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

Table 2-1 The Energy Market results were competitive

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

- The aggregate market structure was evaluated as competitive because the calculations for hourly HHI (Herfindahl-Hirschman Index) indicate that by the FERC standards, the PJM Energy Market during 2012 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1240 with a minimum of 931 and a maximum of 1657 in 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.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets.
- Market performance was evaluated as competitive because market results in the Energy Market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets.
- Market design was evaluated as effective because the analysis shows that the PJM Energy Market resulted in competitive market outcomes, with prices reflecting, on average, the marginal cost to produce energy. In aggregate, PJM's Energy Market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design mitigates market power and causes the market to provide competitive market outcomes.

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

1 Analysis of 2012 market results requires comparison to prior years. In 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 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.

Overview

Market Structure

- **Supply.** Average offered supply increased by 4,180, or 2.5 percent, from 169,234 MW in the summer of 2011 to 173,414 MW in the summer of 2012.[4] The increase in offered supply was in part the result of the integration of the Duke Energy Ohio/Kentucky (DEOK) Transmission Zone in the first quarter of 2012 and the integration of the American Transmission Systems, Inc. (ATSI) Transmission Zone in the second quarter of 2011. In 2012, 2,669 MW of new capacity were added to PJM. This new supply was more than offset by the deactivation of 45 units (6,961.9 MW) since January 1, 2012.
- **Demand.** The PJM system peak load for 2012 was 154,344 MW in the HE 1700 on July 17, 2012, which was 3,672 MW, or 2.3 percent, lower than the PJM peak load for 2011, which was 158,016 MW in the HE 1700 on July 21, 2011.[5] The DEOK Transmission Zone accounted for 5,360 MW in the peak hour of 2012. The 2012 peak load excluding the DEOK Transmission Zone was 148,984 MW, also occurring on July 17, 2012, HE 1700, a decrease of 9,032 MW, or 5.7 percent, from the 2011 peak load.
- **Market Concentration.** Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload and intermediate segments, but high concentration in the peaking segment.
- **Local Market Structure and Offer Capping.** PJM continued to apply a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in 2012. PJM offer caps units only when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer capping levels have historically been low in PJM. In the Day-Ahead Energy Market offer-capped unit hours increased from 0.0 percent in 2011 to 0.6 percent in 2012. In the Real-Time Energy Market offer-capped unit hours increased from 0.9 percent in 2011 to 1.2 percent in 2012.
- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 133 units eligible for FMU or AU status in at least one month during 2012, 25 units (18.8 percent) were FMUs or AUs for all months, and 25 (18.8 percent) qualified in only one month of 2012.

  The MMU recommends the elimination of FMU and AU adders. FMU and AU adders were added to the market rules in 2006 in order to address revenue inadequacy for frequently mitigated units. Since that time, PJM has undertaken major redesigns of its market rules addressing revenue adequacy, including implementation of the RPM capacity market construct in 2007, and significant changes to the scarcity pricing rules in 2012. The reasons that FMU and AU adders were implemented no longer exist. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.
- **Local Market Structure.** In 2012, 11 Control Zones experienced congestion resulting from one or more constraints binding for 100 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.[6]

Market Performance: Markup, Load, Generation and LMP

- **Markup.** The markup conduct of individual owners and units has an impact on market prices. The markup analysis is a key indicator of the competitiveness of the Energy Market.

  All generating units, including coal units, are allowed to include a 10 percent adder in their cost offer. The 10 percent adder was included in the definition of cost offers prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions. Coal units do

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

5 All hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2012 State of the Market Report for PJM*, Appendix I, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

6 See the *2012 State of the Market Report for PJM*, Volume II, Appendix D, "Local Energy Market Structure: TPS Results" for detailed results of the TPS test.

not face the same cost uncertainty as gas-fired CTs. Actual participant behavior support this view, as the owners of coal units, facing competition, typically remove the 10 percent adder from their actual offers. The adjusted markup is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder.

In 2012, the unadjusted markup was negative, primarily as a result of competitive behavior by coal units. The unadjusted markup component of LMP was -$1.38 per MWh. The adjusted markup was $.43 per MWh or 1.2 percent of the PJM real-time, load-weighted average LMP of $35.23 per MWh.

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

- **Load.** PJM average real-time load in 2012 increased by 5.4 percent from 2011, from 82,546 MW to 87,011 MW. The PJM average real-time load in 2012 would have decreased by 2.0 percent from 2011, from 82,546 MW to 80,909 MW, if the DEOK and ATSI Transmission Zones were not included in this comparison for the months prior to their integration to PJM.[7]

  PJM average day-ahead load in 2012, including DECs and up-to congestion transactions, increased by 15.6 percent from 2011, from 113,866 MW to 131,612 MW. PJM average day-ahead load in 2012, including DECs and up-to congestion transactions, would have been 8.9 percent higher than in 2011, from 113,866 MW to 124,046 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison. The day-ahead load growth was 188.9 percent higher than the real-time load growth as a result of the continued growth of up-to congestion transactions.

- **Generation.** PJM average real-time generation in 2012 increased by 3.4 percent from 2011, from 85,755 MW to 88,708 MW. PJM average real-time generation in 2012 would have decreased by 2.5 percent from 2011, from 85,755 MW to 83,630 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison.

  PJM average day-ahead generation in 2012, including INCs and up-to congestion transactions, increased by 14.8 percent from 2011, from 117,130 MW to 134,479 MW. PJM average day-ahead generation in 2012, including INCs and up-to congestion transactions, would have been 4.7 percent higher than in 2011, from 117,130 MW to 122,599 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison. The day-ahead generation growth was 335.3 percent higher than the real-time generation growth as a result of the continued growth of up-to congestion transactions.

- **Generation Fuel Mix.** During 2012, coal units provided 42.1 percent, nuclear units 34.6 percent and gas units 18.8 percent of total generation. Compared to 2011, generation from coal units decreased 7.4 percent, generation from nuclear units increased 4.0 percent, and generation from gas units increased 39.0 percent.

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

  PJM Real-Time Energy Market prices decreased in 2012 compared to 2011. The system average LMP was 22.7 percent lower in 2012 than in 2011, $33.11 per MWh versus $42.84 per MWh. The load-weighted average LMP was 23.3 percent lower in 2012 than in 2011, $35.23 per MWh versus $45.94 per MWh.

  PJM Day-Ahead Energy Market prices decreased in 2012 compared to 2011. The system average LMP was 22.9 percent lower in 2012 than in 2011, $32.79 per MWh versus $42.52 per MWh. The load-weighted average LMP was 23.5 percent lower in 2012 than in 2011, $34.55 per MWh versus $45.19 per MWh.[8]

7 The ATSI zone was integrated on June 1, 2011. The DEOK zone was integrated on January 1, 2012. The ATSI zone was not included in this comparison for January through May 2011, and January through May 2012. The DEOK zone was not included in this comparison.

