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 six 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 six 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 (Herfindahl-Hirschman Index) indicate that by the FERC standards, the PJM Energy Market during the first six months of 2012 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1262 with a minimum of 992 and a maximum of 1657 in the first six 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 13,865, or 8.9 percent, from 154,963 MW in the first six months of 2011 to 168,828 MW in the first six months of 2012. The increase in offered supply was the result of the integration of the Duke Energy Ohio/Kentucky (DEOK) transmission zone in the first quarter of 2012, the integration of the American Transmission Systems, Inc. (ATSI) transmission zone in the second quarter of 2011, the addition of 5,008 MW of nameplate capacity to PJM in 2011 and the addition of 1,392 MW of nameplate capacity to PJM in the first six months of 2012.

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.

The increases in supply were partially offset by the deactivation of 14 units (2,261 MW) since January 1, 2012.

- In January through June 2012, coal units provided 40.3 percent, nuclear units 35.2 percent and gas units 19.4 percent of total generation. Compared to January through June 2011, generation from coal units decreased 9.9 percent, generation from nuclear units increased 7.6 percent, while generation from natural gas units increased 58.3 percent, and generation from oil units increased 159.4 percent.
- The PJM system peak load for the first six months of 2012 was 147,913 MW, which was 3,563 MW, or 2.5 percent, higher than the PJM peak load for the first six months of 2011.[4] The ATSI and DEOK transmission zones accounted for 17,502 MW in the peak hour of the first six months of 2012. The peak load excluding the ATSI and DEOK transmission zones was 130,411 MW, a decrease of 13,939 MW, or 9.7 percent, from the peak load for the first six months 2011.
- PJM average real-time load in the first six months of 2012 increased by 7.8 percent from the first six months of 2011, from 78,823 MW to 84,935 MW. The PJM average real-time load in the first six months of 2012 would have decreased by 5.5 percent from the first six months of 2011, from 78,823 MW to 74,470 MW, if the DEOK and ATSI transmission zones were excluded.
- PJM average day-ahead load, including DECs and up-to congestion transactions, increased in the first six months of 2012 by 23.6 percent from the first six months of 2011, from 105,070 MW to 129,881 MW. PJM average day-ahead load would have increased in the first six months of 2012 by 12.2 percent from the first six months of 2011, from 105,070 MW to 117,922 MW, if the DEOK and ATSI transmission zones were excluded.
- PJM average real-time generation increased by 5.9 percent in the first six months of 2012 from the first six months of 2011, from 81,483 MW to 86,310 MW. PJM average real-time generation would have decreased 4.9 percent in the first six months of 2012 from the first six months of 2011, from 81,483 MW to 77,473 MW, if the DEOK and ATSI transmission zones were excluded.
- PJM Real-Time Energy Market prices decreased in the first six months of 2012 compared to the first six months of 2011. The load-weighted average LMP was 35.6 percent lower in the first six months of 2012 than in the first six months of 2011, $31.21 per MWh versus $48.47 per MWh.
- PJM Day-Ahead Energy Market prices decreased in the first six months of 2012 compared to the first six months of 2011. The load-weighted average LMP was 32.4 percent lower in the first six months of 2012 than in the first six months of 2011, $31.84 per MWh versus $47.12 per MWh.
- Based on average spot fuel prices, the fuel cost of a new entrant combined cycle unit ($18.74/MWh) was lower than the fuel cost of a new entrant coal plant ($20.38/MWh) in the first six months of 2012.
- Levels of offer capping for local market power remained low. In the first six months of 2012, 1.7 percent of unit hours and 1.1 percent of MW were offer capped in the Real-Time Energy Market and 0.1 percent of unit hours and 0.1 percent of MW were offer capped in the Day-Ahead Energy Market.
- Of the 108 units that were eligible to include a Frequently Mitigated Unit (FMU) or Associated Unit (AU) adder in their cost-based offer during the first six months of 2012, 77 (71.3 percent) qualified in all months, and 12 (11.1 percent) qualified in only one month of the first six months of 2012.
- There were no scarcity pricing events in the first six months of 2012 under PJM's current Emergency Action based scarcity pricing rules.

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).

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in the first six 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 supply offered increased by 13,865 MW in the first six months of 2012 compared to the first six months of 2011, while aggregate peak load increased by 3,563 MW, modifying the general supply demand balance with a corresponding impact on energy market prices. In the Real-Time Energy Market, average load in the first six months of 2012 increased from the first six months of 2011, from 78,823 MW to 84,935 MW. Market concentration levels remained moderate. This relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive for most hours.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load. LMP is a broader indicator of the level of competition. While PJM has experienced price spikes, these have been limited in duration and, in general, prices in PJM have been well below the marginal cost of the highest cost unit installed on the system. The significant price spikes in PJM have been directly related to supply and demand fundamentals. In PJM, prices tend to increase as the market approaches scarcity conditions as a result of generator offers and the associated shape of the aggregate supply curve. The pattern of prices within days and across months and years illustrates how prices are directly related to demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price. Energy Market results for the first six 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. 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.[5]

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers and prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between

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

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 six months of 2012.

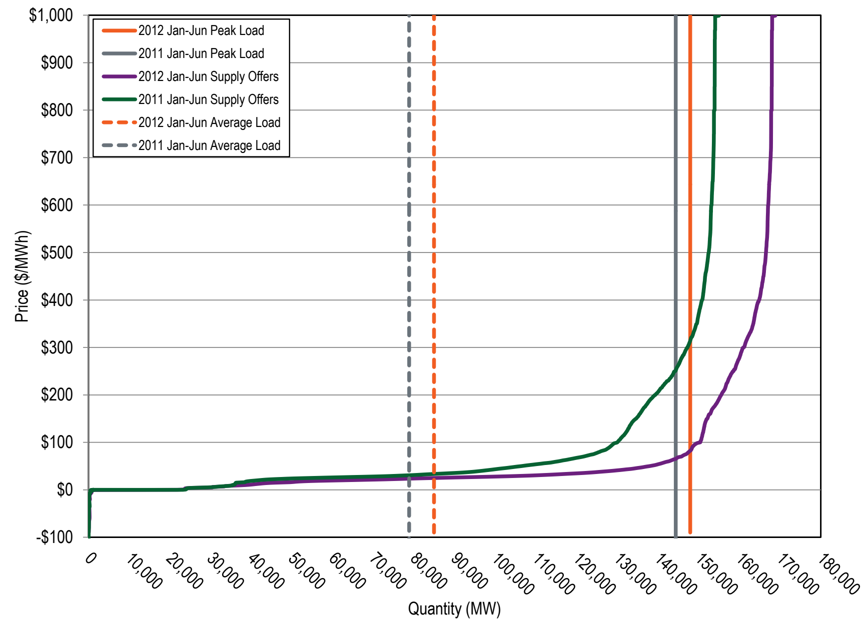
Market Structure

Supply

Average offered supply increased by 13,865, or 8.9 percent, from 154,963 MW in the first six months of 2011 to 168,828 MW in the first six months of 2012.[6] The increase in offered supply was the result of the integration of the DEOK transmission zone in the first quarter of 2012, integration of the ATSI transmission zone in the second quarter of 2011, the addition of 5,008 MW of nameplate capacity to PJM in 2011 and the addition of 1,392 MW of nameplate capacity to PJM in the first six months of 2012. This includes six large plants (over 500 MW) that began generating in PJM between January 1,2011 and June 30, 2012. The increases in supply were partially offset by the deactivation of 14 units (2,261 MW) since January 1, 2012.

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

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



Energy Production by Fuel Source

Compared to January through June, 2011, generation from coal units decreased 9.9 percent and generation from natural gas units increased 58.3 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 22.5 percent in the first two quarters of 2012 compared to the first two quarters of 2011.

6 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.

Table 2-2 PJM generation (By fuel source (GWh)): January through June 2011 and 2012[7] (See 2011 SOM, Table 2-2)

	Jan-Jun 2011		Jan-Jun 2012		
	GWh	Percent	GWh	Percent	Change in Output
Coal	171,383.6	47.4%	154,421.6	40.3%	(9.9%)
Standard Coal	165,440.4	45.7%	149,358.0	39.0%	(9.4%)
Waste Coal	5,943.2	1.6%	5,063.6	1.3%	(0.5%)
Nuclear	125,257.1	34.6%	134,802.4	35.2%	7.6%
Gas	47,066.3	13.0%	74,280.3	19.4%	57.8%
Natural Gas	46,203.7	12.8%	73,131.1	19.1%	58.3%
Landfill Gas	862.6	0.2%	1,148.9	0.3%	33.2%
Biomass Gas	0.1	0.0%	0.2	0.0%	194.2%
Wind	6,370.2	1.8%	7,729.1	2.0%	21.3%
Hydroelectric	8,031.1	2.2%	6,815.9	1.8%	(15.1%)
Waste	2,596.4	0.7%	2,590.6	0.7%	(0.2%)
Solid Waste	1,981.4	0.5%	2,089.7	0.5%	5.5%
Miscellaneous	614.9	0.2%	500.9	0.1%	(18.5%)
Oil	932.1	0.3%	2,417.8	0.6%	159.4%
Heavy Oil	789.2	0.2%	2,287.6	0.6%	189.9%
Light Oil	130.5	0.0%	124.7	0.0%	(4.5%)
Diesel	7.8	0.0%	4.4	0.0%	(44.0%)
Kerosene	4.6	0.0%	1.2	0.0%	(74.0%)
Jet Oil	0.0	0.0%	0.0	0.0%	(39.0%)
Solar	21.6	0.0%	119.7	0.0%	453.8%
Battery	0.1	0.0%	0.2	0.0%	34.2%
Total	361,658.6	100.0%	383,177.5	100.0%	6.0%

7 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.

Table 2-3 PJM Generation (By fuel source (GWh)): January through June 2011 and 2012; excluding ATSI and DEOK zones[8] (See 2011 SOM, Table 2-2)

	Jan-Jun 2011		Jan-Jun 2012		
	GWh	Percent	GWh	Percent	Change in Output
Coal	171,383.6	47.4%	132,761.7	37.6%	(22.5%)
Standard Coal	165,440.4	45.7%	127,698.1	36.2%	(22.0%)
Waste Coal	5,943.2	1.6%	5,063.6	1.4%	(0.5%)
Nuclear	125,257.1	34.6%	127,592.1	36.2%	1.9%
Gas	47,066.3	13.0%	72,733.5	20.6%	54.5%
Natural Gas	46,203.7	12.8%	71,652.4	20.3%	55.1%
Landfill Gas	862.6	0.2%	1,080.9	0.3%	25.3%
Biomass Gas	0.1	0.0%	0.2	0.0%	194.2%
Wind	6,370.2	1.8%	7,729.1	2.2%	21.3%
Hydroelectric	8,031.1	2.2%	6,815.9	1.9%	(15.1%)
Waste	2,596.4	0.7%	2,590.6	0.7%	(0.2%)
Solid Waste	1,981.4	0.5%	2,089.7	0.6%	5.5%
Miscellaneous	614.9	0.2%	500.9	0.1%	(18.5%)
Oil	932.1	0.3%	2,416.7	0.7%	159.3%
Heavy Oil	789.2	0.2%	2,287.6	0.6%	189.9%
Light Oil	130.5	0.0%	124.3	0.0%	(4.8%)
Diesel	7.8	0.0%	3.6	0.0%	(53.5%)
Kerosene	4.6	0.0%	1.2	0.0%	(74.0%)
Jet Oil	0.0	0.0%	0.0	0.0%	(39.0%)
Solar	21.6	0.0%	119.7	0.0%	453.8%
Battery	0.1	0.0%	0.2	0.0%	34.2%
Total	361,658.6	100.0%	352,759.5	100.0%	(2.5%)

8 ATSI zone is included only for the months of June 2011 and June 2012.

Generator Offers

Table 2-4 shows the distribution of MW generator offers by offer prices for the first six months of 2012.

