Energy Market

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 2011, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM Energy Market results were competitive in 2011.

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 2011 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1203 with a minimum of 889 and a maximum of 1564 in 2011.
- 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 (TPS) test, used to test local market structure, indicate 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.

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]

Overview

Market Structure

- **Supply.** Average offered supply increased by 14,478 MW, or 9.3 percent, from 156,003 MW in the summer of 2010 to 170,481 MW in the summer of 2011.[4] The large increase in offered supply was the result of the integration of the ATSI zone in the second quarter, plus the addition of 5,008 MW of nameplate capacity to PJM in 2011. This includes five large plants (over 500 MW) that began generating in PJM in 2011. The increases in supply were partially offset by the deactivation of twelve units (738 MW) since January 1, 2011.
- **Demand.** The PJM system peak load for the summer of 2011 was 158,016 MW in the HE 1700 on July 21,

1 Analysis of 2011 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. In June 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. 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 *2011 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

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

2011, which was 21,556 MW, or 15.8 percent, higher than the PJM peak load for the summer of 2010, which was 136,460 MW in the HE 1700 on July 6, 2010.[5] The ATSI transmission zone accounted for 13,953 MW in the peak hour of summer 2011. The peak load excluding the ATSI transmission zone was 144,063 MW, also occurring on July 21, 2011, HE 1700, an increase of 7,603 MW from the 2010 peak load.

- **Market Concentration.** Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.
- **Local Market Structure and Offer Capping.** 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 2011. 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 decreased from 0.2 percent in 2010 to 0.0 percent in 2011. In the Real-Time Energy Market offer-capped unit hours decreased from 1.2 percent in 2010 to 0.9 percent in 2011.
- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 188 units that were eligible to include a Frequently Mitigated Unit (FMU) or Associated Unit (AU) adder in their cost-based offer in 2011, 54 (28.7 percent) qualified in all months, and 11 (5.9 percent) qualified in only one month of 2011.
- **Local Market Structure.** In 2011, ten 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.[6]

Market Performance: Load, Generation and Locational Marginal Price

- **Load.** PJM average real-time load in 2011 increased by 3.7 percent from 2010, from 79,611 MW to 82,541 MW. The PJM average real-time load in 2011 would have decreased by 2.0 percent from 2010, from 79,611 MW to 78,000 MW, if the ATSI transmission zone were excluded.

  PJM average day-ahead load in 2011, including DECs and up-to congestion transactions, increased by 6.2 percent from 2010, from 103,935 MW to 113,866 MW. PJM average day-ahead load in 2011, including DECs and up-to congestion transactions, would have been 0.2 percent lower than in 2010, from 103,935 MW to 103,746 MW if the ATSI transmission zone were excluded.

- **Generation.** PJM average real-time generation in 2011 increased by 3.9 percent from 2010, from 82,582 MW to 85,775 MW. PJM average real-time generation in 2011 would have decreased 1.4 percent from 2010, from 82,582 MW to 81,645 MW if the ATSI transmission zone were excluded.

  PJM average day-ahead generation in 2011, including INCs and up-to congestion transactions, increased by 9.2 percent from 2010, from 107,290 MW to 117,130 MW. PJM average day-ahead generation in 2011, including INCs and up-to congestion transactions, would have been 4.8 percent higher than in 2010, from 107,290 MW to 112,424 MW if the ATSI transmission zone were excluded.

- **Generation Fuel Mix.** During 2011, coal units provided 46.9 percent, nuclear units 34.2 percent and gas units 14.4 percent of total generation. Compared to 2010, generation from coal units decreased 0.8 percent, generation from nuclear units increased 3.3 percent, generation from natural gas units increased 18.2 percent, and generation from oil units decreased 35.5 percent.

5 All hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2011 State of the Market Report for PJM*, Appendix I, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

6 See the *2011 State of the Market Report for PJM*, Volume II, Appendix D, "Local Energy Market Structure: TPS Results" for detailed results of the TPS test.

- **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 changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses and local price differences caused by congestion.

  PJM Real-Time Energy Market prices decreased in 2011 compared to 2010. The system simple average LMP was 4.4 percent lower in 2011 than in 2010, $42.84 per MWh versus $44.83 per MWh. The load-weighted average LMP was 5.0 percent lower in 2011 than in 2010, $45.94 per MWh versus $48.35 per MWh.

  PJM Day-Ahead Energy Market prices decreased in 2011 compared to 2010. The system simple average LMP was 4.6 percent lower in 2011 than in 2010, $42.52 per MWh versus $44.57 per MWh. The load-weighted average LMP was 5.2 percent lower in 2011 than in 2010, $45.19 per MWh versus $47.65 per MWh.[7]

- **Load and Spot Market.** Companies that serve load in PJM can do so using 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 2011, 10.5 percent of real-time load was supplied by bilateral contracts, 26.6 percent by spot market purchases and 62.9 percent by self-supply. Compared with 2010, reliance on bilateral contracts decreased by 1.3 percentage points; reliance on spot supply increased by 6.4 percentage points; and reliance on self-supply decreased by 5.1 percentage points in 2011. In 2011, 5.8 percent of day-ahead load was supplied by bilateral contracts, 24.4 percent by spot market purchases and 69.8 percent by self-supply. Compared with 2010, reliance on bilateral contracts increased by 0.9 percentage points; reliance on spot supply increased by 5.1 percentage points; and reliance on self-supply decreased by 6.1 percentage points in 2011.

7 Tables reporting zonal and jurisdictional load and prices are in Appendix C. See the *2011 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market".

Scarcity

- **Scarcity Pricing Events in 2011.** PJM did not declare a scarcity event in 2011.
- **Scarcity and High Load Analyses.** There were no reserve shortage events in 2011. There were a total of 35 high-load hours in 2011. There were 22 Hot Weather Alerts called within the PJM footprint in 2011.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in 2011, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand-side response programs, loads and prices in this section of the report.

Aggregate hourly supply offered increased by about 14,478 MWh in the summer of 2011 compared to the summer of 2010, while aggregate peak load increased by 21,556 MW, modifying the general supply demand balance with a corresponding impact on Energy Market prices. In the Real-Time Market, average load in 2011 increased from 2010, from 79,611 MW to 82,541 MW. Market concentration levels remained moderate. 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. Energy Market results for 2011 generally reflected supply-demand fundamentals.

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.[8]

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers and prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. Nonetheless, with a market design that includes a direct and explicit scarcity pricing revenue true up mechanism, scarcity pricing can be a mechanism to appropriately increase reliance on the energy market as a source of revenues and incentives in a competitive market without reliance on the exercise of market power. Any such market design modification should occur only after scarcity pricing for price signals has been implemented and sufficient experience has been gained to permit a well calibrated and gradual change in the mix of revenues.

The MMU concludes that the PJM Energy Market results were competitive in 2011.

Market Structure

Supply

During the June to September 2011 summer period, the PJM Energy Market received a daily average of 170,481 MW in total supply offers including hydroelectric generation. The summer 2011 average daily offered supply was 14,478 MW higher than the summer 2010 average daily offered supply of 156,003 MW. Supply was affected by the integration of ATSI.

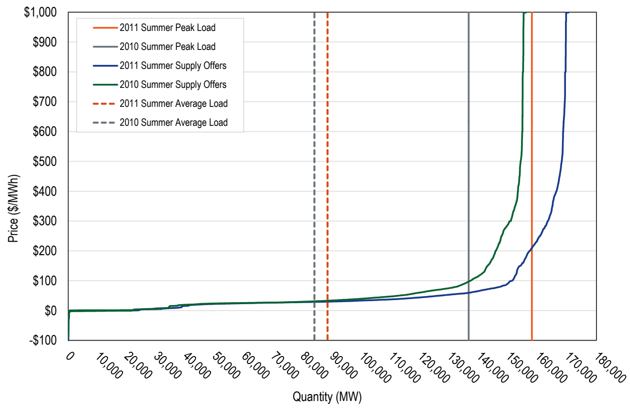
During the summer of 2011, the peak demand was 21,556 MW higher, 15.8 percent, than the 2010 peak, which, when combined with a shift to the right of the 2011 supply curve, resulted in a higher price level for peak demand (Figure 2-1). The smaller increase in average summer load resulted in approximately the same price level. Demand was affected by the integration of ATSI.

Some fuel types experienced price increases for the summer months in 2011 compared to the summer months in 2010, including a 16.3 percent increase in

8 See the *2011 State of the Market Report for PJM*, Volume II, Appendix D, "Local Energy Market Structure: TPS Results" for detailed results of the TPS test.

coal prices, and a 48.8 percent increase in oil prices.[9] Natural gas prices in the PJM region decreased by 6.1 percent in the summer months of 2011 compared to the summer months of 2010. The result was somewhat lower prices in the summer months of 2011 than in 2010.

Figure 2-1 Average PJM aggregate supply curves: Summer 2010 and 2011



Energy Production by Fuel Source

In 2011, coal units provided 46.9 percent, nuclear units 34.2 percent, gas 14.4 percent, oil 0.3 percent, hydroelectric 2.0 percent, waste 0.7 percent and wind 1.5 percent of total generation (Table 2-2). Compared to calendar year 2010, generation from coal units decreased 0.8 percent and generation from oil units decreased 35.5 percent. Generation from natural gas units increased 18.2 percent and generation from nuclear units increased 3.3 percent. Although starting from a relatively small base, generation from wind increased 19.3 percent and generation from solar increased 872.5 percent.

Table 2-2 PJM generation (By fuel source (GWh)): Calendar years 2010 and 2011[10]

	2010		2011		Change in
	GWh	Percent	GWh	Percent	Output
Coal	363,035.1	48.7%	360,306.2	46.9%	(0.8%)
Standard Coal	350,539.2	47.0%	348,100.5	45.3%	(0.7%)
Waste Coal	12,495.9	1.7%	12,205.7	1.6%	(0.1%)
Nuclear	254,534.1	34.2%	262,968.3	34.2%	3.3%
Gas	93,455.9	12.5%	110,345.3	14.4%	18.1%
Natural Gas	91,729.4	12.3%	108,456.7	14.1%	18.2%
Landfill Gas	1,726.0	0.2%	1,887.9	0.2%	9.4%
Biomass Gas	0.5	0.0%	0.6	0.0%	39.4%
Hydroelectric	14,384.4	1.9%	15,277.9	2.0%	6.2%
Wind	9,688.2	1.3%	11,561.1	1.5%	19.3%
Waste	6,731.5	0.9%	5,559.6	0.7%	(17.4%)
Solid Waste	5,033.9	0.7%	4,442.9	0.6%	(11.7%)
Miscellaneous	1,697.7	0.2%	1,116.6	0.1%	(34.2%)
Oil	3,313.3	0.4%	2,136.0	0.3%	(35.5%)
Heavy Oil	2,748.3	0.4%	1,749.8	0.2%	(36.3%)
Light Oil	508.8	0.1%	356.6	0.0%	(29.9%)
Diesel	32.3	0.0%	16.9	0.0%	(47.9%)
Kerosene	23.8	0.0%	12.8	0.0%	(46.4%)
Jet Oil	0.1	0.0%	0.1	0.0%	1.0%
Solar	5.7	0.0%	55.7	0.0%	872.5%
Battery	0.3	0.0%	0.2	0.0%	(24.8%)
Total	745,148.6	100.0%	768,210.2	100.0%	3.1%

Generator Offers

Table 2-3 shows the distribution of MW generator offers by offer prices for 2011. For example, daily generator offer prices between $0 and $200 in 2011 accounted for 57.1 percent of all daily MW generator offers in 2011. Of the 57.1 percent of daily MW generators offered at prices between $0 and $200, 70.9 percent were dispatchable by PJM, 40.5 percent of all offered MW, while the other 29.1 percent were self-scheduled, 16.6 percent of all offered MW. Daily generator offer prices above $800 in 2011 accounted for 0.7 percent of all daily generator offers, of which 89.9 percent were economically dispatchable, and the other 10.1 percent self-scheduled.

9 Natural gas, light oil, and coal prices are the average of daily fuel price indices in the PJM footprint. All fuel prices are from Platts.

10 Hydroelectric generation is total generation output and does not net out the MWh used at pumped storage facilities to pump water.

Table 2-3 Distribution[11] of MW for unit offer prices: Calendar year 2011

	Range												
	($200) - $0		$0 - $200		$200 - $400		$400 - $600		$600 - $800		$800 - $1,000		
Unit Type	Dispatchable	Self-Scheduled	Dispatchable	Self-Scheduled	Dispatchable	Self-Scheduled	Dispatchable	Self-Scheduled	Dispatchable	Self-Scheduled	Dispatchable	Self-Scheduled	Total
Battery	2.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	97.9%	0.0%	100.0%
CC	0.0%	0.1%	65.5%	11.3%	14.6%	0.3%	3.0%	0.1%	3.8%	0.4%	0.9%	0.0%	100.0%
CT	0.0%	0.4%	41.6%	0.1%	16.1%	0.0%	11.8%	0.1%	27.4%	0.0%	2.3%	0.1%	100.0%
Diesel	0.0%	17.1%	11.3%	10.3%	51.8%	0.1%	6.5%	0.0%	1.8%	0.0%	1.0%	0.0%	100.0%
Hydro	0.1%	97.8%	0.0%	1.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%	100.0%
Nuclear	0.0%	51.2%	11.7%	37.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Pumped Storage	57.5%	42.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Solar	0.3%	99.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Steam	0.0%	1.5%	48.6%	21.2%	20.6%	6.9%	0.8%	0.1%	0.0%	0.1%	0.1%	0.1%	100.0%
Transaction	0.0%	77.0%	0.0%	23.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Wind	33.5%	65.2%	1.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
All Offers (by type)	1.8%	13.2%	40.5%	16.6%	14.4%	3.1%	3.2%	0.1%	6.2%	0.1%	0.7%	0.1%	100.0%
All Offers (total)		15.0%		57.1%		17.5%		3.3%		6.3%		0.7%	100.0%

Table 2-4 Actual PJM footprint peak loads: 2002 to 2011

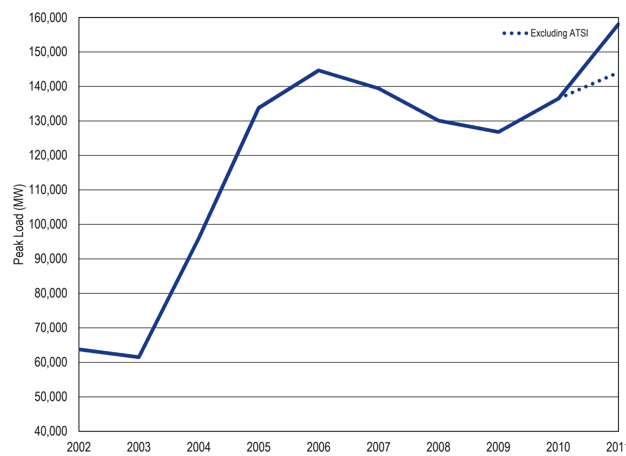
Year	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
2002	Wed, August 14	16	63,762	NA	NA
2003	Fri, August 22	16	61,499	(2,263)	(3.5%)
2004	Mon, December 20	19	96,016	34,517	56.1%
2005	Tue, July 26	16	133,761	37,746	39.3%
2006	Wed, August 02	17	144,644	10,883	8.1%
2007	Wed, August 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	136,460	9,662	7.6%
2011 (with ATSI)	Thu, July 21	17	158,016	21,556	15.8%
2011 (without ATSI)	Thu, July 21	17	144,063	7,603	5.6%

Demand

Table 2-4 shows the coincident summer peak loads for the years 2002 through 2011. The 2011 summer peak load of 158,016 MW was 21,556 MW more than the 2010 summer peak load of 136,465 MW and was the highest peak load since 2006, when peak load reached 144,644 MW. The 2011 summer peak load not including the ATSI zone was 144,063 MW. This peak load was 7,603 MW more than the 2010 summer peak load and was still the highest peak demand since 2006. 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.[12]

Figure 2-2 shows the annual peak loads since 2002.