8 Tables reporting zonal and jurisdictional load and prices are in Appendix C. See the *2012 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

- **Load and Spot Market.** Companies that serve load in PJM can do so using a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In 2012, 9.0 percent of real-time load was supplied by bilateral contracts, 23.2 percent by spot market purchase and 67.8 percent by self-supply. Compared with 2011, reliance on bilateral contracts decreased 1.5 percentage points, reliance on spot supply decreased by 3.4 percentage points and reliance on self-supply increased by 4.9 percentage points. In 2012, 6.7 percent of day-ahead load was supplied by bilateral contracts, 22.3 percent by spot market purchases, and 71.0 percent by self-supply. Compared with 2011, reliance on bilateral contracts increased by 0.9 percentage points, reliance on spot supply decreased by 2.1 percentage points, and reliance on self-supply increased by 1.3 percentage points.

Scarcity

- **Scarcity Pricing Events in 2012.** PJM did not declare an administrative scarcity event in 2012. PJM's market did not experience any reserve-based shortage events in 2012.
- **Scarcity and High Load Analyses.** There were no reserve shortages in 2012. There were seven high load days and 40 high-load hours in 2012. There were 28 Hot Weather Alerts called in 2012.

Conclusion

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

Average real-time supply offered increased by 4,180 MW in the summer of 2012 compared to the summer of 2011, while peak load decreased by 3,672 MW, modifying the general supply demand balance with a corresponding impact on energy market prices. In the Day-Ahead Energy Market, average load in 2012 increased from 2011, from 113,866 MW to 131,612 MW, or 15.6 percent. In the Real-Time Energy Market, average load in 2012 increased from 2011, from 82,546 MW to 87,011 MW, or 5.4 percent. Market concentration levels remained moderate. This relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive for most hours.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load in each hour. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price. Energy Market results for 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.[9] 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

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

exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers and prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. Nonetheless, with a market design that includes a direct and explicit scarcity pricing revenue true up mechanism, scarcity pricing can be a mechanism to appropriately increase reliance on the energy market as a source of revenues and incentives in a competitive market without reliance on the exercise of market power. PJM implemented new scarcity pricing rules in 2012. There are significant issues with the scarcity pricing true up mechanism in the new PJM scarcity pricing design, which will create issues when scarcity pricing occurs.

The overall market results support the conclusion that prices in PJM are set, on average, by marginal units operating at, or close to, their marginal costs. This is evidence of competitive behavior and competitive market outcomes. Given the structure of the Energy Market, tighter markets or a change in participant behavior remain potential sources of concern in the Energy Market. The MMU concludes that the PJM Energy Market results were competitive in 2012.

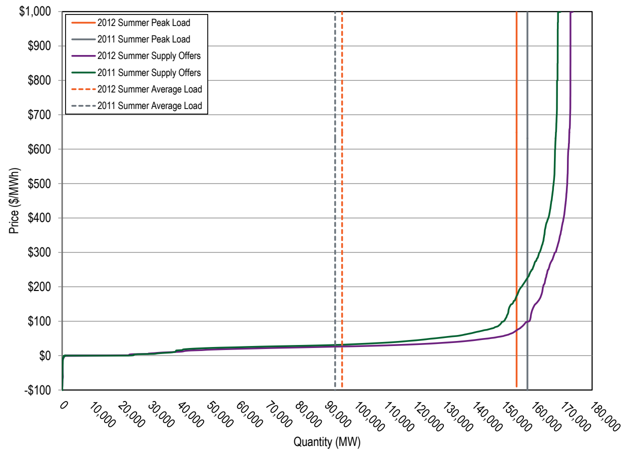
Market Structure

Supply

Average offered supply increased by 4,180 MW, or 2.5 percent, from 169,234 MW in the summer of 2011 to 173,414 MW in the summer of 2012.[10] The increase in offered supply was in part the result of the integration of the DEOK Transmission Zone in the first quarter of 2012. In 2012, 2,669 MW of new capacity were added to PJM. This new supply was more than offset by the deactivation of 45 units (6,961.9 MW) since January 1, 2012.

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

Figure 2-1 Average PJM aggregate supply curves: Summer 2011 and 2012



Energy Production by Fuel Source

Compared to 2011, generation from coal units decreased 7.4 percent and generation from natural gas units increased 39.0 percent (Table 2-2). If the impact of the increased coal generation in the newly integrated ATSI and DEOK zones is eliminated, generation from coal units decreased 19.1 percent in 2012 compared to 2011.

10 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)): 2011 and 2012[11]

	2011		2012		Change in
	GWh	Percent	GWh	Percent	Output
Coal	359,410.4	47.1%	332,762.0	42.1%	(7.4%)
Standard Coal	347,940.4	45.6%	323,043.5	40.9%	(6.9%)
Waste Coal	11,470.0	1.5%	9,718.5	1.2%	(0.5%)
Nuclear	262,968.3	34.5%	273,372.2	34.6%	4.0%
Gas	106,853.3	14.0%	148,230.4	18.8%	38.7%
Natural Gas	105,049.7	13.8%	146,007.5	18.5%	39.0%
Landfill Gas	1,803.2	0.2%	2,222.3	0.3%	23.2%
Biomass Gas	0.3	0.0%	0.5	0.0%	61.0%
Hydroelectric	14,729.2	1.9%	12,649.7	1.6%	(14.1%)
Wind	11,037.0	1.4%	12,633.6	1.6%	14.5%
Waste	5,200.2	0.7%	5,177.6	0.7%	(0.4%)
Solid Waste	4,083.5	0.5%	4,200.3	0.5%	2.9%
Miscellaneous	1,116.6	0.1%	977.3	0.1%	(12.5%)
Oil	2,271.5	0.3%	5,030.9	0.6%	121.5%
Heavy Oil	1,885.4	0.2%	4,796.9	0.6%	154.4%
Light Oil	356.6	0.0%	218.9	0.0%	(38.6%)
Diesel	16.8	0.0%	9.9	0.0%	(40.9%)
Kerosene	12.8	0.0%	5.1	0.0%	(59.7%)
Jet Oil	0.1	0.0%	0.0	0.0%	(31.7%)
Solar	56.0	0.0%	233.5	0.0%	317.3%
Battery	0.2	0.0%	0.3	0.0%	36.9%
Total	762,526.0	100.0%	790,090.3	100.0%	3.6%

Table 2-3 PJM Generation (By fuel source (GWh)): 2011 and 2012; excluding ATSI and DEOK zones[12]

	2011		2012		Change in
	GWh	Percent	GWh	Percent	Output
Coal	359,410.4	47.1%	290,845.1	39.7%	(19.1%)
Standard Coal	347,940.4	45.6%	281,126.7	38.4%	(18.6%)
Waste Coal	11,470.0	1.5%	9,718.5	1.3%	(0.5%)
Nuclear	262,968.3	34.5%	260,508.9	35.6%	(0.9%)
Gas	106,853.3	14.0%	144,809.5	19.8%	35.5%
Natural Gas	105,049.7	13.8%	142,730.3	19.5%	35.9%
Landfill Gas	1,803.2	0.2%	2,078.7	0.3%	15.3%
Biomass Gas	0.3	0.0%	0.5	0.0%	61.0%
Hydroelectric	14,729.2	1.9%	12,649.7	1.7%	(14.1%)
Wind	11,037.0	1.4%	12,633.6	1.7%	14.5%
Waste	5,200.2	0.7%	5,177.6	0.7%	(0.4%)
Solid Waste	4,083.5	0.5%	4,200.3	0.6%	2.9%
Miscellaneous	1,116.6	0.1%	977.3	0.1%	(12.5%)
Oil	2,271.5	0.3%	5,025.6	0.7%	121.2%
Heavy Oil	1,885.4	0.2%	4,796.9	0.7%	154.4%
Light Oil	356.6	0.0%	215.3	0.0%	(39.6%)
Diesel	16.8	0.0%	8.2	0.0%	(50.9%)
Kerosene	12.8	0.0%	5.1	0.0%	(59.7%)
Jet Oil	0.1	0.0%	0.0	0.0%	(31.7%)
Solar	56.0	0.0%	233.5	0.0%	317.3%
Battery	0.2	0.0%	0.3	0.0%	36.9%
Total	762,526.0	100.0%	731,883.9	100.0%	(4.0%)

11 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.

