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 the first nine months of 2012, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM Energy Market results were competitive in the first nine months of 2012.

Table 2-1 The Energy Market results were competitive (See 2011 SOM, Table 2-1)

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 (Herndahl-Hirschman Index) indicate that by the FERC standards, the PJM Energy Market during the first nine months of 2012 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1234 with a minimum of 927 and a maximum of 1657 in the first nine months of 2012.
- 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 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 the exercise of 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]

Highlights

- Average offered supply increased by 10,571, or 6.6 percent, from 159,826 MW in the first nine months of 2011 to 170,397 MW in the first nine months of 2012. The increase in offered supply was in part the result of the integration of the Duke Energy Ohio/Kentucky (DEOK) Transmission Zone in the first quarter of 2012 and the integration of the American Transmission Systems, Inc. (ATSI) Transmission Zone in the second quarter of 2011. In addition, 1,898 MW of nameplate capacity were added to PJM in the first nine months of 2012. The increases in supply were

1 Analysis of 2012 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. In January 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) 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.

partially offset by the deactivation of 43 units (6,722 MW) since January 1, 2012.

- In January through September 2012, coal units provided 41.8 percent, nuclear units 34.1 percent and gas units 19.6 percent of total generation. Compared to January through September 2011, generation from coal units decreased 10.0 percent, generation from nuclear units increased 5.3 percent, while generation from natural gas units increased 45.4 percent, and generation from oil units increased 96.5 percent.
- The PJM system peak load for the first nine months of 2012 was 154,344 MW, which was 3,672 MW, or 2.3 percent, lower than the PJM peak load for the first nine months of 2011.[4] The DEOK Transmission Zone accounted for 5,360 MW in the peak hour of the first nine months of 2012. The peak load in 2012 excluding the DEOK Transmission Zone was 148,984 MW, a decrease of 9,032 MW, or 5.7 percent, from the peak load for the first nine months 2011.
- PJM average real-time load increased in the first nine months of 2012 by 5.9 percent from the first nine months of 2011, from 83,762 MW to 88,680 MW. The PJM average real-time load would have decreased in the first nine months of 2012 by 0.9 percent from the first nine months of 2011, from 83,762 MW to 82,970 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison for the months in 2011 when they were not part of PJM.[5]
- PJM average day-ahead load, including DECs and up-to congestion transactions, increased in the first nine months of 2012 by 16.5 percent from the first nine months of 2011, from 113,724 MW to 132,494 MW. PJM average day-ahead load would have increased in the first nine months of 2012 by 10.7 percent from the first nine months of 2011, from 113,724 MW to 125,917 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison for the months in 2011 when they were not part of PJM. The day-ahead load growth was 179.7 percent higher than the real-time load growth as a result of the continued growth of up-to congestion transactions.
- PJM average real-time generation increased in the first nine months of 2012 by 3.9 percent from the first nine months of 2011, from 86,966 MW to 90,367 MW. PJM average real-time generation would have decreased in the first nine months of 2012 by 1.6 percent from the first nine months of 2011, from 86,966 MW to 85,532 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison for the months in 2011 when they were not part of PJM.
- PJM average day-ahead generation, including INCs and up-to congestion transactions, increased in the first nine months of 2012 by 15.6 percent from the first nine months of 2011, from 116,988 MW to 135,213 MW. PJM average day-ahead generation would have increased 11.5 percent from the first nine months of 2011, from 116,988 MW to 135,213 MW if the DEOK and ATSI transmission zones were excluded from the comparison for the months in 2011 when they were not part of PJM. The day-ahead generation growth was 300.0 percent higher than the real-time generation growth as a result of the continued growth of up-to congestion transactions.
- PJM Real-Time Energy Market prices decreased in the first nine months of 2012 compared to the first nine months of 2011. The load-weighted average LMP was 29.2 percent lower in the first nine months of 2012 than in the first nine months of 2011, $35.02 per MWh versus $49.48 per MWh.
- PJM Day-Ahead Energy Market prices decreased in the first nine months of 2012 compared to the first nine months of 2011. The load-weighted average LMP was 29.1 percent lower in the first nine months of 2012 than in the first nine months of 2011, $34.29 per MWh versus $48.34 per MWh.
- Based on average spot fuel prices, the fuel cost of a new entrant combined cycle unit ($19.54/MWh) was lower than the fuel cost of a new entrant coal plant ($19.83/MWh) in the first nine months of 2012.

4 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).

5 The ATSI Transmission Zone was excluded from this comparison and similar comparisons for the first 5 months of 2012 because it did not join PJM until June 1, 2011. The DEOK Transmission Zone was excluded from this comparison for all of the months of 2012 because it did not join PJM until January 1, 2012.

- Levels of offer capping for local market power remained low. In the first nine months of 2012, 1.6 percent of unit hours and 1.0 percent of MW were offer capped in the Real-Time Energy Market and 0.2 percent of unit hours and 0.2 percent of MW were offer capped in the Day-Ahead Energy Market.
- Of the 131 units that were eligible to include a Frequently Mitigated Unit (FMU) or Associated Unit (AU) adder in their cost-based offer during the first nine months of 2012, 44 (33.6 percent) qualified in all months, and 26 (19.9 percent) qualified in only one month of the first nine months of 2012.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in the first nine months of 2012, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand-side response programs, loads and prices.

Aggregate hourly real-time supply offered increased by 10,571 MW in the first nine months of 2012 compared to the first nine months of 2011, while aggregate peak load decreased by 3,672 MW, modifying the general supply demand balance with a corresponding impact on energy market prices. In the Day-Ahead Energy Market, average load in the first nine months of 2012 increased from the first nine months of 2011, from 113,724 MW to 132,494 MW, or 16.5 percent. In the Real-Time Energy Market, average load in the first nine months of 2012 increased from the first nine months of 2011, from 83,762 MW to 88,680 MW, or 5.9 percent. 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 in each hour. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price. Energy Market results for the first nine months of 2012 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.[6] 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.

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

6 The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.

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 the first nine months of 2012.

Market Structure

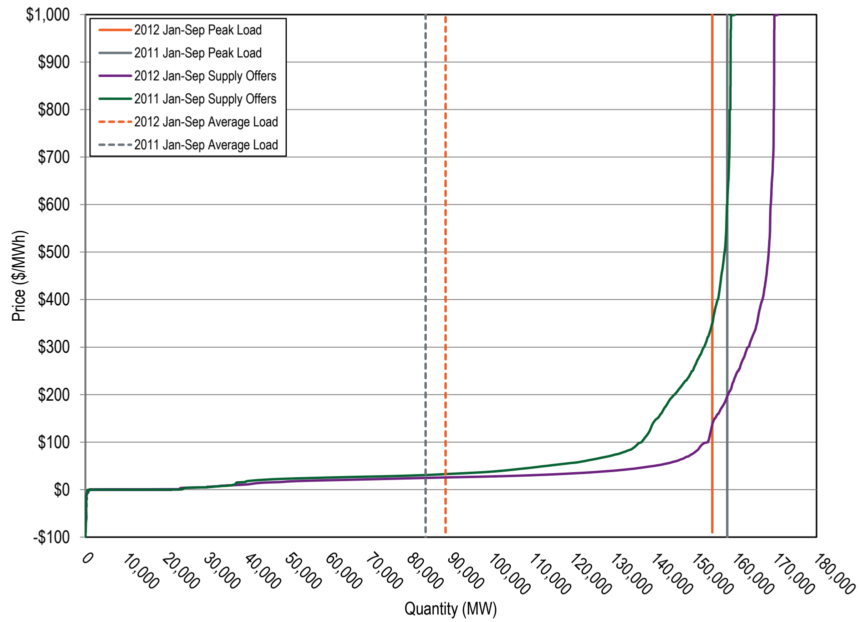
Supply

Average offered supply increased by 10,571 MW, or 6.6 percent, from 159,826 MW in the first nine months of 2011 to 170,397 MW in the first nine months of 2012.[7] The increase in offered supply was in part the result of the integration of the DEOK Transmission Zone in the first quarter of 2012 and the integration of the ATSI Transmission Zone in the second quarter of 2011. In addition, 1,898 MW of nameplate capacity were added to PJM in the first nine months of 2012. This includes six large plants (over 500 MW) that began generating in PJM between January 1, 2011, and September 30, 2012. The increases in supply were partially offset by the deactivation of 43 units (6,722 MW) since January 1, 2012.

7 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.

Figure 2-1 shows the average PJM aggregate supply curves, peak load and average load for the first nine months of 2011 and 2012.

Figure 2-1 Average PJM aggregate supply curves: January through September, 2011 and 2012 (See 2011 SOM, Figure 2-1)



Energy Production by Fuel Source

Compared to January through September, 2011, generation from coal units decreased 10.0 percent and generation from natural gas units increased 44.4 percent (Table 2-2). If the impact of the increased coal from the newly integrated ATSI and DEOK zones is eliminated, generation from coal units decreased 19.1 percent in the first three quarters of 2012 compared to the first three quarters of 2011.

Table 2-2 PJM generation (By fuel source (GWh)): January through September 2011 and 2012[8] (See 2011 SOM, Table 2-2)

	Jan-Sep 2011		Jan-Sep 2012		
	GWh	Percent	GWh	Percent	Change in Output
Coal	279,501.2	48.0%	251,591.7	41.8%	(10.0%)
Standard Coal	270,273.8	46.4%	244,258.0	40.5%	(9.3%)
Waste Coal	9,227.4	1.6%	7,333.6	1.2%	(0.7%)
Nuclear	195,196.7	33.5%	205,503.9	34.1%	5.3%
Gas	82,130.5	14.1%	118,328.2	19.6%	44.1%
Natural Gas	80,774.5	13.9%	116,649.9	19.4%	44.4%
Landfill Gas	1,355.9	0.2%	1,678.0	0.3%	23.8%
Biomass Gas	0.1	0.0%	0.4	0.0%	175.0%
Wind	7,924.5	1.4%	8,944.7	1.5%	12.9%
Hydroelectric	11,379.8	2.0%	9,768.1	1.6%	(14.2%)
Waste	4,254.8	0.7%	3,894.1	0.6%	(8.5%)
Solid Waste	3,318.0	0.6%	3,156.5	0.5%	(4.9%)
Miscellaneous	936.8	0.2%	737.6	0.1%	(21.3%)
Oil	2,207.7	0.4%	4,337.1	0.7%	96.5%
Heavy Oil	1,844.8	0.3%	4,122.7	0.7%	123.5%
Light Oil	334.3	0.1%	201.3	0.0%	(39.8%)
Diesel	15.9	0.0%	8.2	0.0%	(48.2%)
Kerosene	12.7	0.0%	4.9	0.0%	(61.8%)
Jet Oil	0.1	0.0%	0.0	0.0%	(29.1%)
Solar	37.9	0.0%	192.7	0.0%	408.7%
Battery	0.2	0.0%	0.2	0.0%	15.6%
Total	582,633.3	100.0%	602,560.9	100.0%	3.4%

Table 2-3 PJM Generation (By fuel source (GWh)): January through September 2011 and 2012; excluding ATSI and DEOK zones[9] (See 2011 SOM, Table 2-2)

	Jan-Sep 2011		Jan-Sep 2012		
	GWh	Percent	GWh	Percent	Change in Output
Coal	279,501.2	48.0%	226,139.4	39.8%	(19.1%)
Standard Coal	270,273.8	46.4%	218,805.8	38.5%	(18.4%)
Waste Coal	9,227.4	1.6%	7,333.6	1.3%	(0.7%)
Nuclear	195,196.7	33.5%	198,293.7	34.9%	1.6%
Gas	82,130.5	14.1%	116,771.4	20.5%	42.2%
Natural Gas	80,774.5	13.9%	115,161.1	20.3%	42.6%
Landfill Gas	1,355.9	0.2%	1,609.9	0.3%	18.7%
Biomass Gas	0.1	0.0%	0.4	0.0%	175.0%
Hydroelectric	11,379.8	2.0%	9,768.1	1.7%	(14.2%)
Wind	7,924.5	1.4%	8,944.7	1.6%	12.9%
Waste	4,254.8	0.7%	3,894.1	0.7%	(8.5%)
Solid Waste	3,318.0	0.6%	3,156.5	0.6%	(4.9%)
Miscellaneous	936.8	0.2%	737.6	0.1%	(21.3%)
Oil	2,207.7	0.4%	4,334.0	0.8%	96.3%
Heavy Oil	1,844.8	0.3%	4,122.7	0.7%	123.5%
Light Oil	334.3	0.1%	198.9	0.0%	(40.5%)
Diesel	15.9	0.0%	7.5	0.0%	(52.8%)
Kerosene	12.7	0.0%	4.9	0.0%	(61.8%)
Jet Oil	0.1	0.0%	0.0	0.0%	(29.1%)
Solar	37.9	0.0%	192.7	0.0%	408.7%
Battery	0.2	0.0%	0.2	0.0%	15.6%
Total	582,633.3	100.0%	568,338.3	100.0%	(2.5%)

Generator Offers

The generator offers are categorized by dispatchable and self-scheduled MW and are shown in Table 2-4 and Table 2-5.[10,11] Table 2-4 shows the average hourly distribution of MW for dispatchable units by offer prices for the first nine months of 2012. Table 2-5 shows the average hourly distribution of MW for self-scheduled units by offer prices for the first nine months of 2012. Of the dispatchable MW offered by combustion turbines (CT), 25.8 percent were dispatchable at an offered range of $600 to $800. Only wind and solar units have negative offer prices. Of all the MW offered, 74.1 percent are offered in

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

9 ATSI Zone is included only for the months of June through September 2011 and June through September 2012.

10 Each range in the tables is greater than or equal to the lower value and less than the higher value.

11 The unit type battery is not included in these tables because batteries do not make energy offers.

the $0 to $200 range, 42 percent are dispatchable and 32.1 percent are self scheduled.

Table 2-4 Distribution of MW for dispatchable unit offer prices: January through September of 2012 (See 2011 SOM, Table 2-3)

	Dispatchable (Range)						
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Total
CC	0.0%	60.6%	11.7%	3.0%	4.6%	1.2%	81.1%
CT	0.0%	44.1%	15.5%	10.8%	25.8%	3.3%	99.5%
Diesel	0.0%	7.6%	56.9%	7.0%	1.2%	0.8%	73.5%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	10.0%	0.0%	0.0%	0.0%	0.0%	10.0%
Pumped Storage	0.0%	52.7%	0.0%	0.0%	0.0%	0.0%	52.7%
Solar	0.0%	56.9%	0.0%	0.0%	0.0%	0.0%	56.9%
Steam	0.0%	49.5%	11.2%	0.5%	0.1%	0.1%	61.4%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	23.8%	28.1%	0.0%	0.0%	0.0%	0.0%	51.8%
All Dispatchable Offers	0.5%	42.0%	9.8%	2.9%	6.1%	0.9%	62.1%

Table 2-5 Distribution of MW for self-scheduled unit offer prices: January through September of 2012 (See 2011 SOM, Table 2-3)

	Self-Scheduled (Range)						
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Total
CC	0.0%	17.9%	0.8%	0.0%	0.0%	0.2%	18.9%
CT	0.0%	0.4%	0.0%	0.0%	0.0%	0.1%	0.5%
Diesel	0.0%	26.3%	0.1%	0.0%	0.0%	0.2%	26.5%
Hydro	0.0%	99.0%	0.0%	0.0%	0.0%	1.0%	100.0%
Nuclear	0.0%	90.0%	0.0%	0.0%	0.0%	0.0%	90.0%
Pumped Storage	0.0%	47.3%	0.0%	0.0%	0.0%	0.0%	47.3%
Solar	20.5%	22.6%	0.0%	0.0%	0.0%	0.0%	43.1%
Steam	0.0%	26.0%	12.1%	0.0%	0.4%	0.1%	38.6%
Transaction	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Wind	10.0%	38.2%	0.0%	0.0%	0.0%	0.0%	48.2%
All Self-Scheduled Offers	0.2%	32.1%	5.3%	0.0%	0.2%	0.1%	37.9%

Demand

The PJM system peak load for the first nine months of 2012 was 154,344 MW in the HE 1700 on July 17, 2012, which was 3,672 MW, or 2.3 percent, lower than the PJM peak load for the first nine months of 2011, which was 158,016 MW in the HE 1700 on July 21, 2011. The DEOK Transmission Zone accounted for 5,360 MW in the peak hour of the first nine months of 2012. The peak load excluding the DEOK Transmission Zone was 148,984 MW, also occurring on July 17, 2012, HE 1700, a decrease of 9,032 MW, or 5.7 percent, from the first nine months 2011 peak load.