Figure 2-2 PJM[13] footprint annual peak loads: 2002 to 2011



The hourly load and average PJM LMP for the 2011 and 2010 summer peak days are shown in Figure 2-3. The peak for 2011 occurred on July 21, at hour ending 1700. The hourly integrated LMP for this hour was $162.28

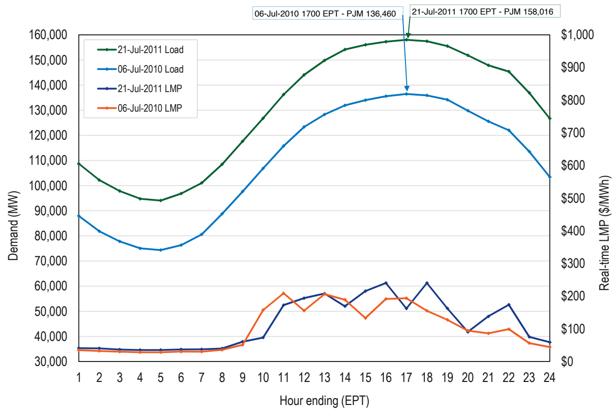
11 Each range in the table is greater than the start value and less than or equal to the end value.

12 Peak loads shown are eMTR load. See the *MMU Technical Reference for the PJM Markets*, at "Load Definitions" for detailed definitions of load.

13 For additional information on the "PJM Integration Period", see the *2011 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

per MWh. The peak for 2010 occurred on July 6, at hour ending 1700. The hourly integrated LMP for this hour was $194.02 per MWh.

Figure 2-3 PJM annual peak-load comparison: Thursday, July 21, 2011, and Tuesday, July 06, 2010



Market Concentration

During 2011, 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.[14] 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 generally effective in preventing the exercise of market power in these areas during 2011. 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 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.[15] 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).

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

14 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.

15 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.

- **Highly Concentrated.** Market HHI greater than 1800, equivalent to between five and six firms with equal market shares.[16]

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during 2011 was moderately concentrated (Table 2-5). In the Energy Market, average hourly HHI was 1203 with a minimum of 889 and a maximum of 1564 in 2011. The highest hourly market share was 30 percent and the average of the highest hourly market share for 2011 was 21 percent.

Table 2-5 PJM hourly Energy Market HHI: Calendar year 2011[17]

	Hourly Market HHI
Average	1203
Minimum	889
Maximum	1564
Highest market share (One hour)	30%
Average of the highest hourly market share	21%
# Hours	8,760
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

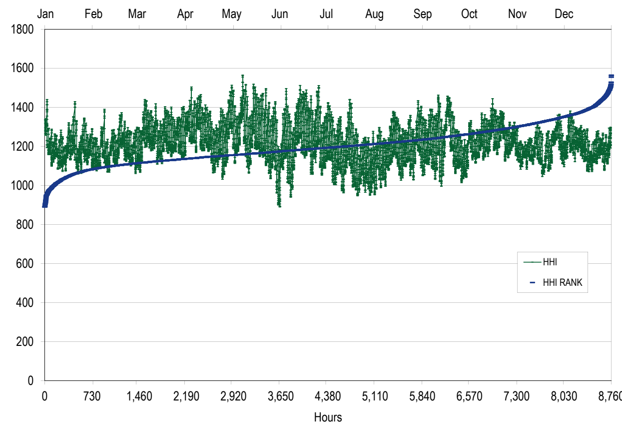
Table 2-6 includes 2011 HHI values by supply curve segment, including base, intermediate and peaking plants. The hourly measure indicates that, on average, the baseload segment of the supply curve is moderately concentrated, while the intermediate and peaking segments of the supply curve are highly concentrated.

Table 2-6 PJM hourly Energy Market HHI (By supply segment): Calendar year 2011

	Minimum	Average	Maximum
Base	1034	1224	1534
Intermediate	676	1831	7964
Peak	596	6034	10000

Figure 2-4 presents the 2011 hourly HHI values in chronological order and an HHI duration curve that shows 2011 HHI values in ascending order of magnitude. The HHI values were in the unconcentrated range for 1.6 percent of the hours while HHI values were in the moderately concentrated range in the remaining 98.4 percent of hours, with a maximum value of 1564, as shown in Table 2-5.

Figure 2-4 PJM hourly Energy Market HHI: Calendar year 2011



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.[18] 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

16 Order No. 592, *"Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement,"* 77 FERC ¶ 61,263, pp. 64-70 (1996)

17 This analysis includes all hours of 2011, regardless of congestion.

18 OA Schedule 1, Section 6.4.2.

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.[19]

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.[20] 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 2007 through 2011

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
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%
2011	0.9%	0.4%	0.0%	0.0%

Table 2-8 presents data on the frequency with which units were offer capped in 2011. 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 2011. For example, in 2011, only nine 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.

Table 2-8 Real-time offer-capped unit statistics: Calendar Year 2011

	2011 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	6	9	4
80% and < 90%	0	0	1	2	5	9
75% and < 80%	0	0	0	0	3	3
70% and < 75%	0	0	0	0	0	10
60% and < 70%	0	1	0	1	1	20
50% and < 60%	0	0	0	2	13	23
25% and < 50%	2	0	0	5	19	70
10% and < 25%	9	2	0	0	2	49

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 31 units (about 2.2 percent of all units) that had offer-capped run hours of at least 200 hours (about 2.3 percent of all hours) in 2011 were offer capped for 10 percent or more of their run hours. Only 14 units (or about one 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.

The number of units that had at least 100 offer capped run hours and that were offer capped for 90 percent or more of their run hours increased from 3 in 2010 to 15 in 2011. The number of units that had at least 500 offer capped hours and that were offer capped for 50 percent or more of their run hours decreased from six in 2010 to 0 in 2011.[21]

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.

19 123 FERC ¶ 61,169 (2008).
20 See the MMU Technical Reference for PJM Markets, at "Three Pivotal Supplier Test."
21 See the *2011 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market" Table C-23 for 2010 data.

Local Market Structure

In 2011, the AECO, AEP, AP, BGE, ComEd, DLCO, Dominion, Met-Ed, PECO and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 100 or more hours. Actual competitive conditions in the Real-Time Energy Market associated with each of these frequently binding constraints were analyzed using the three pivotal supplier results for calendar year 2011.[22] The DAY, DPL, JCPL, PENELEC, Pepco, PPL and RECO Control Zones were not affected by constraints binding for 100 or more hours.[23]

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.[24]

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, 2011, through December 31, 2011. 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.[25] 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 2011, eight regional 500 kV transmission constraints occurred for more than 100 hours. The Cloverdale – Lexington line, along with seven interface constraints (5004/5005, AEP – Dominion, Bedington — Black Oak, Dominion East[26], Eastern, Western and AP South) all experienced more than 100 hours of congestion.[27] Interfaces are groups of transmission facilities where reactive transfer limits are the basis for limits on the total flow across the transmission paths. 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 AEP – Dominion interface, AP South interface, the Cloverdale – Lexington line, and the Dominion East interface.

When compared to 2010 TPS results, the total number of tests applied for the 5004/5005 interface increased from 9,731 to 10,993, while the percentage of tests with one or more owners failing increased from 80 percent to 92 percent on peak and from 61 percent to 94 percent off peak. As shown in Table 2-11 the number of tests that resulted in offer capping for the 5004/5005 interface decreased from 387 in 2010 to 259 in 2011. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped.

22 See the *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test.

23 See the *2011 State of the Market Report for PJM*, Volume II, Appendix D, "Local Energy Market Structure: TPS Results" for detailed results of the TPS test.

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

25 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.

26 The Dominion East (DomEast) interface was temporarily created to monitor for voltage collapse in the Eastern Dominion area. See "Eastern Dominion Voltage Control" <http://www.pjm.com/~/media/etools/oasis/system-information/om66-temporary-domeast-interface-septa-fentress-op-guide.ashx> (Accessed February 20, 2012)

27 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 2011

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	7,304	1,349	18%	6,686	92%
	Off Peak	3,689	511	14%	3,458	94%
AEP-DOM	Peak	1,853	28	2%	1,846	100%
	Off Peak	2,252	48	2%	2,238	99%
AP South	Peak	19,315	638	3%	19,086	99%
	Off Peak	14,439	548	4%	14,255	99%
Bedington - Black Oak	Peak	42	0	0%	42	100%
	Off Peak	9	1	11%	8	89%
Cloverdale - Lexington	Peak	2,453	271	11%	2,363	96%
	Off Peak	9,164	787	9%	8,975	98%
Dominion East	Peak	1,479	12	1%	1,469	99%
	Off Peak	578	8	1%	575	99%
Eastern	Peak	726	221	30%	636	88%
	Off Peak	155	63	41%	118	76%
Western	Peak	211	93	44%	158	75%
	Off Peak	21	10	48%	16	76%

Table 2-10 Three pivotal supplier test details for regional constraints: Calendar year 2011[28]

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	304	372	15	2	13
	Off Peak	367	385	14	2	12
AEP-DOM	Peak	274	311	8	0	8
	Off Peak	337	410	8	0	8
AP South	Peak	368	436	8	0	8
	Off Peak	451	502	9	0	8
Bedington - Black Oak	Peak	71	74	8	0	8
	Off Peak	19	40	9	1	8
Cloverdale - Lexington	Peak	191	231	12	1	11
	Off Peak	198	266	11	1	10
Dominion East	Peak	115	164	1	0	1
	Off Peak	80	140	2	0	2
Eastern	Peak	637	898	16	5	11
	Off Peak	327	531	12	5	7
Western	Peak	434	615	14	6	8
	Off Peak	218	423	13	5	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 owner passing and failing for the regional 500 kV constraints.

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 identified eight 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 three percent of the tests for any constraint resulted in offer capping.

28 The version of this table in prior versions of the State of the Market Report incorrectly reported the Average Effective Supply.

Table 2-11 Summary of three pivotal supplier tests applied for regional constraints: Calendar year 2011

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	7,304	397	5%	190	3%	48%
	Off Peak	3,689	184	5%	69	2%	38%
AEP-DOM	Peak	1,853	38	2%	14	1%	37%
	Off Peak	2,252	47	2%	26	1%	55%
AP South	Peak	19,315	219	1%	62	0%	28%
	Off Peak	14,439	233	2%	58	0%	25%
Bedington - Black Oak	Peak	42	0	0%	0	0%	0%
	Off Peak	9	0	0%	0	0%	0%
Cloverdale - Lexington	Peak	2,453	116	5%	53	2%	46%
	Off Peak	9,164	185	2%	47	1%	25%
Dominion East	Peak	1,479	6	0%	0	0%	0%
	Off Peak	578	0	0%	0	0%	0%
Eastern	Peak	726	12	2%	3	0%	25%
	Off Peak	155	1	1%	0	0%	0%
Western	Peak	211	17	8%	7	3%	41%
	Off Peak	21	1	5%	0	0%	0%

Ownership of Marginal Resources

Table 2-12 shows the contribution to PJM real-time, annual, load-weighted LMP by individual marginal resource owner.[29] 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 2011, the offers of one company contributed 12 percent of the real-time, annual, load-weighted PJM system LMP and that the offers of the top four companies contributed 36 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 2011

Company	Percent of Price
1	12%
2	9%
3	8%
4	7%
5	6%
6	6%
7	5%
8	5%
9	5%
Other (68 companies)	37%

Table 2-13 shows the contribution to PJM day-ahead, annual, load-weighted LMP by individual marginal resource owner.[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 Day-Ahead Energy Market. The results show that, during 2011, the offers of one company contributed 11 percent of the day-ahead, annual, load-weighted PJM system LMP and that the offers of the top four companies contributed 34 percent of the day-ahead, annual, load-weighted, average PJM system LMP.

Table 2-13 Marginal unit contribution to PJM day-ahead, annual, load-weighted LMP (By parent company): Calendar year 2011

Company	Percent of Price
1	11%
2	8%
3	8%
4	7%
5	6%
6	4%
7	4%
8	4%
9	4%
Other (149 companies)	45%

29 See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

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

Type of Marginal Resources

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources generally determine system LMPs, based on their offers. Marginal resource designation is not limited to physical resources, particularly in the Day-Ahead Market. INC offers, DEC bids and price sensitive transactions are dispatchable injections and withdrawals in the Day-Ahead market that can either directly or indirectly set price via their offers and bids. This section identifies the 2011 marginal resources by type for both Real-Time and Day-Ahead Markets.

Table 2-14 shows the type of fuel used by marginal resources in the Real Time Energy Market. In 2011, coal units were 69 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 2011

Fuel Type	2011
Coal	69%
Gas	26%
Wind	2%
Oil	2%
Municipal Waste	1%
Interface	0%
Uranium	0%

Table 2-15 shows the type of marginal resources in the Day-Ahead Energy Market. In 2011, up-to congestion transactions accounted for 73 percent of marginal resources and the decrement bids accounted for 12 percent of all marginal resources cleared in the Day-Ahead market.

Table 2-15 Day-ahead marginal resources by type/fuel: Calendar year 2011

Type/Fuel	2011
Up-to Congestion Transaction	73%
DEC	12%
INC	8%
Coal	5%
Gas	2%
Price Sensitive Demand	0%
Dispatchable Transaction	0%
Wind	0%
Oil	0%
Municipal Waste	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 Mark Up 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 2011

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.10)	($2.36)
$25 to $50	(0.04)	($1.73)
$50 to $75	0.01	$0.38
$75 to $100	0.14	$11.72
$100 to $125	0.25	$27.71
$125 to $150	0.25	$33.16
> $150	0.12	$23.29

Day-Ahead Mark Up 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 2011

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.07)	($2.10)
$25 to $50	(0.04)	($1.77)
$50 to $75	0.03	$1.86
$75 to $100	0.16	$12.62
$100 to $125	0.10	$11.62
$125 to $150	0.03	$4.73
> $150	0.22	$40.93

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.[31]

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 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 component of LMP 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 2011

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($0.42)	(33.1%)
Gas	CC	$1.48	116.0%
Gas	CT	$0.15	11.3%
Gas	Diesel	$0.00	0.1%
Gas	Steam	$0.02	1.3%
Interface	Interface	$0.00	0.0%
Municipal Waste	Diesel	$0.00	0.0%
Municipal Waste	Steam	$0.05	3.8%
Oil	CT	$0.01	0.5%
Oil	Diesel	$0.01	0.4%
Oil	Steam	($0.01)	(0.6%)
Uranium	Steam	($0.00)	(0.0%)
Wind	Wind	$0.00	0.3%
Total		$1.28	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

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

prices. In 2011, $1.28 per MWh of the PJM real-time, load-weighted average LMP was attributable to markup. In 2011, the markup component of LMP was -$0.62 per MWh off peak and $3.05 per MWh on peak.

Table 2-19 Monthly markup components of real-time load-weighted LMP: Calendar year 2011

	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$1.58	$1.84	$1.33
Feb	($0.19)	$0.26	($0.66)
Mar	$0.18	$1.59	($1.39)
Apr	$1.09	$2.86	($0.78)
May	$4.95	$9.55	$0.31
Jun	$2.20	$4.66	($0.84)
Jul	$4.19	$7.50	$1.03
Aug	$2.58	$5.60	($1.23)
Sep	($0.02)	$1.81	($1.75)
Oct	($1.10)	($0.58)	($1.62)
Nov	($0.81)	($0.30)	($1.35)
Dec	($0.66)	($0.10)	($1.14)
2011	$1.28	$3.05	($0.62)

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 ATSI Control Zone, $0.28 per MWh, while the highest all hours' annual average zonal markup component was in the AECO Control Zone, $2.30 per MWh. On peak, the smallest annual average zonal markup was in the ATSI Control Zone, $1.86 per MWh, while the highest annual average zonal markup was in the AECO Control Zone, $4.73 per MWh. Off peak, the smallest annual average zonal markup was in the ATSI Control Zone, -$1.46 per MWh, while the highest annual average zonal markup was in the Dominion Control Zone, $0.12 per MWh.