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

Table 2-4 Monthly PJM Generation (By fuel source (GWh)): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Coal	29,992.9	25,536.7	22,150.9	21,478.8	25,967.5	28,917.3	37,797.3	34,391.3	25,359.0	24,311.7	27,777.6	29,081.0	332,762.0
Standard Coal	28,986.9	24,723.5	21,413.8	20,918.3	25,191.9	28,126.2	36,834.5	33,470.5	24,592.4	23,633.3	26,842.3	28,309.9	323,043.5
Waste Coal	1,005.9	813.2	737.1	560.5	775.7	791.1	962.8	920.8	766.6	678.4	935.3	771.2	9,718.5
Nuclear	25,696.6	22,604.3	22,336.6	20,212.3	21,518.3	22,434.4	23,876.9	24,313.6	22,511.1	21,671.8	21,160.3	25,036.1	273,372.2
Gas	11,851.9	12,745.2	12,398.0	11,165.5	12,148.4	13,672.6	17,312.8	14,513.2	12,520.6	10,555.2	9,404.0	9,943.0	148,230.4
Natural Gas	11,671.2	12,550.6	12,192.0	10,984.6	11,965.1	13,493.5	17,130.0	14,322.1	12,340.9	10,372.3	9,233.2	9,752.2	146,007.5
Landfill Gas	180.7	194.6	206.0	181.0	183.2	179.1	182.9	190.9	179.6	182.8	170.8	190.7	2,222.3
Biomass Gas	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.5
Hydroelectric	1,187.1	953.5	1,217.3	954.4	1,399.7	1,103.9	1,052.1	1,062.5	837.6	819.5	1,018.0	1,044.1	12,649.7
Wind	1,608.3	1,167.0	1,416.3	1,345.6	885.6	882.6	546.7	415.5	677.0	1,213.7	1,022.6	1,452.6	12,633.6
Waste	430.5	408.7	409.8	395.3	443.2	473.4	469.2	455.7	408.3	399.4	433.2	450.9	5,177.6
Solid Waste	339.7	322.0	317.6	334.2	349.9	396.6	381.7	371.4	343.5	335.8	336.6	371.5	4,200.3
Miscellaneous	90.8	86.7	92.2	61.1	93.3	76.9	87.4	84.4	64.9	63.7	96.6	79.4	977.3
Oil	49.7	25.8	281.9	821.5	763.0	445.3	944.9	600.4	404.6	223.7	306.2	163.9	5,030.9
Heavy Oil	39.5	6.4	273.0	811.6	739.6	417.4	875.2	572.5	387.5	210.1	303.8	160.3	4,796.9
Light Oil	10.0	19.3	7.9	9.5	20.7	26.7	64.8	25.9	16.5	12.7	2.0	3.0	218.9
Diesel	0.2	0.1	0.8	0.2	2.3	0.7	3.0	0.3	0.6	0.9	0.3	0.4	9.9
Kerosene	0.0	0.0	0.2	0.2	0.4	0.5	1.9	1.7	0.0	0.0	0.1	0.2	5.1
Jet Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	9.8	14.3	19.1	28.1	21.5	24.8	26.1	26.1	22.9	15.3	14.0	11.5	233.5
Battery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.3
Total	70,826.9	63,455.6	60,229.9	56,401.5	63,147.2	67,954.4	82,026.0	75,778.4	62,741.1	59,210.4	61,135.9	67,183.1	790,090.3

Generator Offers

The generator offers are categorized by dispatchable and self-scheduled MW and are shown in Table 2-5 and Table 2-6.[13,14] Table 2-5 shows the average hourly distribution of MW for dispatchable units by offer prices for 2012. Table 2-6 shows the average hourly distribution of MW for self-scheduled units by offer prices for 2012. Of the dispatchable MW offered by combustion turbines (CT), 26.8 percent were dispatchable at an offered range of $600 to $800. Only wind and solar units have negative offer prices.

Table 2-5 Distribution of MW for dispatchable unit offer prices: 2012

	Dispatchable (Range)						
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Total
CC	0.0%	61.2%	11.6%	2.7%	4.7%	1.1%	81.5%
CT	0.0%	43.4%	15.7%	10.2%	26.8%	3.4%	99.5%
Diesel	0.0%	7.5%	56.3%	6.9%	1.4%	0.8%	72.9%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	10.3%	0.0%	0.0%	0.0%	0.0%	10.3%
Pumped Storage	0.0%	52.0%	0.0%	0.0%	0.0%	0.0%	52.0%
Solar	0.0%	61.7%	0.0%	0.0%	0.0%	0.0%	61.7%
Steam	0.0%	49.4%	10.8%	0.7%	0.2%	0.0%	61.1%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	23.7%	30.1%	0.0%	0.0%	0.0%	0.0%	53.8%
All Dispatchable Offers	0.5%	41.8%	9.6%	2.8%	6.4%	0.9%	62.0%

13 Each range in the tables is greater than or equal to the lower value and less than the higher value.
14 The unit type battery is not included in these tables because batteries do not make energy offers.

Table 2-6 Distribution of MW for self-scheduled unit offer prices: 2012

	Self-Scheduled (Range)						
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Total
CC	0.0%	17.2%	1.2%	0.0%	0.0%	0.2%	18.5%
CT	0.0%	0.4%	0.0%	0.0%	0.0%	0.0%	0.5%
Diesel	0.0%	26.8%	0.1%	0.0%	0.0%	0.2%	27.1%
Hydro	0.0%	99.0%	0.0%	0.0%	0.0%	1.0%	100.0%
Nuclear	0.0%	89.7%	0.0%	0.0%	0.0%	0.0%	89.7%
Pumped Storage	0.0%	48.0%	0.0%	0.0%	0.0%	0.0%	48.0%
Solar	16.6%	21.7%	0.0%	0.0%	0.0%	0.0%	38.3%
Steam	0.0%	25.9%	12.3%	0.1%	0.5%	0.1%	38.9%
Transaction	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Wind	10.4%	35.8%	0.0%	0.0%	0.0%	0.0%	46.2%
All Self-Scheduled Offers	0.2%	32.0%	5.4%	0.1%	0.2%	0.1%	38.0%

Demand

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

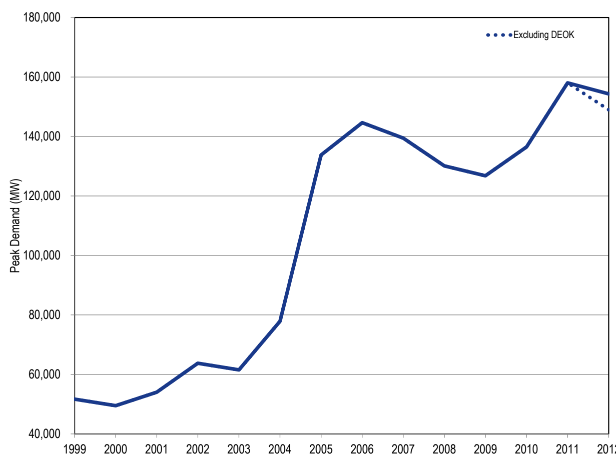
Table 2-7 shows the coincident peak loads for the years 1999 through 2012.