Table 2-6 shows the coincident peak loads for the first nine months of years 2003 through 2012.

Table 2-6 Actual[12,13] PJM footprint peak loads: January through September of 2003 to 2012 (See 2011 SOM, Table 2-4)

(Jan - Sep)	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
2003	Fri, August 22	16	61,499	NA	NA
2004	Tue, August 03	17	77,887	16,387	26.6%
2005	Tue, July 26	16	133,761	55,875	71.7%
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	Thu, July 21	17	158,016	21,556	15.8%
2012 (with DEOK)	Tue, July 17	17	154,344	(3,672)	(2.3%)
2012 (without DEOK)	Tue, July 17	17	148,984	(9,032)	(5.7%)

Figure 2-2 shows the peak loads for the first nine months of years 2003 through 2012.

Figure 2-2 PJM[14] footprint first nine months peak loads: 2003 to 2012 (See 2011 SOM, Figure 2-2)

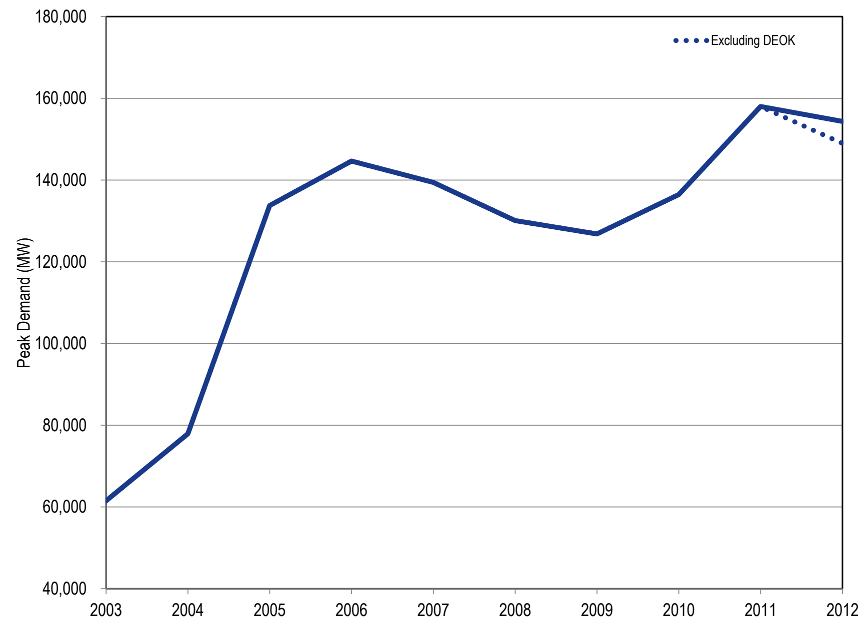


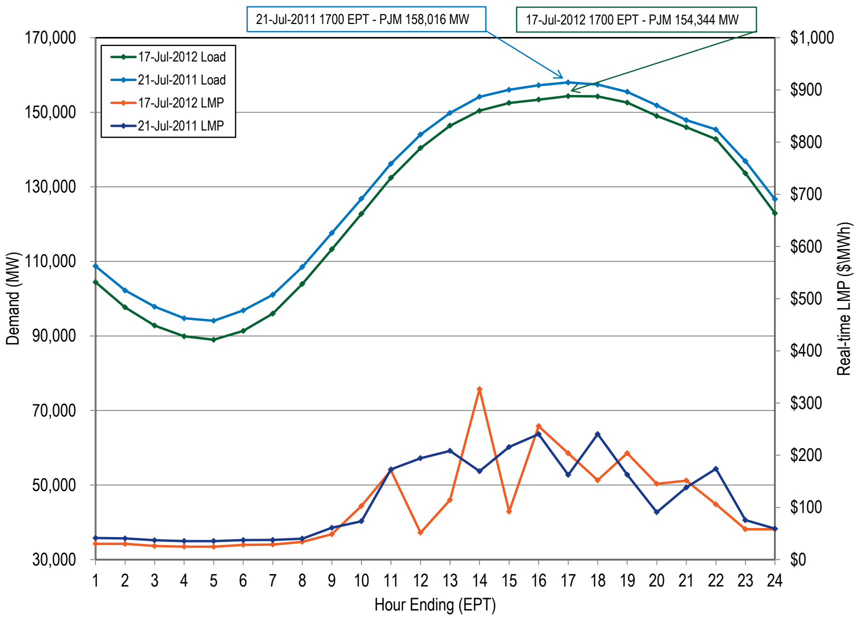
Figure 2-3 compares the peak load days in the first nine months of 2011 and 2012. In every hour on July 21, 2011, the average hourly real-time load was higher than the average hourly real-time load on July 17, 2012. The average hourly real-time LMP peaked at $326.72 on July 17, 2012 and peaked at $240.42 on July 21, 2011.

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 The ATSI Transmission Zone was excluded from this comparison and similar comparisons for the first 5 months of 2012 because it did not join PJM until June 1, 2011. The DEOK Transmission Zone was excluded from this comparison for all of the months of 2012 because it did not join PJM until January 1, 2012.

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

Figure 2-3 PJM peak-load comparison: Tuesday, July 17, 2012, and Thursday, July 21, 2011 (See 2011 SOM, Figure 2-3)



Market Concentration

Analyses of supply curve segments of the PJM Energy Market for the first nine months of 2012 indicate moderate concentration in the base load segment, but high concentration in the intermediate and peaking segments.[15] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal during high demand periods. When transmission constraints exist, local markets are created with ownership that is typically significantly more concentrated than the overall Energy Market. PJM offer-capping rules that limit the exercise of local market power and generation owners' obligations to serve load were generally effective in preventing the exercise of market power in these areas during the first nine months of 2012. 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.

Hourly PJM Energy Market HHIs were calculated based on the real-time energy output of generators, adjusted for hourly net imports by owner (Table 2-7).

Hourly Energy Market HHIs by supply curve segment were calculated based on hourly Energy Market shares, unadjusted for imports.

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during the first nine months of 2012 was moderately concentrated (Table 2-7).

Table 2-7 PJM hourly Energy Market HHI: January through September 2011[16] and 2012 (See 2011 SOM, Table 2-5)

	Hourly Market HHI (Jan - Sep, 2011)	Hourly Market HHI (Jan - Sep, 2012)
Average	1200	1234
Minimum	889	927
Maximum	1564	1657
Highest market share (One hour)	30%	32%
Average of the highest hourly market share	21%	23%
# Hours	6,551	6,575
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 2-8 includes 2012 HHI values by supply curve segment, including base, intermediate and peaking plants.

15 A unit is classified as base load if it runs for more than 50 percent of the total hours, as intermediate if it runs for less than 50 percent but greater than 10 percent of the total hours, and as peak if it runs for less than 10 percent of the total hours.

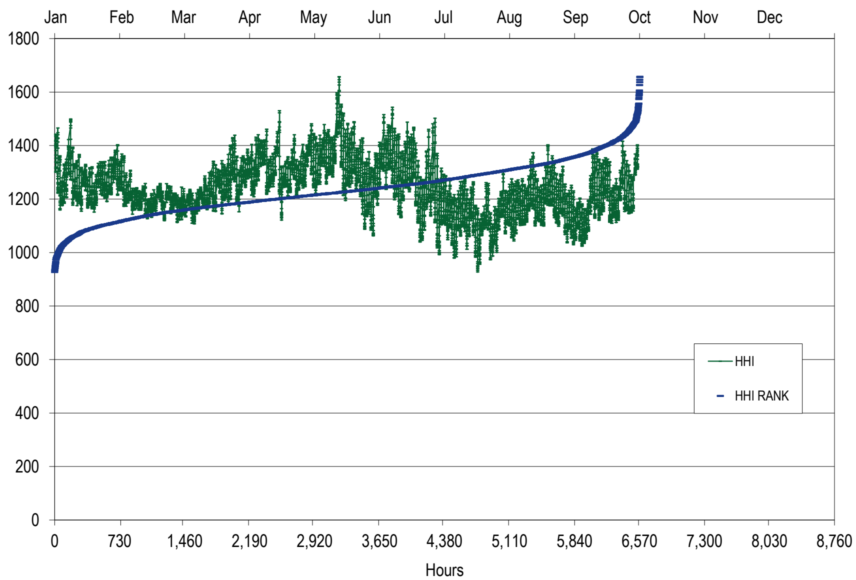
16 This analysis includes all hours in the first nine months of 2012, regardless of congestion.

Table 2-8 PJM hourly Energy Market HHI (By supply segment): January through September 2011 and 2012 (See 2011 SOM, Table 2-6)

	Jan - Sep, 2011			Jan - Sep, 2012		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	1035	1219	1529	1082	1268	1691
Intermediate	842	2801	9467	849	1919	8301
Peak	613	5720	10000	619	5699	10000

Figure 2-4 presents the 2012 hourly HHI values in chronological order and an HHI duration curve.

Figure 2-4 PJM hourly Energy Market HHI: January through September 2012 (See 2011 SOM, Figure 2-4)



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.

Levels of offer capping have historically been low in PJM, as shown in Table 2-9.

Table 2-9 Offer-capping statistics: January through September from 2008 to 2012 (See 2011 SOM, Table 2-7)

	Real Time		Day Ahead	
(Jan - Sep)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2008	1.0%	0.2%	0.2%	0.0%
2009	0.5%	0.1%	0.1%	0.0%
2010	1.2%	0.3%	0.3%	0.1%
2011	0.9%	0.3%	0.1%	0.0%
2012	1.6%	1.0%	0.2%	0.2%

Table 2-10 presents data on the frequency with which units were offer capped in the first nine months of 2011 and 2012.

Table 2-10 Real-time offer-capped unit statistics: January through September 2012 (See 2011 SOM, Table 2-8)

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	(Jan - Sep)	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2012	0	0	1	0	1	1
	2011	0	0	0	4	9	5
80% and < 90%	2012	0	2	0	0	2	4
	2011	0	0	1	1	4	9
75% and < 80%	2012	0	0	0	0	2	0
	2011	0	0	0	0	3	3
70% and < 75%	2012	1	0	0	0	0	4
	2011	0	0	0	0	2	6
60% and < 70%	2012	1	0	0	1	1	8
	2011	0	1	0	1	1	23
50% and < 60%	2012	5	0	1	0	1	9
	2011	0	0	0	1	10	24
25% and < 50%	2012	12	1	2	1	8	42
	2011	1	0	0	3	14	77
10% and < 25%	2012	1	2	0	5	3	55
	2011	5	1	1	1	1	51

Table 2-10 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.

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

Local Market Structure

In the first nine months of 2012, the AEP, AP, ATSI, BGE, ComEd, DEOK, DLCO, Dominion, DPL, Met-Ed, Pepco and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 75 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 the first nine months of 2012.[17] The AECO, DAY, JCPL, PECO, PENELEC, PPL and RECO Control Zones were not affected by constraints binding for 75 or more hours.

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, 2012, through September 30, 2012. 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.

Table 2-11 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.

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

Table 2-11 Three pivotal supplier results summary for regional constraints: January through September 2012 (See 2011 SOM, Table 2-9)

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	2,058	489	24%	1,805	88%
	Off Peak	1,021	525	51%	715	70%
AEP-DOM	Peak	824	32	4%	815	99%
	Off Peak	437	24	5%	429	98%
AP South	Peak	3,167	405	13%	3,045	96%
	Off Peak	1,525	249	16%	1,456	95%
Bedington - Black Oak	Peak	1,074	169	16%	1,007	94%
	Off Peak	282	38	13%	270	96%
Central	Peak	27	6	22%	26	96%
	Off Peak	NA	NA	NA	NA	NA
Eastern	Peak	160	69	43%	107	67%
	Off Peak	NA	NA	NA	NA	NA
Western	Peak	528	114	22%	470	89%
	Off Peak	39	14	36%	31	79%

Table 2-12 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the regional 500 kV constraints.

Table 2-12 Three pivotal supplier test details for regional constraints: January through September 2012 (See 2011 SOM, Table 2-10)

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	332	484	16	4	13
	Off Peak	247	478	16	8	9
AEP-DOM	Peak	276	373	8	0	8
	Off Peak	214	353	9	0	8
AP South	Peak	376	557	11	1	10
	Off Peak	364	583	12	1	10
Bedington - Black Oak	Peak	93	133	10	1	9
	Off Peak	114	102	9	1	8
Central	Peak	347	451	15	2	13
	Off Peak	NA	NA	NA	NA	NA
Eastern	Peak	426	656	15	8	7
	Off Peak	NA	NA	NA	NA	NA
Western	Peak	754	837	17	4	13
	Off Peak	849	976	15	5	10

Table 2-13 provides, for the identified seven 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 2-13 Summary of three pivotal supplier tests applied for regional constraints: January through September 2012 (See 2011 SOM, Table 2-11)

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	2,058	104	5%	25	1%	24%
	Off Peak	1,021	21	2%	3	0%	14%
AEP-DOM	Peak	824	49	6%	26	3%	53%
	Off Peak	437	22	5%	18	4%	82%
AP South	Peak	3,167	77	2%	15	0%	19%
	Off Peak	1,525	24	2%	5	0%	21%
Bedington - Black Oak	Peak	1,074	36	3%	3	0%	8%
	Off Peak	282	8	3%	0	0%	0%
Central	Peak	27	0	0%	0	0%	0%
	Off Peak	NA	NA	NA	NA	NA	NA
Eastern	Peak	160	9	6%	4	3%	44%
	Off Peak	NA	NA	NA	NA	NA	NA
Western	Peak	528	47	9%	11	2%	23%
	Off Peak	39	6	15%	0	0%	0%

Ownership of Marginal Resources

Table 2-14 shows the contribution to PJM real-time, annual, load-weighted LMP by individual marginal resource owner.[18] The contribution of each marginal resource to price at each load bus is calculated for January through September, 2012, and summed by the company that offers the marginal resource into the Real-Time Energy Market. The results show that, during the first nine months of 2012, the offers of one company contributed 21 percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies contributed 51 percent of the real-time, load-weighted, average PJM system LMP.

Table 2-14 Marginal unit contribution to PJM real-time, load-weighted LMP (By parent company): January through September 2012 (See 2011 SOM, Table 2-12)

Company	Percent of Price
1	21%
2	13%
3	8%
4	8%
5	8%
6	6%
7	6%
8	5%
9	4%
Other (54 companies)	20%

Table 2-15 shows the contribution to PJM day-ahead, load-weighted LMP by individual marginal resource owner.[19] The contribution of each marginal resource to price at each load bus is calculated for the January through

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

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

September, 2012, period and summed by the company that offers the marginal resource into the Day-Ahead Energy Market.

Table 2-15 Marginal unit contribution to PJM day-ahead, load-weighted LMP (By parent company): January through September, 2012 (See 2011 SOM, Table 2-13)

Company	Percent of Price
1	15%
2	11%
3	7%
4	6%
5	5%
6	5%
7	5%
8	4%
9	4%
Other (132 companies)	40%

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 up-to congestion transactions are dispatchable injections and withdrawals in the Day-Ahead Market that can set price via their offers and bids.

Table 2-16 shows the type of fuel used by marginal resources in the Real-Time Energy Market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In the first nine months of 2012, coal units were 58 percent and natural gas units were 31 percent of the total marginal resources.

Table 2-16 Type of fuel used (By real-time marginal units): January through September, 2012 (See 2011 SOM, Table 2-14)

Fuel Type	Jan - Sep, 2012
Coal	58%
Gas	31%
Municipal Waste	0%
Oil	6%
Other	1%
Uranium	0%
Wind	4%

Table 2-17 shows the type, and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In the first nine months of 2012, Up-to Congestion transactions were 87 percent of the total marginal resources.

Table 2-17 Day-ahead marginal resources by type/fuel: January through September, 2012 (See 2011 SOM, Table 2-15)

Type/Fuel	Jan - Sep, 2012
Up-to Congestion Transaction	87%
DEC	5%
INC	4%
Coal	2%
Gas	1%
Dispatchable Transaction	0%
Price Sensitive Demand	0%
Oil	0%
Wind	0%
Diesel	0%
Municipal Waste	0%
Total	100%

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.[20] 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

20 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00), the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost.

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 2-18 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 dispatch solution associated with the interval in which it was marginal, based on its offer price at that time. The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point.

