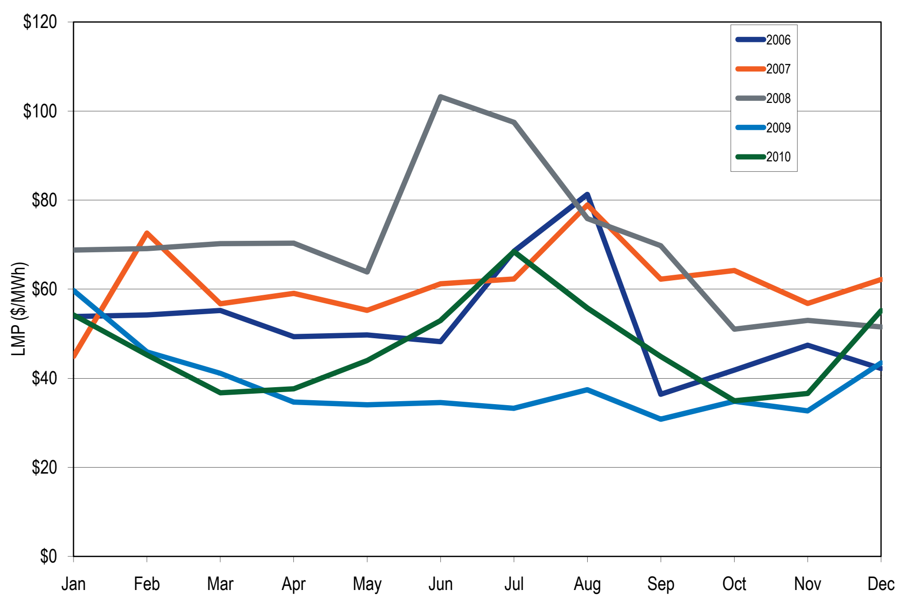
Table 2-38 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 1998 to 2010

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.7%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	15.4%	8.9%	10.9%
2009	$39.05	$34.23	$18.21	(45.1%)	(42.5%)	(55.6%)
2010	$48.35	$39.13	$28.90	23.8%	14.3%	58.7%

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

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

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



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

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

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

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

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

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

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

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

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

Fuel Cost

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

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

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

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

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

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

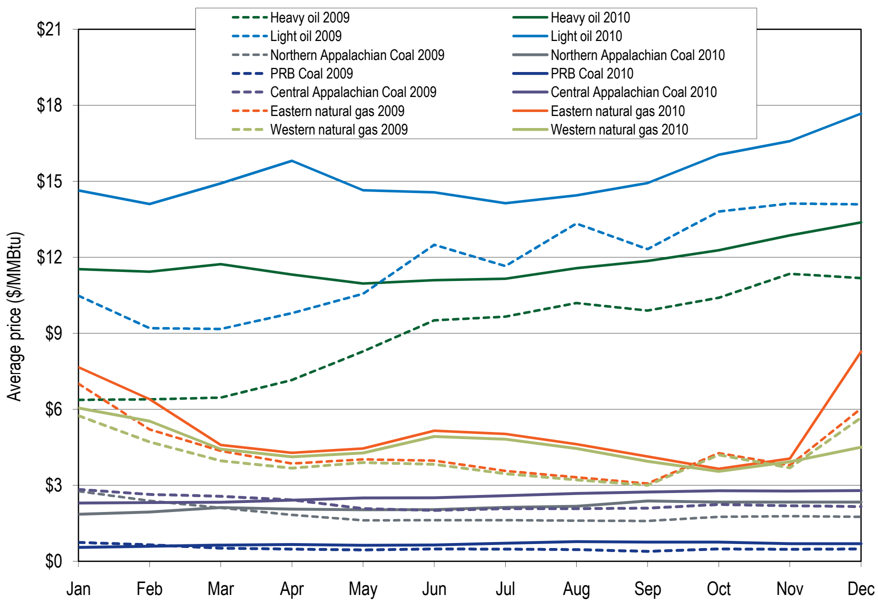


Table 2-41 compares the 2010 PJM real-time fuel-cost-adjusted, load-weighted, average LMP to the 2009 load-weighted, average LMP. The load-weighted, average LMP for 2010 was 23.4 percent higher than the load-weighted, average LMP for 2009. The real-time fuel-cost-adjusted, load-weighted, average LMP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