Table 2-7 Actual PJM footprint peak loads: 1999 to 2012[15]

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
1999	Tue, July 06	14	51,689	NA	NA
2000	Wed, August 09	17	49,469	(2,220)	(4.3%)
2001	Thu, August 09	15	54,015	4,546	9.2%
2002	Wed, August 14	16	63,762	9,747	18.0%
2003	Fri, August 22	16	61,499	(2,263)	(3.5%)
2004	Tue, August 03	17	77,887	16,387	26.6%
2005	Tue, July 26	16	133,761	55,875	71.7%
2006	Wed, August 02	17	144,644	10,883	8.1%
2007	Wed, August 08	16	139,428	(5,216)	(3.6%)
2008	Mon, June 09	17	130,100	(9,328)	(6.7%)
2009	Mon, August 10	17	126,798	(3,302)	(2.5%)
2010	Tue, July 06	17	136,460	9,662	7.6%
2011	Thu, July 21	17	158,016	21,556	15.8%
2012 (with DEOK)	Tue, July 17	17	154,344	(3,672)	(2.3%)
2012 (without DEOK)	Tue, July 17	17	148,984	(9,032)	(5.7%)

Figure 2-2 shows the peak loads for the years 1999 through 2012.

Figure 2-2 PJM footprint calendar year peak loads: 1999 to 2012[16]

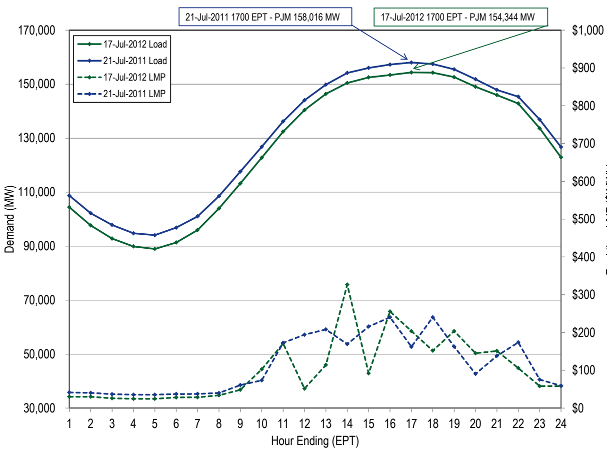


15 Peak loads shown are eMTR load. See the *MMU Technical Reference for the PJM Markets*, at "Load Definitions" for detailed definitions of load.

16 For additional information on the "PJM Integration Period", see the *2012 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

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

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



Market Concentration

Analyses of supply curve segments of the PJM Energy Market for 2012 indicate moderate concentration in the base load segment and intermediate segment, but high concentration in the peaking segment.[17] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal during high demand periods. When transmission constraints exist, local markets are created with ownership that is typically significantly more concentrated than the overall Energy Market. PJM offer-capping rules that limit the exercise of local market power and generation owners' obligations to serve load were generally effective in preventing the exercise of market power in these areas during 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.

Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate that comparatively small numbers of sellers dominate a market; low concentration ratios mean larger numbers of sellers split market sales more equally. The best tests of market competitiveness are direct tests of the conduct of individual participants and their impact on price. The direct examination of offer behavior by individual market participants is one such test. Low aggregate market concentration ratios establish neither that a market is competitive nor that participants are unable to exercise market power. High concentration ratios do, however, indicate an increased potential for participants to exercise market power.

Despite their significant limitations, concentration ratios provide useful information on market structure.[18] The concentration ratio used here is the Herfindahl-Hirschman Index (HHI), calculated by summing the squares of the market shares of all firms in a market. Hourly PJM Energy Market HHIs were calculated based on the real-time energy output of generators, adjusted for hourly net imports by owner (Table 2-8).

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

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

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

- **Unconcentrated.** Market HHI below 1000, equivalent to 10 firms with equal market shares;

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

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

- **Moderately Concentrated.** Market HHI between 1000 and 1800; and
- **Highly Concentrated.** Market HHI greater than 1800, equivalent to between five and six firms with equal market shares.[19]

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during 2012 was moderately concentrated (Table 2-8).

Table 2-8 PJM hourly Energy Market HHI: 2011[20] and 2012

	Hourly Market HHI (2011)	Hourly Market HHI (2012)
Average	1203	1240
Minimum	889	931
Maximum	1564	1657
Highest market share (One hour)	30%	32%
Average of the highest hourly market share	21%	23%
# Hours	8,760	8,784
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

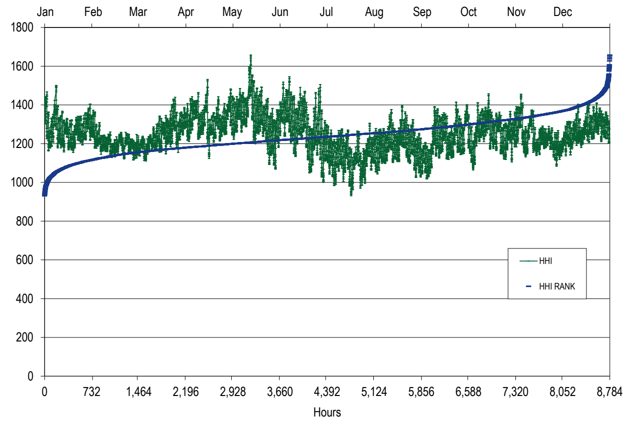
Table 2-9 includes 2012 HHI values by supply curve segment, including base, intermediate and peaking plants.

Table 2-9 PJM hourly Energy Market HHI (By supply segment): 2011 and 2012

	2011			2012		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	1034	1224	1534	1025	1239	1624
Intermediate	676	1831	7964	787	1625	3974
Peak	596	6034	10000	679	5262	10000

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

Figure 2-4 PJM hourly Energy Market HHI: 2012



Local Market Structure and Offer Capping

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

PJM has clear rules limiting the exercise of local market power.[21] The rules provide for offer capping when conditions on the transmission system create a structurally noncompetitive local market (as measured by the three pivotal supplier test), when units in that local market have made noncompetitive offers and when such offers would set the price above the competitive level in the absence of mitigation. Offer caps are set at the level of a competitive offer. Offer-capped units receive the higher of the market price or their offer cap. Thus, if broader market conditions lead to a price greater than the offer cap, the unit receives the higher market price. The rules governing the exercise of local market power recognize that units in certain areas of the system would be in a position to extract monopoly profits, but for these rules.