Table 2-18 Average, real-time marginal unit markup index (By offer price category): January through September (See 2011 SOM, Table 2-16)

Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.08)	($3.01)	30.8%
$25 to $50	(0.04)	($2.07)	48.6%
$50 to $75	0.06	$2.27	4.4%
$75 to $100	0.33	$29.22	0.6%
$100 to $125	0.21	$21.35	0.6%
$125 to $150	0.17	$23.44	0.3%
>= $150	0.04	$9.65	5.5%

Day-Ahead Mark Up Conduct

Table 2-19 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 2-19 Average marginal unit markup index (By offer price category): January through September, 2012 (See 2011 SOM, Table 2-17)

Offer Price Category	Average Markup Index	Average Dollar Markup	Freqency
< $25	(0.09)	($3.00)	32.2%
$25 to $50	(0.05)	($2.58)	64.2%
$50 to $75	0.09	$4.13	3.1%
$75 to $100	0.45	$36.25	0.2%
$100 to $125	0.00	$0.00	0.0%
$125 to $150	0.04	$4.99	0.1%
>= $150	0.03	$4.84	0.2%

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.[21]

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

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

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 2-20 shows the annual average unit markup component of LMP for marginal units, by unit type and primary fuel. The markup component of LMP is a measure of the impact of the markups of marginal units shown in Table 2-18 on the system-wide load-weighted LMP. The negative markup components of LMP reflect the negative markups shown in the Table 2-18.

Table 2-20 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type[22]: January through September 2012 (See 2011 SOM, Table 2-18)

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($1.60)	343.2%
Gas	CC	$0.89	(191.3%)
Gas	CT	$0.32	(68.9%)
Gas	Diesel	$0.03	(6.6%)
Gas	Steam	($0.03)	7.1%
Municipal Waste	Diesel	$0.00	0.0%
Municipal Waste	Steam	$0.02	(5.0%)
Oil	CT	$0.01	(2.9%)
Oil	Diesel	$0.01	(1.7%)
Oil	Steam	($0.12)	24.8%
Other	Solar	$0.00	(0.0%)
Uranium	Steam	$0.00	0.0%
Wind	Wind	($0.01)	1.3%
Total		($0.47)	100.0%

Markup Component of Real-Time System Price

Table 2-21 shows the markup component of average prices and of average monthly on-peak and off-peak prices. In the first nine months of 2012, -$0.47 per MWh of the PJM real-time, load-weighted average LMP was attributable to markup. In first nine months of 2012, the markup component of LMP was -$2.27 per MWh off peak and $1.22 per MWh on peak.

Table 2-21 Monthly markup components of real-time load-weighted LMP: January through September 2012 (See 2011 SOM, Table 2-19)

	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($2.49)	($2.53)	($2.46)
Feb	($1.95)	($2.74)	($1.19)
Mar	($1.26)	($1.85)	($0.72)
Apr	($2.56)	($3.38)	($1.78)
May	$0.25	($2.63)	$2.85
Jun	($1.67)	($2.73)	($0.73)
Jul	$4.21	($1.55)	$9.66
Aug	($0.00)	($1.90)	$1.49
Sep	($0.14)	($1.40)	$1.24
Total	($0.47)	($2.27)	$1.22

22 The Unit Type Diesel refers to power generation using reciprocating internal combustion engines. Such Diesel units can use a variety of fuel types including diesel, natural gas, oil and municipal waste.

Markup Component of Real-Time Zonal Prices

The annual average real-time price component of unit markup is shown for each zone in Table 2-22. The smallest zonal all hours average markup component for the first nine months of 2012 was in the PPL Control Zone, -$0.79 per MWh, while the highest all hours' average zonal markup component for the first nine months of 2012 was in the Pepco Control Zone, $0.21 per MWh. Off peak, the smallest average zonal markup for the first nine months of 2012 was in the ATSI Control Zone, -$2.58 per MWh, while the highest annual average zonal markup was in the BGE Control Zone, -$1.74 per MWh. On peak, the smallest annual average zonal markup was in the PPL Control Zone, $0.71 per MWh, while the highest annual average zonal markup was in the Pepco Control Zone, $2.11 per MWh.

Table 2-22 Average real-time zonal markup component: January through September 2012 (See 2011 SOM, Table 2-20)

	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	($0.27)	($2.03)	$1.42
AEP	($0.78)	($2.36)	$0.75
AP	($0.57)	($2.36)	$1.13
ATSI	($0.77)	($2.58)	$0.92
BGE	($0.12)	($1.74)	$1.42
ComEd	($0.54)	($2.35)	$1.13
DAY	($0.74)	($2.49)	$0.88
DEOK	($0.68)	($2.39)	$0.94
Dominion	$0.06	($1.89)	$1.90
DPL	($0.57)	($2.49)	$1.27
DLCO	($0.48)	($2.42)	$1.34
JCPL	$0.02	($2.23)	$2.05
Met-Ed	($0.71)	($2.44)	$0.88
PECO	($0.42)	($2.12)	$1.17
PENELEC	($0.75)	($2.58)	$0.95
Pepco	$0.21	($1.86)	$2.11
PPL	($0.79)	($2.40)	$0.71
PSEG	($0.27)	($2.30)	$1.58
RECO	($0.04)	($2.35)	$1.93

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 2-23 shows the average markup component of observed prices when the PJM system LMP was in the identified price range.

Table 2-23 Average real-time markup component (By LMP category): January through September 2012 (See 2011 SOM, Table 2-21)

LMP Category	Average Markup Component	Frequency
< $25	($0.74)	27.9%
$25 to $50	($1.52)	61.7%
$50 to $75	$0.47	4.4%
$75 to $100	$0.33	1.4%
$100 to $125	$0.20	0.7%
$125 to $150	$0.17	0.3%
>= $150	$0.63	0.6%

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 2-24.

Table 2-24 Markup component of the overall PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through September, 2012 (See 2011 SOM, Table 2-22)

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($1.68)	89.9%
Diesel	Diesel	$0.00	0.0%
Gas	CT	$0.09	(4.6%)
Gas	Diesel	$0.00	0.0%
Gas	Steam	($0.20)	10.5%
Municipal Waste	Steam	($0.00)	0.1%
Oil	Steam	($0.08)	4.0%
Wind	Wind	$0.00	0.0%
Total		($1.87)	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 2-25 shows the markup component of average prices and of average monthly on-peak and off-peak prices.

Table 2-25 Monthly markup components of day-ahead, load-weighted LMP: January through September, 2012 (See 2011 SOM, Table 2-23)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($2.77)	($2.22)	($3.30)
Feb	($3.04)	($3.66)	($2.39)
Mar	($2.29)	($2.00)	($2.61)
Apr	($2.67)	($2.36)	($2.99)
May	($1.51)	($1.11)	($1.95)
Jun	($1.94)	($1.11)	($2.89)
Jul	$0.41	$2.73	($2.07)
Aug	($1.86)	($0.96)	($3.04)
Sep	($1.75)	($1.37)	($2.11)
Total	($1.87)	($1.19)	($2.59)

Markup Component of Day-Ahead Zonal Prices

The annual average price component of unit markup is shown for each zone in Table 2-26.

Table 2-26 Day-ahead, average, zonal markup component: January through September, 2012 (See 2011 SOM, Table 2-24)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($1.49)	($0.57)	($2.49)
AEP	($1.95)	($1.35)	($2.58)
AP	($1.81)	($1.34)	($2.32)
ATSI	($1.99)	($1.42)	($2.62)
BGE	($1.86)	($1.22)	($2.55)
ComEd	($1.83)	($1.30)	($2.41)
DAY	($1.89)	($1.24)	($2.60)
DEOK	($1.83)	($1.22)	($2.48)
DLCO	($1.76)	($1.11)	($2.48)
Dominion	($1.80)	($1.07)	($2.58)
DPL	($1.61)	($0.77)	($2.50)
JCPL	($1.45)	($0.55)	($2.48)
Met-Ed	($1.82)	($1.08)	($2.64)
PECO	($1.68)	($0.97)	($2.45)
PENELEC	($2.14)	($1.68)	($2.63)
Pepco	($1.89)	($1.32)	($2.49)
PPL	($2.07)	($1.49)	($2.72)
PSEG	($1.54)	($0.53)	($2.69)
RECO	($1.47)	($0.52)	($2.61)

Markup by Day-Ahead System Price Levels

The annual average markup component of the identified price range and its frequency are shown in Table 2-27.

Table 2-27 shows the average markup component of observed price when the PJM day-ahead, system LMP was in the identified price range.

Table 2-27 Average, day-ahead markup (By LMP category): January through September, 2012 (See 2011 SOM, Table 2-25)

LMP Category	Average Markup Component	Frequency
< $25	($3.42)	25%
$25 to $50	($2.77)	71%
$50 to $75	$2.51	3%
$75 to $100	$6.96	1%
$100 to $125	$18.93	0%
$125 to $150	$4.54	0%
>= $150	$19.06	0%

Frequently Mitigated Units and Associated Units

An FMU is a frequently mitigated unit. FMU designations were created to provide additional compensation as a form of scarcity pricing in 2005.[23] 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.[24] These categories are designated Tier 1, Tier 2 and Tier 3, respectively.[25,26]

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.

23 110 FERC ¶ 61,053 (2005).
24 OA, Schedule 1 § 6.4.2.
25 114 FERC ¶ 61, 076 (2006).
26 See "Settlement Agreement," Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).

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.[27]

Table 2-28 shows the number of FMUs and AUs in the first nine months of 2011 and 2012. For example, in June 2012, there were 22 FMUs and AUs in Tier 1, 13 FMUs and AUs in Tier 2, and 48 FMUs and AUs in Tier 3.

Table 2-28 Number of frequently mitigated units and associated units (By month): January through September, 2012 (See 2011 SOM, Table 2-26)

	FMUs and AUs							
	2011				2012			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	46	22	66	134	26	21	52	99
February	34	43	60	137	26	22	47	95
March	30	46	66	142	25	17	47	89
April	34	45	62	141	23	17	46	86
May	37	48	59	144	23	14	47	84
June	31	50	61	142	22	13	48	83
July	45	32	43	120	25	11	50	86
August	33	14	44	91	25	23	43	91
September	18	19	55	92	17	6	33	56
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.

27 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 September, 2012 (See 2011 SOM, Figure 2-5)

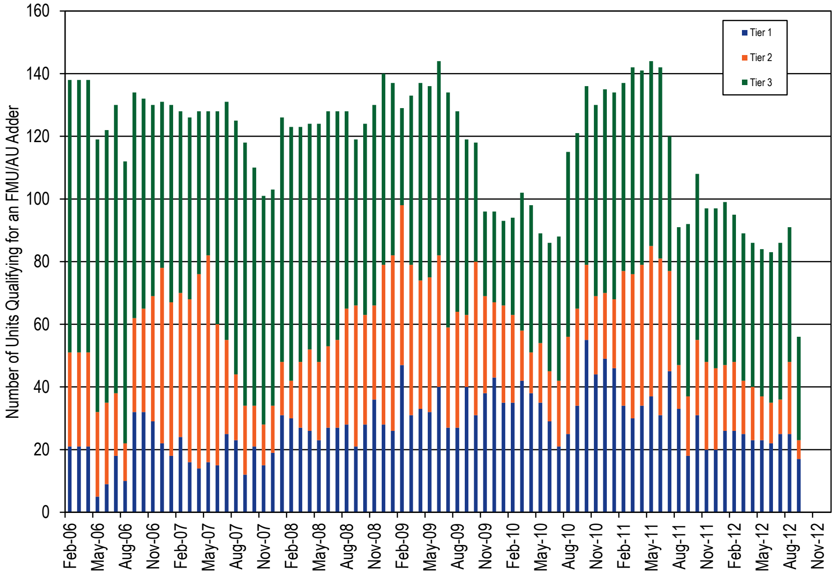


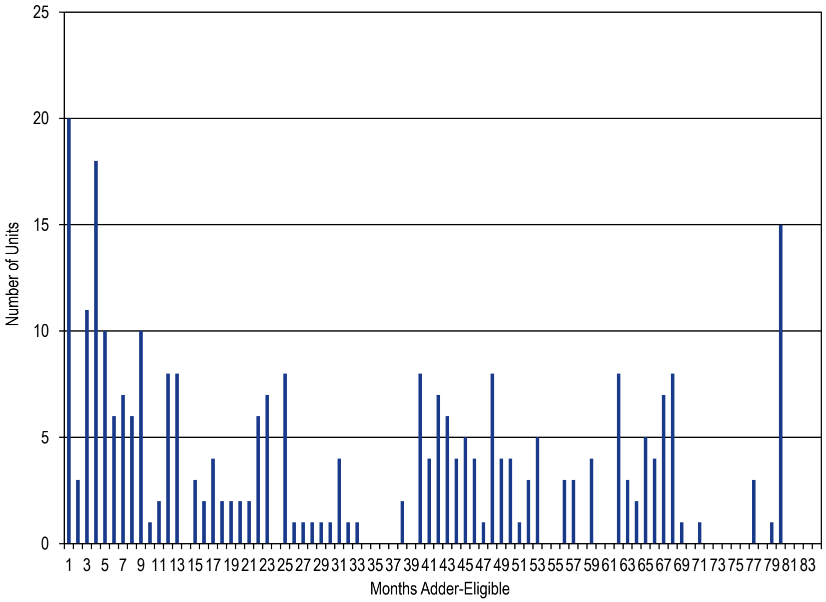
Table 2-29 shows the number of months FMUs and AUs that were eligible for any adder (Tier 1, Tier 2 or Tier 3) during the first nine months of 2011 and 2012. Of the 131 units eligible in at least one month during the first nine months of 2012, 44 units (33.6 percent) were FMUs or AUs for all nine months, and 26 (19.9 percent) qualified in only one month of 2012.

Table 2-29 Frequently mitigated units and associated units total months eligible: January through September, 2011 and 2012 (See 2011 SOM, Table 2-27)

Months Adder-Eligible	FMU & AU Count	
	2011	2012
1	20	26
2	5	11
3	7	5
4	2	9
5	8	2
6	30	2
7	26	14
8	20	18
9	58	44
Total	176	131

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 September 30, 2012, there have been 293 unique units that have qualified for an FMU adder in at least one month. Of these 293 units, no unit qualified for an adder in all potential months. Fifteen units qualified in 80 of the 81 possible months, and 132 of the 293 units (45.1 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 September, 2012 (See 2011 SOM, Figure 2-6)



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

PJM average real-time load in the first nine months of 2012 increased by 5.9 percent from the nine six months of 2011, from 83,762 MW to 88,680 MW. The PJM average real-time load in the first nine months of 2012 would have decreased by 0.9 percent from the first nine months of 2011, from 83,762 MW to 86,680 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison for the months in 2011 when they were not part of PJM. [28]

PJM average day-ahead load, including DECs and up-to congestion transactions, in the first nine months of 2012 increased by 16.5 percent from the first nine months of 2011, from 113,724 MW to 132,494 MW. PJM average day-ahead load in the first nine months of 2012, including DECs and up-to congestion transactions, would have increased by 10.7 percent from the first nine months of 2011, from 113,724 MW 125,917 MW if the DEOK and ATSI Transmission Zones were excluded from the comparison for the months in 2011 when they were not part of PJM.

The day-ahead load growth was 179.7 percent higher than the real-time load growth because of the continued growth of up-to congestion transactions. If up-to congestion transactions had not grown in the first nine months of 2012 compared to the first nine months of 2011, the day-ahead load, including DECs and up-to congestion transactions, would have increased 1.8 percent instead of 16.5 percent. The day-ahead load growth would have been 69.5 percent lower than the real-time load growth.