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

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

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

Components of Real-Time, Load-Weighted LMP

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

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

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

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

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

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

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

Day-Ahead LMP

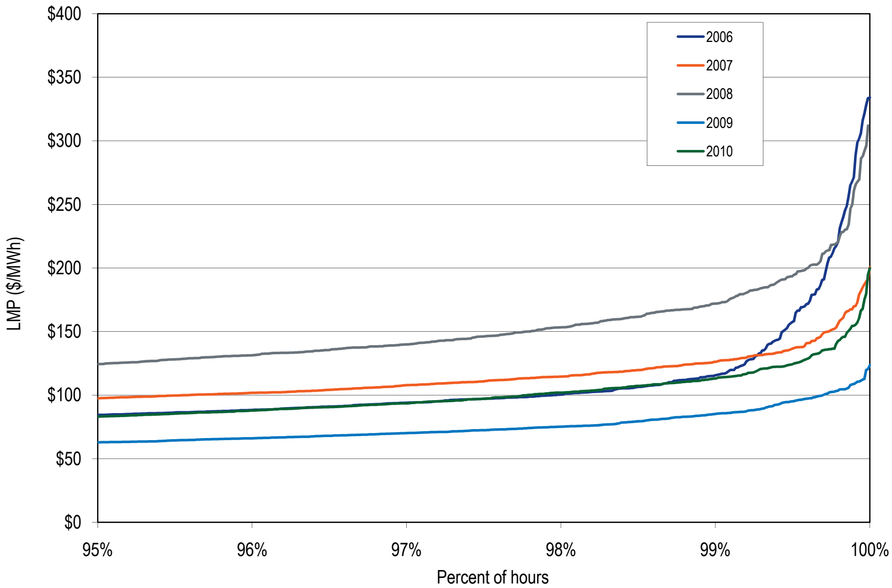
Day-ahead LMP is the hourly LMP for the PJM Day-Ahead Energy Market.

Day-Ahead Average LMP

PJM Day-Ahead LMP Duration

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

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



PJM Day-Ahead, Annual Average LMP

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

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

	Day-Ahead LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$31.97	$24.42	$21.33	NA	NA	NA
2001	$32.75	$27.05	$30.42	2.4%	10.8%	42.6%
2002	$28.46	$23.28	$17.68	(13.1%)	(14.0%)	(41.9%)
2003	$38.73	$35.22	$20.84	36.1%	51.3%	17.8%
2004	$41.43	$40.36	$16.60	7.0%	14.6%	(20.4%)
2005	$57.89	$50.08	$30.04	39.7%	24.1%	81.0%
2006	$48.10	$44.21	$23.42	(16.9%)	(11.7%)	(22.0%)
2007	$54.67	$52.34	$23.99	13.7%	18.4%	2.4%
2008	$66.12	$58.93	$30.87	20.9%	12.6%	28.7%
2009	$37.00	$35.16	$13.39	(44.0%)	(40.3%)	(56.6%)
2010	$44.57	$39.97	$18.83	20.5%	13.7%	40.6%

Zonal Day-Ahead, Annual Average LMP

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

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

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

Day-Ahead, Annual Average LMP by Jurisdiction

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

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

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

Day-Ahead, Load-Weighted, Average LMP

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

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

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

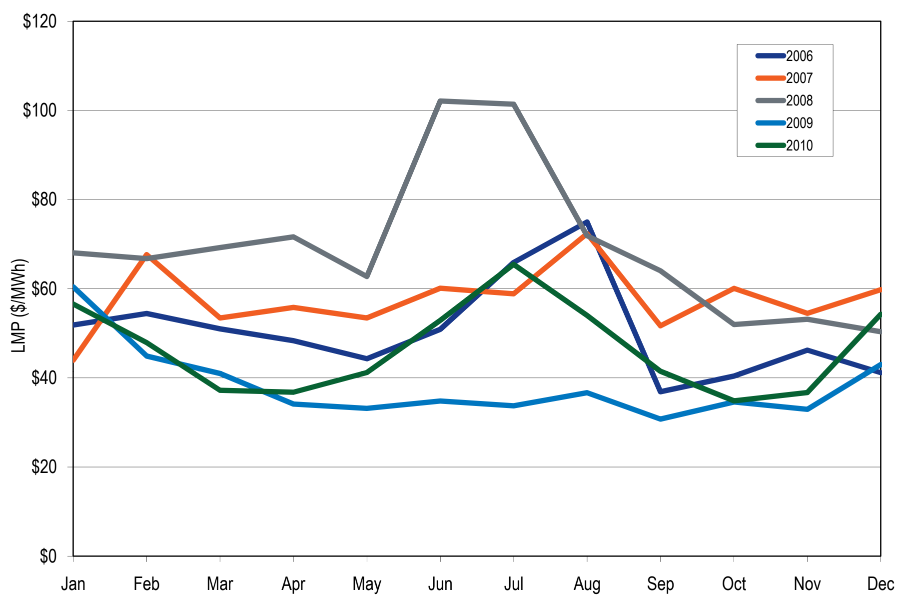
Table 2-46 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2000 to 2010