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

20 This analysis includes all hours in 2012, regardless of congestion.

21 OA Schedule 1, § 6.4.2.

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

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

Levels of offer capping have historically been low in PJM, as shown in Table 2-10.

Table 2-11 presents data on the frequency with which units were offer capped in 2011 and 2012.

Table 2-11 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.

Table 2-10 Offer-capping statistics: 2008 to 2012

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2008	1.0%	0.2%	0.2%	0.1%
2009	0.4%	0.1%	0.1%	0.0%
2010	1.2%	0.4%	0.2%	0.1%
2011	0.9%	0.4%	0.0%	0.0%
2012	1.2%	0.8%	0.6%	0.4%

Table 2-11 Real-time offer-capped unit statistics: 2011 and 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%	2012	0	2	0	1	1	1
	2011	0	0	0	6	9	4
80% and < 90%	2012	0	1	0	0	2	4
	2011	0	0	1	2	5	9
75% and < 80%	2012	0	0	0	0	1	2
	2011	0	0	0	0	3	3
70% and < 75%	2012	0	0	0	0	1	2
	2011	0	0	0	0	0	10
60% and < 70%	2012	1	0	0	1	1	8
	2011	0	1	0	1	1	20
50% and < 60%	2012	7	0	1	0	1	10
	2011	0	0	0	2	13	23
25% and < 50%	2012	5	1	1	2	8	49
	2011	2	0	0	5	19	70
10% and < 25%	2012	6	0	0	3	13	58
	2011	9	2	0	0	2	49

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

Local Market Structure

In 2012, the AP, ATSI, BGE, ComEd, DEOK, DLCO, Dominion, DPL, PECO, Pepco and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 100 or more hours. Actual competitive conditions in the Real-Time Energy Market associated with each of these frequently binding constraints were analyzed using the three pivotal supplier results for 2012.[23] The AECO, AEP, DAY, JCPL, Met-Ed, PENELEC, PPL and RECO Control Zones were not affected by constraints binding for 100 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 December 31, 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.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and does not result in offer capping when that is not the case. Local markets are noncompetitive when the number of suppliers is relatively small.

Information is provided for each constraint including the number of tests applied and the number of tests that could have resulted in offer capping.[24] Additional information is provided for each constraint including the average MW required to relieve a constraint, the average supply available, the average number of owners included in each test and the average number of owners that passed or failed each test.

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

Table 2-12 Three pivotal supplier test details for regional constraints: 2012

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005 Interface	Peak	332	482	16	4	13
	Off Peak	247	478	16	8	9
AEP-DOM	Peak	276	373	8	0	8
	Off Peak	214	353	9	0	8
AP South	Peak	366	550	11	1	10
	Off Peak	347	557	11	1	10
Bedington - Black Oak	Peak	93	133	10	1	9
	Off Peak	114	102	9	1	8
Central	Peak	347	451	15	2	13
	Off Peak	NA	NA	NA	NA	NA
Eastern	Peak	426	656	15	8	7
	Off Peak	NA	NA	NA	NA	NA
Western	Peak	466	576	16	5	11
	Off Peak	350	600	16	9	7

The three pivotal supplier test is applied every time the PJM market system solution indicates that incremental relief is needed to relieve a transmission constraint. While every system solution that requires incremental relief to transmission constraints will result in a test, not all tested providers of effective supply are eligible for capping. Only uncommitted resources, which would be started as a result of incremental relief needs, are eligible to be offer capped. Already committed units that can provide incremental relief cannot, regardless of test score, be switched from price to cost offers. Table 2-13 provides, for the identified seven regional constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping uncommitted units.

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

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

Table 2-13 Summary of three pivotal supplier tests applied for regional constraints 2012

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
5004/5005 Interface	Peak	2,086	112	5%	29	1%	26%
	Off Peak	1,021	21	2%	3	0%	14%
AEP-DOM	Peak	824	49	6%	26	3%	53%
	Off Peak	441	22	5%	18	4%	82%
AP South	Peak	4,078	109	3%	25	1%	23%
	Off Peak	2,097	36	2%	6	0%	17%
Bedington - Black Oak	Peak	1,074	36	3%	3	0%	8%
	Off Peak	282	8	3%	0	0%	0%
Central	Peak	27	0	0%	0	0%	0%
	Off Peak	NA	NA	NA	NA	NA	NA
Eastern	Peak	160	9	6%	4	3%	44%
	Off Peak	NA	NA	NA	NA	NA	NA
Western	Peak	1,270	118	9%	31	2%	26%
	Off Peak	482	51	11%	4	1%	8%

Ownership of Marginal Resources

Table 2-14 shows the contribution to PJM real-time, annual, load-weighted LMP by individual marginal resource owner.[25] The contribution of each marginal resource to price at each load bus is calculated for 2012, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. The results show that in 2012, the offers of one company contributed 21.9 percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies contributed 51.5 percent of the real-time, load-weighted, average PJM system LMP. In comparison, during 2011, the offers of one company contributed 15.4 percent of the real time, load-weighted PJM system LMP and offers of the top four companies contributed 48 percent of the real-time, load-weighted, average PJM system LMP.

Table 2-14 Marginal unit contribution to PJM real-time, load-weighted LMP (By parent company): 2012 and 2011

2012		2011	
Company	Percent of Price	Company	Percent of Price
1	21.9%	1	15.4%
2	12.9%	2	14.1%
3	8.9%	3	10.1%
4	7.8%	4	8.3%
5	7.8%	5	6.9%
6	6.1%	6	6.7%
7	5.7%	7	5.3%
8	5.2%	8	4.8%
9	3.7%	9	4.4%
Other (56 companies)	19.9%	Other (47 companies)	23.9%

Table 2-15 shows the contribution of PJM day ahead, load-weighted LMP by individual marginal resource owner.[26] The contribution of each marginal resource to price at each load bus is calculated for 2012, period and summed by the company that offers the marginal resource into the Day-Ahead Energy Market.

Table 2-15 Marginal unit contribution to PJM day-ahead, load-weighted LMP (By parent company): 2012 and 2011

2012		2011	
Company	Percent of Price	Company	Percent of Price
1	16.0%	1	17.3%
2	6.2%	2	8.6%
3	6.1%	3	7.8%
4	5.8%	4	5.2%
5	4.6%	5	4.5%
6	4.4%	6	4.2%
7	4.1%	7	4.0%
8	4.0%	8	3.4%
9	3.5%	9	3.3%
Other (142 companies)	45.4%	Other (150 companies)	41.8%

Type of Marginal Resources

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources 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.

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

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

Table 2-16 shows the type of fuel used by marginal resources in the Real-Time Energy Market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In 2012, coal units were 58.8 percent and natural gas units were 30.4 percent of the total marginal resources. In 2011, coal units were 67.3 percent and natural gas units were 26.5 percent of the total marginal resources.[27]

Table 2-16 Type of fuel used (By real-time marginal units): 2012 and 2011

Fuel Type	2012	2011
Coal	58.8%	67.3%
Gas	30.4%	26.5%
Municipal Waste	0.1%	0.1%
Oil	6.0%	2.6%
Other	0.5%	0.4%
Uranium	0.0%	0.0%
Wind	4.2%	2.9%

Table 2-17 shows the type, and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In 2012, Up-to Congestion transactions were 88.4 percent of the total marginal resources. In comparison, Up-to Congestion transactions were 73.4 percent of the total marginal resources in 2011.