Table 2-4 Distribution[9,10] of MW for unit offer prices: January through June of 2012 (See 2011 SOM, Table 2-3)

	Range												
	($200) - $0		$0 - $200		$200 - $400		$400 - $600		$600 - $800		$800 - $1,000		
Unit Type	Dispatchable	Self-Scheduled	Dispatchable	Self-Scheduled	Dispatchable	Self-Scheduled	Dispatchable	Self-Scheduled	Dispatchable	Self-Scheduled	Dispatchable	Self-Scheduled	Total
CC	0.0%	0.2%	61.5%	15.6%	12.4%	0.5%	3.1%	0.0%	5.5%	0.3%	0.9%	0.0%	100.0%
CT	0.0%	0.1%	41.3%	0.3%	16.4%	0.0%	12.0%	0.0%	26.0%	0.0%	3.7%	0.1%	100.0%
Diesel	0.0%	15.6%	8.6%	10.1%	56.9%	0.1%	6.6%	0.0%	1.2%	0.0%	0.8%	0.2%	100.0%
Hydro	0.0%	96.5%	0.0%	2.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%	100.0%
Nuclear	0.0%	42.9%	9.8%	47.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Pumped Storage	53.0%	47.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Solar	0.0%	59.1%	40.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Steam	0.0%	1.4%	49.9%	23.8%	12.5%	11.8%	0.1%	0.0%	0.1%	0.2%	0.1%	0.1%	100.0%
Transaction	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Wind	38.5%	55.2%	6.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
All Offers (by type)	1.9%	11.9%	40.0%	19.9%	10.6%	5.1%	3.0%	0.0%	6.4%	0.1%	1.0%	0.1%	100.0%
All Offers (total)		13.9%		59.8%		15.7%		3.0%		6.5%		1.1%	100.0%

Demand

The PJM system peak load for the first six months of 2012 was 147,913 MW in the HE 1800 on June 20, 2012, which was 3,563 MW, or 2.5 percent, higher than the PJM peak load for the first six months of 2011, which was 144,350 MW in the HE 1700 on June 8, 2011. The ATSI and DEOK transmission zones accounted for 17,502 MW in the peak hour of the first six months of 2012. The peak load excluding the ATSI and DEOK transmission zones was 130,411 MW, also occurring on June 20, 2012, HE 1800, a decrease of 13,939 MW, or 9.7 percent, first six months of 2011 peak load.

Table 2-5 shows the coincident peak loads for the first six months of years 2003 through 2012.

Table 2-5 Actual[11] PJM footprint peak loads: January through June of 2003 to 2012 (See 2011 SOM, Table 2-4)

(Jan - Jun)	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
2003	Thu, June 26	17	61,310	NA	NA
2004	Wed, June 09	17	77,676	16,366	26.7%
2005	Tue, June 28	16	124,052	46,375	59.7%
2006	Tue, May 30	17	121,165	(2,887)	(2.3%)
2007	Wed, June 27	16	130,971	9,806	8.1%
2008	Mon, June 09	17	130,100	(871)	(0.7%)
2009	Fri, January 16	19	117,169	(12,930)	(9.9%)
2010	Wed, June 23	17	126,188	9,019	7.7%
2011	Wed, June 08	17	144,350	18,162	14.4%
2012 (with DEOK and ATSI)	Wed, June 20	18	147,913	3,563	2.5%
2012 (without DEOK and ATSI)	Wed, June 20	18	130,411	(13,939)	(9.7%)

9 Each range in the table is greater than the start value and less than or equal to the end value.
10 The unit type battery is not included in this table because batteries do not make energy offers.

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

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

Figure 2-2 PJM[12] footprint first six months peak loads: 2003 to 2012 (See 2011 SOM, Figure 2-2)

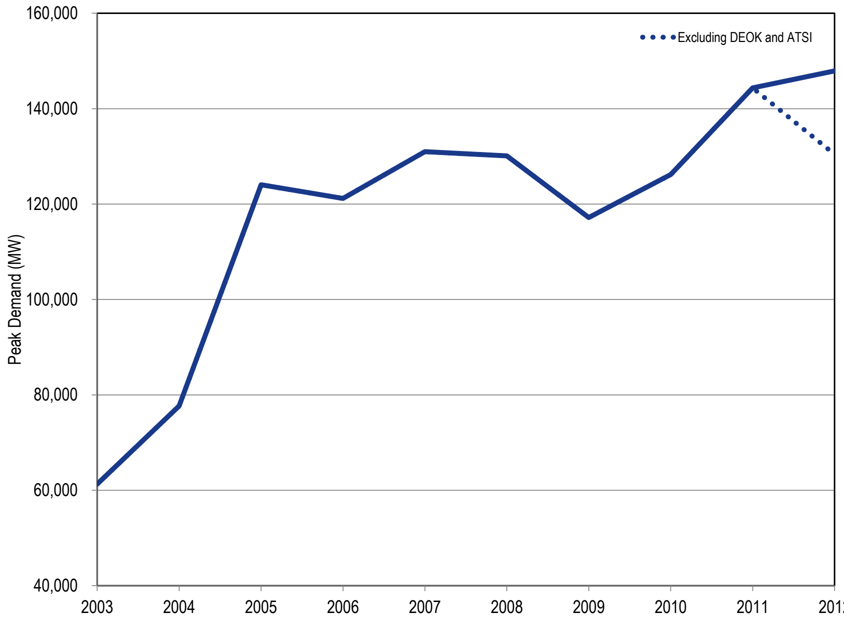
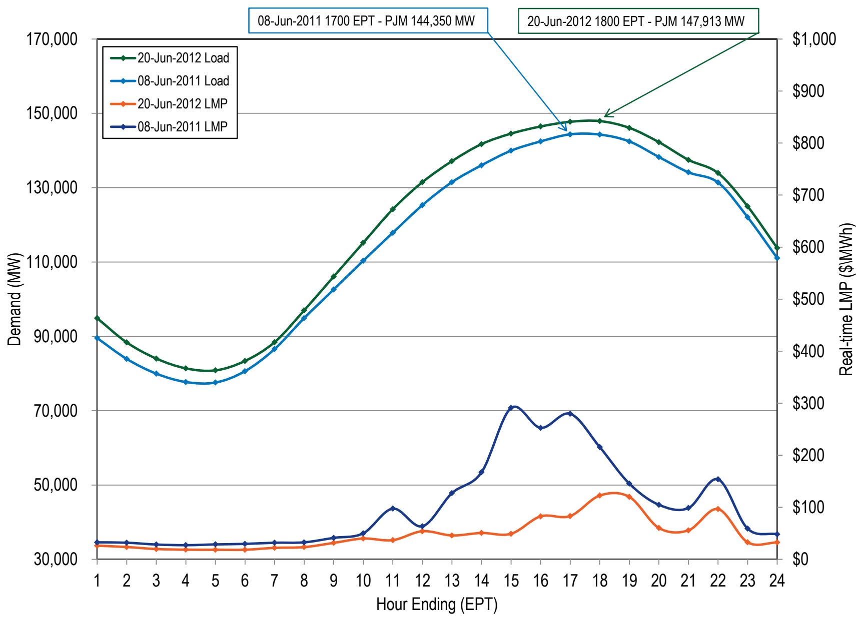


Figure 2-3 shows the peak load and LMP comparison for the first six months of 2011 and 2012.

Figure 2-3 PJM peak-load comparison: Wednesday, June 20, 2012, and Wednesday, June 08, 2011 (See 2011 SOM, Figure 2-3)



Market Concentration

Analyses of supply curve segments of the PJM Energy Market for the first six months of 2012 indicate moderate concentration in the baseload segment and intermediate segment, but high concentration in the peaking segment.[13] 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

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

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

power and generation owners' obligations to serve load were generally effective in preventing the exercise of market power in these areas during the first six 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 2-6).

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 six months of 2012 was moderately concentrated (Table 2-6).

Table 2-6 PJM hourly Energy Market HHI: January through June 2011[14] and 2012 (See 2011 SOM, Table 2-5)

	Hourly Market HHI (Jan - Jun, 2012)	Hourly Market HHI (Jan - Jun, 2011)
Average	1262	1216
Minimum	992	889
Maximum	1657	1564
Highest market share (One hour)	32%	30%
Average of the highest hourly market share	23%	21%
# Hours	4,367	4,343
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 2-7 includes 2012 HHI values by supply curve segment, including base, intermediate and peaking plants.[15]

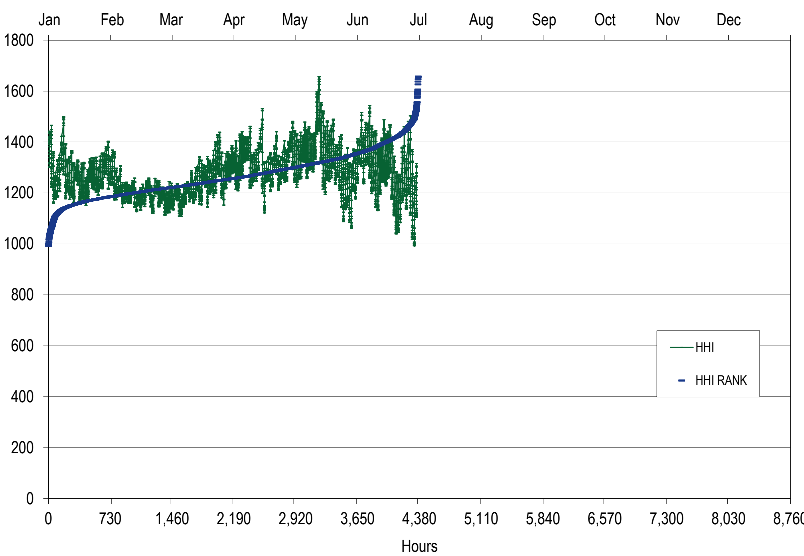
14 This analysis includes all hours in the first six months of 2012, regardless of congestion.
15 A unit is classified as 'Base' if it runs for more than 50% of the total hours, 'Intermediate' if it runs for less than 50% but greater than 10% of the total hours, and 'Peak' if it runs for less than 10% of the total hours.

Table 2-7 PJM hourly Energy Market HHI (By supply segment): January through June 2012 (See 2011 SOM, Table 2-6)

	Minimum	Average	Maximum
Base	1126	1308	1703
Intermediate	1015	1664	4924
Peak	614	6020	10000

Figure 2-4 presents the 2012 hourly HHI values in chronological order and an HHI duration curve that shows 2012 HHI values in ascending order of magnitude.

Figure 2-4 PJM hourly Energy Market HHI: January through June 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 2-8.

Table 2-8 Offer-capping statistics: January through June from 2008 to 2012 (See 2011 SOM, Table 2-7)

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2008	1.0%	0.2%	0.2%	0.0%
2009	0.5%	0.2%	0.1%	0.0%
2010	0.9%	0.3%	0.3%	0.1%
2011	0.7%	0.3%	0.0%	0.0%
2012	1.7%	1.1%	0.1%	0.1%

Table 2-9 presents data on the frequency with which units were offer capped in the first six months of 2012.

Table 2-9 Real-time offer-capped unit statistics: January through June 2012 (See 2011 SOM, Table 2-8)

	2012 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	1	2	16
80% and < 90%	0	0	0	0	1	5
75% and < 80%	1	0	0	0	0	5
70% and < 75%	1	0	0	0	0	7
60% and < 70%	3	0	0	0	2	11
50% and < 60%	3	0	1	0	1	12
25% and < 50%	7	1	2	3	2	53
10% and < 25%	0	1	1	2	4	50

Table 2-9 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 six months of 2012, the AEP, AP, BGE, ComEd, DLCO, Dominion, DPL, Met-Ed, PECO, Pepco and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 50 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 six months of 2012.[16] The AECO, DAY, JCPL, PENELEC, PPL and RECO Control Zones were not affected by constraints binding for 50 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 June 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 2-10 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.

16 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 2-10 Three pivotal supplier results summary for regional constraints: January through June 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	1,751	399	23%	1,551	89%
	Off Peak	575	278	48%	422	73%
AEP-DOM	Peak	663	31	5%	654	99%
	Off Peak	437	24	5%	429	98%
AP South	Peak	1,317	133	10%	1,277	97%
	Off Peak	951	236	25%	882	93%
Bedington - Black Oak	Peak	257	108	42%	199	77%
	Off Peak	NA	NA	NA	NA	NA
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	486	105	22%	433	89%
	Off Peak	39	14	36%	31	79%

Table 2-11 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing for the regional 500 kV constraints.

Table 2-11 Three pivotal supplier test details for regional constraints: January through June 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	335	482	16	3	13
	Off Peak	213	409	16	7	9
AEP-DOM	Peak	242	320	8	0	8
	Off Peak	214	353	9	0	8
AP South	Peak	333	465	10	1	10
	Off Peak	262	522	11	2	9
Bedington - Black Oak	Peak	91	137	11	4	6
	Off Peak	NA	NA	NA	NA	NA
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	772	857	17	4	13
	Off Peak	849	976	15	5	10

Table 2-12 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 2-12 Summary of three pivotal supplier tests applied for regional constraints: January through June 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	1,751	63	4%	22	1%	35%
	Off Peak	575	9	2%	0	0%	0%
AEP-DOM	Peak	663	36	5%	19	3%	53%
	Off Peak	437	22	5%	18	4%	82%
AP South	Peak	1,317	26	2%	6	0%	23%
	Off Peak	951	9	1%	0	0%	0%
Bedington - Black Oak	Peak	257	2	1%	2	1%	100%
	Off Peak	NA	NA	NA	NA	NA	NA
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	486	36	7%	7	1%	19%
	Off Peak	39	6	15%	0	0%	0%

Ownership of Marginal Resources

Table 2-13 shows the contribution to PJM real-time, annual, load-weighted LMP by individual marginal resource owner.[17] The contribution of each marginal resource to price at each load bus is calculated for January through June, 2012, and summed by the company that offers the marginal resource into the Real-Time Energy Market. The results show that, during the first six months of 2012, the offers of one company contributed 24 percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies contributed 58 percent of the real-time, load-weighted, average PJM system LMP.