Real-Time Load

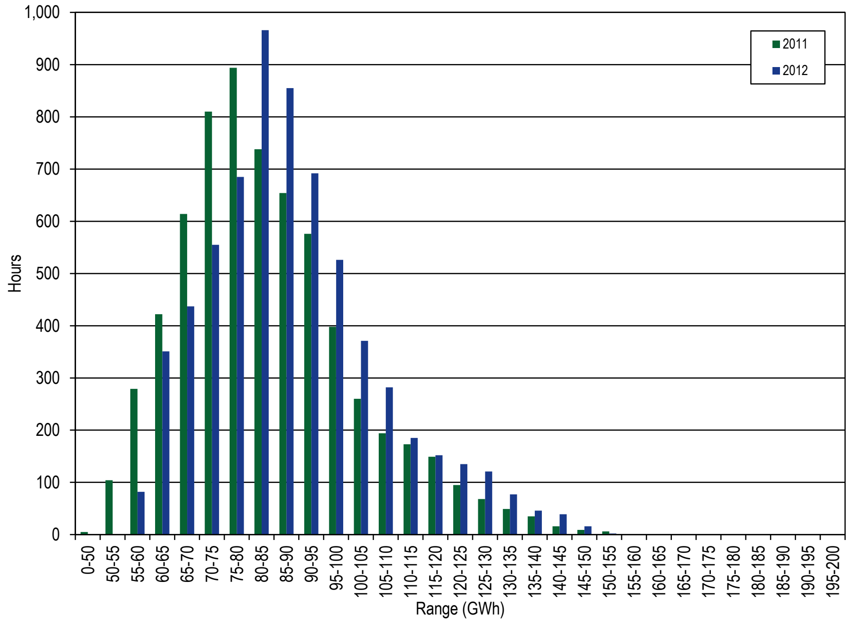
PJM Real-Time Load Duration

Figure 2-7 shows the hourly distribution of PJM real-time load for the first nine months of 2011 and 2012.[29]

28 The ATSI Transmission Zone was excluded from year to year comparisons for the first 5 months of 2012 because it did not join PJM until June 1, 2011. The DEOK Transmission Zone was excluded from this comparison for all of the months of 2012 because it did not join PJM until January 1, 2012.

29 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: January through September for years 2011 and 2012[30] (See 2011 SOM, Figure 2-7)



PJM Real-Time, Average Load

Table 2-30 presents summary real-time load statistics for the first nine months for the 15 year period 1998 to 2012. 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.[31]

Table 2-30 PJM real-time average hourly load: January through September for years 1998 through 2012[32] (See 2011 SOM, Table 2-28)

	PJM Real-Time Load (MWh)		Year-to-Year Change	
(Jan-Sep)	Average Load	Load Standard Deviation	Average Load	Load Standard Deviation
1998	29,112	5,780	NA	NA
1999	30,236	6,306	3.9%	9.1%
2000	30,266	5,765	0.1%	(8.6%)
2001	31,060	6,156	2.6%	6.8%
2002	35,715	8,688	15.0%	41.1%
2003	37,996	7,187	6.4%	(17.3%)
2004	45,294	10,512	19.2%	46.3%
2005	78,235	17,541	72.7%	66.9%
2006	80,717	15,568	3.2%	(11.2%)
2007	83,114	15,386	3.0%	(1.2%)
2008	80,611	14,389	(3.0%)	(6.5%)
2009	76,954	13,879	(4.5%)	(3.5%)
2010	81,068	16,209	5.3%	16.8%
2011	83,762	17,604	3.3%	8.6%
2012	88,680	17,432	5.9%	(1.0%)

30 Each range on the vertical axis includes the start value and excludes the end value.
31 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.

32 The version of this table in the *2012 Q1 State of the Market Report for PJM* incorrectly reported the standard deviation.

PJM Real-Time, Monthly Average Load

Figure 2-8 compares the real-time, monthly average hourly loads in the first nine months of 2012 with those in 2011.

Figure 2-8 PJM real-time monthly average hourly load: 2011 through September of 2012 (See 2011 SOM, Figure 2-8)

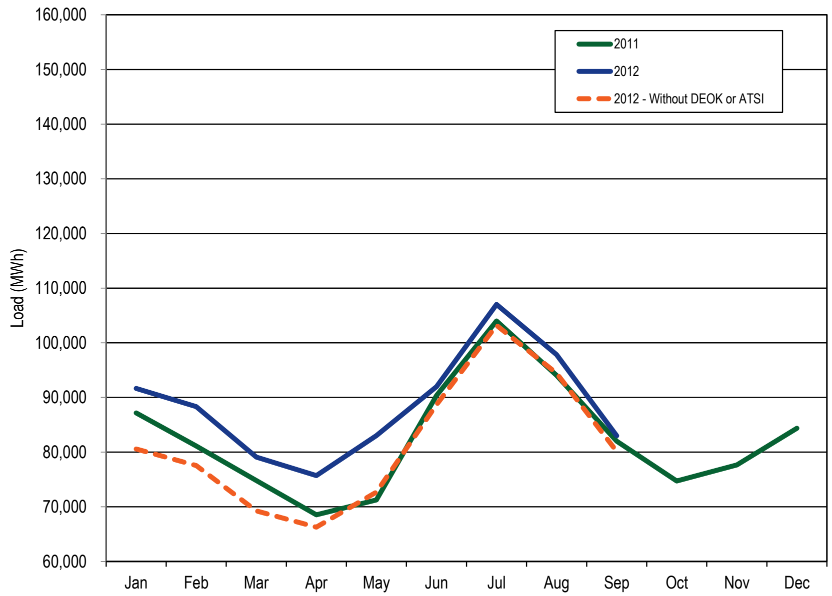


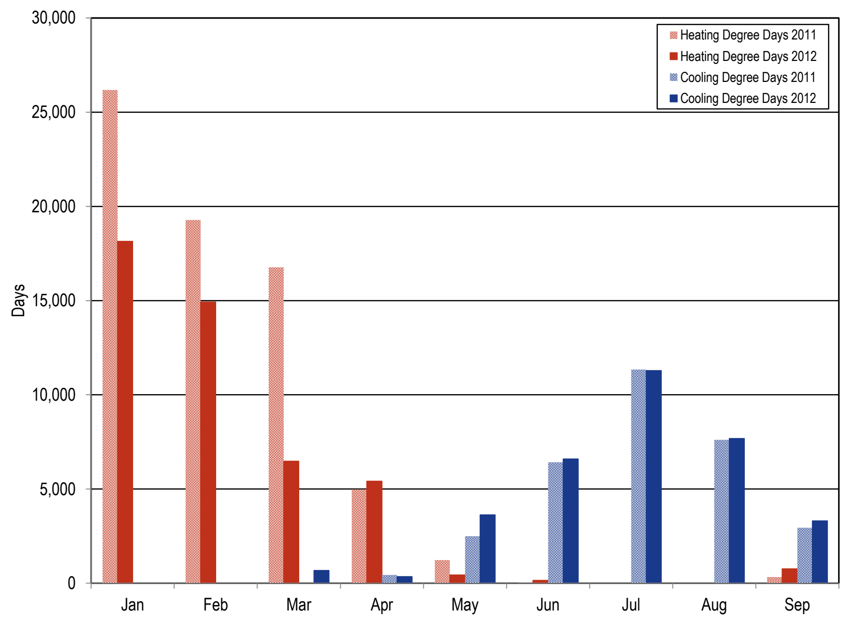
Table 2-31 shows the load weighted THI, WWP and average temperature for heating, cooling and shoulder seasons.[33]

Table 2-31 PJM annual Summer THI, Winter WWP and average temperature (Degrees F): cooling, heating and shoulder months of 2007 through June of 2012 (See 2011 SOM, Table 2-30)

	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	24.28	57.22
2011	70.80	27.08	52.23
2012	70.22	36.06	58.40

Figure 2-9 compares the total PJM monthly heating and cooling degree days in the first nine months of 2012 with those in 2011.

Figure 2-9 PJM Heating and Cooling Degree Days for January through September for 2011 and 2012



33 The Summer THI is calculated by taking average of daily maximum THI in June, July, August and September. The Winter WWP is calculated by taking average of daily minimum WWP in January and February (December of each year is not included). 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 20 (June 28, 2012), Section 3, pp. 15-16. Load weighting using real-time zonal accounting load.

Day-Ahead Load

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

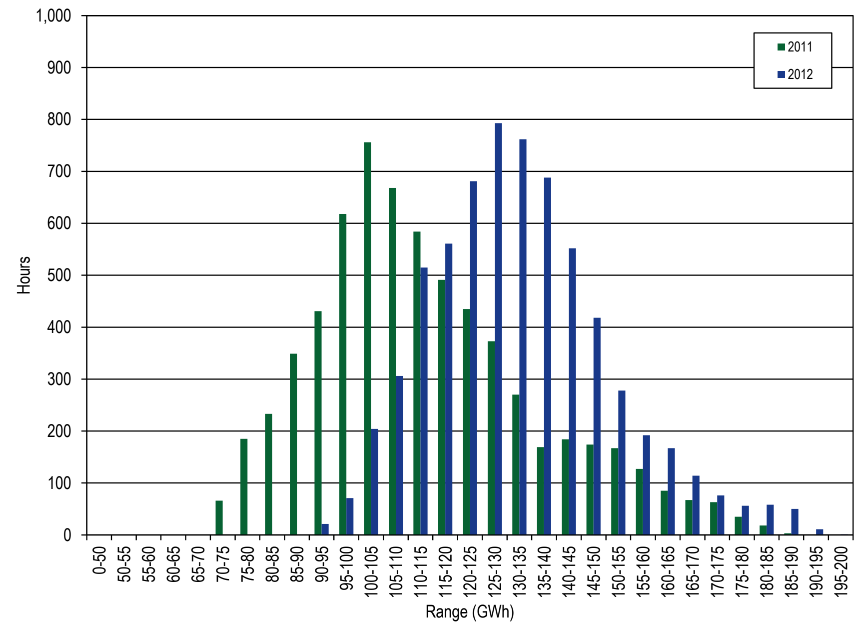
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** financial bid to purchase a defined MWh level of 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.[34] 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 four types of cleared demand bids.[35]

PJM Day-Ahead Load Duration

Figure 2-10 shows the hourly distribution of PJM day-ahead load for the first nine months of 2011 and 2012.

Figure 2-10 PJM day-ahead load: January through September for years 2011 and 2012 (See 2011 SOM, Figure 2-9)



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

35 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.

PJM Day-Ahead, Average Load

Table 2-32 presents summary day-ahead load statistics for the first nine months of 12 year period 2001 to 2012.

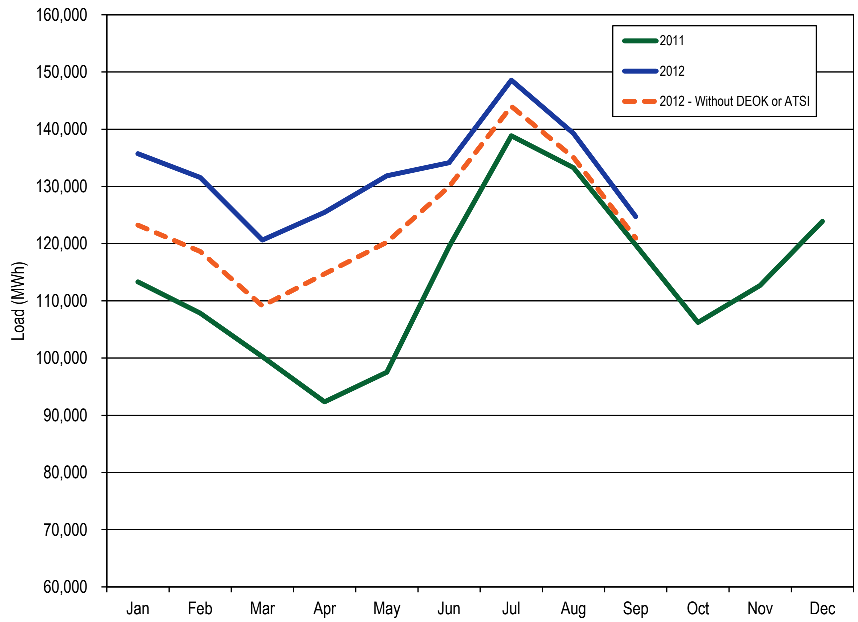
Table 2-32 PJM day-ahead average load: January through September for years 2001 through 2012[36] (See 2011 SOM, Table 2-31)

	PJM Day-Ahead Load (MWh)						Year-to-Year Change		
	Average			Standard Deviation			Average		
(Jan-Sep)	Load	Up-to Congestion	Total Load	Load	Up-to Congestion	Total Load	Load	Up-to Congestion	Total Load
2001	33,878	66	33,944	6,978	199	7,016	NA	NA	NA
2002	41,547	87	41,634	11,053	202	11,073	22.6%	32.2%	22.7%
2003	45,083	288	45,371	8,409	287	8,377	8.5%	230.4%	9.0%
2004	54,997	833	55,830	13,103	584	13,319	22.0%	189.4%	23.1%
2005	92,162	1,363	93,525	18,867	851	19,126	67.6%	63.6%	67.5%
2006	95,572	3,831	99,403	17,415	1,657	18,165	3.7%	181.1%	6.3%
2007	102,742	4,553	107,295	17,075	1,535	17,580	7.5%	18.8%	7.9%
2008	97,506	6,080	103,586	16,051	1,830	16,618	(5.1%)	33.6%	(3.5%)
2009	89,680	6,340	96,020	15,756	2,018	16,995	(8.0%)	4.3%	(7.3%)
2010	92,683	12,335	105,018	17,769	8,637	22,972	3.3%	94.6%	9.4%
2011	92,828	20,896	113,724	19,456	5,481	22,444	0.2%	69.4%	8.3%
2012	94,857	37,637	132,494	18,419	5,706	18,115	2.2%	80.1%	16.5%

PJM Day-Ahead, Monthly Average Load

Figure 2-11 compares the day-ahead, monthly average hourly loads of the first nine months of 2012 with those of 2011.

Figure 2-11 PJM day-ahead monthly average hourly load: 2011 through September of 2012 (See 2011 SOM, Figure 2-10)



Real-Time and Day-Ahead Load

Table 2-33 presents summary statistics for the first nine months of 2011 and 2012 day-ahead and real-time loads.

36 The version of this table in the *2012 State of the Market Report for PJM: January through March* incorrectly reported the standard deviation.

Table 2-33 Cleared day-ahead and real-time load (MWh): January through September for years 2011 and 2012 (See 2011 SOM, Table 2-32)

		Day Ahead					Real Time	Average Difference	
	(Jan-Sep)	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	2011	80,729	864	11,235	20,896	113,724	83,762	29,962	(2,169)
	2012	85,748	756	8,354	37,637	132,494	88,680	43,815	(2,176)
Median	2011	77,364	859	10,959	19,698	109,755	81,027	28,728	(1,929)
	2012	83,361	725	8,019	36,844	130,970	86,116	44,854	(9)
Standard Deviation	2011	17,424	192	2,578	5,481	22,444	17,604	4,840	(3,219)
	2012	17,044	142	1,856	5,706	18,115	17,432	682	(6,880)
Peak Average	2011	89,882	941	13,011	21,788	125,621	93,020	32,601	(2,198)
	2012	95,511	810	9,347	37,608	143,276	98,393	44,883	(2,072)
Peak Median	2011	86,816	945	12,752	20,492	121,966	89,953	32,013	(1,230)
	2012	91,277	781	9,084	36,899	139,945	93,920	46,026	42
Peak Standard Deviation	2011	16,471	189	2,135	5,687	21,056	16,475	4,581	(3,240)
	2012	15,176	143	1,750	5,551	15,563	15,605	(42)	(7,343)
Off-Peak Average	2011	72,646	795	9,668	20,109	103,219	75,586	27,632	(2,145)
	2012	77,186	708	7,483	37,663	123,039	80,161	42,878	(2,268)
Off-Peak Median	2011	70,493	793	9,418	18,907	101,198	72,998	28,200	(125)
	2012	74,624	684	7,138	36,794	121,287	77,549	43,738	(194)
Off-Peak Standard Deviation	2011	13,887	168	1,803	5,168	17,938	14,191	3,747	(3,224)
	2012	13,653	123	1,469	5,840	14,567	14,198	369	(6,940)

Figure 2-12 shows the first nine months average 2012 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.