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$35.12	$28.50	$22.26	NA	NA	NA
2001	$36.01	$29.02	$37.48	2.5%	1.8%	68.3%
2002	$31.80	$26.00	$20.68	(11.7%)	(10.4%)	(44.8%)
2003	$41.43	$38.29	$21.32	30.3%	47.3%	3.1%
2004	$42.87	$41.96	$16.32	3.5%	9.6%	(23.4%)
2005	$62.50	$54.74	$31.72	45.8%	30.4%	94.3%
2006	$51.33	$46.72	$26.45	(17.9%)	(14.6%)	(16.6%)
2007	$57.88	$55.91	$25.02	12.8%	19.7%	(5.4%)
2008	$70.25	$62.91	$33.14	21.4%	12.5%	32.4%
2009	$38.82	$36.67	$14.03	(44.7%)	(41.7%)	(57.7%)
2010	$47.65	$42.06	$20.59	22.7%	14.7%	46.8%

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

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

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



Zonal Day-Ahead, Annual, Load-Weighted LMP

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

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

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

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

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

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

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

Components of Day-Ahead, Load-Weighted LMP

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

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

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

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

Marginal Losses

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

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

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

55 For additional information, see OATT Section 3.4.

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

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

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2006	$49.27	$47.19	$2.08	$0.00
2007	$57.58	$56.56	$1.00	$0.02
2008	$66.40	$66.30	$0.06	$0.04
2009	$37.08	$37.01	$0.05	$0.03
2010	$44.83	$44.72	$0.07	$0.04

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

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

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

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

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

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

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

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

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

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

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

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

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2006	$48.10	$46.45	$1.65	$0.00
2007	$54.67	$54.60	$0.25	($0.18)
2008	$66.12	$66.43	($0.10)	($0.21)
2009	$37.00	$37.15	($0.06)	($0.09)
2010	$44.57	$44.61	$0.03	($0.06)

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

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

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

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

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

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

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

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

Marginal Loss Accounting

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

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

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

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

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

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

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

Marginal Loss Costs and Loss Credits

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

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

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

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

	Total Marginal Loss Costs	Loss Credits	Percent
2007	$1,246,944,931	$630,277,662	50.5%
2008	$2,493,333,212	$1,309,286,301	52.5%
2009	$1,268,085,226	$639,684,849	50.4%
2010	$1,634,719,184	$836,596,012	51.2%

Monthly Marginal Loss Costs

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

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

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

Zonal Marginal Loss Costs

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

59 2007 only includes data from June 1, 2007 through December 31, 2007. PJM began including marginal losses in economic dispatch and LMP models on June 1, 2007.

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

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

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

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

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

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

Virtual Offers and Bids

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

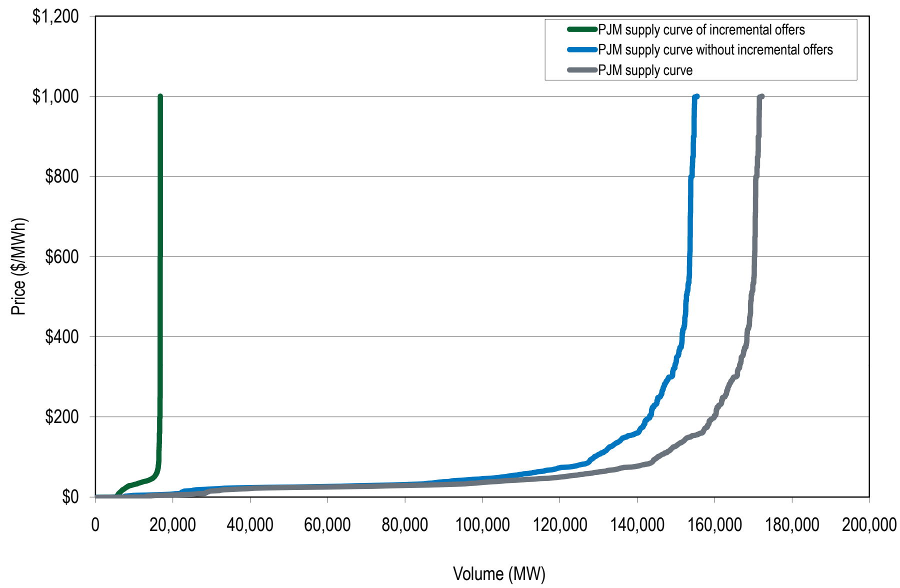
Figure 2-18 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve without increment offers and the system aggregate supply curve