Table 2-13 Marginal unit contribution to PJM real-time, load-weighted LMP (By parent company): January through June 2012 (See 2011 SOM, Table 2-12)

Company	Percent of Price
1	24%
2	16%
3	9%
4	8%
5	7%
6	5%
7	5%
8	4%
9	4%
Other (51companies)	18%

Table 2-14 shows the contribution to PJM day-ahead, load-weighted LMP by individual marginal resource owner.[18] The contribution of each marginal resource to price at each load bus is calculated for the January through June, 2012, period and summed by the company that offers the marginal resource into the Day-Ahead Energy Market.

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

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

Table 2-14 Marginal unit contribution to PJM day-ahead, load-weighted LMP (By parent company): January through June, 2012 (See 2011 SOM, Table 2-13)

Company	Percent of Price
1	17%
2	10%
3	7%
4	6%
5	6%
6	5%
7	4%
8	4%
9	3%
Other (115 companies)	38%

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 2-15 shows the type of fuel used by marginal resources in the Real Time Energy Market. In the first six months of 2012, coal units were 59 percent of marginal resources and natural gas units were 29 percent of marginal resources.

Table 2-15 Type of fuel used (By real-time marginal units): January through June, 2012 (See 2011 SOM, Table 2-14)

Fuel Type	Jan - Jun, 2012
Coal	59%
Gas	29%
Municipal Waste	0%
Oil	4%
Wind	8%
Total	100%

Table 2-16 shows the type, and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market.

Table 2-16 Day-ahead marginal resources by type/fuel: January through June, 2012 (See 2011 SOM, Table 2-15)

Type/Fuel	Jan - Jun 2012
Up-to Congestion Transaction	86%
DEC	5%
INC	5%
Coal	3%
Gas	1%
Dispatchable Transaction	0%
Price Sensitive Demand	0%
Wind	0%
Oil	0%
Municipal Waste	0%
Diesel	0%
Total	100%

Frequently Mitigated Units and Associated Units

An FMU is a frequently mitigated unit. FMUs were first provided additional compensation as a form of scarcity pricing in 2005.[19] The definition of FMUs provides for a set of graduated adders associated with increasing levels of offer capping. Units capped for 60 percent or more of their run hours and less than 70 percent are entitled to an adder of either 10 percent of their cost-based offer or $20 per MWh. Units capped 70 percent or more of their run hours and less than 80 percent are entitled to an adder of either 15 percent of their cost-based offer (not to exceed $40) or $30 per MWh. Units capped 80 percent or more of their run hours are entitled to an adder of $40 per MWh or the unit-specific, going-forward costs of the affected unit as a cost-based offer.[20] These categories are designated Tier 1, Tier 2 and Tier 3, respectively.[21,22]

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

19 110 FERC ¶ 61,053 (2005).
20 OA, Schedule 1 § 6.4.2.
21 114 FERC ¶ 61, 076 (2006).
22 See "Settlement Agreement," Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).

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.

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.[23]

Table 2-17 shows the number of FMUs and AUs in the first six months of 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 2-17 Number of frequently mitigated units and associated units (By month): January through June, 2012 (See 2011 SOM, Table 2-26)

	FMUs and AUs			Total Eligible
	Tier 1	Tier 2	Tier 3	for Any Adder
January	26	21	52	99
February	26	22	47	95
March	25	17	47	89
April	23	17	46	86
May	23	14	47	84
June	22	13	48	83

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.

Figure 2-5 Frequently mitigated units and associated units (By month): February, 2006 through June, 2012 (See 2011 SOM, Figure 2-5)

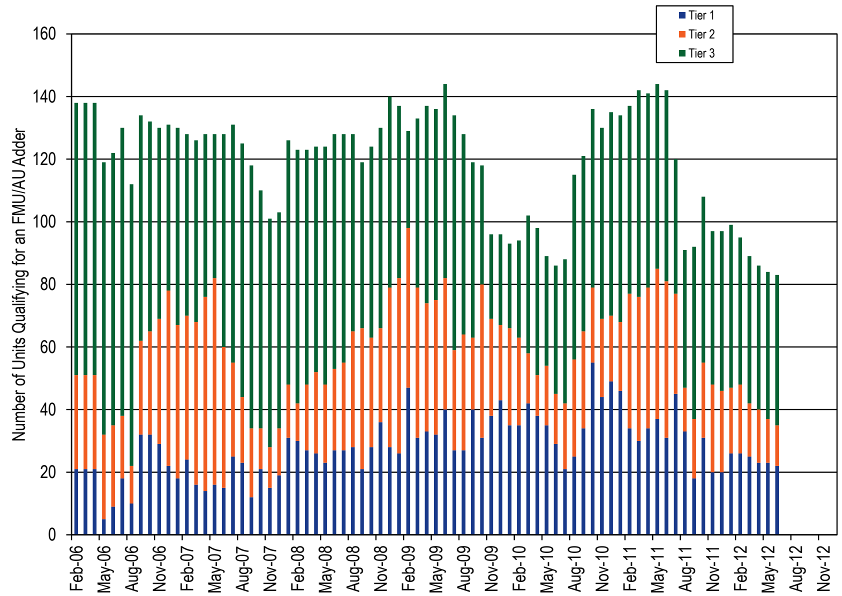


Table 2-18 shows the number of months FMUs and AUs that were eligible for any adder (Tier 1, Tier 2 or Tier 3) during the first six months 2012. Of the 108 units eligible in at least one month during the first six months of 2012, 77 units (71.3 percent) were FMUs or AUs for all six months, and 12 (11.1 percent) qualified in only one month of 2012.

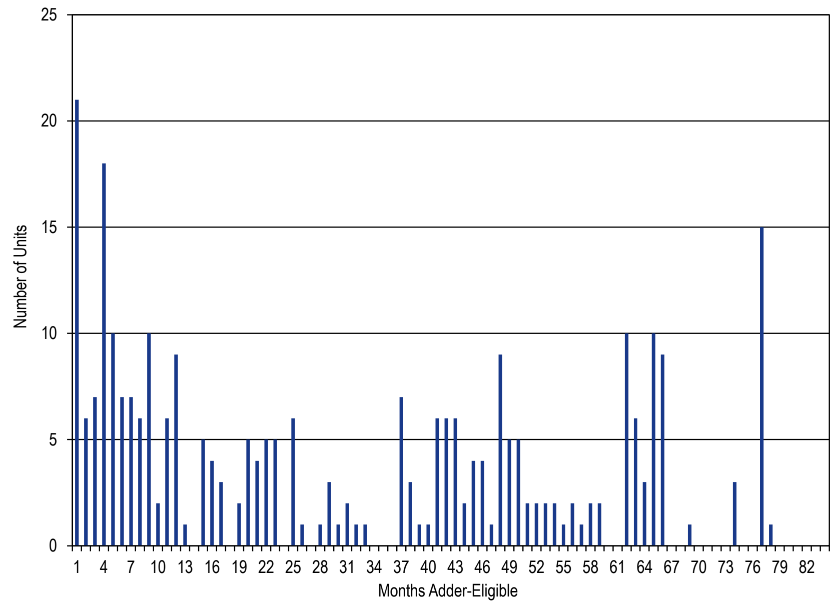
23 OA, Schedule 1 § 6.4.2. In 2007, the FERC approved OA revisions to clarify the AU criteria.

Table 2-18 Frequently mitigated units and associated units total months eligible: January through June, 2012 (See 2011 SOM, Table 2-27)

Months Adder-Eligible	FMU & AU Count
1	12
2	10
3	0
4	8
5	1
6	77
Total	108

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 June 30, 2012, there have been 293 unique units that have qualified for an FMU adder in at least one month. Of these 293 units, only one unit qualified for an adder in all potential months. Fifteen additional units qualified in 77 of the 78 possible months, and 123 of the 293 units (42.0 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 June, 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 six months of 2012 increased by 7.8 percent from the first six months of 2011, from 78,823 MW to 84,935 MW. The PJM average real-time load in the first six months of 2012 would have decreased by 5.5 percent from the first six months of 2011, from 78,823 MW to 74,470 MW, if the DEOK and ATSI transmission zones were excluded.

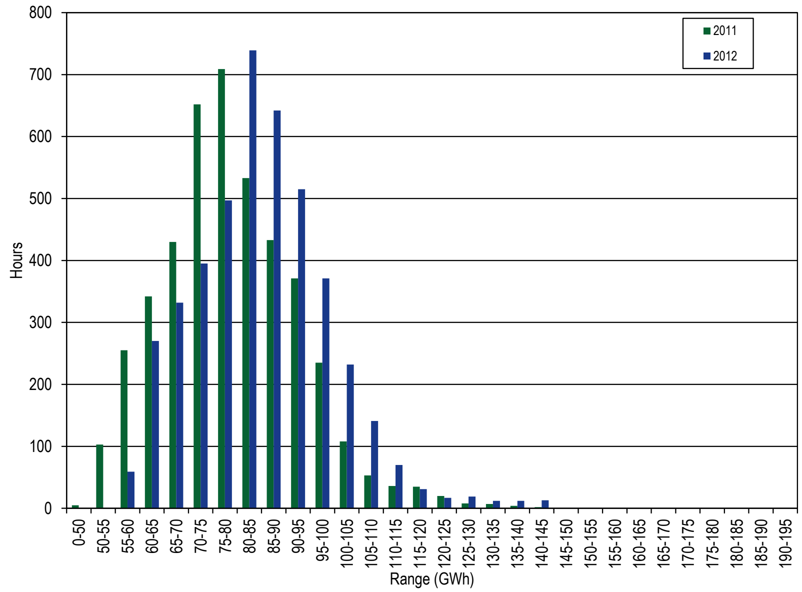
PJM average day-ahead load in the first six months of 2012, including DECs and up-to congestion transactions, increased by 23.6 percent from the first six months of 2011, from 105,070 MW to 129,881 MW. PJM average day-ahead load in the first six months of 2012, including DECs and up-to congestion transactions, would have been 12.2 percent higher than in the first six months of 2011, from 105,070 MW to 117,922 MW if the DEOK and ATSI transmission zones were excluded.

Real-Time Load

PJM Real-Time Load Duration

Figure 2-7 shows the hourly distribution of PJM real time load for the first six months of 2011 and 2012.[24]

Figure 2-7 PJM real-time accounting load histogram: January through June for years 2011 and 2012[25] (See 2011 SOM, Figure 2-7)



24 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.

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

PJM Real-Time, Average Load

Table 2-19 presents summary real-time load statistics for the first six 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.[26]

Table 2-19 PJM real-time average hourly load: January through June for years 1998 through 2012[27] (See 2011 SOM, Table 2-28)

	PJM Real-Time Load (MWh)		Year-to-Year Change	
(Jan-Jun)	Average Load	Load Standard Deviation	Average Load	Load Standard Deviation
1998	27,662	4,703	NA	NA
1999	28,714	5,113	3.8%	8.7%
2000	29,649	5,382	3.3%	5.3%
2001	30,180	5,274	1.8%	(2.0%)
2002	32,678	6,457	8.3%	22.4%
2003	36,727	6,428	12.4%	(0.4%)
2004	41,787	8,999	13.8%	40.0%
2005	71,939	13,603	72.2%	51.2%
2006	77,232	12,003	7.4%	(11.8%)
2007	81,110	13,499	5.0%	12.5%
2008	78,685	12,819	(3.0%)	(5.0%)
2009	75,991	12,899	(3.4%)	0.6%
2010	78,106	13,643	2.8%	5.8%
2011	78,823	13,931	0.9%	2.1%
2012	84,935	13,951	7.8%	0.1%

26 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.*

27 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 six months of 2012 with those in 2011.