Table 2-17 Day-ahead marginal resources by type/fuel: 2011 and 2012

Type/Fuel	2012	2011
Up-to Congestion Transaction	88.4%	73.4%
DEC	4.3%	12.4%
INC	3.8%	7.5%
Coal	2.3%	4.7%
Gas	1.0%	1.5%
Dispatchable Transaction	0.1%	0.2%
Price Sensitive Demand	0.0%	0.2%
Wind	0.0%	0.1%
Oil	0.0%	0.0%
Diesel	0.0%	0.0%
Municipal Waste	0.0%	0.0%
Total	100.0%	100.0%

Market Conduct: Markup

The markup index is a summary measure of participant offer behavior or conduct for individual marginal units. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[28] The markup index is normalized and can vary from -1.00 when the offer price is less than marginal cost, to 1.00 when the offer price is higher than marginal cost. This index calculation method weights the impact of individual unit markups using sensitivity factors, to reflect their relative importance in the system dispatch solution. The markup index does not measure the impact of unit markup on total LMP.

Real-Time Mark Up Conduct

Table 2-18 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category. A unit is assigned to a price category for each dispatch solution associated with the interval in which it was marginal, based on its offer price at that time. The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point.

27 The percentages of marginal fuel reported in the *2011 State of the Market Report for PJM*, Volume I, were based on both Locational Pricing Algorithm (LPA) and dispatch (SCED) marginal resources. In this report, marginal fuel percentages are based only on resources that were marginal in dispatch (SCED). See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

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

Table 2-18 Average, real-time marginal unit markup index (By price category): 2012 and 2011

	2012			2011		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.09)	($3.25)	29.0%	(0.10)	($3.89)	12.1%
$25 to $50	(0.05)	($2.67)	52.3%	(0.07)	($6.58)	68.7%
$50 to $75	0.05	$1.23	4.5%	(0.02)	($6.05)	8.3%
$75 to $100	0.28	$24.25	0.6%	0.12	$6.80	1.6%
$100 to $125	0.23	$23.66	0.5%	0.25	$25.53	0.7%
$125 to $150	0.20	$27.69	0.2%	0.25	$33.72	0.4%
>= $150	0.04	$9.47	5.5%	0.12	$24.73	4.1%

Day-Ahead Mark Up Conduct

Table 2-19 shows the average markup index of marginal units in Day-Ahead Energy Market, by offer price category. A unit is assigned to a price category for each interval in which it was marginal, based on its offer price at that time.

Table 2-19 Average marginal unit markup index (By offer price category): 2012 and 2011

	2012			2011		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.08)	($2.69)	29.5%	(0.10)	($3.76)	11.0%
$25 to $50	(0.05)	($2.43)	67.3%	(0.06)	($4.70)	82.3%
$50 to $75	0.09	$4.20	2.7%	(0.01)	($5.60)	5.2%
$75 to $100	0.45	$36.22	0.1%	0.11	$4.94	0.9%
$125 to $150	0.00	$0.00	0.0%	0.05	$1.54	0.2%
$125 to $150	(0.06)	($8.33)	0.1%	(0.07)	($20.72)	0.1%
>= $150	0.03	$4.84	0.2%	0.18	$30.70	0.3%

Market Performance

Markup

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

The MMU calculates the impact on system prices of marginal unit price-cost markup, based on analysis using sensitivity factors. The calculation shows the markup component of price based on a comparison between the price-based offer and the cost-based offer of each actual marginal unit on the system.[29]

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

The MMU calculated an explicit measure of the impact of marginal unit markups on LMP. The markup impact includes the impact of the identified markup conduct on a unit by unit basis, but the inclusion of negative markup impacts has an offsetting effect. The markup

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

analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval. The markup analysis is a more general measure of the competitiveness of the Energy Market.

Real-Time Markup

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

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

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

Table 2-20 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type:[30] 2012 and 2011

		2012		2011	
Fuel Type	Unit Type	Markup Component of LMP	Percent	Markup Component of LMP	Percent
Coal	Steam	($1.70)	123.1%	($0.22)	5.1%
Gas	CC	$0.42	(30.6%)	($3.66)	84.2%
Gas	CT	($0.03)	2.5%	($0.36)	8.2%
Gas	Diesel	$0.02	(1.7%)	$0.01	(0.3%)
Gas	Steam	($0.03)	2.2%	($0.01)	0.2%
Municipal Waste	Diesel	$0.00	0.0%	$0.00	0.0%
Municipal Waste	Steam	$0.02	(1.5%)	$0.05	(1.2%)
Oil	CT	$0.01	(0.6%)	$0.00	(0.0%)
Oil	Diesel	$0.00	(0.1%)	($0.00)	0.0%
Oil	Steam	($0.08)	5.6%	($0.17)	4.0%
Other	Solar	$0.00	(0.0%)	$0.00	0.0%
Other	Steam	($0.00)	0.3%	($0.00)	0.1%
Uranium	Steam	$0.00	0.0%	($0.00)	0.0%
Wind	Wind	($0.00)	0.3%	$0.01	(0.2%)
Total		($1.38)	100.0%	($4.35)	100.0%

Markup Component of Real-Time System Price

Table 2-21 shows the markup component of average prices and of average monthly on-peak and off-peak prices. In 2012, -$1.38 per MWh of the PJM real-time, load-weighted average LMP was attributable to markup. In 2012, the markup component of LMP was -$2.89 per MWh off peak and $0.04 per MWh on peak. In comparison, in 2011, -$4.35 per MWh of the PJM real-time, load-weighted average LMP was attributable to markup. In 2011, the markup component of LMP was -$5.00 per MWh off peak and $3.74 per MWh on peak.

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

Table 2-21 Monthly markup components of real-time load-weighted LMP: 2012 and 2011

	2012			2011		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($3.25)	($3.51)	($2.98)	($5.60)	($2.76)	($8.59)
Feb	($2.07)	($2.92)	($1.26)	($7.56)	($5.46)	($9.56)
Mar	($2.24)	($2.51)	($2.00)	($5.77)	($5.09)	($6.36)
Apr	($2.71)	($3.60)	($1.86)	($8.93)	($7.31)	($10.45)
May	($1.10)	($3.34)	$0.94	($6.51)	($5.17)	($7.81)
Jun	($2.68)	($3.24)	($2.18)	($2.64)	($8.08)	$1.68
Jul	$3.38	($2.36)	$8.82	($1.32)	($5.49)	$2.99
Aug	($0.90)	($2.30)	$0.20	($3.51)	($7.97)	$0.02
Sep	($0.70)	($1.89)	$0.60	($3.36)	($4.59)	($2.24)
Oct	($1.14)	($2.99)	$0.38	($4.43)	($4.04)	($4.82)
Nov	($1.46)	($2.85)	($0.11)	($3.74)	($3.47)	($3.99)
Dec	($2.98)	($3.27)	($2.65)	($1.44)	($1.26)	($1.62)
Total	($1.38)	($2.89)	$0.04	($4.35)	($5.00)	($3.74)

Markup Component of Real-Time Zonal Prices

The annual average real-time price component of unit markup is shown for each zone in Table 2-22. The smallest zonal all hours average markup component for 2012 was in the DAY Control Zone, -$1.71 per MWh, while the highest all hours' average zonal markup component for 2012 was in the Pepco Control Zone, -$0.85 per MWh. On peak, the smallest annual average zonal markup was in the DEOK Control Zone, -$0.41 per MWh, while the highest annual average zonal markup was in the JCPL Control Zone, $0.72 per MWh.