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

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

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

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



Price Convergence

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

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

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

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

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

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

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

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

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
2000	$31.97	$30.36	($1.61)	(5.0%)
2001	$32.75	$32.38	($0.37)	(1.1%)
2002	$28.46	$28.30	($0.16)	(0.6%)
2003	$38.73	$38.28	($0.45)	(1.2%)
2004	$41.43	$42.40	$0.97	2.3%
2005	$57.89	$58.08	$0.18	0.3%
2006	$48.10	$49.27	$1.17	2.4%
2007	$54.67	$57.58	$2.90	5.3%
2008	$66.12	$66.40	$0.28	0.4%
2009	$37.00	$37.08	$0.08	0.2%
2010	$44.57	$44.83	$0.26	0.6%

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

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

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

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

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

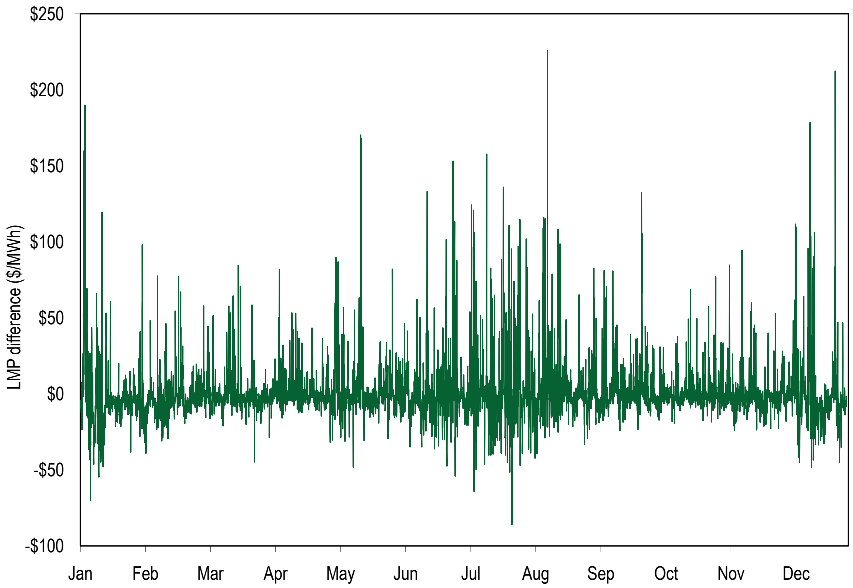


Figure 2-20 shows the monthly simple average differences between the day-ahead and real-time LMP in 2010. The highest monthly difference was in September.