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

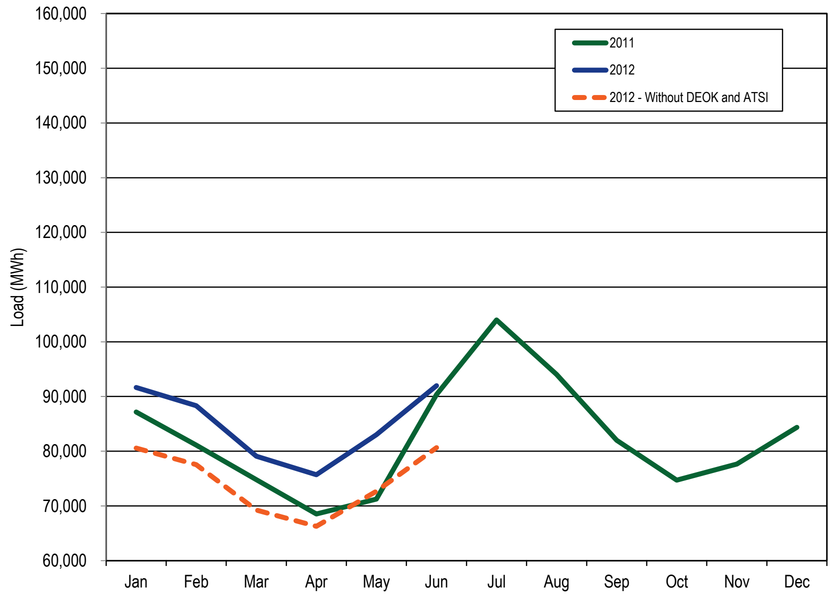


Table 2-20 shows the load weighted THI, WWP and average temperature for heating, cooling and shoulder seasons.[28]

Table 2-20 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	75.14	26.43	52.22
2012	73.99	30.26	58.33

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.[29] 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.

28 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, February and December. Average temperature is used for the rest of months. For additional information on the calculation of these weather variables, see PJM "Manual 19: Load Forecasting and Analysis," Revision 20 (June 28, 2012), Section 3, pp. 15-16. Load weighting using real-time zonal accounting load.

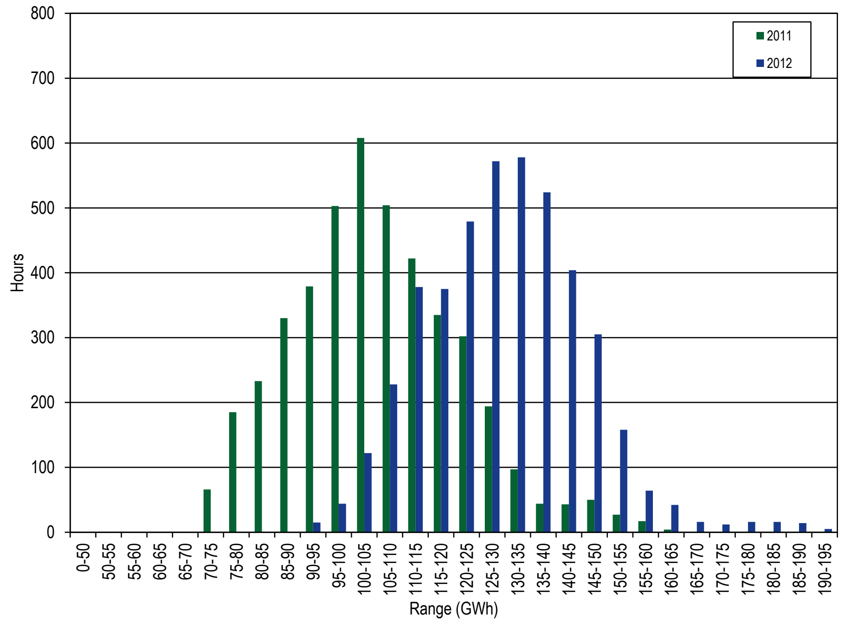
29 Up-to congestion transactions are cleared based on the entire price difference between source and sink including the congestion and loss components of LMP.

PJM day-ahead load is the hourly total of the four types of cleared demand bids.[30]

PJM Day-Ahead Load Duration

Figure 2-9 shows the hourly distribution of PJM day-ahead load for the first six months of 2011 and 2012.

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



PJM Day-Ahead, Average Load

Table 2-21 presents summary day-ahead load statistics for the first six months of 12 year period 2001 to 2012.

Table 2-21 PJM day-ahead average load: January through June for years 2001 through 2012[31] (See 2011 SOM, Table 2-31)

	PJM Day-Ahead Load (MWh)						Year-to-Year Change		
	Average			Standard Deviation			Average		
(Jan-Jun)	Load	Up-to Congestion	Total Load	Load	Up-to Congestion	Total Load	Load	Up-to Congestion	Total Load
2001	32,413	11	32,425	6,016	39	6,014	NA	NA	NA
2002	37,497	65	37,561	8,268	149	8,293	15.7%	481.9%	15.8%
2003	44,112	279	44,391	7,730	289	7,717	17.6%	332.5%	18.2%
2004	49,393	768	50,161	10,003	575	10,304	12.0%	175.1%	13.0%
2005	85,784	1,106	86,890	14,632	737	14,677	73.7%	44.0%	73.2%
2006	91,060	3,410	94,470	12,862	1,383	12,925	6.1%	208.3%	8.7%
2007	100,097	4,640	104,737	14,532	1,455	15,019	9.9%	36.1%	10.9%
2008	95,486	5,462	100,948	13,724	1,642	14,255	(4.6%)	17.7%	(3.6%)
2009	88,688	6,441	95,130	14,650	2,134	15,878	(7.1%)	17.9%	(5.8%)
2010	89,830	9,861	99,691	15,372	5,836	18,097	1.3%	53.1%	4.8%
2011	87,260	17,810	105,070	15,402	3,081	16,452	(2.9%)	80.6%	5.4%
2012	91,062	38,820	129,881	14,851	5,803	15,268	4.4%	118.0%	23.6%

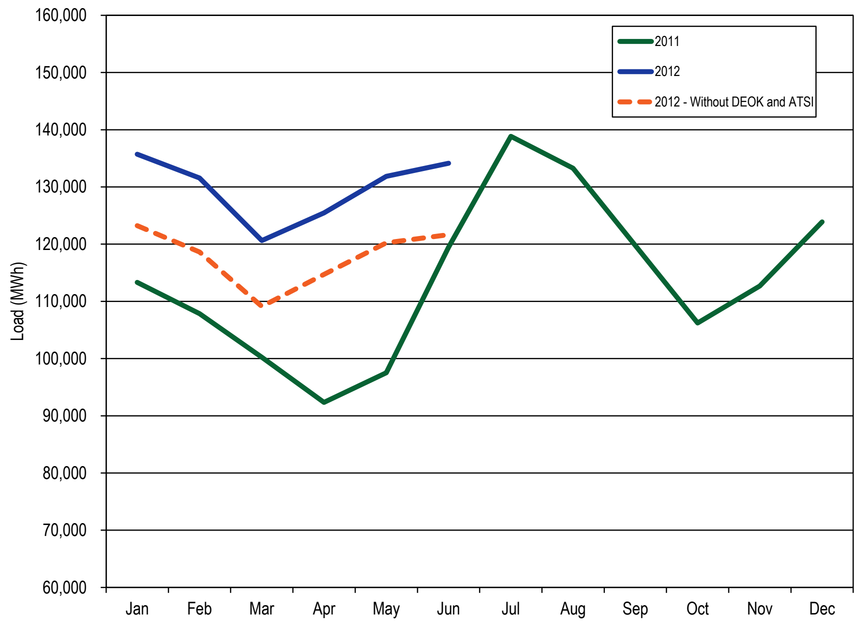
PJM Day-Ahead, Monthly Average Load

Figure 2-10 compares the day-ahead, monthly average hourly loads of the first six months of 2012 with those of 2011.

30 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.

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

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



Real-Time and Day-Ahead Load

Table 2-22 presents summary statistics for the first six months of 2011 and 2012 day-ahead and real-time loads.

Figure 2-11 shows the first six 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 2-11 Day-ahead and real-time loads (Average hourly volumes): January through June of 2012 (See 2011 SOM, Figure 2-10)

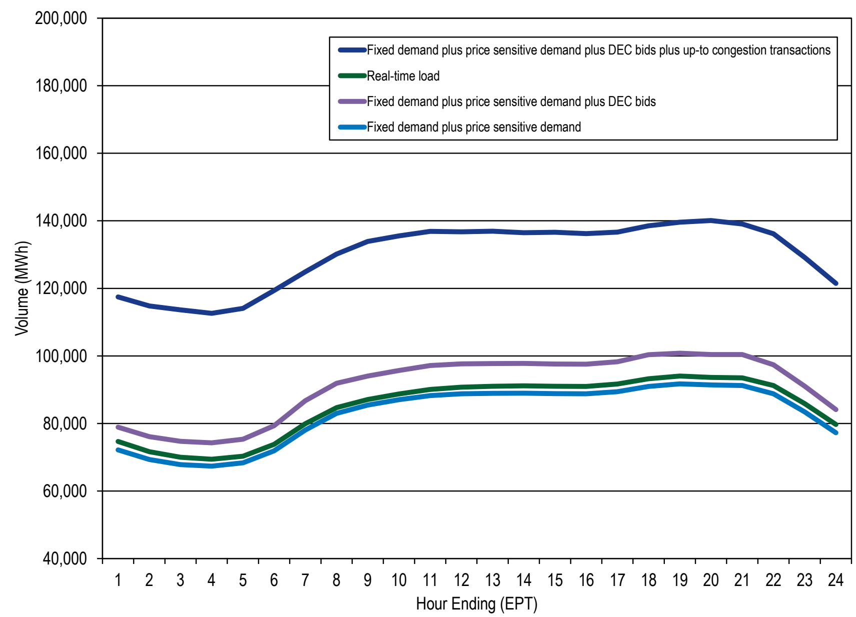
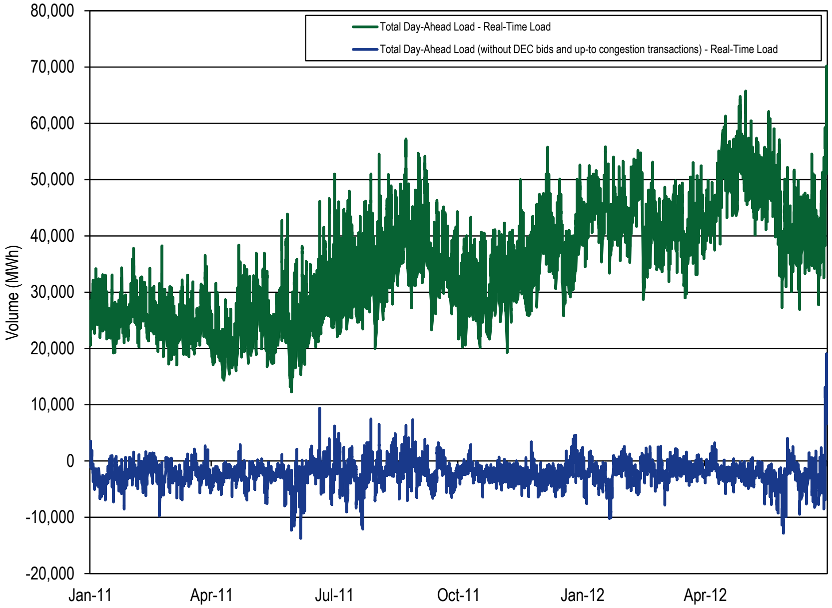


Table 2-22 Cleared day-ahead and real-time load (MWh): January through June for years 2011 and 2012 (See 2011 SOM, Table 2-32)

		Day Ahead					Real Time	Average Difference	
	(Jan-Jun)	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	75,532	816	10,913	17,810	105,070	78,823	26,247	(2,476)
	2012	82,005	803	8,254	38,820	129,881	84,935	44,947	(2,127)
Median	2011	74,208	794	10,675	17,669	104,014	77,321	26,693	(1,651)
	2012	81,798	786	7,941	37,924	129,714	84,339	45,375	(490)
Standard Deviation	2011	13,371	186	2,349	3,081	16,452	13,931	2,521	(2,909)
	2012	13,458	145	1,826	5,803	15,268	13,951	1,317	(6,312)
Peak Average	2011	83,290	897	12,465	18,565	115,217	86,848	28,368	(2,661)
	2012	90,072	863	9,047	39,039	139,020	93,082	45,938	(2,148)
Peak Median	2011	80,961	879	12,204	18,452	112,756	84,494	28,262	(2,394)
	2012	87,994	835	8,704	38,201	137,526	90,635	46,891	(14)
Peak Standard Deviation	2011	11,775	183	1,960	3,186	13,976	12,279	1,697	(3,448)
	2012	10,646	142	1,809	5,675	11,984	11,283	701	(6,784)
Off-Peak Average	2011	68,608	744	9,527	17,137	96,016	71,662	24,354	(2,310)
	2012	74,775	750	7,543	38,623	121,691	77,633	44,058	(2,108)
Off-Peak Median	2011	67,494	721	9,391	17,026	94,851	70,488	24,363	(2,054)
	2012	73,291	722	7,265	37,511	120,445	75,915	44,531	(245)
Off-Peak Standard Deviation	2011	10,630	158	1,715	2,819	12,810	11,135	1,674	(2,860)
	2012	11,459	126	1,524	5,909	13,092	11,913	1,180	(6,254)

Figure 2-12 shows the difference between the day-ahead and real-time average daily loads in the first six months of 2012 and the first six months of 2011.