Figure 2-12 Day-ahead and real-time loads (Average hourly volumes): January through September of 2012 (See 2011 SOM, Figure 2-10)

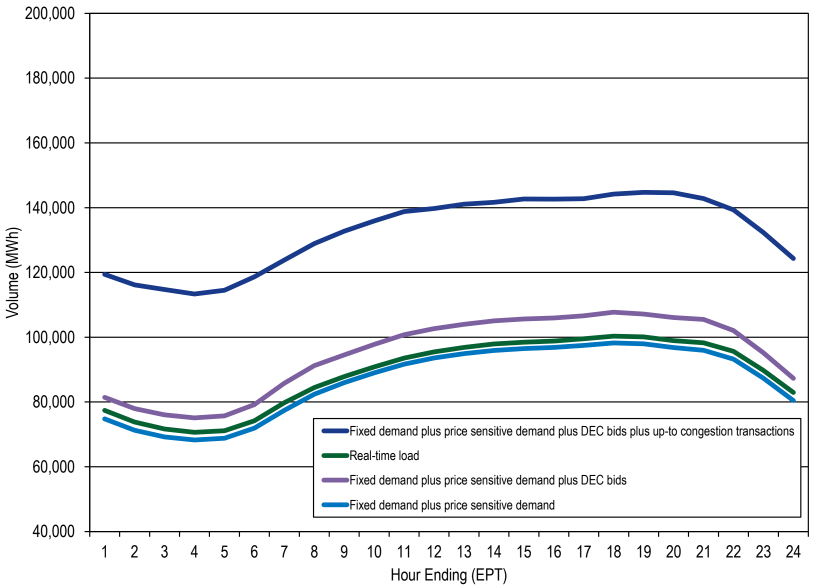
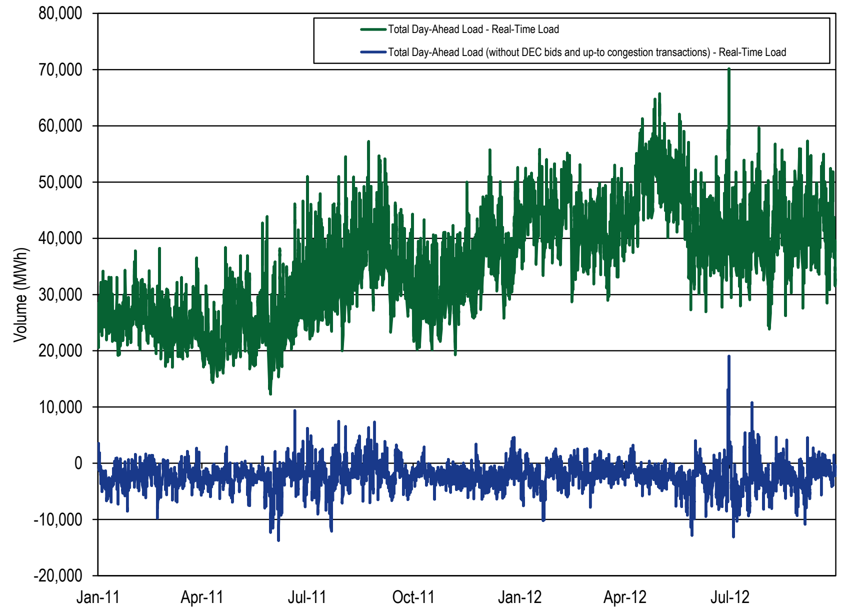


Figure 2-13 shows the difference between the day-ahead and real-time average daily loads in the first nine months of 2012 and the first nine months of 2011.

Figure 2-13 Difference between day-ahead and real-time loads (Average daily volumes): January 2011 through September 2012 (See 2011 SOM, Figure 2-12)



Real-Time and Day-Ahead Generation

PJM average real-time generation in the first nine months of 2012 increased by 3.9 percent from the first nine months of 2011, from 86,966 MW to 90,367 MW. PJM average real-time generation in the first nine months of 2012 would have decreased 1.6 percent from the first nine months of 2011, from 86,966 MW to 85,532 MW if the DEOK and ATSI Transmission Zones were excluded from the comparison for the months in 2011 when they were not part of PJM.[37]

PJM average day-ahead generation in the first nine months of 2012, including INCs and up-to congestion transactions, increased by 15.6 percent from the

37 The ATSI Transmission Zone was excluded from this comparison for the first 5 months of 2012 because it did not join PJM until June 1, 2011. The DEOK Transmission Zone was excluded from this comparison for all of the months of 2012 because it did not join PJM until January 1, 2012.

first nine months of 2011, from 116,988 MW to 135,213 MW. PJM average day-ahead generation in the first nine months of 2012, including INCs and up-to congestion transactions, would have increased 11.5 percent from the first nine months of 2011, from 116,988 MW to 135,213 MW if the DEOK and ATSI transmission zones were excluded from the comparison for the months in 2011 when they were not part of PJM.

The day-ahead generation growth was 300.0 percent higher than the real-time generation growth because of the continued growth of up-to congestion transactions. If up-to congestion transactions had not grown in the first nine months of 2012 compared to the first nine months of 2011, the day-ahead generation, including INCs and up-to congestion transactions, would have increased 1.3 percent instead of 15.6 percent. The day-ahead generation growth would have been 66.7 percent lower than the real-time generation growth.

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: [38]

- **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.[39]
- **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.[40] 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 2-34 presents summary real-time generation statistics for the first nine months of each year from 2003 through 2012.

Table 2-34 PJM real-time average hourly generation[41]: January through September for years 2003 through 2012 (See 2011 SOM, Table 2-33)

	PJM Real-Time Generation (MWh)		Year-to-Year Change	
(Jan-Sep)	Average Generation	Generation Standard Deviation	Average Generation	Generation Standard Deviation
2003	37,211	6,556	NA	NA
2004	45,888	11,035	23.3%	68.3%
2005	81,095	16,710	76.7%	51.4%
2006	84,260	14,696	3.9%	(12.1%)
2007	87,297	14,853	3.6%	1.1%
2008	85,241	14,203	(2.4%)	(4.4%)
2009	78,850	14,242	(7.5%)	0.3%
2010	84,086	16,346	6.6%	14.8%
2011	86,966	17,369	3.4%	6.3%
2012	90,367	16,893	3.9%	(2.7%)

Table 2-35 presents summary day-ahead generation statistics for the first nine months of each year from 2003 through 2012.

38 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."
39 The definition of self-scheduled is based on the PJM. "eMKT User Guide" (December 1, 2011), pp. 38-40.
40 Up-to congestion transactions are cleared based on the entire price difference between source and sink including the congestion and loss components of LMP.
41 The version of this table in the *2012 State of the Market Report for PJM*: January through March incorrectly reported the standard deviation.

Table 2-35 PJM day-ahead average hourly generation[42]: January through September for years 2003 through 2012 (See 2011 SOM, Table 2-34)

	PJM Day-Ahead Generation (MWh)						Year-to-Year Change		
	Average			Standard Deviation			Average		
(Jan-Sep)	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
2003	39,736	288	40,024	9,113	287	9,079	NA	NA	NA
2004	55,270	833	56,103	13,158	584	13,380	39.1%	189.4%	40.2%
2005	93,074	1,363	94,437	18,401	851	18,671	68.4%	63.6%	68.3%
2006	97,056	3,831	100,888	17,304	1,657	18,061	4.3%	181.1%	6.8%
2007	105,748	4,553	110,300	17,092	1,535	17,561	9.0%	18.8%	9.3%
2008	101,287	6,080	107,367	16,015	1,830	16,601	(4.2%)	33.6%	(2.7%)
2009	92,187	6,340	98,527	16,220	2,018	17,462	(9.0%)	4.3%	(8.2%)
2010	95,974	12,335	108,309	18,086	8,637	23,294	4.1%	94.6%	9.9%
2011	96,092	20,896	116,988	19,705	5,481	22,722	0.1%	69.4%	8.0%
2012	97,576	37,637	135,213	18,929	5,706	18,553	1.5%	80.1%	15.6%

Table 2-36 presents summary statistics for first nine months of 2011 and 2012 for day-ahead and real-time generation.

Table 2-36 Day-ahead and real-time generation (MWh): January through September for years 2011 and 2012 (See 2011 SOM, Table 2-35)

		Day Ahead				Real Time	Average Difference	
	(Jan-Sep)	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	2011	88,220	7,872	20,896	116,988	86,966	1,255	30,023
	2012	91,382	6,194	37,637	135,213	90,367	1,015	44,846
Median	2011	85,314	7,800	19,698	113,095	84,276	1,038	28,819
	2012	88,873	6,191	36,844	133,659	87,665	1,207	45,993
Standard Deviation	2011	18,881	1,388	5,481	22,722	17,369	1,512	5,353
	2012	18,736	906	5,706	18,553	16,893	1,843	1,659
Peak Average	2011	98,419	8,823	21,788	129,030	95,885	2,534	33,145
	2012	102,016	6,547	37,608	146,171	99,382	2,635	46,789
Peak Median	2011	95,643	8,690	20,492	125,500	92,952	2,691	32,548
	2012	97,816	6,477	36,899	142,800	95,406	2,410	47,393
Peak Standard Deviation	2011	17,199	1,133	5,687	21,229	16,250	949	4,979
	2012	16,523	721	5,551	15,938	15,366	1,157	572
Off-Peak Average	2011	79,214	7,031	20,109	106,355	79,090	125	27,265
	2012	82,057	5,884	37,663	125,604	82,461	(405)	43,142
Off-Peak Median	2011	76,818	6,864	18,907	104,245	76,703	115	27,542
	2012	79,731	5,810	36,794	123,948	80,263	(532)	43,685
Off-Peak Standard Deviation	2011	15,400	994	5,168	18,252	14,235	1,164	4,017
	2012	15,277	939	5,840	15,023	13,960	1,318	1,064

42 The version of this table in the *2012 Q1 State of the Market Report for PJM* incorrectly reported the standard deviation.

Figure 2-14 shows the first nine months average 2012 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.[43]

Figure 2-14 Day-ahead and real-time generation (Average hourly volumes): January through September of 2012 (See 2011 SOM, Figure 2-13)

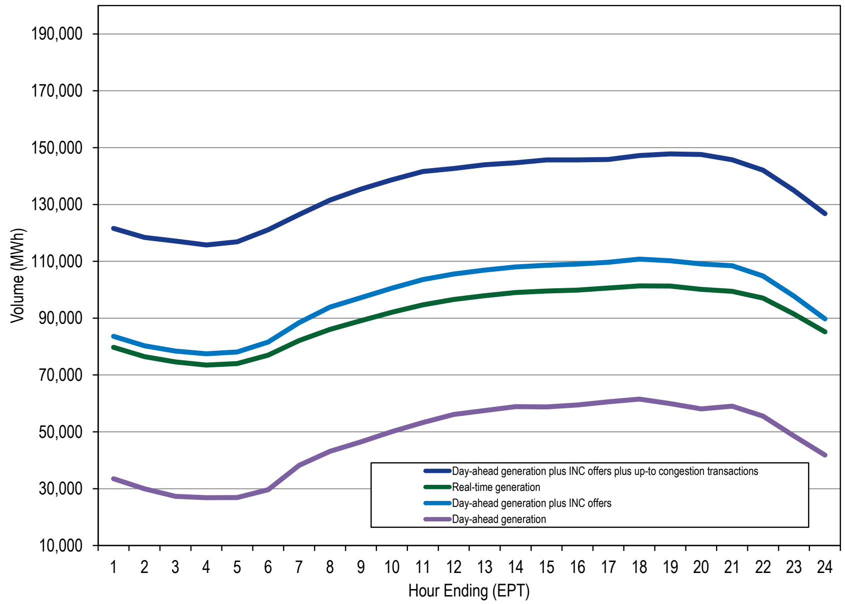
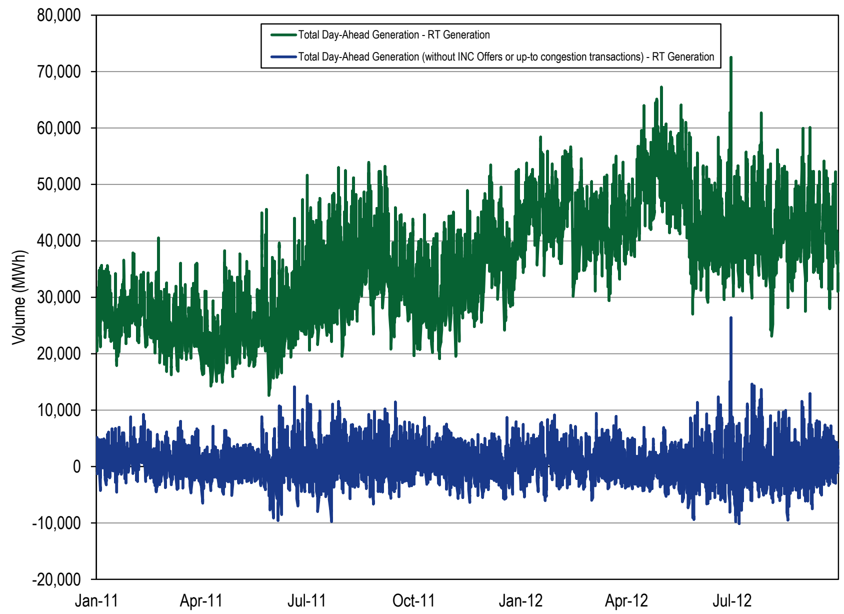


Figure 2-15 shows the difference between the day-ahead and real-time average daily generation in the first nine months of 2012 and the first nine months of 2011.

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

Figure 2-15 Difference between day-ahead and real-time generation (Average daily volumes): January 2011 through September 2012 (See 2011 SOM, Figure 2-14)



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.[44]

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

44 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.

and local price differences caused by congestion. Real-Time and Day-Ahead Energy Market load-weighted prices were 29.2 percent and 29.1 percent lower than in the first nine months of 2011 as a result of lower fuel costs and relatively low demand.[45]

PJM Real-Time Energy Market prices decreased in the first nine months of 2012 compared to the first nine months of 2011. The system average LMP was 29.1 percent lower in the first nine months of 2012 than in the first nine months of 2011, $32.45 per MWh versus $45.79 per MWh. The load-weighted average LMP was 29.2 percent lower in the first nine months of 2012 than in the first nine months of 2011, $35.02 per MWh versus $49.48 per MWh.

PJM Day-Ahead Energy Market prices decreased in the first nine months of 2012 compared to the first nine months of 2011. The system average LMP was 28.8 percent lower in the first nine months of 2012 than in the first nine months of 2011, $32.16 per MWh versus $45.14 per MWh. The load-weighted average LMP was 29.1 percent lower in the first nine months of 2012 than in the first nine months of 2011, $34.29 per MWh versus $48.34 per MWh.[46]

Real-Time LMP

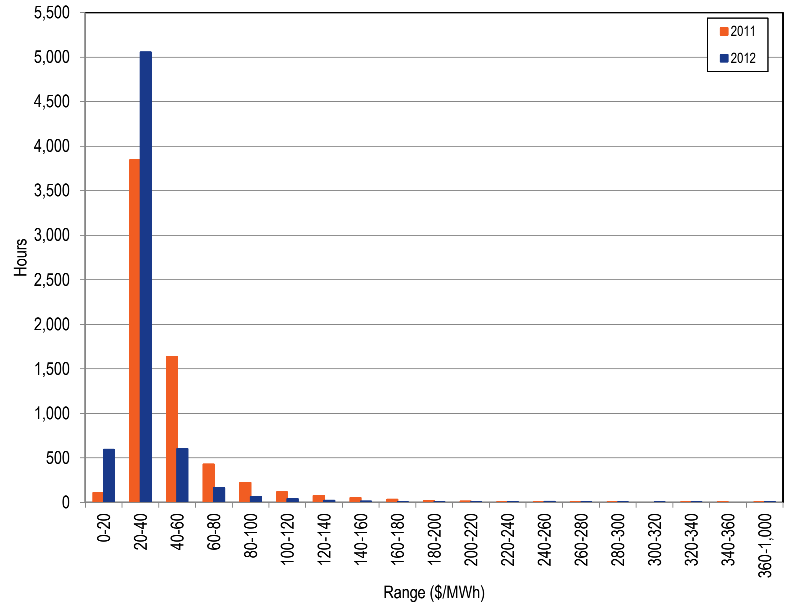
Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[47] This section discusses the real-time average LMP and the real-time load weighted average LMP. Average LMP is the unweighted average LMP.

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 2-16 shows the number of hours that PJM real-time average LMP for the first nine months of 2011 and 2012 were within a defined range.

Figure 2-16 Average LMP for the PJM Real-Time Energy Market: January through September, 2011 and 2012 (See 2011 SOM, Figure 2-15)



PJM Real-Time, Average LMP

Table 2-37 shows the PJM real-time, annual, average LMP for the first nine months of the 15-year period 1998 to 2012.[48]

45 There was an average reduction of 3.9 heating degree days and an average increase of 1.5 cooling degree days in the first nine months of 2012 which meant overall reduced demand.

46 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".