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

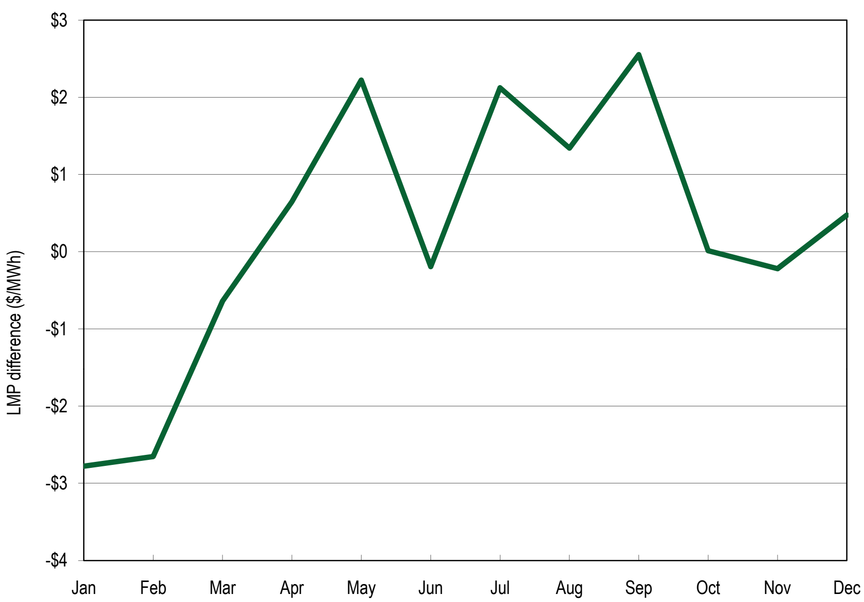
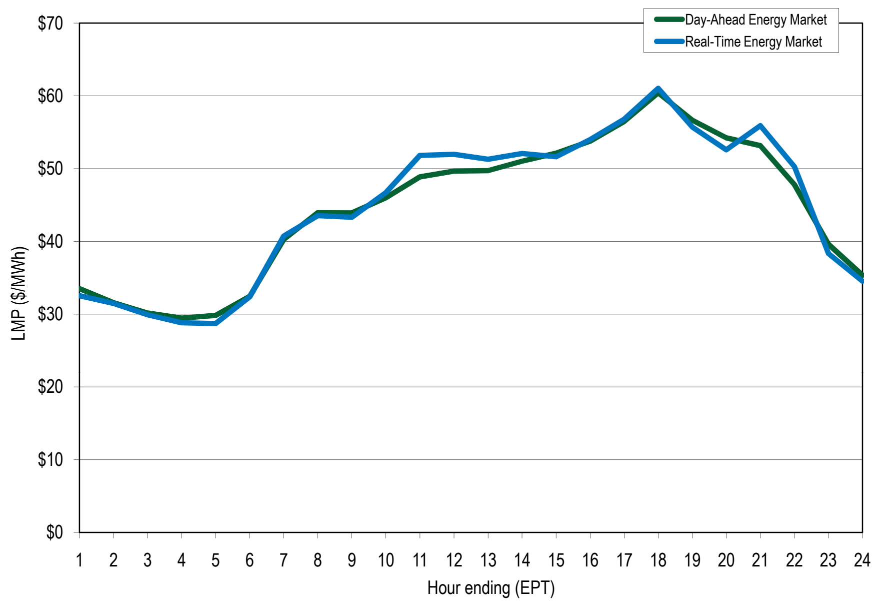


Figure 2-21 shows simple day-ahead and real-time LMP on an average hourly basis. Real-time simple average LMP was greater than day-ahead simple average LMP for 11 out of 24 hours.[64]

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



Zonal Price Convergence

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

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

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

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

Price Convergence by Jurisdiction

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

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

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

Load and Spot Market

Real-Time Load and Spot Market

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

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

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

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

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

Day-Ahead Load and Spot Market

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

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

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

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

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

Demand-Side Response (DSR)

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

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

Most end use customers pay a fixed retail rate with no direct relationship to the hourly wholesale market LMP. End use customers pay load serving entities (LSEs) an annual amount designed to recover, among other things, the total cost of wholesale power for the year.[65] End use customers paying fixed retail rates do not face even the hourly zonal average LMP. Thus, it would be a substantial step forward for customers to face the hourly zonal average price. But the actual market price of energy and the appropriate price signal for end use customers is the nodal locational marginal price. Within a zone, the actual costs of serving load, as reflected in the nodal hourly LMP, can vary substantially as a result of transmission constraints. A customer on the high price side of a constraint would have a strong incentive to add demand side resources if they faced the nodal price while that customer currently has an incentive to use more energy than is efficient, under either a flat retail rate or a rate linked to average zonal LMP. The nodal price provides a price signal with the actual locational marginal value of energy. In order to achieve the full benefits of nodal pricing on the supply and the demand side, load should ultimately pay nodal prices. However, a transition to nodal pricing could have substantial impacts and therefore must be managed carefully.

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

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

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

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

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

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

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

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

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

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

PJM Load Response Programs Overview

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

Table 2-72 Overview of Demand Side Programs

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

Economic Load Response

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

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

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

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

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

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

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

Emergency Load Response

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

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

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

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

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

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

Energy Only

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

Capacity Only

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

Capacity plus Energy (Full Emergency Option)

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

Minimum Dispatch Price

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

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

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

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

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

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

Load Management

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

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

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

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

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

Measurement Options

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

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

Recent Developments

Economic Incentive Payments

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

78 126 FERC ¶ 61,275 (2009).