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



Real-Time and Day-Ahead Generation

PJM average real-time generation in the first six months of 2012 increased by 5.9 percent from the first six months of 2011, from 81,483 MW to 86,310 MW. PJM average real-time generation in the first six months of 2012 would have decreased 4.9 percent from the first six months of 2011, from 81,483 MW to 77,473 MW if the DEOK and ATSI transmission zones were excluded.

PJM average day-ahead generation in the first six months of 2012, including INCs and up-to congestion transactions, increased by 22.4 percent from the first six months of 2011, from 108,143 MW to 132,328 MW. PJM average day-ahead generation in the first six months of 2012, including INCs and up-to congestion transactions, would have been 15.7 percent higher than in the first six months of 2011, from 108,143 MW to 125,102 MW if the DEOK and ATSI transmission zones were excluded.

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:[32]

- **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.[33]
- **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.[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.

Table 2-23 presents summary real-time generation statistics for the first six months of each year from 2003 through 2012.

32 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."
33 The definition of self-scheduled is based on the PJM. "eMKT User Guide" (December 1, 2011), pp. 38-40.
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.

Table 2-23 PJM[35] real-time average hourly generation: January through June for years 2003 through 2012 (See 2011 SOM, Table 2-33)

	PJM Real-Time Generation (MWh)		Year-to-Year Change	
(Jan-Jun)	Average Generation	Generation Standard Deviation	Average Generation	Generation Standard Deviation
2003	36,034	6,008	NA	NA
2004	41,430	9,435	15.0%	57.0%
2005	74,365	12,661	79.5%	34.2%
2006	80,249	11,011	7.9%	(13.0%)
2007	83,478	12,105	4.0%	9.9%
2008	83,294	12,458	(0.2%)	2.9%
2009	77,508	12,961	(6.9%)	4.0%
2010	80,702	13,968	4.1%	7.8%
2011	81,483	13,677	1.0%	(2.1%)
2012	86,310	13,695	5.9%	0.1%

Table 2-24 presents summary day-ahead generation statistics for the first six months of each year from 2003 through 2012.

Table 2-24 PJM[36] day-ahead average hourly generation: January through June for years 2003 through 2012 (See 2011 SOM, Table 2-34)

	PJM Day-Ahead Generation (MWh)						Year-to-Year Change		
	Average			Standard Deviation			Average		
Year	Generation (Cleared Gen. and INC Offers)	Up-to Congestion	Total Generation	Generation (Cleared Gen. and INC Offers)	Up-to Congestion	Total Generation	Generation (Cleared Gen. and INC Offers)	Up-to Congestion	Total Generation
2003	36,141	279	36,420	7,036	289	7,000	NA	NA	NA
2004	49,321	768	50,089	9,796	575	10,108	36.5%	175.1%	37.5%
2005	86,749	1,106	87,855	14,310	737	14,365	75.9%	44.0%	75.4%
2006	92,153	3,410	95,562	12,581	1,383	12,620	6.2%	208.3%	8.8%
2007	101,830	4,640	106,470	14,029	1,455	14,522	10.5%	36.1%	11.4%
2008	99,243	5,462	104,705	13,565	1,642	14,124	(2.5%)	17.7%	(1.7%)
2009	91,166	6,441	97,607	15,055	2,134	16,283	(8.1%)	17.9%	(6.8%)
2010	92,765	9,861	102,626	15,591	5,836	18,206	1.8%	53.1%	5.1%
2011	90,332	17,810	108,143	15,618	3,081	16,666	(2.6%)	80.6%	5.4%
2012	93,507	38,820	132,326	15,375	5,803	15,710	3.5%	118.0%	22.4%

Table 2-25 presents summary statistics for first six months of 2011 and 2012 for day-ahead and real-time generation.

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

Table 2-25 Day-ahead and real-time generation (MWh): January through June for years 2011 and 2012 (See 2011 SOM, Table 2-35)

		Day Ahead					Average Difference	
	(Jan-Jun)	Cleared Generation	Cleared INC Offers	Cleared Up-to Congestion	Cleared Generation Plus INC Offers Plus Up-to Congestion	Real Time Generation	Cleared Generation	Cleared Generation Plus INC Offers Plus Up-to Congestion
Average	2011	82,443	7,889	17,810	108,143	81,483	960	26,660
	2012	87,146	6,361	38,820	132,326	86,310	836	46,017
Median	2011	81,194	7,802	17,669	107,177	80,089	1,105	27,088
	2012	86,700	6,320	37,924	132,286	85,685	1,015	46,601
Standard Deviation	2011	14,810	1,266	3,081	16,666	13,677	1,133	2,988
	2012	15,282	805	5,803	15,710	13,695	1,587	2,015
Peak Average	2011	91,256	8,676	18,565	118,497	89,371	1,885	29,126
	2012	95,968	6,612	39,039	141,619	93,959	2,009	47,660
Peak Median	2011	88,986	8,570	18,452	116,332	87,053	1,933	29,279
	2012	93,537	6,556	38,201	140,047	91,650	1,887	48,397
Peak Standard Deviation	2011	12,599	1,064	3,186	14,036	12,011	588	2,025
	2012	12,174	623	5,675	12,322	11,303	870	1,018
Off-Peak Average	2011	74,578	7,188	17,137	98,903	74,443	135	24,459
	2012	79,239	6,136	38,623	123,998	79,454	(215)	44,544
Off-Peak Median	2011	73,386	7,079	17,026	97,689	73,368	18	24,321
	2012	77,782	6,016	37,511	122,849	77,725	57	45,124
Off-Peak Standard Deviation	2011	11,929	990	2,819	12,991	10,964	964	2,027
	2012	13,332	880	5,909	13,608	11,904	1,428	1,704

Figure 2-13 shows the first six 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.[37]

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

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

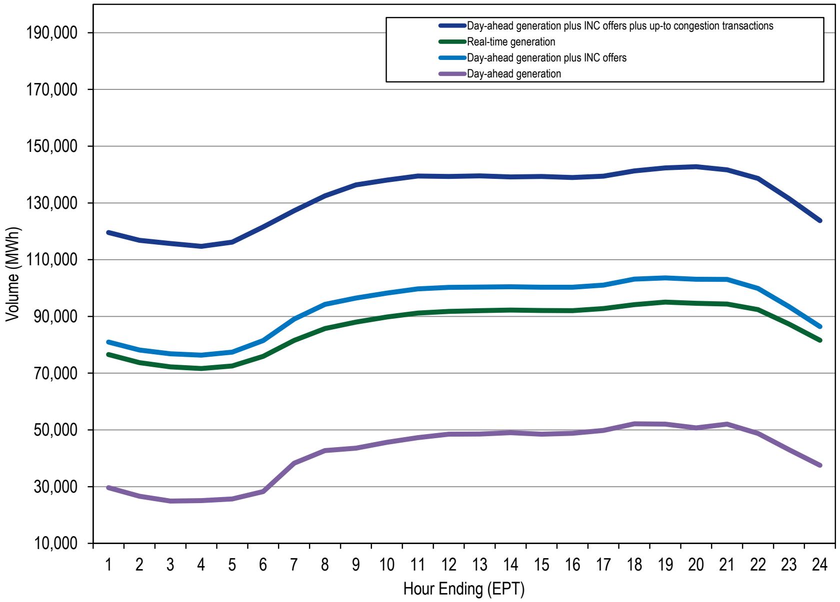
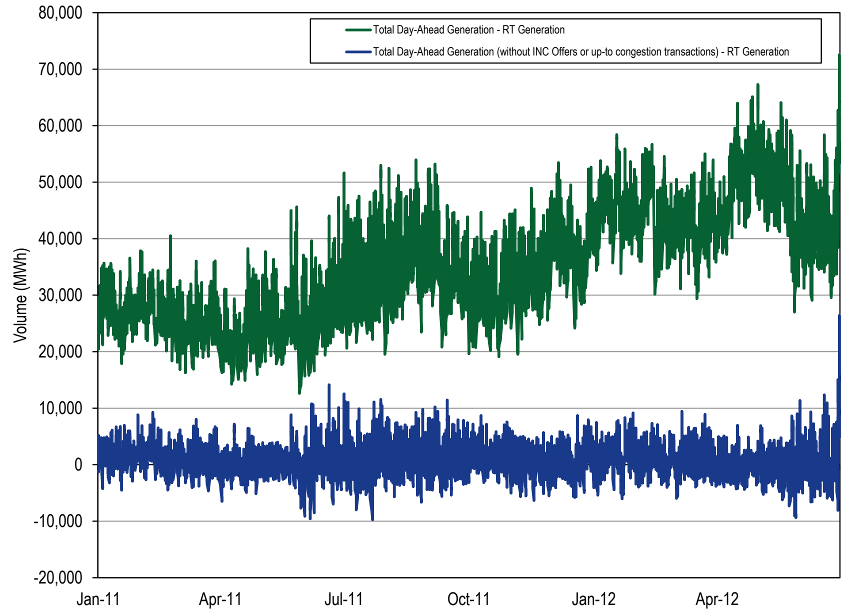


Figure 2-14 shows the difference between the day-ahead and real-time average daily generation in the first six months of 2012 and the first six months of 2011.

Figure 2-14 Difference between day-ahead and real-time generation (Average daily volumes): January 2011 through June 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.[38]

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

38 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 35.6 percent and 32.4 percent lower than in the first six months of 2011 as a result of lower fuel costs and relatively low demand.[39]

PJM Real-Time Energy Market prices decreased in the first six months of 2012 compared to the first six months of 2011. The system average LMP was 34.6 percent lower in the first six months of 2012 than in the first six months of 2011, $29.74 per MWh versus $45.51 per MWh. The load-weighted average LMP was 35.6 percent lower in the first six months of 2012 than in the first six months of 2011, $31.21 per MWh versus $48.47 per MWh.

PJM Day-Ahead Energy Market prices decreased in the first six months of 2012 compared to the first six months of 2011. The system average LMP was 32.0 percent lower in the first six months of 2012 than in the first six months of 2011, $30.44 per MWh versus $44.75 per MWh. The load-weighted average LMP was 32.4 percent lower in the first six months of 2012 than in the first six months of 2011, $31.84 per MWh versus $47.12 per MWh.[40]

Real-Time LMP

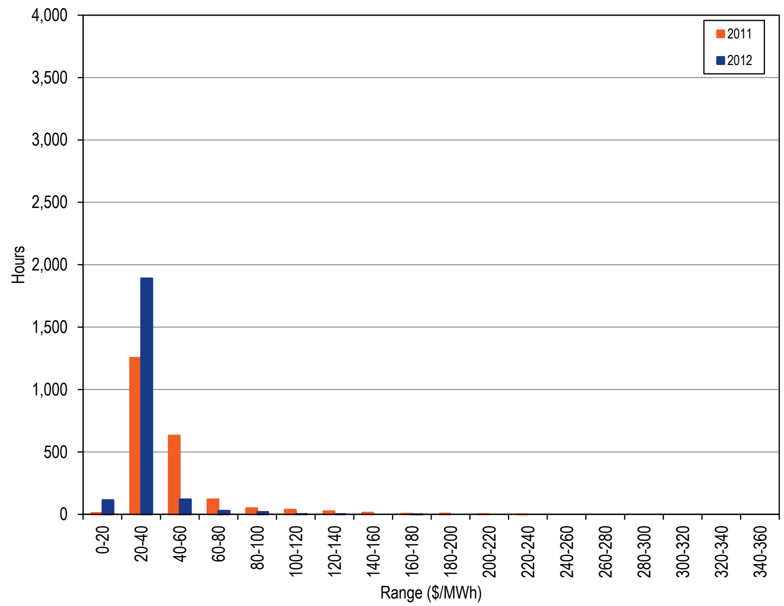
Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[41] This section discusses the real-time average LMP and the real-time load weighted average LMP. Average LMP is the unweighted average LMP.

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 2-15 shows the number of hours that PJM real-time average LMP for the first six months of 2011 and 2012 were within a defined range.

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



39 There was an average reduction of 3.5 heating degree days in the first six months of 2012 which meant reduced demand.
40 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".
41 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price" for detailed definition of Real-Time LMP.