Table 2-22 Average real-time zonal markup component: 2012 and 2011

	2012			2011		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	($1.19)	($2.68)	$0.26	($3.69)	($4.94)	($2.50)
AEP	($1.67)	($2.98)	($0.38)	($4.27)	($4.73)	($3.83)
APS	($1.51)	($2.96)	($0.11)	($5.18)	($5.30)	($5.07)
ATSI	($1.63)	($3.10)	($0.24)	($2.94)	($5.05)	($1.00)
BGE	($1.05)	($2.46)	$0.31	($4.66)	($5.31)	($4.05)
ComEd	($1.38)	($3.04)	$0.16	($2.56)	($3.03)	($2.13)
DAY	($1.71)	($3.11)	($0.40)	($4.04)	($4.75)	($3.39)
DEOK	($1.68)	($3.01)	($0.41)	NA	NA	NA
Dominion	($1.03)	($2.53)	$0.42	($5.71)	($5.91)	($5.51)
DPL	($1.40)	($3.00)	$0.16	($4.46)	($5.39)	($3.56)
DUQ	($1.46)	($2.97)	($0.02)	($4.28)	($4.91)	($3.68)
JCPL	($1.02)	($2.93)	$0.72	($4.36)	($5.54)	($3.31)
Met-Ed	($1.44)	($3.02)	$0.02	($4.62)	($5.34)	($3.96)
PECO	($1.29)	($2.78)	$0.12	($4.63)	($5.55)	($3.77)
PENELEC	($1.60)	($3.12)	($0.17)	($4.70)	($5.02)	($4.41)
Pepco	($0.85)	($2.51)	$0.69	($4.83)	($5.51)	($4.21)
PPL	($1.53)	($3.04)	($0.13)	($4.61)	($5.32)	($3.96)
PSEG	($1.14)	($2.77)	$0.37	($5.10)	($6.10)	($4.19)
RECO	($0.99)	($2.89)	$0.63	($3.12)	($4.31)	($2.12)

Markup by Real-Time System Price Levels

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

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

Table 2-23 Average real-time markup component (By price category): 2012 and 2011

	2012		2011	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.78)	24.1%	($0.33)	5.4%
$25 to $50	($1.83)	65.5%	($5.47)	73.5%
$50 to $75	$0.34	4.5%	($0.71)	9.4%
$75 to $100	$0.24	1.4%	$0.55	3.4%
$100 to $125	$0.10	0.6%	$0.46	1.6%
$125 to $150	$0.11	0.2%	$0.32	0.8%
>= $150	$0.44	0.5%	$0.83	1.1%

Day-Ahead Markup

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

The markup component of the overall PJM day-ahead, load-weighted average LMP by primary fuel and unit type is shown in Table 2-24.

Table 2-24 Markup component of the overall PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: 2012 and 2011

		2012		2011	
Fuel Type	Unit Type	Markup Component of LMP	Percent	Markup Component of LMP	Percent
Coal	Steam	($1.69)	90.9%	($1.16)	32.2%
Diesel	Diesel	$0.00	0.0%	$0.00	0.0%
Gas	CT	$0.06	(3.2%)	$0.04	(1.0%)
Gas	Diesel	$0.00	0.0%	$0.00	0.0%
Gas	Steam	($0.17)	9.0%	($2.32)	64.4%
Municipal Waste	Steam	($0.00)	0.1%	($0.00)	0.0%
Oil	Steam	($0.06)	3.2%	($0.16)	4.4%
Wind	Wind	$0.00	0.0%	$0.00	0.0%
Total		($1.86)	100.0%	($3.60)	100.0%

Markup Component of Day-Ahead System Price

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

Table 2-25 shows the markup component of average prices and of average monthly on-peak and off-peak prices.

Table 2-25 Monthly markup components of day-ahead, load-weighted LMP: 2011 and 2012

	2012			2011		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($2.76)	($2.22)	($3.28)	($3.37)	($4.12)	($2.66)
Feb	($3.01)	($3.61)	($2.38)	($3.68)	($3.92)	($3.43)
Mar	($2.30)	($1.99)	($2.63)	($2.47)	($1.83)	($3.21)
Apr	($2.67)	($2.36)	($2.98)	($3.81)	($3.03)	($4.66)
May	($1.52)	($1.11)	($1.97)	($3.82)	($2.75)	($4.94)
Jun	($1.93)	($1.09)	($2.88)	($4.48)	($3.48)	($5.76)
Jul	$0.35	$2.60	($2.07)	($3.07)	($0.43)	($5.65)
Aug	($1.86)	($0.95)	($3.05)	($3.59)	($1.24)	($6.60)
Sep	($1.75)	($1.36)	($2.10)	($5.76)	($4.27)	($7.43)
Oct	($0.95)	($0.06)	($2.03)	($2.56)	($2.82)	($2.29)
Nov	($2.05)	($0.86)	($3.29)	($4.03)	($3.94)	($4.13)
Dec	($2.42)	($1.97)	($2.82)	($2.68)	($1.81)	($3.52)
Total	($1.86)	($1.14)	($2.63)	($3.60)	($2.72)	($4.55)

Markup Component of Day-Ahead Zonal Prices

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

Table 2-26 Day-ahead, average, zonal markup component: 2011 and 2012

	2012			2011		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($1.56)	($0.66)	($2.53)	($3.50)	($3.13)	($3.91)
AEP	($1.94)	($1.26)	($2.65)	($3.45)	($2.41)	($4.54)
AP	($1.87)	($1.30)	($2.47)	($3.53)	($2.24)	($4.90)
ATSI	($1.99)	($1.32)	($2.72)	($3.44)	($1.72)	($5.34)
BGE	($1.86)	($1.19)	($2.57)	($4.45)	($4.02)	($4.91)
ComEd	($1.77)	($1.17)	($2.44)	($2.41)	($1.35)	($3.58)
DAY	($1.90)	($1.19)	($2.68)	($3.60)	($2.68)	($4.62)
DEOK	($1.85)	($1.17)	($2.56)	NA	NA	NA
DLCO	($1.83)	($1.13)	($2.59)	($2.78)	($1.07)	($4.63)
Dominion	($1.79)	($1.03)	($2.57)	($4.31)	($3.41)	($5.25)
DPL	($1.67)	($0.85)	($2.55)	($3.69)	($3.21)	($4.18)
JCPL	($1.54)	($0.66)	($2.53)	($3.66)	($3.57)	($3.76)
Met-Ed	($1.85)	($1.13)	($2.65)	($3.89)	($3.49)	($4.32)
PECO	($1.71)	($0.98)	($2.49)	($3.65)	($3.18)	($4.17)
PENELEC	($2.07)	($1.50)	($2.69)	($5.03)	($3.33)	($6.95)
Pepco	($1.86)	($1.25)	($2.52)	($4.33)	($3.78)	($4.93)
PPL	($2.04)	($1.43)	($2.71)	($3.67)	($3.39)	($3.98)
PSEG	($1.59)	($0.61)	($2.69)	($3.64)	($3.16)	($4.18)
RECO	($1.49)	($0.54)	($2.63)	($3.26)	($3.23)	($3.30)