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

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

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

82 Supplemental Report at 5-6.

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

Role of Relevant Electric Retail Regulatory Authorities (RERRAs)

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

Load Management Task Force Proposed Rule Changes

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

Double Counting Issue

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

83 Dockets Nos. ER09-701-000 and RM07-19-000.
84 *Id.*
85 PJM filing in ER09-701-005; Letter Order in Docket No. ER09-701-005 (July 29, 2010); OA Schedule 1 § 1.5A.
86 The peak load contribution (PLC) is measured by a customer's consumption during the five coincident peak hours in the prior year.

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

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

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

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

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

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

87 OATT Attachment DD-1 § J.

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

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

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

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

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

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

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

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

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

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

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

Price Responsive Demand

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

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

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

Demand Response Saturation Analysis

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

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

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

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

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

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

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

Participation

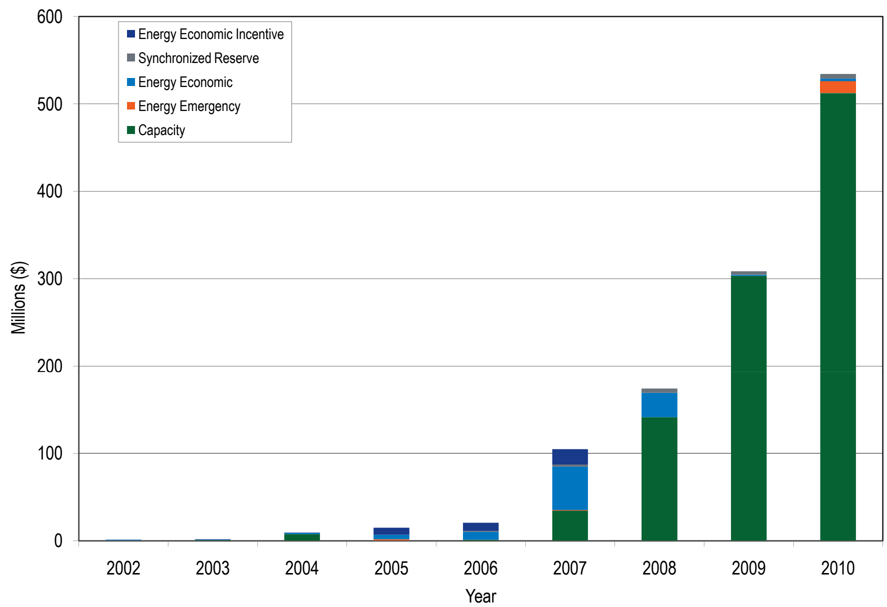
In 2010, in the Economic Program, participation became more concentrated compared to 2009. There were lower participation levels in terms of settlements submitted and active registrations in 2010 compared to 2009, however, activity in terms of settled MWh and credits increased. The number of sites registered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

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

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

94 134 FERC ¶ 61,066 at PP 32 & 41.
95 "Protest of the Independent Market Monitor for PJM," in Docket No. ER11-2288-000 at 1–2 (December 20, 2010).

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



Economic Program

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

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

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

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

	Registrations	Peak-Day, Registered MW
14-Aug-02	96	335.4
22-Aug-03	240	650.6
3-Aug-04	782	875.6
26-Jul-05	2,548	2,210.2
2-Aug-06	253	1,100.7
8-Aug-07	2,897	2,498.0
9-Jun-08	956	2,294.7
10-Aug-09	1,321	2,486.6
6-Jul-10	899	1,725.7