Table 2-20 Average real-time zonal markup component: Calendar year 2011

	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	$2.30	$4.73	($0.21)
AEP	$0.42	$1.92	($1.13)
AP	$0.97	$2.61	($0.75)
ATSI	$0.28	$1.86	($1.46)
BGE	$2.24	$4.45	($0.09)
ComEd	$1.03	$2.41	($0.47)
DAY	$0.48	$2.04	($1.23)
DLCO	$0.47	$2.15	($1.29)
Dominion	$1.97	$3.67	$0.12
DPL	$1.91	$3.94	($0.25)
JCPL	$2.05	$4.34	($0.53)
Met-Ed	$1.71	$3.78	($0.53)
PECO	$1.74	$3.86	($0.51)
PENELEC	$0.77	$2.53	($1.08)
Pepco	$1.95	$3.76	($0.06)
PPL	$1.69	$3.79	($0.58)
PSEG	$1.80	$4.04	($0.66)
RECO	$2.02	$3.85	($0.16)

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 2011

	Average Markup Component	Frequency
< $25	($3.11)	5.6%
$25 to $50	($2.22)	77.2%
$50 to $75	$4.17	10.1%
$75 to $100	$17.04	3.6%
$100 to $125	$25.98	1.6%
$125 to $150	$33.51	0.9%
> $150	$54.60	1.1%

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 118.7 percent of the markup component of overall PJM day-ahead, load-weighted average LMP.

Table 2-22 Markup component of the overall PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: Calendar year 2011

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($1.09)	118.7%
Municipal Waste	Steam	($0.00)	0.1%
Gas	CT	$0.04	(3.8%)
Gas	Diesel	$0.00	0.0%
Gas	Steam	$0.14	(15.3%)
Oil	Steam	($0.00)	0.3%
Wind	Wind	$0.00	0.0%
Total		($0.92)	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 2011, the markup component of LMP was -$1.85 per MWh off peak and -$0.06 per MWh on peak.

Table 2-23 Monthly markup components of day-ahead, load-weighted LMP: Calendar year 2011

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($0.48)	$0.13	($1.04)
Feb	($1.36)	($1.14)	($1.59)
Mar	($1.18)	($0.44)	($2.04)
Apr	($1.04)	($0.37)	($1.76)
May	($0.97)	($0.25)	($1.72)
Jun	($1.45)	($0.80)	($2.28)
Jul	$1.10	$3.82	($1.57)
Aug	($0.40)	$0.72	($1.85)
Sep	($1.64)	($0.92)	($2.46)
Oct	($1.15)	($0.73)	($1.59)
Nov	($1.37)	($0.73)	($2.04)
Dec	($1.78)	($1.17)	($2.37)
Annual	($0.92)	($0.06)	($1.85)

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 PPL Control Zone, -$1.23 per MWh, while the highest all hours' zonal markup component was in the ComEd Control Zone, -$0.34 per MWh. On peak, the smallest zonal markup was in the PPL Control Zone, -$0.62 per MWh, while the highest markup was in the ATSI Control Zone, $0.77 per MWh. Off peak, the smallest zonal markup was in the DAY Control Zone, -$2.11 per MWh, while the highest markup was in the ComEd Control Zone, -$1.08 per MWh.

Table 2-24 Day-ahead, average, zonal markup component: Calendar year 2011

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($1.10)	($0.24)	($2.04)
AEP	($1.00)	($0.01)	($2.04)
AP	($0.84)	$0.19	($1.93)
ATSI	($0.58)	$0.77	($2.05)
BGE	($1.14)	($0.36)	($1.98)
ComEd	($0.34)	$0.34	($1.08)
DAY	($1.18)	($0.34)	($2.11)
DLCO	($0.71)	$0.54	($2.07)
Dominion	($0.87)	$0.06	($1.84)
DPL	($1.10)	($0.28)	($1.96)
JCPL	($1.18)	($0.40)	($2.06)
Met-Ed	($1.17)	($0.49)	($1.92)
PECO	($1.11)	($0.30)	($2.00)
PENELEC	($1.08)	($0.42)	($1.82)
Pepco	($1.20)	($0.49)	($1.98)
PPL	($1.23)	($0.62)	($1.90)
PSEG	($1.19)	($0.42)	($2.06)
RECO	($1.20)	($0.55)	($1.96)

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 2011

	Average Markup Component	Frequency
< $25	($3.70)	3%
$25 to $50	($1.94)	83%
$50 to $75	$0.22	11%
$75 to $100	$3.30	2%
$100 to $125	$8.77	1%
$125 to $150	$3.51	1%
> $150	$18.99	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.[32] 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.[33] These categories are designated Tier 1, Tier 2 and Tier 3, respectively.[34,35]

An AU, or associated unit, is a unit that is physically, electrically and economically identical to an FMU, but does not qualify for the same FMU 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. The AU designation was implemented 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.[36]

Table 2-26 shows the number of FMUs and AUs in each month of 2011. For example, in December 2011, there were 20 FMUs and AUs in Tier 1, 26 FMUs and AUs in Tier 2, and 51 FMUs and AUs in Tier 3.

Table 2-26 Number of frequently mitigated units and associated units (By month): Calendar year 2011

	FMUs and AUs			Total Eligible
	Tier 1	Tier 2	Tier 3	for Any Adder
January	46	22	66	134
February	34	43	60	137
March	30	46	66	142
April	34	45	62	141
May	37	48	59	144
June	31	50	61	142
July	45	32	43	120
August	33	14	44	91
September	18	19	55	92
October	31	24	53	108
November	20	28	49	97
December	20	26	51	97

Figure 2-5 shows the total number of FMUs and AUs that qualified for an adder since the inception of the business rule in February, 2006.

32 110 FERC ¶ 61,053 (2005).

33 OA, Schedule 1 § 6.4.2.

34 114 FERC ¶ 61, 076 (2006).

35 See "Settlement Agreement," Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).

36 OA, Schedule 1 § 6.4.2. In 2007, the FERC approved OA revisions to clarify the AU criteria.

Figure 2-5 Frequently mitigated units and associated units (By month): February, 2006 through December, 2011

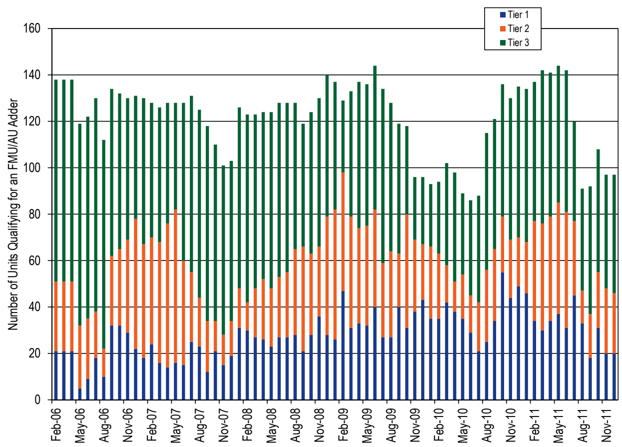


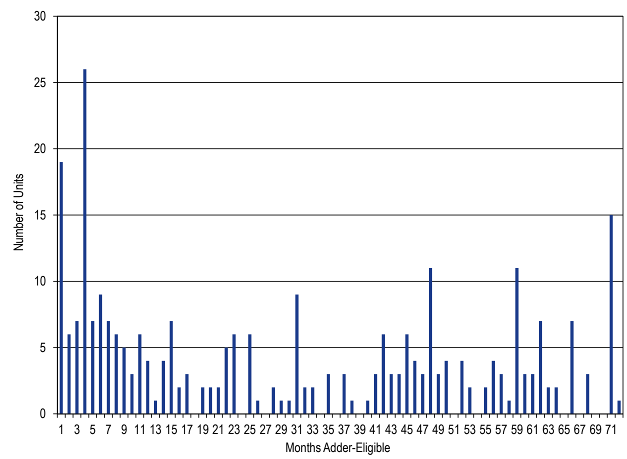
Table 2-27 shows the number of months FMUs and AUs were eligible for any adder (Tier 1, Tier 2 or Tier 3) during 2011. Of the 188 units eligible in at least one month during 2011, 88 units (44.6 percent) were FMUs or AUs for more than eight months. Approximately one third of the units (54 units or 28.7 percent) were eligible every month during the year. In 2010, 52 units out of 176 units or 29.5 percent of the units were eligible every month during the year. This demonstrates that the group of FMUs and AUs has been relatively stable over the past year, 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 2011

Months Adder-Eligible	FMU & AU Count
1	11
2	1
3	4
4	19
5	12
6	33
7	24
8	14
9	5
10	8
11	3
12	54
Total	188

Figure 2-6 shows the number of months FMUs and AUs were eligible for any adder (Tier 1, Tier 2 or Tier 3) since the inception of FMUs effective February 1, 2006. From February 1, 2006, through December 31, 2011, there have been 287 unique units that have qualified for an FMU adder in at least one month. Of these 287 units, only one unit qualified for an adder in all potential months. Fifteen additional units qualified in 71 of the 72 possible months, and 121 of the 287 units (42.2 percent) have qualified for an adder in more than half of the possible months.

Figure 2-6 Frequently mitigated units and associated units total months eligible: February, 2006 through December, 2011



FMU and AU adders contributed $0.12 per MWh to system average real-time LMP in 2011, out of a real-time, load weighted LMP of $45.94 per MWh.

Energy Market Opportunity Cost

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.

The calculation of energy market opportunity costs is designed to calculate the margin (LMP minus cost) for every hour in the projected year for the relevant generator bus. Those margins are the hourly opportunity cost. 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.

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 hours for the coming year.

In order to calculate the opportunity cost for each hour of the coming year, LMPs and fuel 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.[37] By orders issued March 17, 2011 and October 6, 2011, the Commission approved PJM's proposal to include short-term opportunity costs, rejected PJM's proposed allowance of OMC fuel supply limitations, and rejected PJM's proposed "50/50" rule, which would have permitted generators that were self-scheduling and using up emission-limited hours to have OMC outages.[38] A force majeure standard of fuel supply limitations was approved, and language involving OMC fuel limitations was removed.[39]

Two market participants included opportunity costs as a component of cost based offers in 2011. 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 these participants.

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.[40]

PJM Real-Time Load Duration

Figure 2-7 shows the number of hours that PJM real-time accounting load for 2010 and 2011 was within a defined MW range.

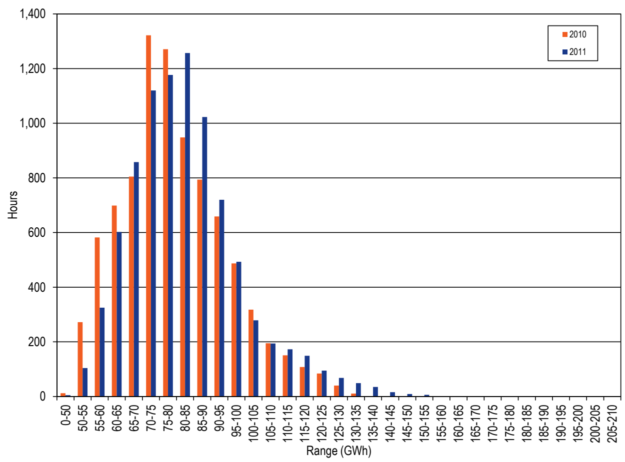
37 133 FERC ¶ 61,081 (2010).

38 134 FERC ¶ 61,192; 137 FERC ¶ 61,017.

39 *Id.*

40 All real-time load data in Section 2, "Energy Market," "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 2-7 PJM real-time accounting load histogram: Calendar years 2010 and 2011[41]



PJM Real-Time, Average Load

Table 2-28 presents summary real-time accounting load statistics for the 14 year period 1998 to 2011. The average hourly load of 82,541 MWh in 2011 was 3.7 percent higher than the 2010 annual average hourly load. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load and losses were addressed through marginal loss pricing.[42]

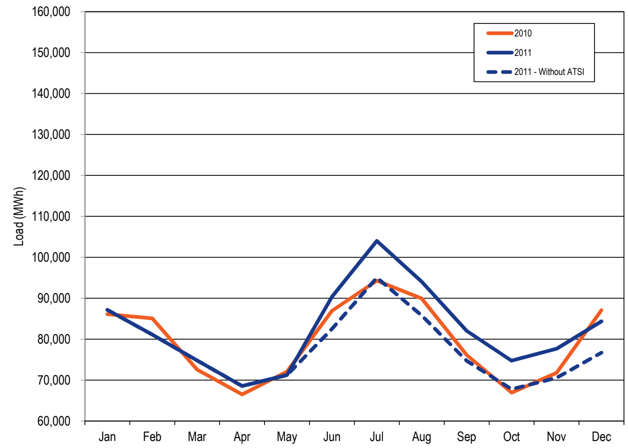
Table 2-28 PJM real-time average hourly load: Calendar years 1998 through 2011

	PJM Real-Time Load (MWh)		Year-to-Year Change	
Year	Average Load	Load Standard Deviation	Average Load	Load Standard Deviation
1998	28,578	5,511	NA	NA
1999	29,641	5,956	3.7%	8.1%
2000	30,113	5,529	1.6%	(7.2%)
2001	30,297	5,873	0.6%	6.2%
2002	35,731	8,013	17.9%	36.4%
2003	37,398	6,832	4.7%	(14.7%)
2004	49,963	13,004	33.6%	90.3%
2005	78,150	16,296	56.4%	25.3%
2006	79,471	14,534	1.7%	(10.8%)
2007	81,581	14,618	2.7%	0.6%
2008	79,515	13,758	(2.5%)	(5.9%)
2009	76,035	13,260	(4.4%)	(3.6%)
2010	79,611	15,504	4.7%	16.9%
2011	82,541	16,156	3.7%	4.2%

PJM Real-Time, Monthly Average Load

Figure 2-8 compares the real-time, monthly average hourly loads in 2011 with those in 2010.

Figure 2-8 PJM real-time monthly average hourly load: Calendar years 2010 and 2011



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.[43] THI is a measure of effective temperature using temperature and relative humidity for the cooling season (June, July and August).[44] Table 2-29 shows the monthly minimum, average and maximum of the PJM hourly THI for the cooling months in 2010 and 2011. When comparing 2011 to 2010, increases in THI were consistent with the increases in load during the cooling months in 2011. For the cooling months of 2011, the average THI was 76.75, 5.1 percent higher than the average 73.01 THI for 2010. The maximum THI (90.55) and minimum THI (59.33) in 2011 were 8.0 percent higher and 5.9 percent higher, than the maximum THI (83.83) and minimum THI (56.02) in 2010 during the cooling months.

41 Each range on the vertical axis includes the start value and excludes the end value.

42 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.

43 The weather stations that provided basis for the analysis are ABE, ACY, AVP, BWI, CAK, CLE, CMH, CRW, DAY, DCA, ERI, EWR, FWA, IAD, ILG, IPT, ORD, ORF, PHL, PIT, RIC, ROA, TOL and WAL.

44 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 18 (November 16, 2011), Section 3, pp. 9-10.

Table 2-29 Monthly minimum, average and maximum of PJM hourly THI: Cooling periods of 2010 and 2011

	2010			2011			Difference		
	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max
Jun	56.02	71.64	81.12	59.33	74.29	87.15	5.9%	3.7%	7.4%
Jul	57.22	74.45	83.83	66.74	79.87	90.55	16.6%	7.3%	8.0%
Aug	59.15	72.93	81.41	62.17	76.10	86.08	5.1%	4.3%	5.7%

WWP is the wind-adjusted temperature for the heating season (January, February and December). The average temperature is used for the months not covered by the THI or WWP. Table 2-30 shows the load weighted THI, WWP and average temperature for heating, cooling and shoulder seasons.[45]

Table 2-30 PJM annual Summer THI, Winter WWP and average temperature (Degrees F): cooling, heating and shoulder months of 2007 through 2011

	Summer THI	Winter WWP	Shoulder Average Temperature
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
2011	76.68	28.42	55.55

Day-Ahead Load

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

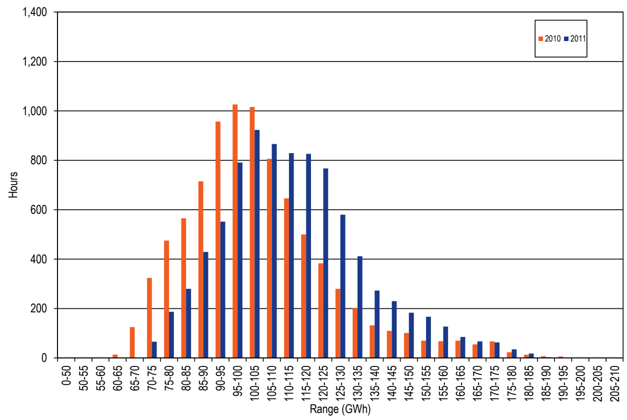
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of 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.
- **Up-to Congestion Transactions.** An up-to congestion transaction is a conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink.[46] In the PJM Day-Ahead Market, an up-to congestion transaction is evaluated and clears as a matched pair of injections and withdrawals analogous to a matched pair of INC offers and DEC bids. The DEC (sink) portion of each up-to congestion transaction is load in the Day-Ahead Energy Market. The INC (source) of each up-to congestion transaction is generation in the Day-Ahead Energy Market.