PJM Real-Time, Average LMP

Table 2-26 shows the PJM real-time, annual, average LMP for the first six months of the 15-year period 1998 to 2012.[42]

Table 2-26 PJM real-time, average LMP (Dollars per MWh): January through June, 1998 through 2012 (See 2011 SOM, Table 2-36)

	Real-Time LMP			Year-to-Year Change		
(Jan-Jun)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$20.13	$15.90	$15.59	NA	NA	NA
1999	$22.94	$17.84	$41.16	14.0%	12.2%	164.0%
2000	$25.38	$18.03	$25.65	10.6%	1.1%	(37.7%)
2001	$33.10	$25.69	$21.11	30.4%	42.5%	(17.7%)
2002	$24.10	$19.64	$13.21	(27.2%)	(23.6%)	(37.4%)
2003	$41.31	$33.74	$27.81	71.4%	71.8%	110.6%
2004	$44.99	$40.75	$22.97	8.9%	20.8%	(17.4%)
2005	$45.71	$39.80	$23.51	1.6%	(2.3%)	2.3%
2006	$49.36	$43.46	$25.26	8.0%	9.2%	7.5%
2007	$55.03	$48.05	$31.42	11.5%	10.6%	24.4%
2008	$70.19	$59.53	$41.77	27.6%	23.9%	33.0%
2009	$40.12	$35.42	$19.30	(42.8%)	(40.5%)	(53.8%)
2010	$43.27	$37.11	$22.20	7.9%	4.8%	15.0%
2011	$45.51	$37.40	$32.52	5.2%	0.8%	46.5%
2012	$29.74	$28.32	$16.10	(34.6%)	(24.3%)	(50.5%)

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 2-27 shows the PJM real-time, load-weighted, average LMP for the first six months of each year of the 15-year period 1998 to 2012.

Table 2-27 PJM real-time, load-weighted, average LMP (Dollars per MWh): January through June, 1998 through 2012 (See 2011 SOM, Table 2-37)

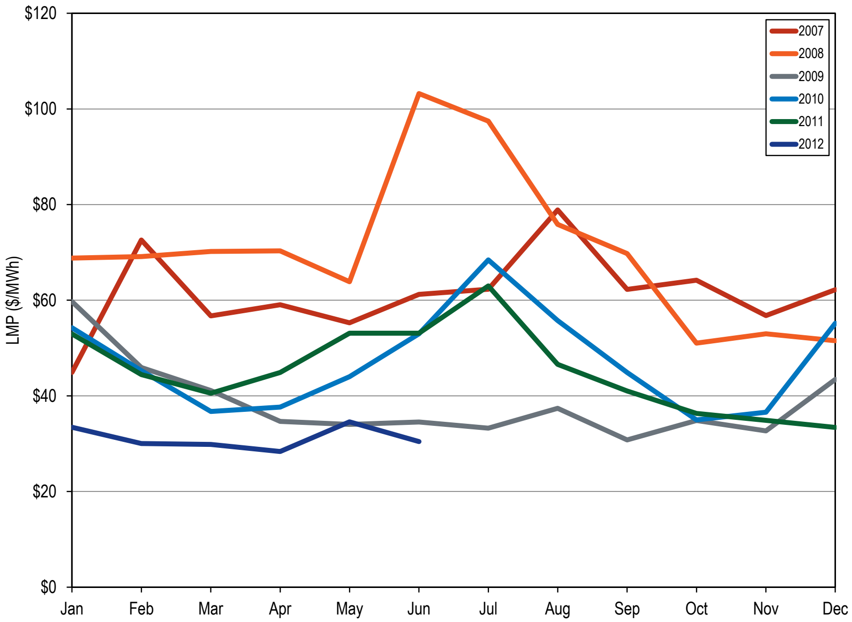
	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Jun)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.66	$16.80	$18.39	NA	NA	NA
1999	$25.34	$18.59	$52.06	17.0%	10.7%	183.1%
2000	$27.76	$18.91	$29.69	9.5%	1.7%	(43.0%)
2001	$35.27	$27.88	$22.12	27.0%	47.4%	(25.5%)
2002	$25.93	$20.67	$14.62	(26.5%)	(25.9%)	(33.9%)
2003	$44.43	$37.98	$28.55	71.4%	83.8%	95.2%
2004	$47.62	$43.96	$23.30	7.2%	15.8%	(18.4%)
2005	$48.67	$42.30	$24.81	2.2%	(3.8%)	6.5%
2006	$51.83	$45.79	$26.54	6.5%	8.3%	7.0%
2007	$58.32	$52.52	$32.39	12.5%	14.7%	22.1%
2008	$74.77	$64.26	$44.25	28.2%	22.4%	36.6%
2009	$42.48	$36.95	$20.61	(43.2%)	(42.5%)	(53.4%)
2010	$45.75	$38.78	$23.60	7.7%	5.0%	14.5%
2011	$48.47	$38.63	$37.59	5.9%	(0.4%)	59.3%
2012	$31.21	$28.97	$17.69	(35.6%)	(25.0%)	(52.9%)

42 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.

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

Figure 2-16 shows the PJM real-time, monthly, load-weighted LMP from 2007 through the first six months of 2012.

Figure 2-16 PJM real-time, monthly, load-weighted, average LMP: 2007 through June 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 six months of 2012. Comparing prices in the first six months of 2012 to prices in the first six months of 2011, the price of Northern Appalachian coal was 7.3 percent lower; the price of Central Appalachian coal was 18.3 percent lower; the price of Powder River Basin coal was 32.7 percent lower; the price of eastern natural gas was 42.9 percent lower; and the price of western natural gas was 41.2 percent lower. Figure 2-17 shows monthly average spot fuel prices for 2011 and 2012.[43]

Figure 2-17 Spot average fuel price comparison: 2011 and January through June 2012 (See 2011 SOM, Figure 2-17)

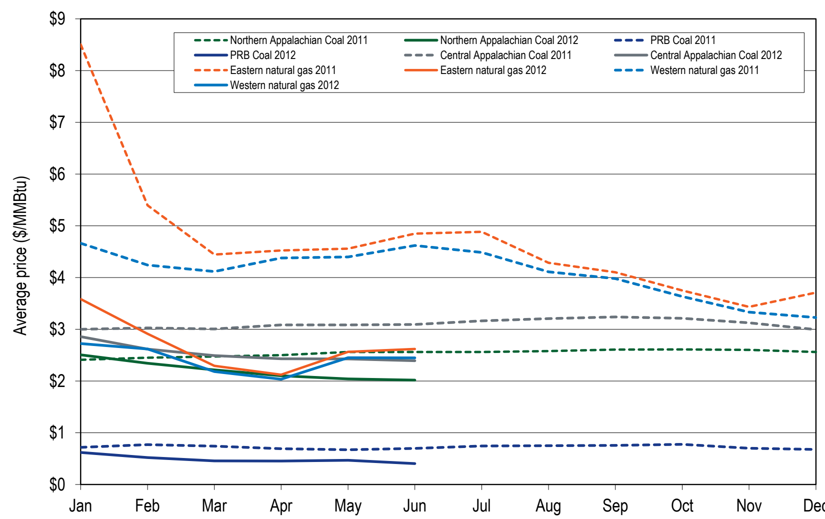


Figure 2-12 shows the average spot cost of generation, comparing the fuel cost of a coal plant, combined cycle, and combustion turbine in dollars per MWh. On average, the fuel cost of a new entrant combined cycle unit ($18.74/MWh) was lower than the fuel cost of a new entrant coal plant ($20.38/MWh) in the first six months of 2012.

43 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 2-18 Average spot fuel cost of generation of CP, CT, and CC: 2011 and January through June 2012 (New Figure)

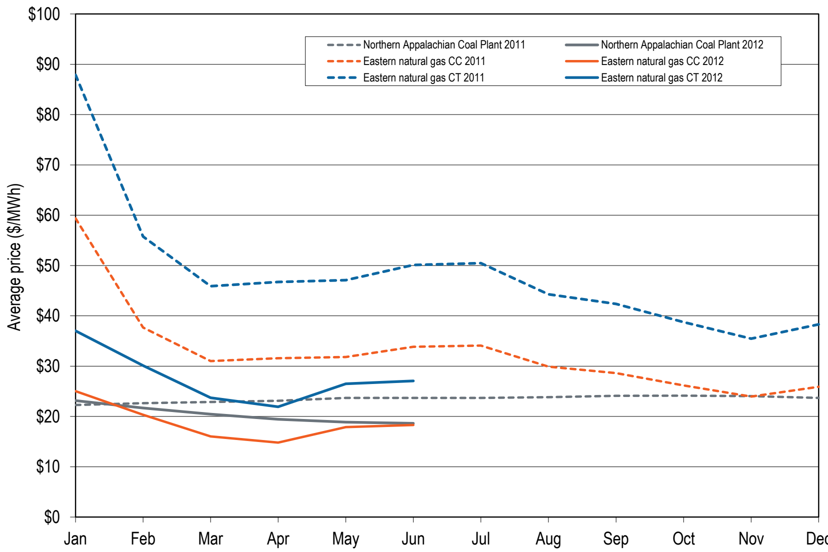


Table 2-28 compares the first six months of 2012 PJM real-time fuel-cost-adjusted, load-weighted, average LMP to the first six months of 2011 load-weighted, average LMP. The fuel-cost adjusted load-weighted, average LMP for the first six month of 2012 was 22.7 percent higher than the load-weighted, average LMP for the first six months of 2012. The real-time, fuel-cost-adjusted, load-weighted, average LMP for the first six months of 2012 was 21.0 percent lower than the load-weighted LMP for the first six months of 2011. If fuel costs in the first six months of 2012 had been the same as in the first six months of 2011, the 2012 load-weighted LMP would have been higher, $38.29 per MWh instead of the observed $31.21 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 2-28 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-Jun, 2012 Load-Weighted LMP	Jan-Jun, 2012 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$31.21	$38.29	22.7%
	Jan-Jun, 2011 Load-Weighted LMP	Jan-Jun, 2012 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$48.47	$38.29	(21.0%)
	Jan-Jun, 2011 Load-Weighted LMP	Jan-Jun, 2012 Load-Weighted LMP	Change
Average	$48.47	$31.21	(35.6%)

Day-Ahead LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[44] This section discusses the day-ahead average LMP and the day-ahead load weighted average LMP. Average LMP is the unweighted average LMP.

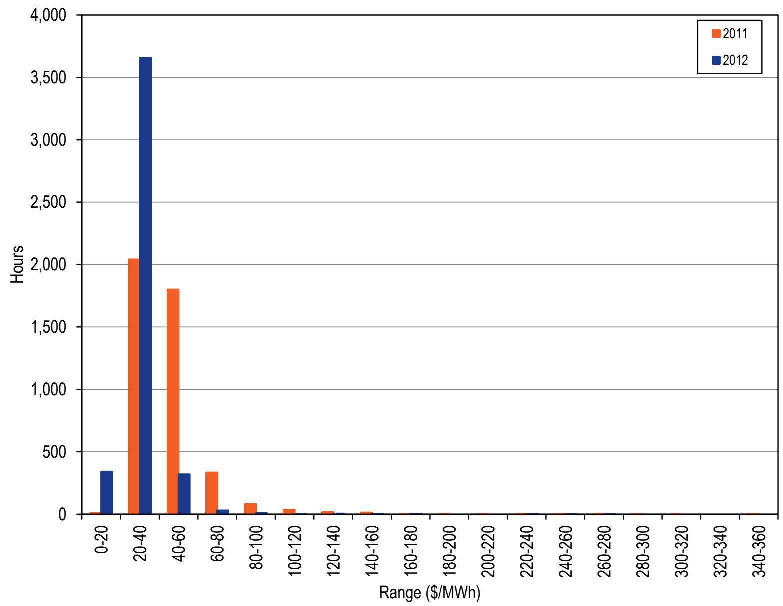
Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 2-19 shows the hourly distribution of PJM day-ahead average LMP for the first six months of 2011 and 2012.

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

Figure 2-19 Price histogram for the PJM Day-Ahead Energy Market: January through June, 2011 and 2012 (See 2011 SOM, Figure 2-18)



PJM Day-Ahead, Average LMP

Table 2-29 shows the PJM day-ahead, average LMP for the first six months of each year for the 12 year period from 2001 to 2012.