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

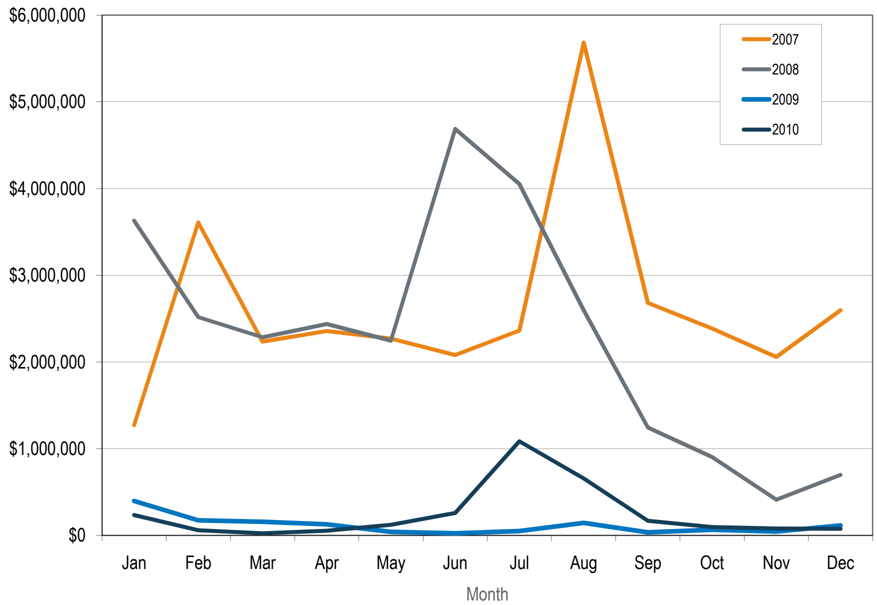


Table 2-78 shows 2010 performance in the Economic Program by control zone and participation type. The total number of curtailed hours for the Economic Program was 33,477 and the total payment amount was $2,933,761.[107] Overall, approximately 73 percent of the MWh reductions, 75 percent of payments and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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Emergency Program

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

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

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

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

Load Management Program

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

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

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

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

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

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

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

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

Load Management Event Compliance

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

111 See RAA, Schedule 6 § L.

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

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

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

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

That PJM may require subzonal Load Management events while CSPs may aggregate customers on a zonal basis and, in some cases, are assessed compliance on a zonal basis, is a broader issue that needs to be addressed. More precise locational deployment of Load Management improves efficiency while reducing the ability of a CSP to aggregate customers. A requirement to identify the subzonal location of demand resources would be a positive step towards nodal pricing and the ability of PJM to deploy demand resources in a manner more consistent with the nodal deployment of generation and more consistent with nodal pricing.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

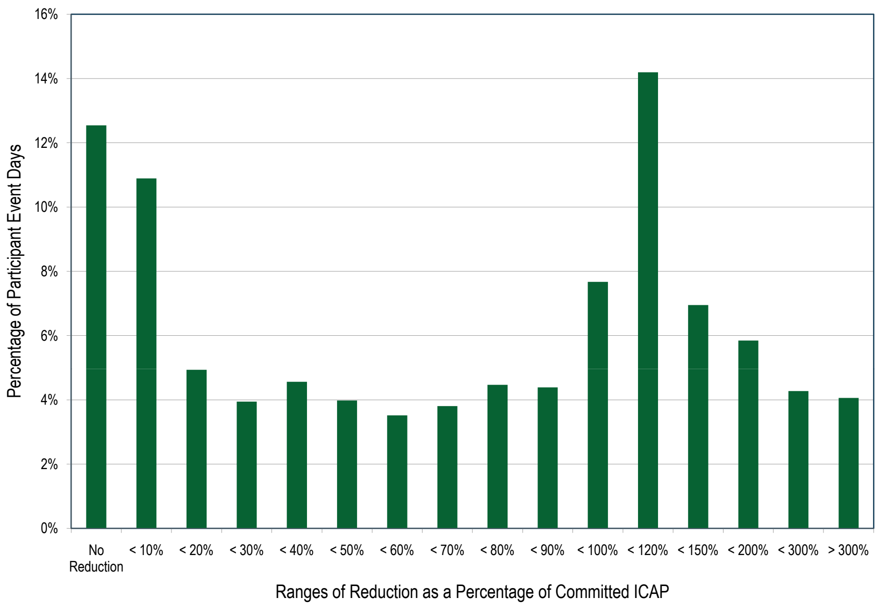
While aggregated performance across all events was 99.7 percent, performance for specific customers varied significantly. Table 2-93 shows the distribution of participant event days across various levels of performance throughout all five events in the 2010/2011 compliance period. For any given event,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

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

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

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

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



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

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

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

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

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

Emergency Energy Payments

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

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

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

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

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

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

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

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

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

Load Management Testing

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

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

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

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

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

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

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

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

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

Measurement and Verification

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

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

Baseline Pilot Study

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

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

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

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

Economic Program

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

Customer Base Line (CBL) - History

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

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

CBL Issues

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

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

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

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

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

Analysis of Settlements

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

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

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

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

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

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

Load Management Program

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

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

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

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

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

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

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

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

Conclusions: Demand Side

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

Emergency Program

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

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

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

Economic Program

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

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

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

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

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