PJM day-ahead load is the hourly total of the above four types of cleared demand bids.[47]

PJM Day-Ahead Load Duration

Figure 2-9 shows the number of hours that PJM day-ahead load for 2010 and 2011 was within a defined MW range. Compared to the distribution of real-time load in Figure 2-7, the day-ahead distribution has a higher average value, has more occurrences of higher load and is more dispersed over defined MW ranges.

Figure 2-9 PJM day-ahead load histogram: Calendar years 2010 and 2011



45 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 18 (November 16, 2011), Section 3, pp. 15-16. Load weighting using real-time zonal accounting load.

46 Up-to congestion transactions are cleared based on the entire price difference between source and sink including the congestion and loss components of LMP.

47 Since an up-to congestion transaction is treated as analogous to a matched pair of INC offers and DEC bids, the DEC portion of the up-to congestion transaction contributes to the PJM day-ahead load, and the INC portion contributes to the PJM day-ahead generation.

Table 2-31 PJM day-ahead average load: Calendar years 2000 through 2011

	PJM Day-Ahead Load (MWh)						Year-to-Year Change		
	Average			Standard Deviation			Average		
Year	Load	Up-to Congestion	Total Load	Load	Up-to Congestion	Total Load	Load	Up-to Congestion	Total Load
2000	33,045	0	33,045	6,850	0	6,850	NA	NA	NA
2001	33,318	76	33,392	6,489	205	6,530	0.8%	NA	1.1%
2002	42,131	196	41,471	10,130	347	12,049	26.5%	159.3%	24.2%
2003	44,340	406	44,735	7,883	353	7,850	5.2%	107.5%	7.9%
2004	61,034	910	61,944	16,318	837	16,603	37.6%	124.1%	38.5%
2005	92,002	1,359	93,369	17,381	796	17,566	50.7%	49.3%	50.7%
2006	94,793	3,681	98,478	16,048	105	16,690	3.0%	170.8%	5.5%
2007	100,912	4,498	105,418	16,190	105	16,656	6.5%	22.2%	7.0%
2008	95,522	6,288	101,287	15,439	106	16,575	(5.3%)	39.8%	(3.9%)
2009	88,707	6,217	94,002	14,896	2,157	16,477	(7.1%)	(1.1%)	(7.2%)
2010	90,985	12,952	103,935	17,014	7,778	21,361	2.6%	108.3%	10.6%
2011	91,713	22,153	113,866	17,830	5,767	20,708	0.8%	71.0%	9.6%

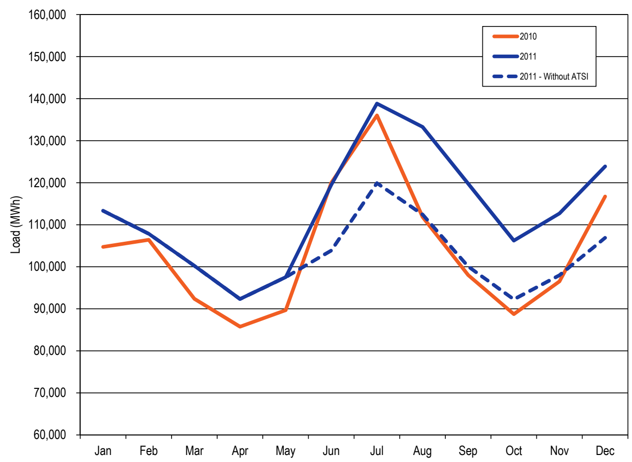
PJM Day-Ahead, Average Load

Table 2-31 presents summary day-ahead load statistics for the 12 year period 2000 to 2011. The average load of 91,713 MWh in 2011 was 0.9 percent higher than in 2010, excluding up-to congestion transactions. When up-to congestion transactions are included in the totals, the average load of 113,866 MWh in 2011 was 9.6 percent higher than in 2010. In 2011, the cleared fixed demand accounted for 69.9 percent, the cleared decrement bids accounted for 9.9 percent, the cleared price sensitive demand accounted for 0.8 percent and up-to congestion transactions accounted for 19.5 percent of average load. The cleared decrement bids were 29.5 percent lower than in 2010, fixed demand was 7.7 percent higher than in 2010, price-sensitive demand was 22.8 percent lower than in 2010 and up-to congestion transactions were 71.0 percent higher than in 2010.

PJM Day-Ahead, Monthly Average Load

Figure 2-10 compares the day-ahead, monthly average hourly loads of 2011 with those of 2010.

Figure 2-10 PJM day-ahead monthly average hourly load: Calendar years 2010 and 2011



Real-Time and Day-Ahead Load

Table 2-32 presents summary statistics for the 2010 and 2011 day-ahead and real-time loads. Total day-ahead load, including up-to congestion transactions, averaged 31,325 MWh more than the real-time load. Total day-ahead load, not including up-to congestion transactions, averaged 9,172 MWh more than the real-time load. Total day-ahead load not including cleared DEC bids or up-to congestion transactions averaged 2,109 MWh less than real-time load. This is the difference between the day-ahead load without virtual transactions and the real-time load. Table 2-32 shows that fixed demand was the largest component of day-ahead load and price-sensitive load was the smallest component.

Table 2-32 Cleared day-ahead and real-time load (MWh): Calendar years 2010 and 2011

		Day Ahead					Real Time	Average Difference	
	Year	Cleared Fixed Demand	Cleared Price Sensitive	Cleared DEC Bids	Cleared Up-to Congestion	Total Load	Total Load	Total Load	Total Load Minus Cleared DEC Bids Minus Up-to Congestion
Average	2010	73,853	1,139	15,993	12,952	103,935	79,611	24,324	(4,621)
	2011	79,553	879	11,282	22,153	113,866	82,541	31,325	(2,109)
Median	2010	71,824	1,030	15,850	10,620	100,891	77,430	23,461	(3,009)
	2011	77,556	880	11,086	21,487	111,650	80,870	30,780	(1,793)
Standard Deviation	2010	14,558	474	2,572	7,778	21,361	15,504	5,857	(4,493)
	2011	15,931	181	2,441	5,767	20,708	16,156	4,551	(3,657)
Peak Average	2010	82,017	1,320	17,360	13,587	114,284	88,061	26,223	(4,724)
	2011	88,273	956	12,971	23,194	125,395	91,402	33,993	(2,173)
Peak Median	2010	79,743	1,199	17,249	10,994	108,729	85,413	23,316	(4,927)
	2011	84,790	972	12,747	22,802	122,634	87,930	34,705	(844)
Peak Standard Deviation	2010	12,820	487	2,123	8,314	20,303	13,752	6,551	(3,886)
	2011	14,784	176	1,979	5,862	18,775	14,842	3,933	(3,908)
Off-Peak Average	2010	66,682	981	14,792	12,347	94,646	72,188	22,458	(4,681)
	2011	71,954	812	9,809	21,247	103,822	74,813	29,009	(2,047)
Off-Peak Median	2010	64,834	893	14,601	10,102	91,687	70,322	21,365	(3,338)
	2011	70,251	819	9,571	20,474	102,278	72,661	29,616	(428)
Off-Peak Standard Deviation	2010	11,991	402	2,320	7,250	17,803	12,944	4,859	(4,711)
	2011	12,668	158	1,755	5,525	16,688	12,983	3,705	(3,575)

Figure 2-11 shows the average 2011 hourly cleared volume of fixed-demand bids, the sum of cleared fixed-demand and cleared price-sensitive bids, total day-ahead load and real-time load. The difference between the cleared fixed-demand and cleared price-sensitive bids and the total day-ahead load is cleared decrement bids and up-to congestion transactions. In 2011, 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 in 1,502 hours during 2011 (17.1 percent of all hours in 2011). When cleared decrement bids and up-to congestion transactions are included, day-ahead load exceeded real-time load in all hours. When cleared decrement bids are included, but up-to congestion transactions are not included, day-ahead load exceeded real-time load in all hours.

Figure 2-11 Day-ahead and real-time loads (Average hourly volumes): Calendar year 2011

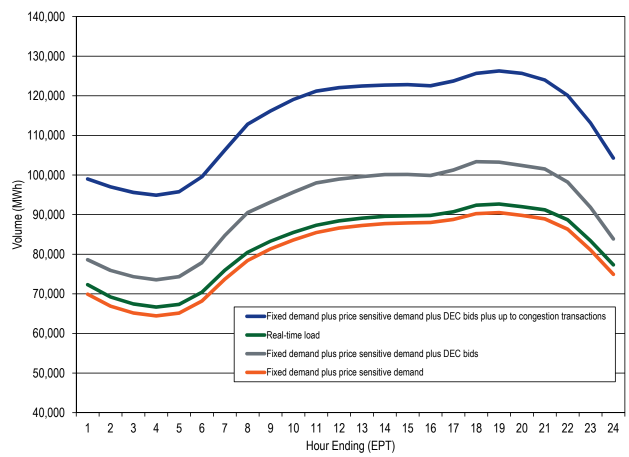
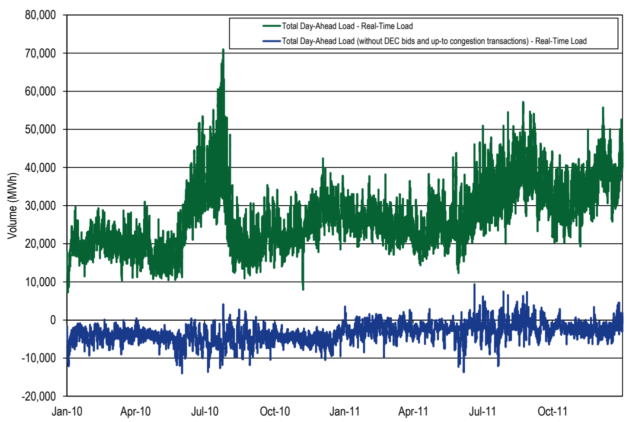


Figure 2-12 Difference between day-ahead and real-time loads (Average daily volumes): January 2010 through December 2011



Real-Time and Day-Ahead Generation

Real-time generation is the actual production of electricity during the operating day. Real-time generation will always be greater than real-time load because of system losses.

In the Day-Ahead Energy Market, four types of financially binding generation offers are made and cleared:[48]

- **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 from a specific unit that also has a dispatchable component above the minimum.[49]
- **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 corresponding offer prices. An increment offer is a financial offer that can be submitted by any market participant.
- **Up-to Congestion Transactions.** An up-to congestion transaction is a conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink.[50]

  In the PJM Day-Ahead Market, an up-to congestion transaction is evaluated and clears as a matched pair of injections and withdrawals analogous to a matched pair of INC offers and DEC bids. The DEC (sink) portion of each up-to congestion transaction is load in the Day-Ahead Energy Market. The INC (source) of each up-to congestion transaction is generation in the Day-Ahead Energy Market.

Table 2-33 presents summary real-time generation statistics for the 12-year period from 2000 through 2011. The average hourly generation of 85,775 was 3.9 percent higher than in 2010.

Table 2-33 PJM real-time average hourly generation: Calendar years 2000 through 2011

	PJM Real-Time Generation (MWh)		Year-to-Year Change	
Year	Average Generation	Generation Standard Deviation	Average Load	Generation Standard Deviation
2000	29,405	5,130	NA	NA
2001	28,634	5,154	(2.6%)	0.5%
2002	32,414	9,632	13.2%	86.9%
2003	35,337	6,439	9.0%	(33.1%)
2004	50,098	14,738	41.8%	128.9%
2005	79,858	15,137	59.4%	2.7%
2006	80,544	13,184	0.9%	(12.9%)
2007	83,424	13,372	3.6%	1.4%
2008	81,929	13,285	(1.8%)	(0.6%)
2009	78,035	13,647	(4.8%)	2.7%
2010	82,582	15,550	5.8%	13.9%
2011	85,775	15,932	3.9%	2.5%

Table 2-34 presents summary day-ahead generation statistics for the 12 year period from 2000 to 2011. The average generation of 94,977 MWh in 2011, including increment offers, was 0.7 percent higher than in 2010, excluding up-to congestion transactions. When up-to congestion transactions are included, the average generation of 117,130 MWh in 2011 was 9.2 percent higher than in 2010. In 2011, the cleared increment bids were 28.8 percent lower than in 2010.

48 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 *2011 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market."

49 The definition of self-scheduled is based on the PJM. "eMKT User Guide" (December 1, 2011), pp. 38-40.

50 Up-to congestion transactions are cleared based on the entire price difference between source and sink including the congestion and loss components of LMP.

Table 2-34 PJM day-ahead average hourly generation: Calendar years 2000 through 2011

	PJM Day-Ahead Generation (MWh)						Year-to-Year Change		
	Average			Standard Deviation			Average		
Year	Generation (Cleared Gen. and INC Offers)	Up-to Congestion	Total Generation	Generation (Cleared Gen. and INC Offers)	Up-to Congestion	Total Generation	Generation (Cleared Gen. and INC Offers)	Up-to Congestion	Total Generation
2000	32,942	0	32,942	15,307	0	6,706	NA	NA	NA
2001	32,966	76	33,042	6,308	205	6,340	0.1%	NA	0.3%
2002	40,849	196	41,045	11,982	347	12,035	23.9%	159.3%	24.2%
2003	43,922	406	44,328	7,822	353	7,779	7.5%	107.5%	8.0%
2004	61,493	910	62,404	17,194	837	17,460	40.0%	124.1%	40.8%
2005	92,911	1,359	94,270	17,440	796	17,621	51.1%	49.3%	51.1%
2006	95,743	3,681	99,424	16,515	105	17,150	3.0%	170.8%	5.5%
2007	103,302	4,498	107,801	16,746	105	17,195	7.9%	22.2%	8.4%
2008	98,487	6,288	104,775	15,996	106	16,404	(4.7%)	39.8%	(2.8%)
2009	90,591	6,217	96,808	15,394	2,157	16,350	(8.0%)	(1.1%)	(7.6%)
2010	94,340	12,952	107,290	17,394	7,778	21,806	4.1%	108.3%	10.8%
2011	94,977	22,153	117,130	18,069	5,767	20,977	0.7%	71.0%	9.2%

Table 2-35 Day-ahead and real-time generation (MWh): Calendar years 2010 and 2011

		Day Ahead				Real Time	Average Difference	
	Year	Cleared Generation	Cleared INC Offers	Cleared Up-to Congestion	Cleared Generation Plus INC Offers Plus Up-to Congestion	Generation	Cleared Generation	Cleared Generation Plus INC Offers Plus Up-to Congestion
Average	2010	83,112	11,243	12,952	107,290	82,582	530	24,708
	2011	86,966	8,010	22,153	117,130	85,775	1,191	31,354
Median	2010	81,197	11,128	10,620	104,135	80,624	573	23,511
	2011	85,218	8,006	21,487	114,938	83,986	1,232	30,951
Standard Deviation	2010	16,715	1,555	7,778	21,806	15,550	1,164	6,256
	2011	17,353	1,313	5,767	20,977	15,932	1,421	5,045
Peak Average	2010	92,259	11,994	13,587	117,839	90,863	1,395	26,976
	2011	96,750	8,859	23,194	128,803	94,275	2,475	34,528
Peak Median	2010	89,688	11,886	10,994	112,413	88,351	1,337	24,062
	2011	93,363	8,753	22,802	126,036	90,828	2,535	35,208
Peak Standard Deviation	2010	14,367	1,460	8,314	20,615	13,798	569	6,817
	2011	15,502	1,048	5,862	18,954	14,683	819	4,272
Off-Peak Average	2010	75,083	10,584	12,347	97,848	75,313	(230)	22,535
	2011	78,442	7,271	21,247	106,960	78,368	73	28,591
Off-Peak Median	2010	73,489	10,564	10,102	94,766	73,441	47	21,325
	2011	76,406	7,216	20,474	105,417	76,389	18	29,028
Off-Peak Standard Deviation	2010	14,336	1,319	7,250	18,213	13,188	1,148	5,025
	2011	14,072	1,048	5,525	16,975	13,013	1,059	3,962

Table 2-35 presents summary statistics for 2011 day-ahead and real-time generation. Day-ahead cleared generation from physical units averaged 1,191 MWh higher than real-time generation, an increase from 503 MWh in 2010. Day-ahead cleared generation from physical units plus cleared INC offers averaged 9,201 MWh more than real-time generation, a decrease from 11,773 MWh in 2010. Day-ahead cleared generation from physical units plus cleared INC offers and up-to congestion transactions averaged 31,354 MWh more than real-time generation, an increase from 24,708 MWh in 2010. This increase is due to the significant increase in up-to congestion transactions in 2011 (an increase from an average of 12,952 MW/hour in 2010 to 22,153 MW/hour in 2011).