Table 2-29 PJM day-ahead, average LMP (Dollars per MWh): January through June, 2001 through 2012 (See 2011 SOM, Table 2-40)

	Day-Ahead LMP			Year-to-Year Change		
(Jan-Jun)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$35.02	$31.34	$17.43	NA	NA	NA
2002	$24.76	$21.28	$12.49	(29.3%)	(32.1%)	(28.4%)
2003	$42.83	$39.18	$23.52	73.0%	84.1%	88.3%
2004	$44.02	$43.14	$18.33	2.8%	10.1%	(22.0%)
2005	$45.63	$42.51	$18.35	3.7%	(1.5%)	0.1%
2006	$48.33	$47.07	$16.02	5.9%	10.7%	(12.7%)
2007	$53.03	$51.08	$22.91	9.7%	8.5%	43.0%
2008	$70.12	$66.09	$31.98	32.2%	29.4%	39.6%
2009	$40.01	$37.46	$15.38	(42.9%)	(43.3%)	(51.9%)
2010	$43.81	$40.64	$15.66	9.5%	8.5%	1.8%
2011	$44.75	$40.85	$19.53	2.1%	0.5%	24.8%
2012	$30.44	$29.64	$11.77	(32.0%)	(27.4%)	(39.8%)

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 2-30 shows the PJM day-ahead, load-weighted, average LMP for the first six months of each year of the 12-year period from 2001 to 2012.

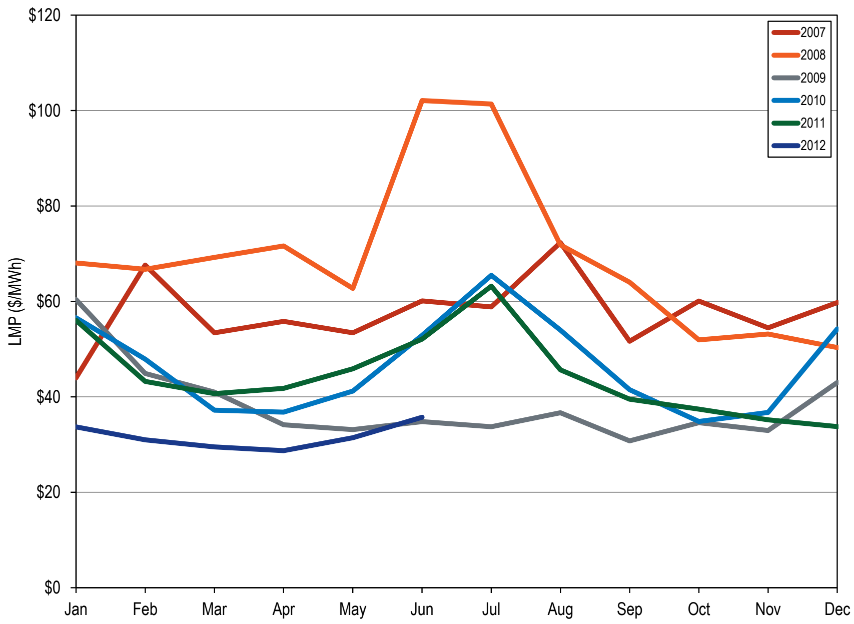
Table 2-30 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January through June, 2001 through 2012 (See 2011 SOM, Table 2-41)

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Jun)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$37.08	$33.91	$18.11	NA	NA	NA
2002	$26.88	$23.00	$14.36	(27.5%)	(32.2%)	(20.7%)
2003	$45.62	$42.01	$23.96	69.8%	82.6%	66.8%
2004	$46.12	$45.45	$18.62	1.1%	8.2%	(22.3%)
2005	$48.12	$44.88	$19.24	4.3%	(1.3%)	3.3%
2006	$50.21	$48.67	$16.23	4.3%	8.5%	(15.7%)
2007	$55.70	$54.26	$23.47	10.9%	11.5%	44.7%
2008	$73.71	$69.33	$33.95	32.3%	27.8%	44.7%
2009	$42.21	$38.83	$16.16	(42.7%)	(44.0%)	(52.4%)
2010	$46.12	$42.50	$16.54	9.3%	9.5%	2.3%
2011	$47.12	$42.58	$22.34	2.2%	0.2%	35.1%
2012	$31.84	$30.35	$13.94	(32.4%)	(28.7%)	(37.6%)

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

Figure 2-20 shows the PJM day-ahead, monthly, load-weighted LMP from 2007 through the first six months of 2012.

Figure 2-20 Day-ahead, monthly, load-weighted, average LMP: 2007 through June of 2012 (See 2011 SOM, Figure 2-19)



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.

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.[45] Table 2-31 shows the average volume of trading in increment offers and

45 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.

decrement bids per hour and the average total MW values of all bids per hour. Table 2-32 shows the average volume of up-to congestion transactions per hour and the average total MW values of all bids per hour.

Table 2-31 Hourly average volume of cleared and submitted INCs, DECs by month: January, 2011 through June, 2012 (See 2011 SOM, Table 2-43)

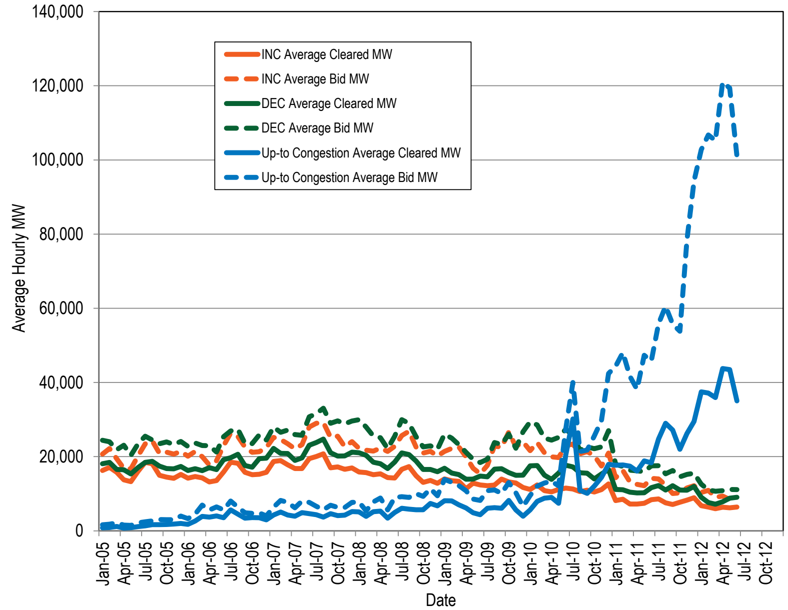
		Increment Offers				Decrement Bids			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2011	Jan	8,137	14,299	218	1077	11,135	17,917	224	963
2011	Feb	8,530	16,263	215	1672	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	Annual	6,362	9,416	87	366	8,249	11,222	107	369

Table 2-32 Hourly average of cleared and submitted up-to congestion bids by month: January, 2011 through June, 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	Annual	38,803	109,353	913	2,257

Figure 2-21 shows the hourly volume of bid and cleared INC, DEC and up-to congestion bids by month.

Figure 2-21 Hourly volume of bid and cleared INC, DEC and Up-to Congestion bids (MW) by month: January, 2005 through June, 2012 (See 2011 SOM, Figure 2-20)



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 2-33 shows, for the January through June period of 2011 and 2012, the total increment offers and decrement bids by the type of parent organization: financial or physical. Table 2-34 shows, for the January through June period of 2011 and 2012, the total up-to congestion transactions by the type of parent organization: financial or physical.

Table 2-33 PJM INC and DEC bids by type of parent organization (MW): January through June, 2011 and 2012 (See 2011 SOM, Table 2-46)

	2011 (Jan through Jun)		2012 (Jan through Jun)	
Category	Total Virtual Bids MW	Percentage	Total Virtual Bids MW	Percentage
Financial	65,264,830	49.1%	32,867,334	36.5%
Physical	67,648,617	50.9%	57,236,478	63.5%
Total	132,913,447	100.0%	90,103,812	100.0%

Table 2-34 PJM up-to congestion transactions by type of parent organization (MW): January through June, 2011 and 2012 (See 2011 SOM, Table 2-47)

	2011 (Jan through Jun)		2012 (Jan through Jun)	
Category	Total Up-to Congestion MW	Percentage	Total Up-to Congestion MW	Percentage
Financial	74,552,641	96.8%	161,702,500	95.4%
Physical	2,798,061	3.2%	7,840,068	4.6%
Total	77,350,702	100.0%	169,542,568	100.0%

Table 2-35 shows increment offers and decrement bids bid by top ten locations for the January through June period of 2011 and 2012.

Table 2-35 PJM virtual offers and bids by top ten locations (MW): January through June, 2011 and 2012 (See 2011 SOM, Table 2-48)

2011 (Jan through Jun)					2012 (Jan through Jun)				
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	13,521,348	15,020,627	28,541,975	WESTERN HUB	HUB	15,133,898	17,235,411	32,369,309
N ILLINOIS HUB	HUB	5,167,001	8,250,732	13,417,732	AEP-DAYTON HUB	HUB	2,603,459	2,869,771	5,473,230
AEP-DAYTON HUB	HUB	2,982,170	3,496,006	6,478,176	N ILLINOIS HUB	HUB	1,592,205	3,188,417	4,780,622
PECO	ZONE	888,857	2,386,767	3,275,624	SOUTHIMP	INTERFACE	4,741,666	0	4,741,666
MISO	INTERFACE	139,799	2,746,673	2,886,472	MISO	INTERFACE	119,274	3,279,711	3,398,985
SOUTHIMP	INTERFACE	2,829,561	0	2,829,561	PPL	ZONE	199,616	2,797,721	2,997,337
PPL	ZONE	148,840	1,910,488	2,059,328	PECO	ZONE	749,347	2,187,144	2,936,491
JCPL BUS	GEN	799,726	796,024	1,595,750	IMO	INTERFACE	1,764,739	16,306	1,781,045
COMED	ZONE	1,336,079	193,406	1,529,485	BGE	ZONE	113,332	983,511	1,096,843
BGE	ZONE	71,237	1,261,260	1,332,498	PSEG	ZONE	339,399	525,698	865,097
		27,884,617	36,061,984	63,946,600			27,356,934	33,083,689	60,440,623
PJM total		59,611,254	73,302,192	132,913,447			41,074,165	49,029,647	90,103,812
Top ten total as percent of PJM total		46.8%	49.2%	48.1%			66.6%	67.5%	67.1%

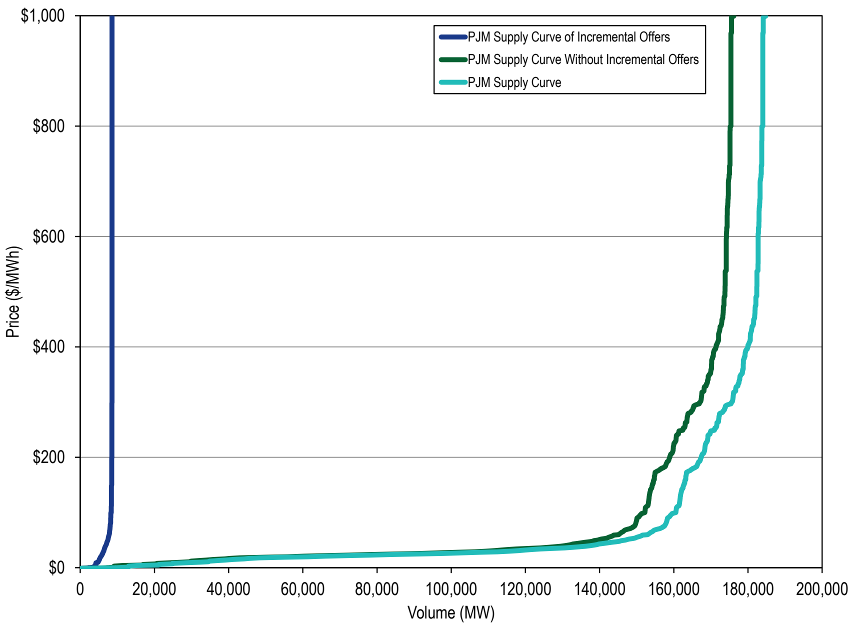
Table 2-36 shows up-to congestion transactions by import, export and wheel for the top ten locations for the January through June period of 2011 and 2012.