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

48 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 2-37 PJM real-time, average LMP (Dollars per MWh): January through September, 1998 through 2012 (See 2011 SOM, Table 2-36)

	Real-Time LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$23.18	$16.86	$36.00	NA	NA	NA
1999	$31.65	$18.77	$83.28	36.6%	11.3%	131.3%
2000	$25.88	$18.22	$23.70	(18.2%)	(2.9%)	(71.5%)
2001	$36.00	$25.48	$51.30	39.1%	39.9%	116.4%
2002	$28.13	$20.70	$23.92	(21.9%)	(18.8%)	(53.4%)
2003	$40.42	$33.68	$26.00	43.7%	62.7%	8.7%
2004	$43.85	$39.99	$21.82	8.5%	18.7%	(16.1%)
2005	$54.69	$44.53	$33.67	24.7%	11.4%	54.3%
2006	$51.79	$43.50	$34.93	(5.3%)	(2.3%)	3.7%
2007	$57.34	$49.40	$35.52	10.7%	13.6%	1.7%
2008	$71.94	$61.33	$41.64	25.4%	24.2%	17.2%
2009	$37.42	$33.00	$17.92	(48.0%)	(46.2%)	(57.0%)
2010	$46.13	$37.89	$26.99	23.3%	14.8%	50.6%
2011	$45.79	$37.05	$32.25	(0.7%)	(2.2%)	19.5%
2012	$32.45	$28.78	$21.94	(29.1%)	(22.3%)	(32.0%)

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, Load-Weighted, Average LMP

Table 2-38 shows the PJM real-time, load-weighted, average LMP for the first nine months of each year of the 15-year period 1998 to 2012.

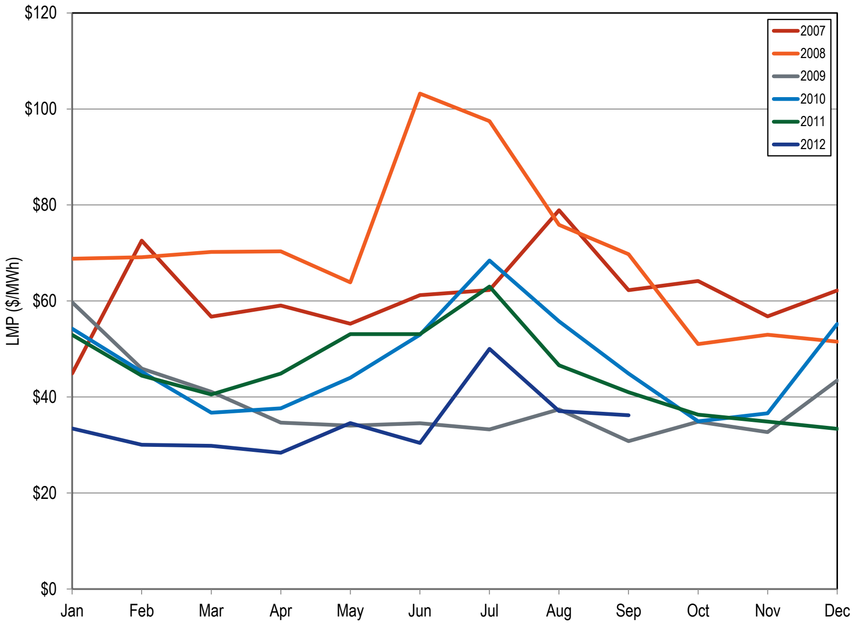
Table 2-38 PJM real-time, load-weighted, average LMP (Dollars per MWh): January through September, 1998 through 2012 (See 2011 SOM, Table 2-37)

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$26.06	$18.20	$44.65	NA	NA	NA
1999	$38.65	$20.02	$104.17	48.3%	10.0%	133.3%
2000	$28.49	$19.30	$26.89	(26.3%)	(3.6%)	(74.2%)
2001	$40.96	$28.18	$64.57	43.8%	46.0%	140.1%
2002	$31.95	$23.09	$29.14	(22.0%)	(18.1%)	(54.9%)
2003	$43.57	$38.17	$26.53	36.3%	65.3%	(9.0%)
2004	$46.44	$43.03	$21.89	6.6%	12.7%	(17.5%)
2005	$60.44	$50.10	$36.52	30.2%	16.4%	66.9%
2006	$56.39	$46.82	$40.70	(6.7%)	(6.5%)	11.4%
2007	$61.83	$55.12	$37.98	9.7%	17.7%	(6.7%)
2008	$77.27	$66.73	$43.80	25.0%	21.1%	15.3%
2009	$39.57	$34.57	$19.04	(48.8%)	(48.2%)	(56.5%)
2010	$49.91	$40.33	$29.65	26.2%	16.7%	55.7%
2011	$49.48	$38.72	$37.02	(0.9%)	(4.0%)	24.8%
2012	$35.02	$29.84	$25.44	(29.2%)	(22.9%)	(31.3%)

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

Figure 2-17 shows the PJM real-time, monthly, load-weighted LMP from 2007 through the first nine months of 2012.

Figure 2-17 PJM real-time, monthly, load-weighted, average LMP: 2007 through September of 2012 (See 2011 SOM, Figure 2-16)



Fuel Price Trends and 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. Changes in emission allowance costs are another contributor to changes in the marginal cost of marginal units. Both coal and natural gas decreased in price in the first nine months of 2012. Comparing prices in the first nine months of 2012 to prices in the first nine months of 2011, the price of Northern Appalachian coal was 15.5 percent lower; the price of Central Appalachian coal was 19.4 percent lower; the price of Powder River Basin coal was 34.1 percent lower; the price of eastern natural gas was 40.5 percent lower; and the price of western natural gas was 37.1 percent lower. Figure 2-18 shows monthly average spot fuel prices for 2011 and 2012.[49]

Figure 2-18 Spot average fuel price comparison: 2011 and January through September 2012 ($/MMBtu) (See 2011 SOM, Figure 2-17)

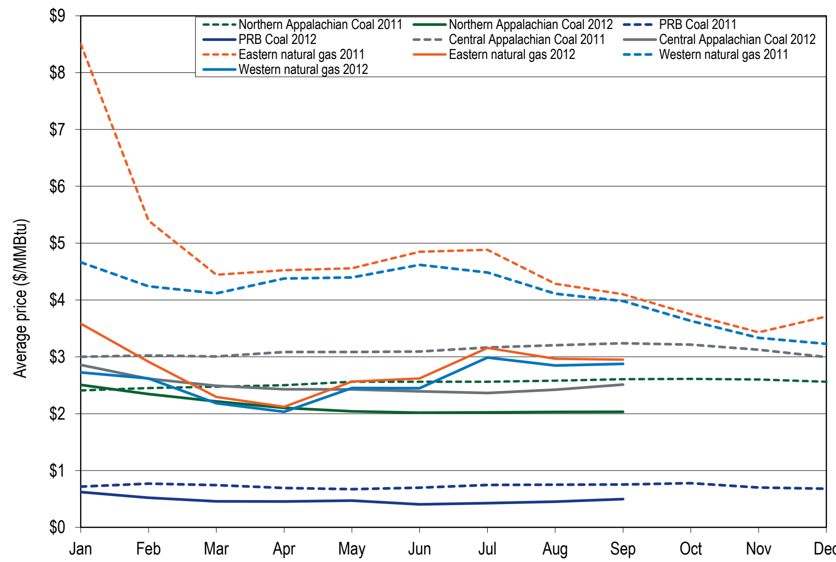


Figure 2-19 shows the average spot cost of generation, comparing the fuel cost of a coal plant, combined cycle, and combustion turbine in dollars per MWh. On average, the fuel cost of a new entrant combined cycle unit ($19.54/MWh) was lower than the fuel cost of a new entrant coal plant ($19.83/MWh) in the first nine months of 2012. On a $/MWh basis, a new entrant combined cycle was lower cost than a new entrant coal plant from February through June, but higher cost in the months of July through September.

49 Eastern natural gas and Western natural gas 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.

Figure 2-19 Average spot fuel cost of generation of CP, CT, and CC: 2011 and January through September 2012 ($/MWh) (New Figure)

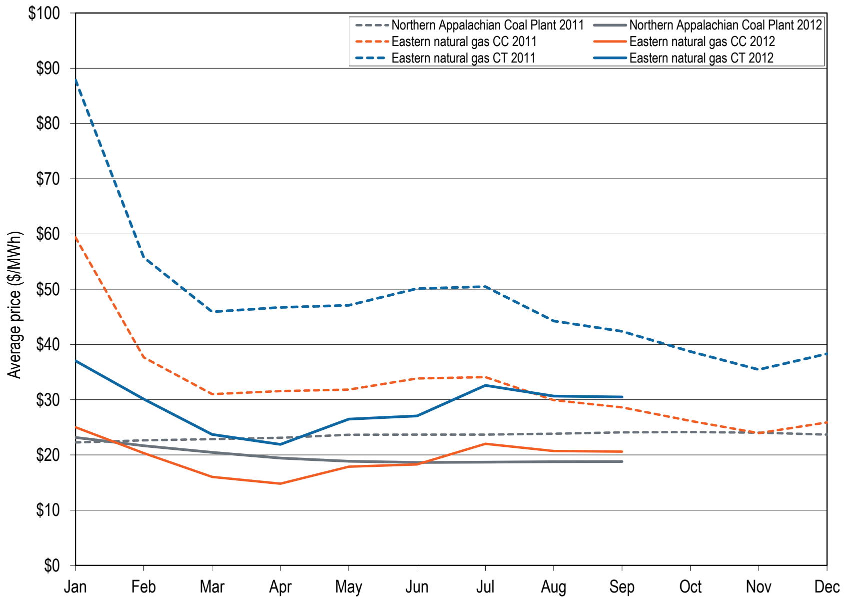


Table 2-39 compares the first nine months of 2012 PJM real-time fuel-cost-adjusted, load-weighted, average LMP to the first nine months of 2011 load-weighted, average LMP. The fuel-cost adjusted load-weighted, average LMP for the first nine month of 2012 was 20.3 percent higher than the load-weighted, average LMP for the first nine months of 2012. The real-time, fuel-cost-adjusted, load-weighted, average LMP for the first nine months of 2012 was 14.8 percent lower than the load-weighted LMP for the first nine months of 2011. If fuel costs in the first nine months of 2012 had been the same as in the first nine months of 2011, the 2012 load-weighted LMP would have been higher, $42.15 per MWh instead of the observed $35.02 per MWh. The mix of fuel types and fuel costs in 2012 resulted in lower prices in 2012 than would have occurred if fuel prices had remained at their 2011 levels.

Table 2-39 PJM real-time annual, fuel-cost-adjusted, load-weighted average LMP (Dollars per MWh): Year-over-year method (See 2011 SOM, Table 2-11)

	Jan-Sep, 2012 Load-Weighted LMP	Jan-Sep, 2012 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$35.02	$42.15	20.3%
	Jan-Sep, 2011 Load-Weighted LMP	Jan-Sep, 2012 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$49.48	$42.15	(14.8%)
	Jan-Sep, 2011 Load-Weighted LMP	Jan-Sep, 2012 Load-Weighted LMP	Change
Average	$49.48	$35.02	(29.2%)

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

Table 2-40 shows that 53.8 percent of the annual, load-weighted LMP was the result of coal costs, 21.7 percent was the result of gas costs and 0.6 percent was the result of the cost of emission allowances. Markup was -$ 0.47. 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. (Numbers in parentheses in the table are negative.) The components of this difference are listed in Table 2-40.[50]

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

Table 2-40 Components of PJM real-time, annual, load-weighted, average LMP: January through September 2012

Element	Contribution to LMP	Percent
Coal	$18.86	53.8%
Gas	$7.61	21.7%
Ten Percent Adder	$3.41	9.7%
VOM	$2.49	7.1%
Oil	$2.00	5.7%
NA	$0.73	2.1%
LPA-SCED Differential	$0.13	0.4%
LPA Rounding Difference	$0.12	0.4%
FMU Adder	$0.11	0.3%
CO2 Cost	$0.10	0.3%
NOx Cost	$0.09	0.3%
Increase Generation Adder	$0.07	0.2%
Market-to-Market Adder	$0.03	0.1%
Constraint Violation Adder	$0.02	0.1%
SO2 Cost	$0.02	0.1%
Municipal Waste	$0.01	0.0%
Uranium	$0.00	0.0%
Other	($0.00)	(0.0%)
Wind	($0.06)	(0.2%)
Decrease Generation Adder	($0.26)	(0.7%)
Markup	($0.47)	(1.3%)
Total	$35.02	100.0%

Day-Ahead LMP

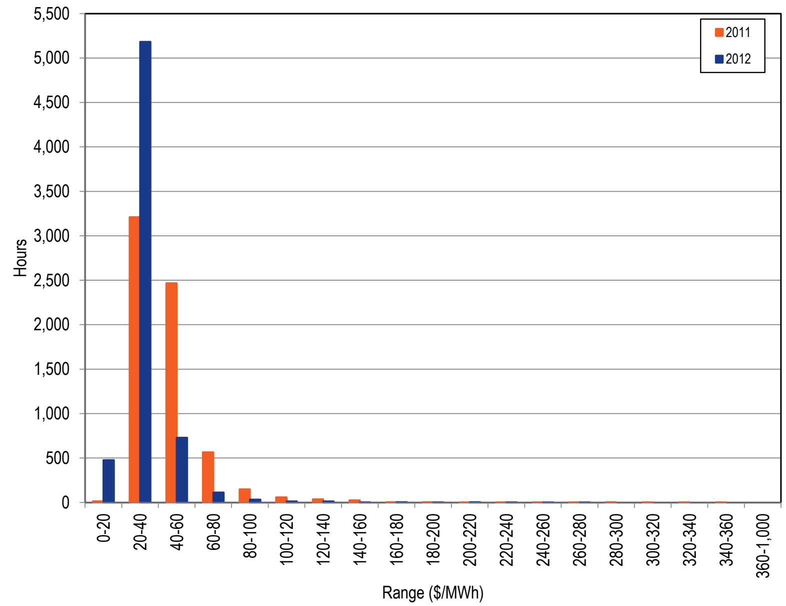
Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[51] This section discusses the day-ahead average LMP and the day-ahead load weighted average LMP. Average LMP is the unweighted average LMP.

Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 2-20 shows the hourly distribution of PJM day-ahead average LMP for the first nine months of 2011 and 2012.

Figure 2-20 Price for the PJM Day-Ahead Energy Market: January through September, 2011 and 2012 (See 2011 SOM, Figure 2-18)



PJM Day-Ahead, Average LMP

Table 2-41 shows the PJM day-ahead, average LMP for the first nine months of each year for the 12 year period from 2001 to 2012.

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

Table 2-41 PJM day-ahead, average LMP (Dollars per MWh): January through September, 2001 through 2012 (See 2011 SOM, Table 2-40)

	Day-Ahead LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$36.07	$30.02	$34.25	NA	NA	NA
2002	$28.29	$22.54	$19.09	(21.6%)	(24.9%)	(44.3%)
2003	$41.20	$38.24	$22.02	45.6%	69.7%	15.4%
2004	$42.64	$42.07	$17.47	3.5%	10.0%	(20.7%)
2005	$54.48	$46.67	$28.83	27.8%	10.9%	65.1%
2006	$50.45	$46.32	$24.93	(7.4%)	(0.8%)	(13.5%)
2007	$54.24	$51.40	$24.95	7.5%	11.0%	0.1%
2008	$71.43	$66.38	$33.11	31.7%	29.2%	32.7%
2009	$37.35	$35.29	$14.32	(47.7%)	(46.8%)	(56.8%)
2010	$45.81	$41.03	$19.59	22.7%	16.3%	36.8%
2011	$45.14	$40.20	$22.68	(1.5%)	(2.0%)	15.7%
2012	$32.16	$30.10	$14.54	(28.8%)	(25.1%)	(35.9%)

Day-Ahead, Load-Weighted, Average LMP

Day-ahead, load-weighted LMP reflects the average LMP paid for day-ahead MWh. 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, Load-Weighted, Average LMP

Table 2-42 shows the PJM day-ahead, load-weighted, average LMP for the first nine months of each year of the 12-year period from 2001 to 2012.