Figure 2-13 shows the average 2011 hourly cleared volumes of day-ahead generation without increment offers or up-to congestion transactions, the day-ahead generation including cleared increment bids and up-to congestion transactions and the real-time generation.[51] Real-time generation was less than day-ahead generation from physical units on an hourly average basis. Real-time hourly average generation was lower than day-ahead generation in 65.1 percent of all hours in 2011. Real-time generation was greater than day-ahead generation from physical units for HE 1 through 6, and HE 24. When cleared increment offers and up-to congestion transactions are included, average hourly

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

total day-ahead cleared MW offers exceeded real-time generation.

Figure 2-13 Day-ahead and real-time generation (Average hourly volumes): Calendar year 2011

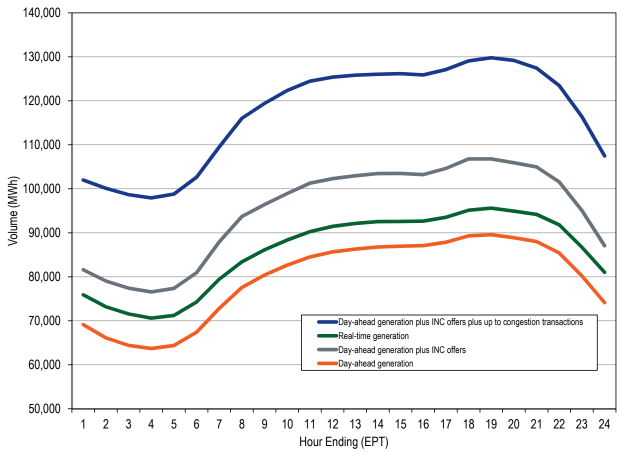
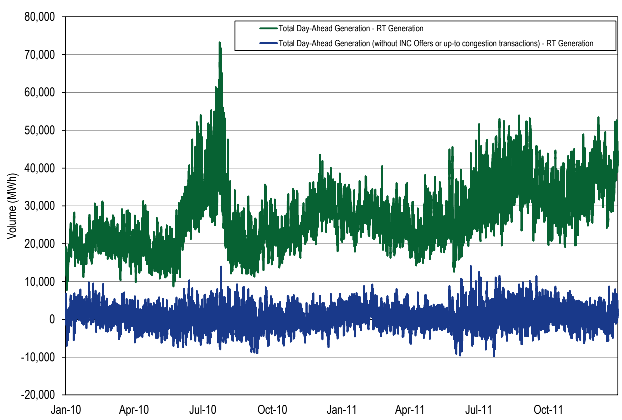


Figure 2-14 Difference between day-ahead and real-time generation (Average daily volumes): January 2010 through December 2011



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.[52]

Real-Time LMP

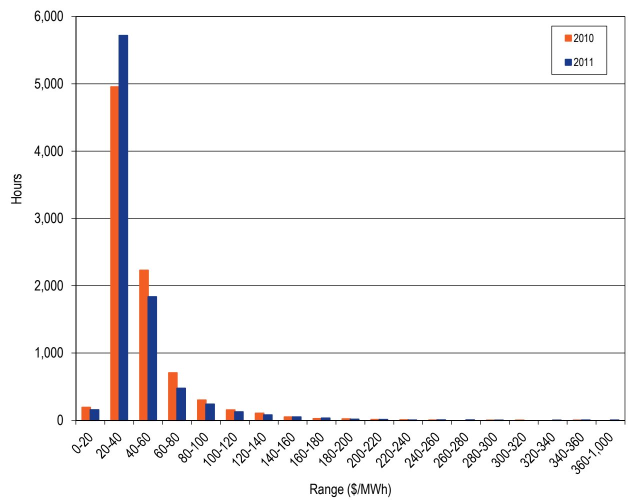
Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[53] This section discusses the real-time average LMP and the real-time load weighted average LMP. Average LMP is the simple, unweighted average LMP.

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 2-15 shows the number of hours that PJM real-time average LMP in 2010 and 2011 were within a defined range. As Figure 2-15 shows, the real-time average LMP was less than $100 per MWh during 95.7 percent of the hours in 2010 and 96.2 percent of the hours in 2011.

Figure 2-15 Average LMP histogram for the PJM Real-Time Energy Market: Calendar years 2010 and 2011



PJM Real-Time, Average LMP

Table 2-36 shows the PJM real-time, annual, average LMP for the 14-year period 1998 to 2011.[54] The system average LMP for 2011 was 4.4 percent lower than the 2010 annual average, $42.84 per MWh versus $44.83 per MWh. The PJM real-time, annual, average LMP in 2011 was lower than the average LMP in every year from 2005 through 2008.

52 See the *2011 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.

53 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price" for detailed definition of Real-Time LMP.

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

Table 2-36 PJM real-time, average LMP (Dollars per MWh): Calendar years 1998 through 2011

	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%
2011	$42.84	$35.38	$29.03	(4.4%)	(4.1%)	10.8%

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 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 LMP, each weighted by the PJM total hourly load.

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

Table 2-37 shows the PJM real-time, annual, load-weighted, average LMP for the 14-year period 1998 to 2011. The load-weighted, average system LMP for 2011 was 5.0 percent lower than the 2010 annual, load-weighted, average, $45.94 per MWh versus $48.35 per MWh. The PJM real-time, annual, load-weighted, average LMP in 2011 was lower than the average LMP in every year from 2005 through 2008.

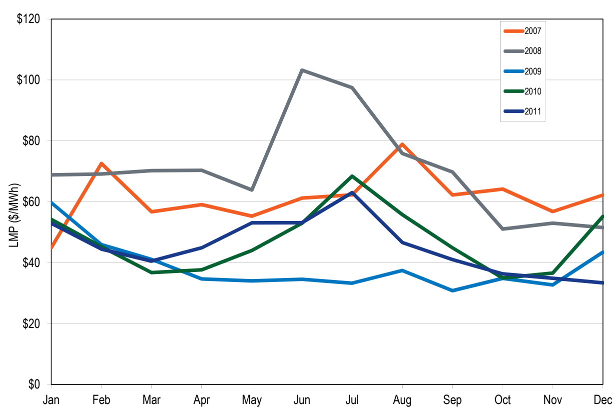
Table 2-37 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 1998 through 2011

	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%
2011	$45.94	$36.54	$33.47	(5.0%)	(6.6%)	15.8%

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

Figure 2-16 shows the PJM real-time, monthly, load-weighted LMP from 2007 through 2011.

Figure 2-16 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2007 through 2011



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

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.[55] 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 2010 and 2011, the 2011 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.[56]

Of the prices of the primary fuel types used in the PJM footprint, coal and oil increased in price, while on average, natural gas decreased in price in 2011. In 2011, for example, the price of Northern Appalachian coal was 18.4 percent higher than in 2010. The price of Central Appalachian coal was 22.3 percent higher than in 2010. The price of Powder River Basin coal was 7.1 percent higher than in 2010. No. 2 (light) oil prices were 38.6 percent higher and No. 6 (heavy) oil prices were 40.9 percent higher in 2011 than in 2010. Eastern natural gas prices were 9.4 percent lower in 2011 than in 2010. Western natural gas prices were 9.7 percent lower in 2011 than 2010. Figure 2-17 shows spot average fuel prices for 2010 and 2011.[57]

Figure 2-17 Spot average fuel price comparison: Calendar years 2010 through 2011

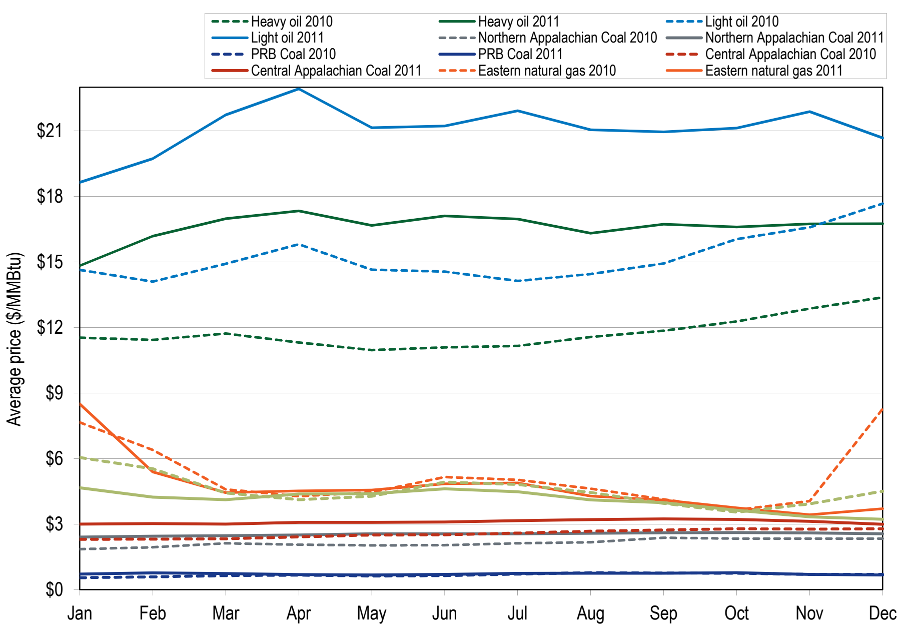


Table 2-38 compares the 2011 PJM real-time fuel-cost-adjusted, load-weighted, average LMP to the 2010 load-weighted, average LMP. The fuel-cost adjusted load-weighted, average LMP for 2011 was 2.6 percent lower than the load-weighted, average LMP for 2011. The real-time fuel-cost-adjusted, load-weighted, average LMP in 2011 was 7.4 percent lower than the load-weighted LMP in 2010. If fuel costs for the year 2011 had been the same as for 2010, the 2011 load-weighted LMP would have been lower, $44.75 per MWh instead of the observed $45.94 per MWh. The mix of fuel types and costs in 2011 resulted in higher prices in 2011 than would have occurred if fuel prices had remained at their 2010 levels.

Table 2-38 PJM real-time annual, fuel-cost-adjusted, load-weighted average LMP (Dollars per MWh): Year-over-year method

	2011 Load-Weighted LMP	2011 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$45.94	$44.75	(2.6%)
	2010 Load-Weighted LMP	2011 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$48.35	$44.75	(7.4%)
	2010 Load-Weighted LMP	2011 Load-Weighted LMP	Change
Average	$48.35	$45.94	(5.0%)

Components of Real-Time, Load-Weighted LMP

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 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,

55 See the *2011 State of the Market Report for PJM*, Volume II, Section 2,"Energy Market," at Table 2-15, "Type of fuel used (By marginal units): Calendar year 2011."

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

57 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.

SO_2, and CO_2 and emission allowance costs and unit-specific emission rates, when applicable.

Table 2-39 shows that 46.4 percent of the annual, load-weighted LMP was the result of coal costs, 31.2 percent was the result of gas costs and 1.5 percent was the result of the cost of emission allowances. Markup was 2.8 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 2011 was $0.02 per MWh. (Numbers in parentheses in the table are negative.) The components of this difference are listed in Table 2-39.[58]

Table 2-39 Components of PJM real-time, annual, load-weighted, average LMP: Calendar year 2011

Element	Contribution to LMP	Percent
Coal	$21.30	46.4%
Gas	$14.32	31.2%
10% Cost Adder	$3.95	8.6%
VOM	$2.52	5.5%
Markup	$1.28	2.8%
Oil	$1.21	2.6%
NA	$0.73	1.6%
NOX	$0.31	0.7%
CO2	$0.31	0.7%
FMU Adder	$0.12	0.3%
SO2	$0.04	0.1%
Unit LMP Differential	$0.02	0.1%
Municipal Waste	$0.00	0.0%
Uranium	$0.00	0.0%
M2M Adder	($0.00)	(0.0%)
Shadow Price Limit Adder	($0.00)	(0.0%)
Wind	($0.03)	(0.1%)
Dispatch Differential	($0.12)	(0.3%)
Total	$45.94	100.0%

Day-Ahead LMP

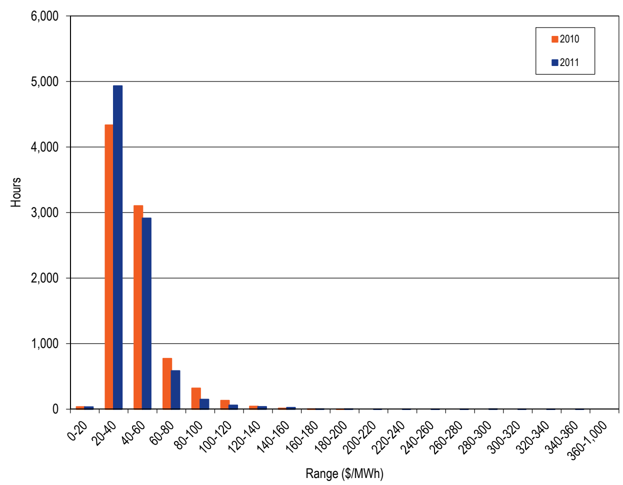
Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[59] This section discusses the day-ahead average LMP and the day-ahead load weighted average LMP. Average LMP is the simple, unweighted average LMP.

Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 2-18 shows the number of hours that PJM day-ahead average LMP was within a defined range in 2010 and 2011. As Figure 2-18 shows, day-ahead average LMP was less than $100 per MWh during 97.8 percent of the hours in 2010 and 98.3 percent of the hours in 2011.

Figure 2-18 Price histogram for the PJM Day-Ahead Energy Market: Calendar years 2010 and 2011



PJM Day-Ahead, Annual Average LMP

Table 2-40 shows the PJM day-ahead annual, average LMP for the 12 year period 2000 to 2011. The system average LMP for 2011 was 4.6 percent lower than the 2010 annual average, $42.52 per MWh versus $44.57 per MWh. The PJM day-ahead annual, average LMP in 2011 was lower than the average LMP in every year from 2005 through 2008.

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

59 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price" for detailed definition of Day-Ahead LMP.

Table 2-40 PJM day-ahead, average LMP (Dollars per MWh): Calendar years 2000 through 2011

	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%
2011	$42.52	$38.13	$20.48	(4.6%)	(4.6%)	8.8%

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 LMP, each weighted by the PJM total cleared day-ahead hourly load, including day-ahead fixed load, price-sensitive load, decrement bids and up-to congestion.

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

Table 2-41 shows the PJM day-ahead, annual, load-weighted, average LMP for the 12-year period 2000 to 2011. The day-ahead, load-weighted, average LMP for 2011 was 5.2 percent lower than the 2010 annual, load-weighted, average, $45.19 per MWh versus $47.65 per MWh. The PJM day-ahead, load-weighted, average LMP in 2011 was lower than the average LMP in every year from 2005 through 2008.