Table 2-36 PJM cleared up-to congestion import, export and wheel bids by top ten source and sink pairs (MW): January through June, 2011 and 2012 (See 2011 SOM, Table 2-49)

2011 (January through June)														
Imports					Exports					Wheels				
Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	N ILLINOIS HUB	HUB	1,566,224	WESTERN HUB	HUB	MISO	INTERFACE	1,486,776	CPLEIMP	INTERFACE	NCMPAEXP	INTERFACE	397,775
NORTHWEST	INTERFACE	ZION 1	AGGREGATE	1,355,383	23 COLLINS	EHVAGG	MISO	INTERFACE	1,005,341	CPLEIMP	INTERFACE	DUKEXP	INTERFACE	287,643
MISO	INTERFACE	112 WILTON	EHVAGG	1,290,029	21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	804,854	NORTHWEST	INTERFACE	SOUTHWEST	INTERFACE	167,796
OVEC	INTERFACE	CONESVILLE 6	AGGREGATE	965,895	BEAV DUQ UNIT1	AGGREGATE	MICHFE	INTERFACE	743,053	NORTHWEST	INTERFACE	MISO	INTERFACE	150,948
NORTHWEST	INTERFACE	BRAIDWOOD 1	AGGREGATE	719,932	SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	674,829	NYIS	INTERFACE	MICHFE	INTERFACE	115,589
NYIS	INTERFACE	MARION	AGGREGATE	696,115	RECO	ZONE	NYIS	INTERFACE	560,500	SOUTHWEST	INTERFACE	OVEC	INTERFACE	88,991
NYIS	INTERFACE	PSEG	ZONE	672,970	21 KINCA ATR24304	AGGREGATE	OVEC	INTERFACE	533,746	MISO	INTERFACE	NIPSCO	INTERFACE	79,841
MISO	INTERFACE	COMED	ZONE	593,581	LUMBERTON	AGGREGATE	SOUTHEAST	INTERFACE	487,644	NCMPAIMP	INTERFACE	OVEC	INTERFACE	62,459
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	581,458	RECO	ZONE	IMO	INTERFACE	482,114	NIPSCO	INTERFACE	MISO	INTERFACE	60,622
OVEC	INTERFACE	STUART 1	AGGREGATE	566,262	FOWLER 34.5 KV FWLR1AWF	AGGREGATE	OVEC	INTERFACE	434,279	NIPSCO	INTERFACE	OVEC	INTERFACE	59,038
Top ten total				9,007,850					7,213,137					1,470,701
PJM total				45,396,035					29,423,712					2,530,954
Top ten total as percent of PJM total				19.8%					24.5%					58.1%
2012 (January through June)														
Imports					Exports					Wheels				
Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	112 WILTON	EHVAGG	7,245,551	ROCKPORT	EHVAGG	OVEC	INTERFACE	2,693,217	NYIS	INTERFACE	IMO	INTERFACE	143,538
OVEC	INTERFACE	DEOK	ZONE	1,583,967	23 COLLINS	EHVAGG	MISO	INTERFACE	2,252,902	MISO	INTERFACE	NORTHWEST	INTERFACE	106,417
OVEC	INTERFACE	CONESVILLE 4	AGGREGATE	1,560,571	ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	2,052,448	MISO	INTERFACE	NIPSCO	INTERFACE	63,951
OVEC	INTERFACE	COOK	EHVAGG	1,487,704	STUART 1	AGGREGATE	OVEC	INTERFACE	1,436,886	NORTHWEST	INTERFACE	MISO	INTERFACE	60,546
OVEC	INTERFACE	MARYSVILLE	EHVAGG	1,486,388	QUAD CITIES 1	AGGREGATE	NORTHWEST	INTERFACE	1,292,085	SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	46,108
MISO	INTERFACE	N ILLINOIS HUB	HUB	1,448,387	SPORN 3	AGGREGATE	OVEC	INTERFACE	1,278,055	SOUTHWEST	INTERFACE	OVEC	INTERFACE	40,090
OVEC	INTERFACE	JEFFERSON	EHVAGG	1,441,163	WESTERN HUB	HUB	MISO	INTERFACE	1,194,255	MISO	INTERFACE	OVEC	INTERFACE	39,842
OVEC	INTERFACE	DUMONT	EHVAGG	1,200,575	167 PLANO	EHVAGG	MISO	INTERFACE	1,113,337	OVEC	INTERFACE	NIPSCO	INTERFACE	32,268
OVEC	INTERFACE	CONESVILLE 6	AGGREGATE	1,170,669	ROCKPORT	EHVAGG	MISO	INTERFACE	1,113,054	NIPSCO	INTERFACE	IMO	INTERFACE	30,013
NYIS	INTERFACE	HUDSON BC	AGGREGATE	1,049,825	SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	886,940	NIPSCO	INTERFACE	NORTHWEST	INTERFACE	20,306
Top ten total				19,674,798					15,313,180					583,079
PJM total				84,966,083					83,675,782					900,702
Top ten total as percent of PJM total				23.2%					18.3%					64.7%

Figure 2-22 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 2-22 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 2-23). There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis (Figure 2-24).

As Table 2-37 shows, day-ahead and real-time prices were relatively close, on average, in the first six months of 2011 and 2012.

Table 2-37 Day-ahead and real-time average LMP (Dollars per MWh): January through June, 2011 and 2012[46] (See 2011 SOM, Table 2-50)

	2011 (Jan - Jun)				2012 (Jan - Jun)			
	Day Ahead	Real Time	Difference	Difference as Percent of Real Time	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Average	$44.75	$45.51	$0.76	1.7%	$30.44	$29.74	($0.69)	(2.3%)
Median	$40.85	$37.40	($3.45)	(9.2%)	$29.64	$28.32	($1.31)	(4.6%)
Standard deviation	$19.53	$32.52	$12.99	39.9%	$11.77	$16.10	$4.33	26.9%
Peak average	$52.44	$54.09	$1.64	3.0%	$35.02	$35.07	$0.05	0.1%
Peak median	$47.54	$42.58	($4.96)	(11.6%)	$32.27	$30.85	($1.42)	(4.6%)
Peak standard deviation	$22.28	$40.61	$18.32	45.1%	$14.17	$18.61	$4.44	23.8%
Off peak average	$37.89	$37.86	($0.03)	(0.1%)	$26.38	$25.04	($1.35)	(5.4%)
Off peak median	$34.62	$33.44	($1.18)	(3.5%)	$26.14	$24.96	($1.18)	(4.7%)
Off peak standard deviation	$13.38	$20.16	$6.77	33.6%	$6.96	$11.62	$4.66	40.1%

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 2-38 shows the difference between the Real-Time and the Day-Ahead Energy Market Prices for the first six months of 2001 to 2012.

Table 2-38 Day-ahead and real-time average LMP (Dollars per MWh): January through June, 2001 through 2012 (See 2011 SOM, Table 2-51)

(Jan - Jun)	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
2001	$35.02	$33.10	($1.92)	(5.5%)
2002	$24.76	$24.10	($0.66)	(2.7%)
2003	$42.83	$41.31	($1.53)	(3.6%)
2004	$44.02	$44.99	$0.97	2.2%
2005	$45.63	$45.71	$0.07	0.2%
2006	$48.33	$49.36	$1.03	2.1%
2007	$53.03	$55.03	$2.00	3.8%
2008	$70.12	$70.19	$0.08	0.1%
2009	$40.01	$40.12	$0.11	0.3%
2010	$43.81	$43.27	($0.54)	(1.2%)
2011	$44.75	$45.51	$0.76	1.7%
2012	$30.44	$29.74	($0.69)	(2.3%)

Table 2-39 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 six months of years 2007 through 2012.

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

Table 2-39 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): January through June, 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%	0	0.00%	4	0.09%
($150) to ($100)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.02%	4	0.18%
($100) to ($50)	17	0.39%	62	1.42%	3	0.07%	6	0.14%	27	0.64%	8	0.37%
($50) to $0	2,365	54.85%	2,578	60.45%	2,541	58.58%	2,890	66.68%	2,773	64.49%	2,940	67.69%
$0 to $50	1,832	97.03%	1,505	94.92%	1,772	99.38%	1,366	98.13%	1,414	97.05%	1,377	99.22%
$50 to $100	118	99.75%	195	99.38%	25	99.95%	69	99.72%	105	99.47%	25	99.79%
$100 to $150	7	99.91%	23	99.91%	2	100.00%	5	99.84%	16	99.84%	5	99.91%
$150 to $200	0	99.91%	2	99.95%	0	100.00%	7	100.00%	2	99.88%	2	99.95%
$200 to $250	1	99.93%	1	99.98%	0	100.00%	0	100.00%	2	99.93%	0	99.95%
$250 to $300	1	99.95%	0	99.98%	0	100.00%	0	100.00%	0	99.93%	1	99.98%
$300 to $350	2	100.00%	1	100.00%	0	100.00%	0	100.00%	0	99.93%	1	100.00%
$350 to $400	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.93%	0	100.00%
$400 to $450	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.93%	0	100.00%
$450 to $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.93%	0	100.00%
>= $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%	0	100.00%

Figure 2-23 shows the hourly differences between day-ahead and real-time load-weighted hourly LMP in the first six months of 2012.

Figure 2-23 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: January through June, 2012 (See 2011 SOM, Figure 2-22)

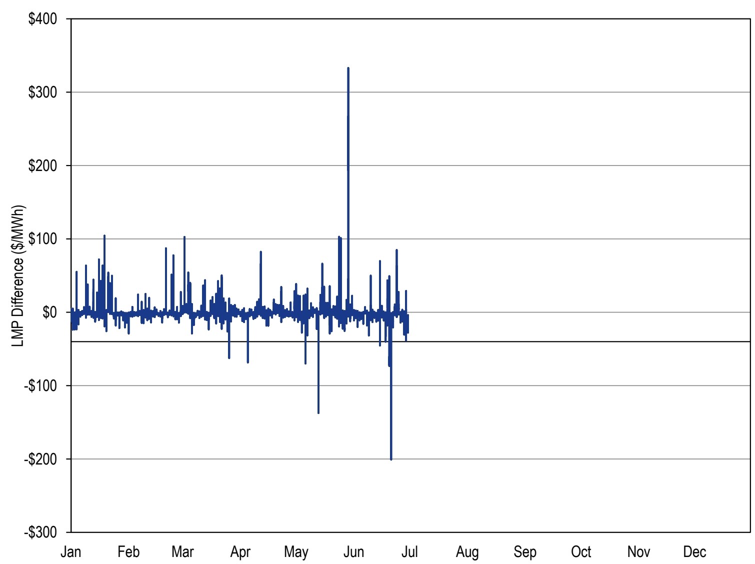
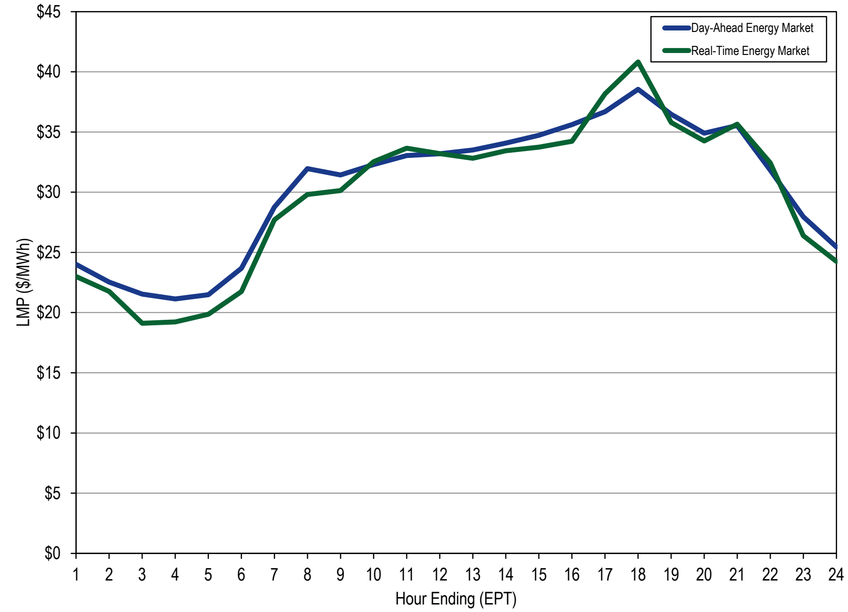


Figure 2-24 shows the monthly average differences between the day-ahead and real-time LMP in the first six months of 2012.

Figure 2-24 Monthly average of real-time minus day-ahead LMP: January through June, 2012 (See 2011 SOM, Figure 2-23)

Figure 2-25 shows day-ahead and real-time LMP on an average hourly basis.

Figure 2-25 PJM system hourly average LMP: January through June, 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 2-40 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, 9.7 percent of real-time load was supplied by bilateral contracts, 23.4 percent by spot market purchase and 66.9 percent by self-supply. Compared with 2011, reliance on bilateral contracts decreased 0.8 percentage points, reliance on spot supply decreased by 3.3 percentage points and reliance on self-supply increased by 4.0 percentage points.

Table 2-40 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%						
Aug	10.3%	24.6%	65.1%						
Sep	10.9%	26.7%	62.4%						
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%	9.7%	23.4%	66.9%	(0.8%)	(3.3%)	4.0%

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 2-41 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, 6.9 percent of day-ahead load was supplied by bilateral contracts, 21.9 percent by spot market purchases, and 71.3 percent by self-supply. Compared with 2011, reliance on bilateral contracts increased by 1.1 percentage points, reliance on spot supply decreased by 2.5 percentage points, and reliance on self-supply increased by 1.5 percentage points.

Table 2-41 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%						
Aug	5.7%	24.1%	70.1%						
Sep	5.8%	25.2%	69.0%						
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%	6.9%	21.9%	71.3%	1.1%	(2.5%)	1.5%