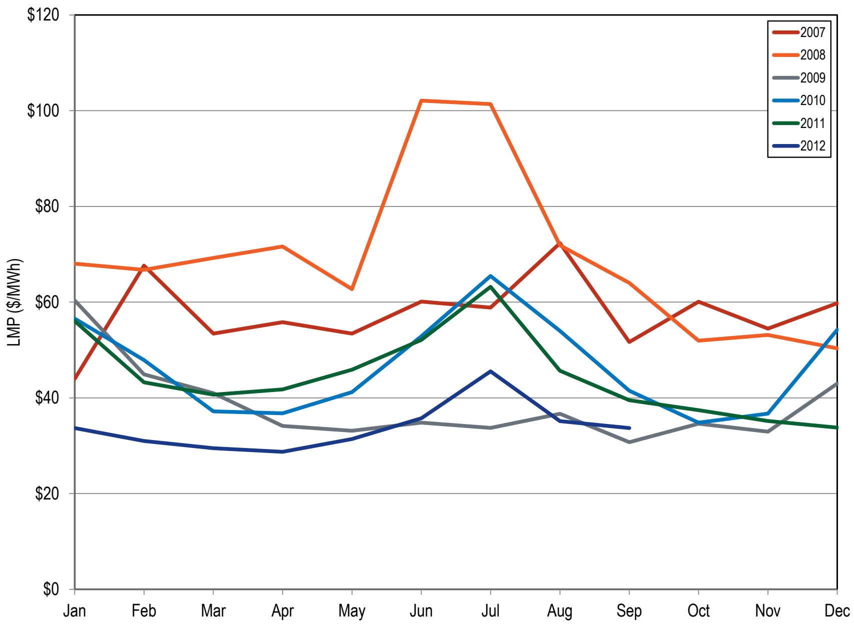
Table 2-42 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January through September, 2001 through 2012 (See 2011 SOM, Table 2-41)

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$39.88	$32.68	$42.01	NA	NA	NA
2002	$32.29	$25.22	$22.81	(19.0%)	(22.8%)	(45.7%)
2003	$44.11	$41.51	$22.34	36.6%	64.6%	(2.1%)
2004	$44.59	$44.47	$17.40	1.1%	7.1%	(22.1%)
2005	$59.51	$51.33	$31.13	33.5%	15.4%	78.9%
2006	$54.19	$48.87	$28.35	(8.9%)	(4.8%)	(8.9%)
2007	$57.79	$55.62	$26.07	6.6%	13.8%	(8.0%)
2008	$75.96	$70.35	$35.19	31.5%	26.5%	35.0%
2009	$39.35	$36.92	$14.98	(48.2%)	(47.5%)	(57.4%)
2010	$49.12	$43.33	$21.35	24.8%	17.4%	42.6%
2011	$48.34	$42.35	$26.54	(1.6%)	(2.3%)	24.3%
2012	$34.29	$31.17	$17.12	(29.1%)	(26.4%)	(35.5%)

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

Figure 2-21 shows the PJM day-ahead, monthly, load-weighted LMP from 2007 through the first nine months of 2012.

Figure 2-21 Day-ahead, monthly, load-weighted, average LMP: 2007 through September of 2012 (See 2011 SOM, Figure 2-19)



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 2-43 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.[52]

Table 2-43 Components of PJM day-ahead, annual, load-weighted, average LMP (Dollars per MWh): January through September, 2012 (See 2011 SOM, Table 2-42)

Element	Contribution to LMP	Percent
Coal	$13.49	39.3%
DEC	$8.40	24.5%
Gas	$4.29	12.5%
INC	$3.41	10.0%
10% Cost Adder	$1.98	5.8%
Up-to Congestion Transaction	$1.66	4.8%
VOM	$1.52	4.4%
Price Sensitive Demand	$0.58	1.7%
Dispatchable Transaction	$0.51	1.5%
Oil	$0.39	1.1%
DASR Offer Adder	$0.19	0.6%
CO_2	$0.06	0.2%
NO_x	$0.06	0.2%
SO_2	$0.01	0.0%
Constrained Off	$0.00	0.0%
Diesel	$0.00	0.0%
Wind	($0.00)	(0.0%)
DASR LOC Adder	($0.41)	(1.2%)
Markup	($1.87)	(5.4%)
NA	$0.01	0.0%
Total	$34.29	100.0%

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

Virtual Offers and Bids

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.

Table 2-44 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 2-45 shows the average volume of up-to congestion transactions per hour and the average total MW values of all bids per hour.

Table 2-44 Hourly average volume of cleared and submitted INCs, DECs by month: January, 2011 through September, 2012 (See 2011 SOM, Table 2-43)

		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
2011	Jan	8,137	14,299	218	1077	11,135	17,917	224	963
2011	Feb	8,530	16,263	215	1672	11,071	17,355	230	1034
2011	Mar	7,230	13,164	201	1059	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	1084	11,648	17,542	279	1015
2011	Jul	8,595	14,006	185	1234	12,196	17,567	213	1140
2011	Aug	7,540	12,349	120	1034	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
2012	Jan	6,781	10,341	91	455	9,031	12,562	111	428
2012	Feb	6,428	10,930	96	591	7,641	11,043	108	511
2012	Mar	5,969	9,051	90	347	7,193	10,654	112	362
2012	Apr	6,355	9,368	87	298	7,812	10,811	105	329
2012	May	6,224	8,447	80	271	8,785	11,141	109	316
2012	Jun	6,415	8,360	79	234	9,030	11,124	97	270
2012	Jul	6,485	8,270	81	285	8,981	11,121	112	349
2012	Aug	5,809	7,873	74	291	8,471	10,507	100	320
2012	Sep	5,274	7,509	78	313	8,192	10,814	109	381
2012	Annual	6,193	8,905	84	343	8,348	11,086	107	363

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.[53]

53 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.

Table 2-45 Hourly average of cleared and submitted up-to congestion bids by month: January, 2011 through September, 2012 (See 2011 SOM, Table 2-44)

		Up-to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
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
2012	Jan	37,469	102,762	805	1,950
2012	Feb	37,132	106,741	830	2,115
2012	Mar	35,921	105,222	865	2,224
2012	Apr	43,777	120,955	1013	2,519
2012	May	43,468	119,374	1052	2,541
2012	Jun	35,052	101,065	915	2,193
2012	Jul	35,179	118,294	981	2,710
2012	Aug	35,515	122,458	986	2,787
2012	Sep	35,199	112,731	946	2,801
2012	Annual	37,635	112,178	933	2,427

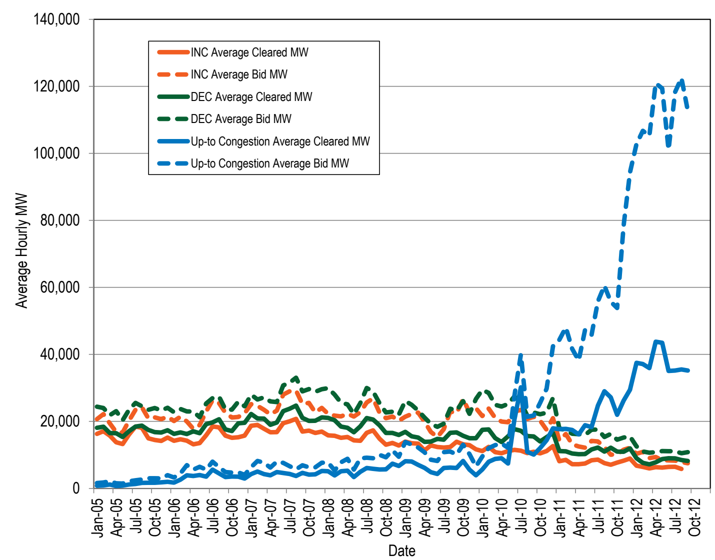
Table 2-46 shows the frequency with which generation offers, import or export transactions, up-to congestion transactions, decrement bids, increment offers and price-sensitive demand are marginal for each month.[54]

Table 2-46 Type of day-ahead marginal units: January through September, 2012 (See 2011 SOM, Table 2-45)

	Generation	Dispatchable Transaction	Up-to Congestion Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	3.8%	0.1%	87.3%	5.7%	3.1%	0.1%
Feb	3.7%	0.1%	83.8%	5.4%	6.9%	0.1%
Mar	3.5%	0.1%	83.2%	6.2%	6.9%	0.1%
Apr	3.5%	0.1%	85.3%	5.2%	5.9%	0.0%
May	3.1%	0.1%	87.9%	4.6%	4.4%	0.0%
Jun	4.3%	0.0%	88.7%	4.3%	2.6%	0.0%
Jul	3.3%	0.1%	88.0%	6.1%	2.5%	0.1%
Aug	4.0%	0.1%	89.4%	4.1%	2.3%	0.0%
Sep	3.7%	0.1%	86.8%	4.5%	5.0%	0.0%
Annual	3.6%	0.1%	86.7%	5.1%	4.4%	0.1%

Figure 2-22 shows the hourly volume of bid and cleared INC, DEC and up-to congestion bids by month.

Figure 2-22 Hourly volume of bid and cleared INC, DEC and Up-to Congestion bids (MW) by month: January, 2005 through September, 2012 (See 2011 SOM, Figure 2-20)



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

In order to evaluate the ownership of virtual bids, the MMU categorized all participants 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 2-47 shows, for the January through September period of 2011 and 2012, the total increment offers and decrement bids by the type of parent organization: financial or physical. Table 2-48 shows, for the January through September period of 2011 and 2012, the total up-to congestion transactions by the type of parent organization: financial or physical.

Table 2-47 PJM INC and DEC bids by type of parent organization (MW): January through September, 2011 and 2012 (See 2011 SOM, Table 2-46)

	2011 (Jan - Sep)		2012 (Jan - Sep)	
Category	Total Virtual Bids MW	Percentage	Total Virtual Bids MW	Percentage
Financial	89,824,892	45.8%	47,082,084	35.8%
Physical	106,162,195	54.2%	84,316,277	64.2%
Total	195,987,087	100.0%	131,398,361	100.0%

Table 2-48 PJM up-to congestion transactions by type of parent organization (MW): January through September, 2011 and 2012 (See 2011 SOM, Table 2-47)

	2011 (Jan - Sep)		2012 (Jan - Sep)	
Category	Total Up-to Congestion MW	Percentage	Total Up-to Congestion MW	Percentage
Financial	132,143,539	96.8%	235,531,919	95.2%
Physical	4,308,481	3.2%	11,950,279	4.8%
Total	136,452,020	100.0%	247,482,198	100.0%

Table 2-49 shows increment offers and decrement bids bid by top ten locations for the January through September period of 2011 and 2012.

Table 2-49 PJM virtual offers and bids by top ten locations (MW): January through September, 2011 and 2012 (See 2011 SOM, Table 2-48)

2011 (Jan - Sep)					2012 (Jan - Sep)				
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	21,803,278	25,055,528	46,858,806	WESTERN HUB	HUB	22,645,383	25,448,690	48,094,072
N ILLINOIS HUB	HUB	7,548,766	11,359,168	18,907,933	AEP-DAYTON HUB	HUB	3,906,488	4,420,709	8,327,197
AEP-DAYTON HUB	HUB	4,595,058	6,186,285	10,781,343	SOUTHIMP	INTERFACE	7,038,188	0	7,038,188
MISO	INTERFACE	189,307	5,304,896	5,494,202	N ILLINOIS HUB	HUB	2,059,281	4,605,627	6,664,908
PECO	ZONE	1,322,244	3,821,502	5,143,746	MISO	INTERFACE	248,793	5,303,608	5,552,401
SOUTHIMP	INTERFACE	4,480,640	0	4,480,640	PPL	ZONE	286,342	4,331,684	4,618,026
PPL	ZONE	201,981	3,028,982	3,230,963	PECO	ZONE	858,512	3,219,905	4,078,417
COMED	ZONE	1,965,887	216,118	2,182,004	IMO	INTERFACE	2,591,173	45,924	2,637,097
JCPL BUS	GEN	1,037,760	1,037,827	2,075,587	BGE	ZONE	167,525	1,542,604	1,710,129
BGE	ZONE	89,509	1,680,790	1,770,299	METED	ZONE	133,855	1,063,889	1,197,744
Top Ten Total		43,234,428	57,691,095	100,925,523			39,935,538	49,982,640	89,918,178
PJM total		86,469,663	109,517,424	195,987,087			58,491,377	72,906,984	131,398,361
Top ten total as percent of PJM total		50.0%	52.7%	51.5%			68.3%	68.6%	68.4%

Table 2-50 shows up-to congestion transactions by import bids for the top ten locations for the January through September period of 2011 and 2012.[55]

55 The source and sink aggregates in these tables refer to the name and location of a bus and do not include information about the behavior of any individual market participant.

Table 2-50 PJM cleared up-to congestion import bids by top ten source and sink pairs (MW): January through September, 2011 and 2012 (See 2011 SOM, Table 2-49)

2011 (Jan - Sep)				
Imports				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	N ILLINOIS HUB	HUB	2,697,394
NORTHWEST	INTERFACE	ZION 1	AGGREGATE	1,950,476
OVEC	INTERFACE	CONESVILLE 6	AGGREGATE	1,686,827
MISO	INTERFACE	112 WILTON	EHVAGG	1,584,297
NYIS	INTERFACE	MARION	AGGREGATE	1,137,814
NYIS	INTERFACE	PSEG	ZONE	966,283
SOUTHEAST	AGGREGATE	CRVWOOD	AGGREGATE	855,719
OVEC	INTERFACE	MARYSVILLE	EHVAGG	813,663
OVEC	INTERFACE	JEFFERSON	EHVAGG	800,642
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	798,145
Top ten total				13,291,259
PJM total				75,607,294
Top ten total as percent of PJM total				17.6%
2012 (Jan - Sep)				
Imports				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	112 WILTON	EHVAGG	8,832,551
MISO	INTERFACE	N ILLINOIS HUB	HUB	2,265,566
OVEC	INTERFACE	JEFFERSON	EHVAGG	1,958,932
OVEC	INTERFACE	DEOK	ZONE	1,795,528
OVEC	INTERFACE	COOK	EHVAGG	1,664,824
OVEC	INTERFACE	MARYSVILLE	EHVAGG	1,658,701
OVEC	INTERFACE	CONESVILLE 4	AGGREGATE	1,598,854
NYIS	INTERFACE	HUDSON BC	AGGREGATE	1,477,807
OVEC	INTERFACE	STUART 1	AGGREGATE	1,456,182
MISO	INTERFACE	COOK	EHVAGG	1,386,981
Top ten total				24,095,925
PJM total				122,824,468
Top ten total as percent of PJM total				19.6%

Table 2-51 shows up-to congestion transactions by export bids for the top ten locations for the January through September period of 2011 and 2012.

Table 2-51 PJM cleared up-to congestion export bids by top ten source and sink pairs (MW): January through September, 2011 and 2012 (See 2011 SOM, Table 2-49)

2011 (Jan - Sep)				
Exports				
Source	Source Type	Sink	Sink Type	MW
LUMBERTON	AGGREGATE	SOUTHEAST	AGGREGATE	5,458,432
WESTERN HUB	HUB	MISO	INTERFACE	2,629,676
FE GEN	AGGREGATE	SOUTHWEST	AGGREGATE	1,286,402
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	1,269,001
23 COLLINS	EHVAGG	MISO	INTERFACE	1,149,885
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	AGGREGATE	1,074,975
BELMONT	EHVAGG	OVEC	INTERFACE	934,962
FOWLER 34.5 KV FWLR1AWF	AGGREGATE	OVEC	INTERFACE	783,782
RECO	ZONE	IMO	INTERFACE	776,982
BEAV DUQ UNIT1	AGGREGATE	MICHFE	INTERFACE	742,722
Top ten total				16,106,818
PJM total				58,031,610
Top ten total as percent of PJM total				27.8%
2012 (Jan - Sep)				
Exports				
Source	Source Type	Sink	Sink Type	MW
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	3,403,395
ROCKPORT	EHVAGG	OVEC	INTERFACE	3,140,361
23 COLLINS	EHVAGG	MISO	INTERFACE	3,055,342
STUART 1	AGGREGATE	OVEC	INTERFACE	2,144,288
WESTERN HUB	HUB	MISO	INTERFACE	1,643,318
ROCKPORT	EHVAGG	MISO	INTERFACE	1,572,838
QUAD CITIES 1	AGGREGATE	NORTHWEST	INTERFACE	1,554,154
SPORN 3	AGGREGATE	OVEC	INTERFACE	1,472,620
STUART 4	AGGREGATE	OVEC	INTERFACE	1,292,612
SPORN 5	AGGREGATE	OVEC	INTERFACE	1,184,697
Top ten total				20,463,626
PJM total				122,815,948
Top ten total as percent of PJM total				16.7%

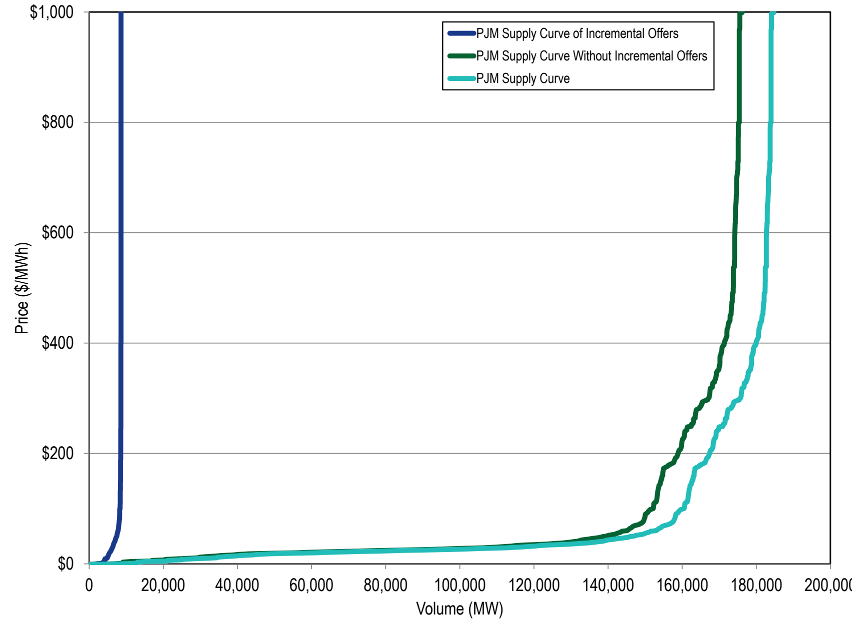
Table 2-52 shows up-to congestion transactions by wheel bids for the top ten locations for the January through September period of 2011 and 2012.