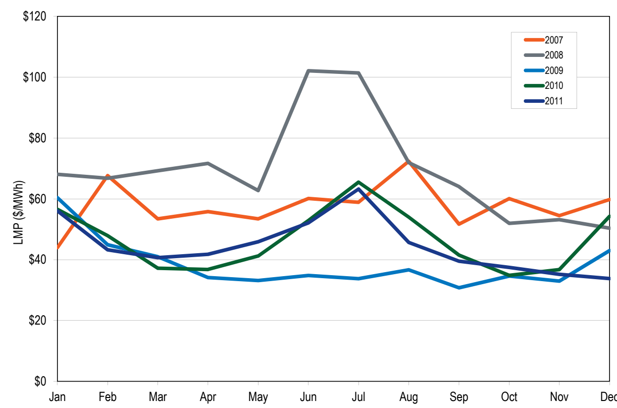
Table 2-41 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2000 through 2011

	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%
2011	$45.19	$39.66	$24.05	(5.2%)	(5.7%)	16.8%

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

Figure 2-19 shows the PJM day-ahead, monthly, load-weighted LMP from 2007 through 2011.

Figure 2-19 Day-ahead, monthly, load-weighted, average LMP: Calendar years 2007 through 2011



Components of Day-Ahead, Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources generally determine system LMPs, based on their offers. For physical units, those offers can be decomposed into fuel costs, emission costs, variable operation and maintenance costs, markup, FMU adder, Day-Ahead Scheduling Reserve (DASR) adder and the 10 percent cost offer adder. INC offers, DEC bids and price sensitive transactions are dispatchable injections and withdrawals in the Day Ahead market. To the extent that INCs, DECs or transactions are the marginal resource, they either directly or indirectly set price via their offers and bids. Using identified marginal resource offers and the components of the offers, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors. Table 2-42 shows the components of the PJM day ahead, annual, load-weighted average LMP.

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. Day Ahead Scheduling Reserve (DASR) lost opportunity cost (LOC) and DASR offer adders are the calculated contribution to LMP when redispatch of resources is needed in order to satisfy DASR requirements. Cost offers of marginal units are broken into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. 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 CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware, Maryland and New Jersey.[60]

Table 2-42 Components of PJM day-ahead, annual, load-weighted, average LMP (Dollars per MWh): Calendar year 2011

Element	Contribution to LMP	Percent
Coal	$12.57	27.8%
DEC	$11.21	24.8%
INC	$7.27	16.1%
Gas	$5.51	12.2%
10% Cost Adder	$1.98	4.4%
Price Sensitive Demand	$1.85	4.1%
Up-to Congestion Transaction	$1.70	3.8%
Dispatchable Transaction	$1.41	3.1%
VOM	$1.30	2.9%
DASR LOC Adder	$0.52	1.2%
NO_x	$0.16	0.4%
CO_2	$0.16	0.4%
Oil	$0.14	0.3%
DASR offer Adder	$0.09	0.2%
SO_2	$0.02	0.0%
FMU Adder	$0.02	0.0%
Constrained Off	$0.00	0.0%
Wind	$0.00	(0.0%)
Markup	($0.92)	(2.0%)
NA	$0.19	0.4%
Total	$45.19	100.0%

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. In addition, the PJM Day-Ahead Energy Market includes up-to congestion transactions. Up-to congestion transactions are treated as a matched pair of injections and withdrawals analogous to a matched pair of INC offers and DEC bids, and affect the outcome of the PJM Day-Ahead Energy Market. Since increment offers, decrement bids and up-to congestion transactions do not require physical generation or load, they are also referred to as virtual offers and bids. Virtual offers and bids 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.

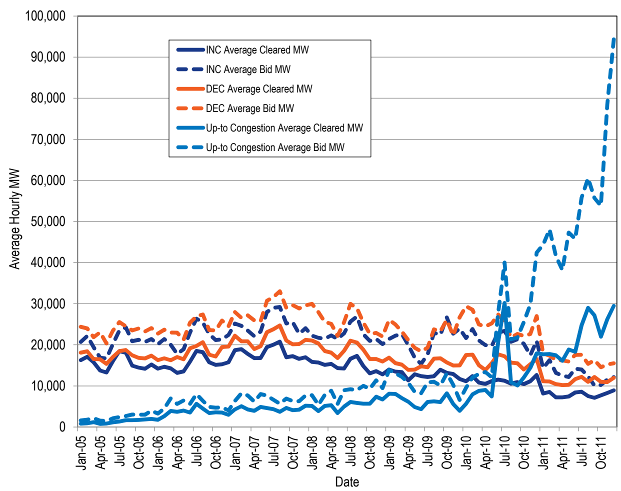
60 New Jersey withdrew from RGGI, effective January 1, 2012.

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 PJM optimization algorithm works.

Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids and up-to congestion transactions as financial instruments that do not require physical generation or load. Increment offers, decrement bids and up-to congestion transactions may be submitted at any hub, transmission zone, aggregate, or single bus for which LMP is calculated.[61] Table 2-43 shows the average volume of trading in increment offers and decrement bids per hour and the average total MW values of all bids per hour. Table 2-44 shows the average volume of up-to congestion transactions per hour and the average total MW values of all bids per hour.

Table 2-45 shows the frequency with which generation offers, import or export transactions, up-to congestion transactions, decrement bids, increment offers and price-sensitive demand are marginal for each month in 2011.[62] Together, increment offers and decrement bids represented 19.9 percent of the marginal bids or offers in 2011.

Figure 2-20 Hourly volume of bid and cleared INC, DEC and Up-to Congestion bids (MW) by month: January, 2005 through December, 2011



61 An import up-to congestion transaction must source at an interface, but may sink at any hub, transmission zone, aggregate, or single bus for which LMP is calculated. An export up-to congestion transaction may source at any hub, transmission zone, aggregate, or single bus for which LMP is calculated, but must sink at an interface. Wheeling up-to congestion transactions must both source and sink at an interface.

62 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.

Table 2-43 Hourly average volume of cleared and submitted INCs, DECs by month: Calendar years 2010 and 2011

		Increment Offers				Decrement Bids			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2010	Jan	11,144	21,634	282	936	17,513	29,406	266	893
2010	Feb	12,387	23,827	387	1,122	17,602	28,542	270	883
2010	Mar	10,811	21,062	308	915	15,019	24,968	253	763
2010	Apr	10,512	19,940	289	784	13,875	24,458	246	705
2010	May	11,165	19,744	218	806	15,556	25,194	223	787
2010	Jun	11,534	22,956	254	1,496	17,689	27,422	258	1,246
2010	Jul	11,276	23,414	250	1,585	17,223	25,690	304	1,284
2010	Aug	10,567	20,751	226	1,332	15,656	21,745	327	1,140
2010	Sep	10,944	21,365	263	1,232	15,522	22,646	311	1,072
2010	Oct	10,454	20,253	234	1,129	14,011	22,154	253	1,030
2010	Nov	11,134	17,495	220	1,035	15,315	22,618	271	1,055
2010	Dec	12,656	20,957	277	1,340	16,560	26,995	274	1,266
2010	Annual	11,208	21,101	267	1,143	15,952	25,135	271	1,011
2011	Jan	8,137	14,299	218	1,077	11,135	17,917	224	963
2011	Feb	8,530	16,263	215	1,672	11,071	17,355	230	1,034
2011	Mar	7,230	13,164	201	1,059	10,435	16,343	219	982
2011	Apr	7,222	12,516	185	984	10,211	16,199	202	846
2011	May	7,443	12,161	220	835	10,250	15,956	243	800
2011	Jun	8,405	14,171	238	1,084	11,648	17,542	279	1,015
2011	Jul	8,595	14,006	185	1,234	12,196	17,567	213	1,140
2011	Aug	7,540	12,349	120	1,034	10,992	15,368	161	847
2011	Sep	7,092	10,071	114	591	12,171	16,268	147	648
2011	Oct	7,726	10,242	104	351	10,983	14,550	116	396
2011	Nov	8,290	11,545	105	382	10,936	15,204	118	416
2011	Dec	8,914	12,159	107	409	11,964	15,515	114	404
2011	Annual	7,792	12,924	180	992	11,109	16,507	203	867

Table 2-44 Hourly average of cleared and submitted up-to congestion bids by month: Calendar years 2010 and 2011

		Up-to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2010	Jan	5,647	9,549	114	189
2010	Feb	7,961	12,047	150	244
2010	Mar	8,796	12,916	149	234
2010	Apr	9,004	13,398	137	215
2010	May	7,430	12,114	131	208
2010	Jun	20,537	27,576	168	266
2010	Jul	30,176	40,006	202	336
2010	Aug	10,902	21,354	150	287
2010	Sep	10,114	21,777	156	488
2010	Oct	12,044	25,544	195	473
2010	Nov	14,380	29,788	261	602
2010	Dec	17,928	42,414	319	724
2010	Annual	12,910	22,374	178	355
2011	Jan	17,687	44,361	338	779
2011	Feb	17,759	48,052	386	877
2011	Mar	17,451	41,666	419	940
2011	Apr	16,114	38,182	488	1,106
2011	May	18,854	47,312	560	1,199
2011	Jun	18,323	45,802	508	1,141
2011	Jul	24,742	55,809	641	1,285
2011	Aug	28,996	60,531	654	1,348
2011	Sep	27,184	55,706	638	1,267
2011	Oct	21,985	53,830	616	1,345
2011	Nov	26,234	78,486	718	1,682
2011	Dec	29,471	94,316	720	1,837
2011	Annual	22,067	55,338	557	1,234

Table 2-45 Type of day-ahead marginal units: Calendar year 2011

	Generation	Dispatchable Transaction	Up-to Congestion Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	10.5%	0.2%	63.9%	14.8%	10.2%	0.3%
Feb	10.0%	0.4%	67.0%	13.3%	9.1%	0.2%
Mar	8.9%	0.2%	66.4%	16.4%	7.8%	0.3%
Apr	7.6%	0.4%	66.0%	16.4%	9.3%	0.2%
May	5.3%	0.3%	73.2%	13.6%	7.2%	0.3%
Jun	8.0%	0.3%	66.4%	15.7%	9.2%	0.4%
Jul	5.3%	0.1%	68.3%	16.1%	9.8%	0.3%
Aug	4.6%	0.1%	76.2%	11.8%	7.0%	0.3%
Sep	8.0%	0.2%	72.3%	12.5%	6.9%	0.3%
Oct	6.1%	0.1%	74.2%	11.2%	8.1%	0.3%
Nov	3.9%	0.1%	79.9%	9.4%	6.6%	0.1%
Dec	4.5%	0.0%	83.7%	7.2%	4.4%	0.1%
Annual	6.3%	0.2%	73.4%	12.4%	7.5%	0.2%

In order to evaluate the ownership of virtual bids, the MMU categorized all participants making 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 2-46 shows the total increment offers and decrement bids by the type of parent organization: financial or physical.[63] Table 2-47 shows the total up-to congestion transactions by the type of parent organization: financial or physical.

Table 2-46 PJM INC and DEC bids by type of parent organization (MW): Calendar years 2010 and 2011

	2010		2011	
Category	Total Virtual Bids MW	Percentage	Total Virtual Bids MW	Percentage
Financial	174,249,033	43.02%	125,432,065	42.99%
Physical	230,775,843	56.98%	166,308,872	57.01%
Total	405,024,876	100.0%	291,740,937	100.0%

Table 2-47 PJM up-to congestion transactions by type of parent organization (MW): Calendar years 2010 and 2011

	2010		2011	
Category	Total Up-to Congestion MW	Percentage	Total Up-to Congestion MW	Percentage
Financial	110,269,067	97.25%	187,509,868	96.84%
Physical	3,121,859	2.75%	6,113,860	3.16%
Total	113,390,926	100.0%	193,623,729	100.00%

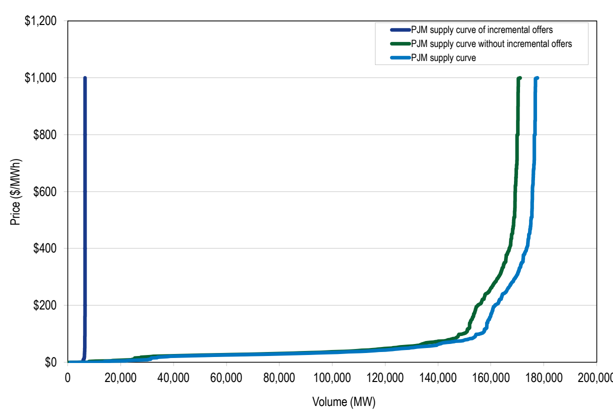
Table 2-48 shows increment offers and decrement bids bid by top ten locations.[64] In 2011, more offers and bids were submitted at the WESTERN HUB than any other location. Total increment offer and decrement bid MW at WESTERN HUB were 25.5 percent of the total PJM offered bids. The top ten locations for increment offers and decrement bids accounted for 55.7 percent of all offers and bids in PJM in 2011.

Table 2-49 shows up-to congestion transactions by import, export and wheel for the top ten locations. For import transactions, in 2011, the highest volume of cleared MW occurred on the path with the source of MISO and the sink of the Northern Illinois Hub. This path accounted for 3.6 percent of all import up-to congestion transactions. The top ten path combinations for import transactions accounted for 18.8 percent of all import up-to congestion transactions. For export transactions, in 2011, the highest volume of cleared MW occurred on the path with the source of the Lumberton aggregate and the sink of the Southeast aggregate. This path accounted for 7.1 percent of all export up-to congestion transactions. The top ten path combinations for export transactions accounted for 23.1 percent of all export up-to congestion transactions.

For wheeling transactions, in 2011, the highest volume of cleared MW occurred on the path with the source of the CPLEIMP interface and the sink of the NCMPAEXP interface. This path accounted for 12.4 percent of all wheeling up-to congestion transactions. The top ten path combinations for wheeling transactions accounted for 54.9 percent of all wheeling up-to congestion transactions.

Figure 2-21 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve without increment offers and the system aggregate supply curve with increment offers for an example day in June 2011. There were average hourly increment offers of 6,511 MW and average hourly total offers of 176,664 MW for the example day.

Figure 2-21 PJM day-ahead aggregate supply curves: 2011 example day



63 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>.

64 There was an error in the information about virtual offers at the top ten aggregates in the *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>.

Table 2-48 PJM virtual offers and bids by top ten locations (MW): Calendar years 2010 and 2011

2010					2011				
Aggregate/Bus Name	Aggregate/ Bus Type	INC MW	DEC MW	Total MW	Aggregate/ Bus Name	Aggregate/ Bus Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	59,498,730	67,461,162	126,959,892	WESTERN HUB	HUB	34,784,275	39,727,544	74,511,819
N ILLINOIS HUB	HUB	12,227,336	13,489,896	25,717,232	N ILLINOIS HUB	HUB	10,740,204	17,271,222	28,011,425
AEP-DAYTON HUB	HUB	5,903,338	7,754,930	13,658,269	AEP-DAYTON HUB	HUB	8,161,997	9,878,692	18,040,689
PPL	ZONE	524,776	8,491,950	9,016,726	SOUTHIMP	INTERFACE	11,363,163	0	11,363,163
PSEG	ZONE	2,412,903	5,229,766	7,642,670	MISO	INTERFACE	292,005	8,755,249	9,047,254
BGE	ZONE	3,675,033	3,624,029	7,299,062	PECO	ZONE	2,080,316	5,855,528	7,935,844
PEPCO	ZONE	5,922,591	1,215,146	7,137,737	PPL	ZONE	318,717	4,727,485	5,046,202
JCPL	ZONE	3,939,569	2,210,312	6,149,881	COMED	ZONE	3,208,552	243,813	3,452,365
MISO	INTERFACE	1,223,081	3,768,471	4,991,553	IMO	INTERFACE	2,754,598	108,998	2,863,597
COMED	ZONE	2,251,251	2,422,361	4,673,613	PSEG	ZONE	544,733	1,740,038	2,284,771
Top ten total		97,578,609	115,668,025	213,246,633			74,248,561	88,308,567	162,557,128
PJM total		184,846,624	220,178,252	405,024,876			130,593,253	161,147,684	291,740,937
Top ten total as percent of PJM total		52.8%	52.5%	52.7%			56.9%	54.8%	55.7%

Table 2-49 PJM cleared up-to congestion import, export and wheel bids by top ten source and sink pairs (MW): Calendar years 2010 and 2011

2010														
Imports					Exports					Wheels				
Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	COMED	ZONE	3,479,436	COMED	ZONE	MISO	INTERFACE	3,216,407	SOUTHIMP	INTERFACE	SOUTHEXP	INTERFACE	3,014,673
MISO	INTERFACE	DAY	ZONE	3,131,119	BEAV DUQ UNIT1	AGGREGATE	MICHFE	INTERFACE	2,800,821	NCMPAIMP	INTERFACE	NCMPAEXP	INTERFACE	2,129,852
MISO	INTERFACE	112 WILTON	EHVAGG	2,918,147	DAY	ZONE	MISO	INTERFACE	2,760,390	NORTHWEST	INTERFACE	NIPSCO	INTERFACE	795,172
MISO	INTERFACE	COOK	EHVAGG	2,840,633	23 COLLINS	EHVAGG	MISO	INTERFACE	2,043,536	NORTHWEST	INTERFACE	SOUTHWEST	AGGREGATE	653,232
MISO	INTERFACE	AEP-DAYTON HUB	HUB	2,349,595	ROCKPORT	EHVAGG	MISO	INTERFACE	1,836,300	MISO	INTERFACE	OVEC	INTERFACE	204,838
NYIS	INTERFACE	PSEG	ZONE	1,743,747	COOK	EHVAGG	MISO	INTERFACE	1,331,189	NORTHWEST	INTERFACE	MISO	INTERFACE	201,636
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	1,660,718	MT STORM	EHVAGG	MISO	INTERFACE	1,076,845	NORTHWEST	INTERFACE	IMO	INTERFACE	165,740
MISO	INTERFACE	GREENLAND GAP	EHVAGG	942,071	21 KINCA ATR24304	AGGREGATE	MISO	INTERFACE	1,012,193	SOUTHEAST	AGGREGATE	CPLEEXP	INTERFACE	131,010
NYIS	INTERFACE	MARION	AGGREGATE	940,157	21 KINCA ATR24304	AGGREGATE	SOUTHWEST	AGGREGATE	892,080	OVEC	INTERFACE	MISO	INTERFACE	118,225
NORTHWEST	INTERFACE	COMED	ZONE	779,805	QUAD CITIES 2	AGGREGATE	MISO	INTERFACE	729,155	OVEC	INTERFACE	SOUTHEXP	INTERFACE	93,177
Top ten total				20,785,428					17,698,915					7,507,555
PJM total				55,024,722					49,156,193					9,210,022
Top ten total as percent of PJM total				37.8%					36.0%					81.5%

2011														
Imports					Exports					Wheels				
Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	N ILLINOIS HUB	HUB	3,763,388	LUMBERTON	AGGREGATE	SOUTHEAST	AGGREGATE	6,076,609	CPLEIMP	INTERFACE	NCMPAEXP	INTERFACE	397,775
MISO	INTERFACE	112 WILTON	EHVAGG	2,649,235	WESTERN HUB	HUB	MISO	INTERFACE	3,932,018	CPLEIMP	INTERFACE	DUKEXP	INTERFACE	287,643
OVEC	INTERFACE	CONESVILLE 6	AGGREGATE	2,419,245	23 COLLINS	EHVAGG	MISO	INTERFACE	1,684,900	NORTHWEST	INTERFACE	MISO	INTERFACE	239,020
NORTHWEST	INTERFACE	ZION 1	AGGREGATE	2,205,202	SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	1,591,281	NORTHWEST	INTERFACE	SOUTHWEST	AGGREGATE	204,835
OVEC	INTERFACE	CONESVILLE 4	AGGREGATE	2,103,635	FE GEN	AGGREGATE	SOUTHWEST	AGGREGATE	1,363,004	SOUTHWEST	AGGREGATE	OVEC	INTERFACE	174,891
NYIS	INTERFACE	MARION	AGGREGATE	1,674,479	167 PLANO	EHVAGG	MISO	INTERFACE	1,166,857	NYIS	INTERFACE	MICHFE	INTERFACE	115,574
OVEC	INTERFACE	CONESVILLE 5	AGGREGATE	1,645,825	21 KINCA ATR24304	AGGREGATE	SOUTHWEST	AGGREGATE	1,157,710	MISO	INTERFACE	NIPSCO	INTERFACE	114,199
NYIS	INTERFACE	PSEG	ZONE	1,158,004	BELMONT	EHVAGG	OVEC	INTERFACE	992,732	NIPSCO	INTERFACE	OVEC	INTERFACE	93,186
OVEC	INTERFACE	JEFFERSON	EHVAGG	1,043,124	FOWLER 34.5 KV FWLR1AWF	AGGREGATE	OVEC	INTERFACE	969,853	NIPSCO	INTERFACE	MISO	INTERFACE	73,321
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	986,945	RECO	ZONE	IMO	INTERFACE	847,660	NCMPAIMP	INTERFACE	OVEC	INTERFACE	62,459
Top ten total				19,649,082					19,782,624					1,762,903
PJM total				104,786,982					85,627,554					3,209,193
Top ten total as percent of PJM total				18.8%					23.1%					54.9%

Price Convergence

The introduction of the PJM Day-Ahead Energy Market created the possibility that competition, exercised through the use of virtual offers and bids, would tend to cause prices in the Day-Ahead and Real-Time Energy Markets to converge. 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 differences in 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

Table 2-50 Day-ahead and real-time average LMP (Dollars per MWh): Calendar years 2010 and 2011[65]

	2010				2011			
	Day Ahead	Real Time	Difference	Difference as Percent of Real Time	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Average	$44.57	$44.83	$0.26	0.6%	$42.52	$42.84	$0.32	0.7%
Median	$39.97	$36.88	($3.09)	(8.4%)	$38.13	$35.38	($2.75)	(7.8%)
Standard deviation	$18.83	$26.20	$7.38	28.2%	$20.48	$29.03	$8.55	29.4%
Peak average	$52.67	$53.25	$0.58	1.1%	$50.45	$51.20	$0.74	1.4%
Peak median	$45.48	$43.20	($2.29)	(5.3%)	$44.56	$40.25	($4.31)	(10.7%)
Peak standard deviation	$20.07	$28.93	$8.85	30.6%	$24.60	$36.11	$11.51	31.9%
Off peak average	$37.46	$37.44	($0.02)	(0.1%)	$35.61	$35.56	($0.05)	(0.1%)
Off peak median	$33.73	$31.83	($1.90)	(6.0%)	$32.43	$31.58	($0.85)	(2.7%)
Off peak standard deviation	$14.27	$20.93	$6.66	31.8%	$12.44	$18.07	$5.63	31.2%

to negative (Figure 2-22). There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis (Figure 2-23).

As Table 2-50 shows, day-ahead and real-time prices were relatively close, on average, in 2010 and 2011. The annual average LMP in the Real-Time Energy Market was $0.32 per MWh or 0.7 percent higher than the annual average LMP in the Day-Ahead Energy Market in 2011.

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 2011, the real-time, load-weighted, hourly LMPs were higher than day-ahead, load-weighted, hourly LMPs by more than $50 per MWh for 214 hours, more than $100 per MWh for 29 hours, more than $150 per MWh for 8 hours and more than $300 per MWh for 3 hours. Although real-time prices were higher than day-ahead prices on average in 2011, real-time prices were lower than day-ahead prices for 64.7 percent of the hours. During hours when real-time prices were higher than day-ahead prices, the average positive difference between them was $12.75 per MWh. During hours when real-time prices were less than day-ahead prices, the average negative difference was -$6.47 per MWh.

Table 2-51 shows the difference between the Real-Time and the Day-Ahead Energy Market Prices from 2000 to 2011. From 2000 to 2003, the real-time annual average LMP was lower than the day-ahead annual average LMP. Since 2004, the real-time annual average LMP has been higher than the day-ahead annual average LMP.[66]

Table 2-51 Day-ahead and real-time average LMP (Dollars per MWh): Calendar years 2000 through 2011

	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%
2011	$42.52	$42.84	$0.32	0.7%

Table 2-52 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 2007 through 2011. 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 2007 to calendar year 2011, 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 2011 where 3 hourly price differences were 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

65 The averages used are the annual average of the hourly average PJM prices for day-ahead and real-time.

66 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 2-52 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): Calendar years 2007 through 2011

	2007		2008		2009		2010		2011	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.02%
($150) to ($100)	0	0.00%	1	0.02%	0	0.00%	0	0.00%	2	0.05%
($100) to ($50)	26	0.40%	88	1.35%	3	0.05%	13	0.20%	49	0.79%
($50) to $0	3,385	52.07%	3,730	58.08%	3,776	57.69%	4,091	62.65%	4,011	62.02%
$0 to $50	2,914	96.55%	2,448	95.32%	2,736	99.45%	2,288	97.57%	2,290	96.98%
$50 to $100	193	99.50%	264	99.33%	34	99.97%	130	99.56%	169	99.56%
$100 to $150	21	99.82%	37	99.89%	2	100.00%	20	99.86%	21	99.88%
$150 to $200	4	99.88%	4	99.95%	0	100.00%	8	99.98%	2	99.91%
$200 to $250	1	99.89%	2	99.98%	0	100.00%	1	100.00%	3	99.95%
$250 to $300	3	99.94%	0	99.98%	0	100.00%	0	100.00%	0	99.95%
$300 to $350	2	99.97%	1	100.00%	0	100.00%	0	100.00%	0	99.95%
$350 to $400	0	99.97%	0	100.00%	0	100.00%	0	100.00%	0	99.95%
$400 to $450	1	99.98%	0	100.00%	0	100.00%	0	100.00%	0	99.95%
$450 to $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.95%
>= $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%

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.

Figure 2-22 shows the hourly differences between day-ahead and real-time load-weighted hourly LMP in 2011. Although the average difference between the Day-Ahead and Real-Time Energy Market was $0.65 per MWh for the entire year, Figure 2-22 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 $621.55 per MWh for the hour ended 1700 on May 31, 2011, when the real-time load-weighted hourly LMP was $770.58 and the day-ahead load-weighted hourly LMP was $149.03. The large difference between the day-ahead and real-time load-weighted hourly LMP on May 31, 2011 was the result of several unplanned generator outages. A Maximum Emergency Generation Action was issued in order to increase generation above the normal economic limit in order to meet load demands. End-use customers who are registered in PJM's Mandatory Load Management with Long Lead Time were requested to reduce load.

Figure 2-22 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: Calendar year 2011

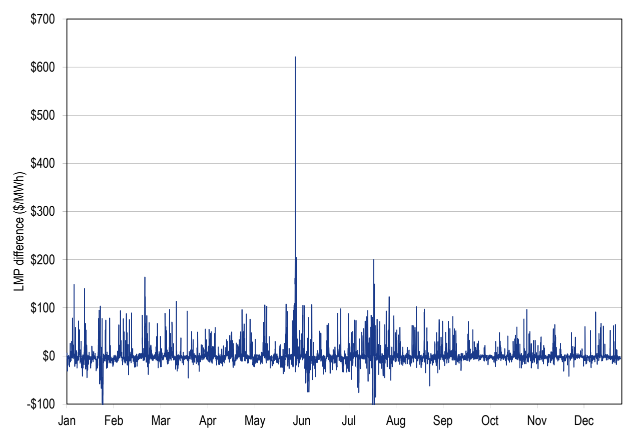
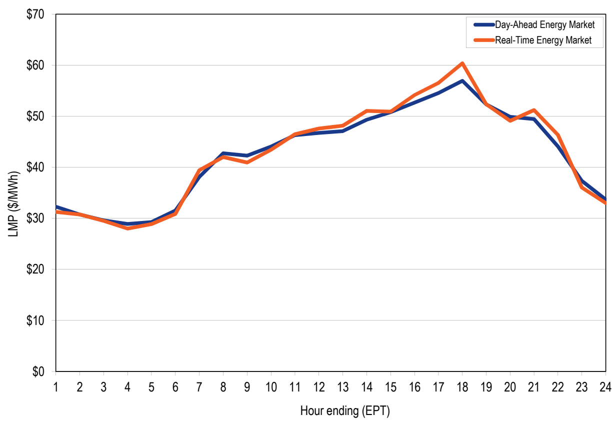


Figure 2-23 shows the monthly average differences between the day-ahead and real-time LMP in 2011. The highest monthly difference was in May.

Figure 2-23 Monthly average of real-time minus day-ahead LMP: Calendar year 2011

Figure 2-24 shows day-ahead and real-time LMP on an average hourly basis. Real-time average LMP was greater than day-ahead average LMP for 12 out of 24 hours.[67]

Figure 2-24 PJM system hourly average LMP: Calendar year 2011



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 from a non-affiliated company 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 2-53 shows the monthly average share of real-time load served by self-supply, bilateral contract and spot purchase in 2010 and 2011 based on parent company. For 2011, 10.5 percent of real-time load was supplied by bilateral contracts, 26.6 percent by spot market purchase and 62.9 percent by self-supply. Compared with 2010, reliance on bilateral contracts decreased 1.3 percentage points, reliance on spot supply increased by 6.4 percentage points and reliance on self-supply decreased by 5.1 percentage points.

67 See the *2011 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market," for more details on the frequency distribution of prices.

Table 2-53 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: Calendar years 2010 through 2011

	2010			2011			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	12.0%	17.4%	70.5%	9.3%	28.8%	61.9%	(2.7%)	11.4%	(8.6%)
Feb	13.5%	18.1%	68.4%	10.9%	27.9%	61.2%	(2.6%)	9.8%	(7.2%)
Mar	12.8%	18.2%	68.9%	10.4%	29.3%	60.3%	(2.5%)	11.1%	(8.6%)
Apr	12.6%	19.3%	68.1%	10.7%	25.3%	64.1%	(1.9%)	6.0%	(4.1%)
May	11.6%	19.9%	68.5%	11.1%	25.7%	63.3%	(0.4%)	5.8%	(5.2%)
Jun	10.4%	19.0%	70.5%	10.5%	25.4%	64.1%	0.1%	6.4%	(6.5%)
Jul	9.8%	19.5%	70.7%	9.5%	24.7%	65.8%	(0.3%)	5.2%	(4.9%)
Aug	10.6%	20.5%	68.9%	10.3%	24.6%	65.1%	(0.3%)	4.1%	(3.8%)
Sep	12.0%	22.3%	65.7%	10.9%	26.7%	62.4%	(1.1%)	4.4%	(3.3%)
Oct	13.0%	25.1%	61.9%	12.2%	29.8%	58.0%	(0.8%)	4.7%	(3.9%)
Nov	12.8%	22.7%	64.5%	10.7%	28.3%	61.1%	(2.1%)	5.5%	(3.4%)
Dec	11.5%	21.8%	66.7%	10.1%	24.3%	65.5%	(1.4%)	2.5%	(1.2%)
Annual	11.8%	20.2%	68.0%	10.5%	26.6%	62.9%	(1.3%)	6.4%	(5.1%)

Table 2-54 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: Calendar years 2010 through 2011

	2010			2011			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	4.6%	17.8%	77.6%	4.7%	23.7%	71.6%	0.1%	5.9%	(6.0%)
Feb	4.6%	18.4%	77.0%	5.4%	23.7%	70.9%	0.8%	5.3%	(6.1%)
Mar	4.8%	18.4%	76.8%	5.8%	24.3%	70.0%	1.0%	5.8%	(6.8%)
Apr	4.9%	19.1%	76.0%	6.1%	23.8%	70.1%	1.2%	4.7%	(5.9%)
May	6.6%	19.0%	74.4%	6.0%	24.0%	70.0%	(0.6%)	5.1%	(4.5%)
Jun	4.6%	18.6%	76.7%	6.0%	25.3%	68.8%	1.3%	6.6%	(7.9%)
Jul	4.7%	18.6%	76.6%	5.5%	23.4%	71.2%	0.7%	4.7%	(5.5%)
Aug	4.8%	19.3%	75.9%	5.7%	24.1%	70.1%	1.0%	4.8%	(5.8%)
Sep	4.6%	20.7%	74.8%	5.8%	25.2%	69.0%	1.2%	4.5%	(5.8%)
Oct	4.9%	22.7%	72.4%	5.7%	25.7%	68.5%	0.9%	3.1%	(3.9%)
Nov	4.9%	20.7%	74.4%	6.4%	25.3%	68.3%	1.5%	4.6%	(6.1%)
Dec	4.6%	19.2%	76.2%	6.6%	25.3%	68.1%	2.1%	6.1%	(8.2%)
Annual	4.9%	19.3%	75.8%	5.8%	24.4%	69.8%	0.9%	5.1%	(6.1%)

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 2-54 shows the monthly average share of day-ahead load served by self-supply, bilateral contracts and spot purchases in 2010 and 2011, based on parent companies. For 2011, 5.8 percent of day-ahead load was supplied by bilateral contracts, 24.4 percent by spot market purchases, and 69.8 percent by self-supply. Compared with 2010, reliance on bilateral contracts increased by 0.9 percentage points, reliance on spot supply increased by 5.1 percentage points, and reliance on self-supply decreased by 6.1 percentage points.