Table 2-52 PJM cleared up-to congestion wheel bids by top ten source and sink pairs (MW): January through September, 2011 and 2012 (See 2011 SOM, Table 2-49)

2011 (Jan - Sep)				
Wheels				
Source	Source Type	Sink	Sink Type	MW
CPLEIMP	INTERFACE	NCMPAEXP	INTERFACE	397,775
CPLEIMP	INTERFACE	DUKEXP	INTERFACE	287,643
NORTHWEST	INTERFACE	SOUTHWEST	AGGREGATE	204,835
NORTHWEST	INTERFACE	MISO	INTERFACE	188,239
NYIS	INTERFACE	MICHFE	INTERFACE	115,574
SOUTHWEST	AGGREGATE	OVEC	INTERFACE	111,932
MISO	INTERFACE	NIPSCO	INTERFACE	93,485
NIPSCO	INTERFACE	OVEC	INTERFACE	71,840
NIPSCO	INTERFACE	MISO	INTERFACE	63,809
NCMPAIMP	INTERFACE	OVEC	INTERFACE	62,459
Top ten total				1,597,590
PJM total				2,813,116
Top ten total as percent of PJM total				56.8%
2012 (Jan - Sep)				
Wheels				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	252,804
NYIS	INTERFACE	IMO	INTERFACE	162,091
SOUTHIMP	INTERFACE	MISO	INTERFACE	147,801
SOUTHEAST	INTERFACE	SOUTHEXP	INTERFACE	120,035
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	112,478
MISO	INTERFACE	NIPSCO	INTERFACE	102,657
NORTHWEST	INTERFACE	MISO	INTERFACE	99,449
OVEC	INTERFACE	IMO	INTERFACE	72,960
MISO	INTERFACE	OVEC	INTERFACE	66,900
SOUTHWEST	INTERFACE	OVEC	INTERFACE	61,943
Top ten total				1,199,119
PJM total				1,841,782
Top ten total as percent of PJM total				65.1%

Figure 2-23 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 March 2012.

Figure 2-23 PJM day-ahead aggregate supply curves: 2012 example day (See 2011 SOM, Figure 2-21)



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. Convergence is not the goal of virtual trading but it is a possible outcome. The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Market. 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 to negative (Figure 2-24). There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis (Figure 2-25).

As Table 2-53 shows, day-ahead and real-time prices were relatively close, on average, in the first nine months of 2011 and 2012.

Table 2-53 Day-ahead and real-time average LMP (Dollars per MWh): January through September, 2011 and 2012[56] (See 2011 SOM, Table 2-50)

	2011 (Jan - Sep)				2012 (Jan - Sep)			
	Day Ahead	Real Time	Difference	Difference as Percent of Real Time	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Average	$45.14	$45.79	$0.65	1.4%	$32.16	$32.45	$0.29	0.9%
Median	$40.20	$37.05	($3.14)	(8.5%)	$30.10	$28.78	($1.32)	(4.6%)
Standard deviation	$22.68	$32.25	$9.57	29.7%	$14.54	$21.94	$7.40	33.7%
Peak average	$54.11	$55.31	$1.19	2.2%	$38.16	$39.50	$1.34	3.4%
Peak median	$47.56	$42.89	($4.67)	(10.9%)	$33.74	$32.19	($1.55)	(4.8%)
Peak standard deviation	$27.09	$40.01	$12.92	32.3%	$17.76	$27.37	$9.60	35.1%
Off peak average	$37.22	$37.40	$0.18	0.5%	$26.95	$26.33	($0.62)	(2.4%)
Off peak median	$33.74	$32.90	($0.84)	(2.6%)	$25.95	$25.20	($0.74)	(2.9%)
Off peak standard deviation	$13.67	$19.86	$6.19	31.2%	$7.92	$12.98	$5.06	39.0%

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.

Table 2-54 shows the difference between the Real-Time and the Day-Ahead Energy Market Prices for the first nine months of 2001 to 2012.

Table 2-54 Day-ahead and real-time average LMP (Dollars per MWh): January through September, 2001 through 2012 (See 2011 SOM, Table 2-51)

(Jan - Sep)	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
2001	$36.07	$36.00	($0.07)	(0.2%)
2002	$28.29	$28.13	($0.16)	(0.6%)
2003	$41.20	$40.42	($0.77)	(1.9%)
2004	$42.64	$43.85	$1.22	2.9%
2005	$54.48	$54.69	$0.21	0.4%
2006	$50.45	$51.79	$1.34	2.7%
2007	$54.24	$57.34	$3.10	5.7%
2008	$71.43	$71.94	$0.51	0.7%
2009	$37.35	$37.42	$0.08	0.2%
2010	$45.81	$46.13	$0.32	0.7%
2011	$45.14	$45.79	$0.65	1.4%
2012	$32.16	$32.45	$0.29	0.9%

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

Table 2-55 provides frequency distributions of the differences between PJM real-time load-weighted hourly LMP and PJM day-ahead load-weighted hourly LMP for the first nine months of years 2007 through 2012.

Table 2-55 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): January through September, 2007 through 2012 (See 2011 SOM, Table 2-52)

	2007		2008		2009		2010		2011		2012	
LMP	Frequency	Cumulative Percent	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%	5	0.08%
($150) to ($100)	0	0.00%	1	0.02%	0	0.00%	0	0.00%	2	0.05%	6	0.17%
($100) to ($50)	26	0.40%	88	1.35%	3	0.05%	13	0.20%	49	0.79%	17	0.43%
($50) to $0	3,385	52.07%	3,730	58.08%	3,776	57.69%	4,091	62.65%	4,011	62.02%	4,112	62.97%
$0 to $50	2,914	96.55%	2,448	95.32%	2,736	99.45%	2,288	97.57%	2,290	96.98%	2,343	98.60%
$50 to $100	193	99.50%	264	99.33%	34	99.97%	130	99.56%	169	99.56%	61	99.53%
$100 to $150	21	99.82%	37	99.89%	2	100.00%	20	99.86%	21	99.88%	14	99.74%
$150 to $200	4	99.88%	4	99.95%	0	100.00%	8	99.98%	2	99.91%	10	99.89%
$200 to $250	1	99.89%	2	99.98%	0	100.00%	1	100.00%	3	99.95%	4	99.95%
$250 to $300	3	99.94%	0	99.98%	0	100.00%	0	100.00%	0	99.95%	1	99.97%
$300 to $350	2	99.97%	1	100.00%	0	100.00%	0	100.00%	0	99.95%	2	100.00%
$350 to $400	0	99.97%	0	100.00%	0	100.00%	0	100.00%	0	99.95%	0	100.00%
$400 to $450	1	99.98%	0	100.00%	0	100.00%	0	100.00%	0	99.95%	0	100.00%
$450 to $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.95%	0	100.00%
>= $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%	0	100.00%

Figure 2-24 shows the hourly differences between day-ahead and real-time load-weighted hourly LMP in the first nine months of 2012.

Figure 2-24 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: January through September, 2012 (See 2011 SOM, Figure 2-22)

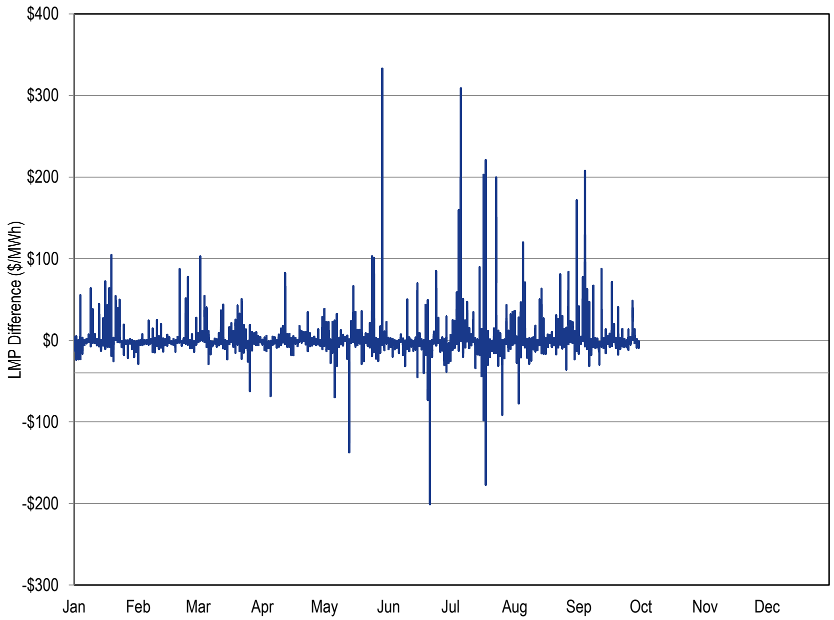
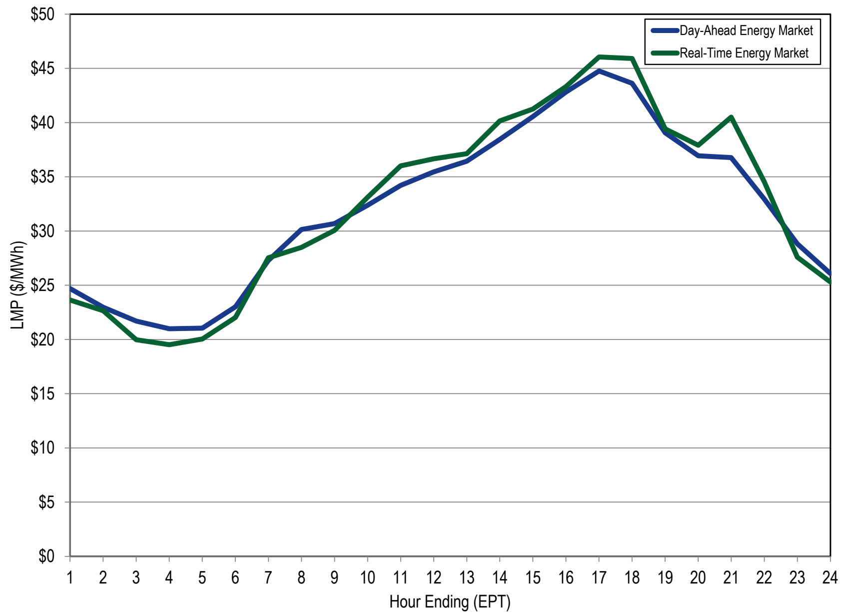


Figure 2-25 shows the monthly average differences between the day-ahead and real-time LMP in the first nine months of 2012.

Figure 2-25 Monthly average of real-time minus day-ahead LMP: January through September, 2012 (See 2011 SOM, Figure 2-23)

Figure 2-26 shows day-ahead and real-time LMP on an average hourly basis.

Figure 2-26 PJM system hourly average LMP: January through September, 2012 (See 2011 SOM, Figure 2-24)



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 2-56 shows the monthly average share of real-time load served by self-supply, bilateral contract and spot purchase in 2011 and 2012 based on parent company. For 2012, 9.4 percent of real-time load was supplied by bilateral contracts, 23.3 percent by spot market purchase and 67.3 percent by self-supply. Compared with 2011, reliance on bilateral contracts decreased 1.1 percentage points, reliance on spot supply decreased by 3.3 percentage points and reliance on self-supply increased by 4.4 percentage points.

Table 2-56 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: 2011 through 2012 (See 2011 SOM, Table 2-53)

	2011			2012			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	9.3%	28.8%	61.9%	10.0%	23.2%	66.9%	0.7%	(5.6%)	5.0%
Feb	10.9%	27.9%	61.2%	10.2%	22.3%	67.5%	(0.7%)	(5.6%)	6.3%
Mar	10.4%	29.3%	60.3%	10.6%	24.5%	64.8%	0.3%	(4.8%)	4.5%
Apr	10.7%	25.3%	64.1%	9.8%	23.8%	66.3%	(0.9%)	(1.4%)	2.3%
May	11.1%	25.7%	63.3%	8.9%	23.6%	67.5%	(2.3%)	(2.1%)	4.2%
Jun	10.5%	25.4%	64.1%	9.1%	23.0%	67.9%	(1.5%)	(2.4%)	3.9%
Jul	9.5%	24.7%	65.8%	8.6%	22.6%	68.8%	(0.9%)	(2.1%)	3.0%
Aug	10.3%	24.6%	65.1%	9.1%	23.2%	67.7%	(1.1%)	(1.4%)	2.6%
Sep	10.9%	26.7%	62.4%	9.6%	24.3%	66.1%	(1.3%)	(2.4%)	3.7%
Oct	12.2%	29.8%	58.0%						
Nov	10.7%	28.3%	61.1%						
Dec	10.1%	24.3%	65.5%						
Annual	10.5%	26.6%	62.9%	9.4%	23.3%	67.3%	(1.1%)	(3.3%)	4.4%

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 2-57 shows the monthly average share of day-ahead load served by self-supply, bilateral contracts and spot purchases in 2011 and 2012, based on parent companies. For 2012, 6.6 percent of day-ahead load was supplied by bilateral contracts, 22.2 percent by spot market purchases, and 71.1 percent by self-supply. Compared with 2011, reliance on bilateral contracts increased by 0.9 percentage points, reliance on spot supply decreased by 2.2 percentage points, and reliance on self-supply increased by 1.3 percentage points.

Table 2-57 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: 2011 through 2012 (See 2011 SOM, Table 2-54)

	2011			2012			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	4.7%	23.7%	71.6%	6.6%	21.4%	72.0%	1.9%	(2.3%)	0.4%
Feb	5.4%	23.7%	70.9%	6.7%	20.0%	73.3%	1.3%	(3.6%)	2.4%
Mar	5.8%	24.3%	70.0%	6.7%	22.9%	70.5%	0.9%	(1.4%)	0.5%
Apr	6.1%	23.8%	70.1%	6.7%	22.9%	70.4%	0.6%	(0.8%)	0.3%
May	6.0%	24.0%	70.0%	6.6%	22.8%	70.6%	0.6%	(1.2%)	0.6%
Jun	6.0%	25.3%	68.8%	7.9%	21.4%	70.7%	2.0%	(3.9%)	1.9%
Jul	5.5%	23.4%	71.2%	5.9%	22.2%	71.9%	0.5%	(1.2%)	0.7%
Aug	5.7%	24.1%	70.1%	6.4%	22.8%	70.8%	0.7%	(1.3%)	0.6%
Sep	5.8%	25.2%	69.0%	6.5%	24.4%	69.1%	0.7%	(0.8%)	0.1%
Oct	5.7%	25.7%	68.5%						
Nov	6.4%	25.3%	68.3%						
Dec	6.6%	25.3%	68.1%						
Annual	5.8%	24.4%	69.8%	6.6%	22.2%	71.1%	0.9%	(2.2%)	1.3%