Scarcity and Scarcity Pricing

In electricity markets, scarcity means that demand, plus reserve requirements, is nearing the limits of the available capacity of the system. Under the current PJM rules, high prices, or scarcity pricing, result from high offers by individual generation owners for specific units when the system is close to its available capacity. These offers give the aggregate energy supply curve its steep upward sloping tail.[68] As demand increases and units

68 See *2011 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market" at Figure 2-1, "Average PJM aggregate supply curves: Summers 2010 and 2011."

with higher markups and higher offers are required to meet demand, prices increase. As a result, positive markups and associated high prices on high-load days may be the result of appropriate scarcity pricing rather than market power. But this is not an efficient way to manage scarcity pricing and makes it difficult to distinguish between market power and scarcity pricing.

The energy market alone frequently does not directly or sufficiently value some of the resources needed to provide for reliability. This is the rationale for administrative scarcity pricing mechanisms such as PJM's Reliability Pricing Model (RPM) market for capacity and its administrative scarcity pricing mechanism in the energy market.

Designation of Maximum Emergency MW

During extreme system conditions when PJM declares Maximum Emergency Alerts, the PJM tariff specifies that capacity can only be designated as maximum emergency if the capacity has limitations on its availability based on environmental limitations, short term fuel limitations, or emergency conditions at the unit, or the additional capacity is obtained by operating the unit past its normal limits.[69,70] The intent of the rule regarding maximum emergency designation is to ensure that only capacity with a clearly defined short term issue limiting its economic availability is defined as maximum emergency MW, which can be made available, at PJM direction, to maintain the system during emergency conditions.

Declarations of Hot/Cold Weather Alerts also affect declarations of maximum emergency capacity under the rules. Hot Weather Alerts indicate that the system is expected to experience possible resource adequacy issues in the declared areas due to an expectation of multiple consecutive days with projected temperatures in excess of 90 degrees with high humidity.[71] Cold Weather Alerts indicate that the system is expected to experience possible resource adequacy issues in the declared areas due to an expectation that temperatures will fall below ten degrees Fahrenheit.[72] A Hot/Cold Weather Alert indicates conditions that require that combustion turbine (CT) and steam units with limited fuel availability need to be removed from economic availability and made available as emergency only capacity.[73] The Hot/Cold Weather Alert rule regarding Maximum emergency capacity declarations, as outlined in Manual 13, is consistent with the Maximum Emergency Alert rule and its intent. Whereas the Maximum Emergency Alert rule limits maximum emergency designations to capacity with limited availability during extreme system conditions, the Hot/Cold Weather Alert rule defines specific availability limitations which require that capacity be defined as maximum emergency during extreme system conditions.[74]

The indicated references are the only place in the PJM rules and tariff that there is a clear definition of maximum emergency status. The analysis suggests that some MW are inappropriately designated as maximum emergency at times of declared Maximum Emergency Alerts. The analysis also suggests that some MW are inappropriately designated as maximum emergency outside of Maximum Emergency Alerts and Hot/Cold Weather Alerts. Such designations could be considered a form of withholding. There should be a clear definition of maximum emergency status that applies throughout the tariff.

There are incentives to keep capacity incorrectly designated as maximum emergency. Capacity designated

69 See PJM Tariff, 6A.1.3 Maximum Emergency Offer Limitations p. 1646. Effective Date: 9/17/2010 See PJM. "Manual 13: Emergency Operations," Revision: 47 (Effective January 1, 2012), p. 69.

70 See PJM. "Manual 13: Emergency Operations," Revision: 47 (Effective January 1, 2012), p. 69: "On days when PJM has declared, prior to 1800 hours on the day prior to the operating day, a Maximum Emergency Generation Alert for the entire PJM Control Area or for specific Control Zones or Scarcity Pricing Regions, the only units for which all of part of their capability may be designated as Maximum Emergency are those that meet the criteria described above. Should PJM declare a Maximum Generation Alert during the operating day for which the alert is effective, generation owners will be responsible for removing any unit availability from the Maximum Generation category that does not meet the above criteria within 4 hours of the issuance of the alert. PJM will make a mechanism available to participants by which they may inform PJM of their generating capability that meets the above criteria and indicate which of the criteria it meets." See also PJM Tariff, 6A.1.3 Maximum Emergency Offer Limitations p. 1646.

71 The purpose of the Hot Weather Alert is to prepare personnel and facilities for extreme hot and/or humid weather conditions which may cause capacity requirements/unit unavailability to be substantially higher than forecast are expected to persist for an extended period. In general, a Hot Weather alert can be issued on a Control Zone basis, if projected temperatures are to exceed 90 degrees with high humidity for multiple days. See PJM. "Manual 13: Emergency Operations," Revision: 47 (Effective January 1, 2012), p 41.

72 The purpose of the Cold Weather Alert is to prepare personnel and facilities for expected extreme cold weather conditions. As a general guide when the forecasted weather conditions approach minimum or actual temperatures for the Control Zone fall near or below ten degrees Fahrenheit. PJM can initiate a Cold Weather Alert at higher temperatures if PJM anticipates increased winds or if PJM projects a portion of gas fired capacity is unable to obtain spot market gas during load pick-up periods (refer to Inter RTO Natural Gas Coordination Procedure below). PJM will generally initiate a Cold Weather Alert on a Control Zone basis. See PJM. "Manual 13: Emergency Operations," Revision: 47 (Effective January 1, 2012), p 39.

73 See PJM. "Manual 13: Emergency Operations," Revision: 47 (Effective January 1, 2012), pp 37-38. CTs burning oil, kerosene or diesel with less than 16 hours of remaining fuel are considered to be fuel limited during a Hot Weather Alert. CTs burning gas with less than 8 hours of daily fuel allowance are considered to be fuel limited during a Hot Weather Alert. Steam units with less than 32 hours of fuel in inventory are considered to be fuel limited during a Hot Weather Alert.

74 During Maximum Emergency Alert days, PJM rules limit maximum emergency declarations to capacity that falls into one of the following categories: environmentally limited, fuel limited, temporary emergency condition limited, or temporary megawatt additions. See PJM. "Manual 13: Emergency Operations," Revision: 47 (Effective January 1, 2012), p 69.

as maximum emergency is considered as available, not on outage, even during the peak five hundred hours of the year defined in RPM. Capacity designated as maximum emergency is substantially less likely to be dispatched than capacity with an economic offer on high load days.

Given the incentives to keep capacity incorrectly designated as maximum emergency under normal system conditions, the rules regarding maximum emergency designations are expected to result in a net decrease in the level of capacity designated as maximum emergency during Maximum Emergency Alerts. This is the case because MW designated as maximum emergency, which do not have to meet a clear standard at other times, must comply with the tariff definition of maximum emergency during Maximum Emergency Alerts. Capacity which was designated as maximum emergency prior to a declaration of Maximum Emergency Alerts but which does not meet this tariff definition be reported as on forced outage or as available economic capacity after such a declaration.

During Maximum Emergency Alert Days in 2011, capacity designated as maximum emergency was used to produce energy in every hour of each day, despite the fact that prices were below $500 and there were no PJM instructions to load the maximum emergency generation. This behavior suggests that these MW designated as maximum emergency were used as economic MW by participants and were therefore incorrectly classified even during Maximum Emergency Alert Days.

Definitions

PJM's current administrative scarcity pricing mechanism is designed to recognize real- time scarcity in the Energy Market and to increase prices to reflect the scarcity conditions. Administrative scarcity pricing results when PJM takes identified emergency actions to support identified scarcity constraints. The scarcity price is based on the highest offer of an operating unit. PJM takes emergency actions on a regional basis when the PJM system is running low on economic sources of energy and reserves. Such actions include voltage reductions, emergency power purchases, manual load dump, and loading of maximum emergency generation.[75,76] These do not represent all of the emergency actions that are available to PJM operators, but the listed steps are defined in the PJM Tariff as the triggers for scarcity pricing events.[77] PJM did not declare any scarcity pricing events in 2011 under PJM's current emergency action based scarcity pricing rules.

This section defines scarcity to exist when the system-wide demand for power exceeds the system-wide capacity available to provide both energy and 10 minute synchronized reserves. There were no such scarcity events in 2011. This section defines a high-load day to exist when hourly total real time demand, including a 30 minute reserve target, equals 96 percent or more of total, within-30 minute supply in the absence of non market administrative intervention, on an hourly integrated basis over a two hour period.[78] There were a total of 35 high-load hours in 2011. There were eight days that met the definition of a high load day in 2011: June 1 and 8, July 20-22 and August 1, 5, and 8.

2011 Results: High-Load Days

There were four Maximum Emergency Alert days in 2011, two in June (June 8 and 9) and two in July (July 21 and 22). Two of the days, June 9 and July 22, had Maximum Emergency Actions for local transmission constraint control which provided for PJM direction to load maximum emergency capacity. Loading maximum emergency capacity to control for local transmission constraints does not trigger scarcity under PJM's current emergency action based scarcity pricing rules. Table 2-55 provides a description of PJM Maximum Emergency Alerts and Actions.

75 A voltage reduction warning (not an action) is evidence that the system is running out of available resources. A voltage reduction warning "is implemented when the available synchronized reserve capacity is less than the synchronized reserve requirement, after all available secondary and primary reserve capacity (except restricted maximum emergency capacity) is brought to a synchronized reserve status and emergency operating capacity is scheduled from adjacent systems." See PJM. "Manual 13: Emergency Operations," Revision: 47 (Effective January 1, 2012), p. 24.

76 "The PJM RTO is normally loaded according to bid prices; however, during periods of reserve deficiencies, other measures must be taken to maintain reliability." See PJM. "Manual 13: Emergency Operations," Revision: 47 (Effective January 1, 2012), p. 29.

77 See OATT, Sheet No. 402A.01.

78 See PJM. "Manual 13: Emergency Operations," Revision: 47 (Effective January 1, 2012), p. 11. The thirty minute reserve target used in the study is the day-ahead operating reserve target based of a percentage of Day Ahead peak load.

Table 2-55 Maximum Emergency Alerts and Actions

Event	Purpose
Maximum Emergency Alert	Day ahead notice that maximum emergency generation has been called into day ahead operating capacity
Maximum Emergency Generation Action Transmission Contingency Support	Real time notice that maximum emergency generation may be required to provide local contingency support
Maximum Emergency Generation Action	Real time notice that maximum emergency generation may be required for system support

Table 2-56 High Load Hour, Hot Weather Alerts and Maximum Emergency Related Events: May through September 2011

Dates	High Load Day (High Load Hours)	Hot Weather Alert	Maximum Emergency Generation Alert	Maximum Emergency Action Transmission Contingency Support	Maximum Emergency Generation Action
5/26/2011					Southern
5/30/2011		PJM			
5/31/2011		PJM			Mid-Atlantic and Southern
6/1/2011	6				
6/7/2011		ComEd			
6/8/2011	2	PJM	Mid-Atlantic		
6/9/2011		PJM	Mid-Atlantic	BGE	
6/22/2011		Dominion			
7/5/2011	1				
7/11/2011		PJM			
7/12/2011		PJM except ComEd			
7/13/2011		Mid-Atlantic and Dominion			
7/17/2011	1				
7/18/2011		PJM			
7/19/2011		PJM			
7/20/2011	2	PJM			
7/21/2011	6	PJM	Mid-Atlantic		
7/22/2011	5	PJM	Mid-Atlantic	BGE , Mid-Atlantic, DLCO	
7/23/2011		PJM		AE (Atl. City Elec.) - Sub-Trans Zone	
7/28/2011		PJM			
7/29/2011		PJM			
7/30/2011	1	Mid-Atlantic and Southern			
8/1/2011	3	PJM			
8/2/2011		PJM			
8/3/2011		BGE, Pepco, Dominion			
8/5/2011	2				
8/8/2011	6	BGE, Pepco, Dominion			

Table 2-56 shows the relationships among high load days, Hot Weather Alerts, Maximum Emergency Alerts and Maximum Emergency Actions in the May through September period. As defined in this section, there were a total of 35 high-load hours in 2011. There were eleven days with high load hours in June, July and August of 2011: two in June, six in July and three in August. There were eight high load hours in June, sixteen in July and eleven in August. Of those eleven days containing high load hours, seven qualified as high load days, with two or more hours of high load on an hourly integrated basis: June 1 and 8, July 20-22 and August 1 and 8. In the May through September period, PJM declared twenty-two Hot Weather Alerts.[79] Six of the declared Hot Weather Alert days corresponded with the high load day defined in this section: June 8, July 20, 21, 22 and August 1, 8. In the June through August period, PJM declared four maximum emergency alert days, four of which corresponded with the high load day defined in this section: June 8, July 21, July 22 and August 8. Four of the Maximum Emergency Alert days in 2011 were also Hot Weather Alert Days: June 8, 9 and July 21, 22.

In general, participant behavior in the summer of 2011 was consistent with the market incentives created by the Capacity Market and Energy Market. During the

79 "The purpose of the Hot Weather Alert is to prepare personnel and facilities for extreme hot and/or humid weather conditions which may cause capacity requirements/unit unavailability to be substantially higher than forecast are expected to persist for an extended period. In general, a Hot Weather alert can be issued on a Control Zone basis, if projected temperatures are to exceed 90 degrees with high humidity for multiple days." See PJM. "Manual 13: Emergency Operations," Revision: 47 (Effective January 1, 2012), p. 41.

declared Hot Weather Alerts in 2011, declared outage MW were lower than the average declared outage MW in the June through August period. Maximum emergency generation declarations during maximum emergency generation periods were also lower than the monthly averages in the period. However, energy was produced from declared emergency segments during two Maximum Emergency Alert days, when energy prices were below $500 per MWh and in the absence of specific PJM instructions to load the maximum emergency generation (June 8 and July 21). This behavior suggests that some emergency MW segments were incorrectly classified by the generation owners.

Figure 2-25 and Figure 2-26 show the hourly proportions of maximum emergency capacity that were producing energy on June 9 and July 21 of 2011. June 9 and July 21 were Maximum Emergency Alert Days during which declared emergency MW segments were producing energy, despite the absence of a PJM Maximum Emergency Generation Event. Steam units provided most of the energy from declared, or in excess of declared, emergency segments in every hour of June 9 and July 21. On June 9 and July 21 these maximum emergency MW segments were providing energy in every hour and in all cases they were making this energy available at hourly integrated prices below $500.

Figure 2-25 June 9 hourly declared emergency MW and emergency MW used

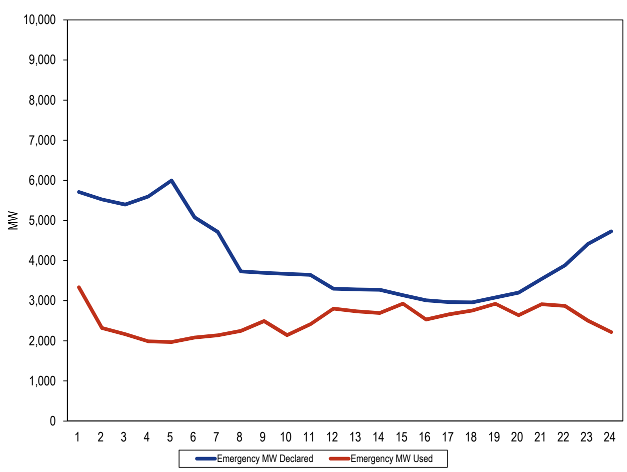


Figure 2-26 July 21 hourly declared emergency MW declared and emergency MW used