Markup by Day-Ahead System Price Levels

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

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

Table 2-27 Average, day-ahead markup (By LMP category): 2011 and 2012

	2012		2011	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($3.25)	21.0%	($12.90)	3.1%
$25 to $50	($2.69)	74.9%	($5.25)	82.8%
$50 to $75	$2.06	3.0%	($2.98)	10.6%
$75 to $100	$6.62	0.6%	$1.38	1.8%
$100 to $125	$18.93	0.2%	$6.54	0.7%
$125 to $150	$4.54	0.1%	$3.58	0.5%
>= $150	$16.80	0.2%	$18.50	0.5%

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.[31] 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.[32] These categories are designated Tier 1, Tier 2 and Tier 3, respectively.[33,34]

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

31 110 FERC ¶ 61,053 (2005).
32 OA, Schedule 1 § 6.4.2.
33 114 FERC ¶ 61, 076 (2006).
34 See "Settlement Agreement," Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).

its dispatch and the FMU would be dispatched in its place after losing its FMU designation.

The MMU recommends the elimination of FMU and AU adders. FMU and AU adders were added to the market rules in 2006 in order to address revenue inadequacy for frequently mitigated units. Since that time, PJM has undertaken major redesigns of its market rules addressing revenue adequacy, including implementation of the RPM capacity market construct in 2007, and significant changes to the scarcity pricing rules in 2012. The reasons that FMU and AU adders were implemented no longer exist. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.

FMUs and AUs are designated monthly, and a unit's capping percentage is based on a rolling 12-month average, effective with a one-month lag.[35]

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

Table 2-28 Number of frequently mitigated units and associated units (By month): 2011 and 2012

	FMUs and AUs							
	2011				2012			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	46	22	66	134	26	21	52	99
February	34	43	60	137	26	22	47	95
March	30	46	66	142	25	17	47	89
April	34	45	62	141	23	17	46	86
May	37	48	59	144	23	14	47	84
June	31	50	61	142	22	13	48	83
July	45	32	43	120	25	11	50	86
August	33	14	44	91	25	23	43	91
September	18	19	55	92	17	6	33	56
October	31	24	53	108	10	18	14	42
November	20	28	49	97	9	21	10	40
December	20	26	51	97	14	17	10	41

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 December, 2012

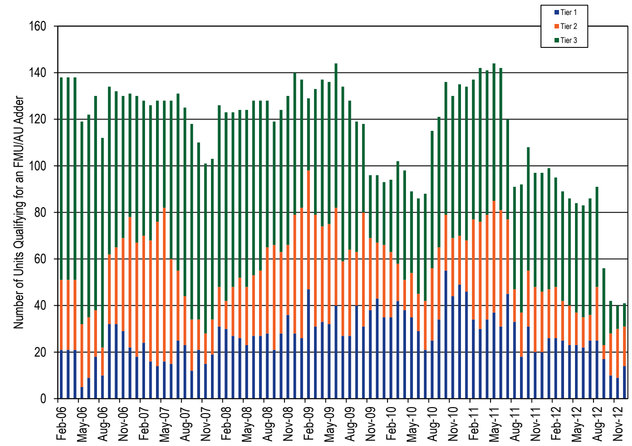


Table 2-29 shows the number of units that were eligible for an FMU or AU adder (Tier 1, Tier 2 or Tier 3) by the number of months they were eligible in 2011 and 2012. Of the 133 units eligible in at least one month during 2012, 25 units (18.8 percent) were FMUs or AUs for all months, and 25 (18.8 percent) qualified in only one month of 2012.

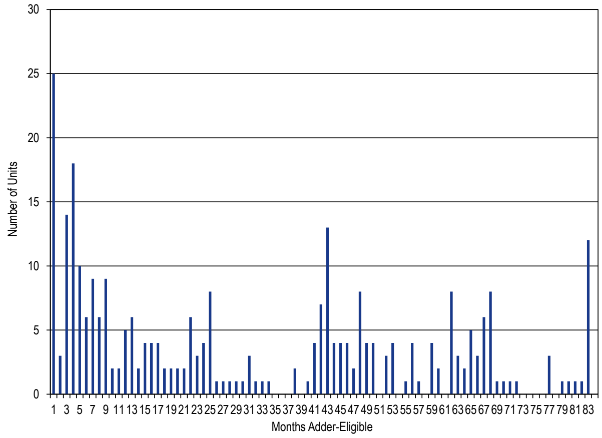
35 OA, Schedule 1 § 6.4.2. In 2007, the FERC approved OA revisions to clarify the AU criteria.

Table 2-29 Frequently mitigated units and associated units total months eligible: 2011 and 2012

Months Adder-Eligible	FMU & AU Count	
	2011	2012
1	11	25
2	1	12
3	4	4
4	19	9
5	12	2
6	33	4
7	24	14
8	14	16
9	5	15
10	8	5
11	3	2
12	54	25
Total	188	133

Figure 2-6 shows the number of months FMUs and AUs were eligible for any adder (Tier 1, Tier 2 or Tier 3) since the inception of FMUs effective February 1, 2006. From February 1, 2006, through September 30, 2012, there have been 303 unique units that have qualified for an FMU adder in at least one month. Of these 303 units, no unit qualified for an adder in all potential months. Twelve units qualified in 83 of the 84 possible months, and 120 of the 303 units (39.6 percent) have qualified for an adder in more than half of the possible months.

Figure 2-6 Frequently mitigated units and associated units total months eligible: February, 2006 through December, 2012



Market Performance: Load and LMP

The PJM system load and average 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 2012 increased by 5.4 percent from 2011, from 82,546 MW to 87,011 MW. The PJM average real-time load in 2012 would have decreased by 2.0 percent from 2011, from 82,546 MW to 80,909 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison.[36]

PJM average day-ahead load, including DECs and up-to congestion transactions, in 2012 increased by 15.6 percent from 2011, from 113,866 MW to 131,612 MW. PJM average day-ahead load in 2012, including DECs and up-to congestion transactions, would have increased by 8.9 percent from 2011, from 113,866 MW to 124,046 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison.

The day-ahead load growth was 188.9 percent higher than the real-time load growth because of the continued growth of up-to congestion transactions. If 2012 up-to congestion transactions had been held to 2011 levels, the day-ahead load, including DECs and up-to congestion transactions, would have increased 1.4 percent instead of 15.6 percent and day-ahead load growth would have been 74.1 percent lower than the real-time load growth.

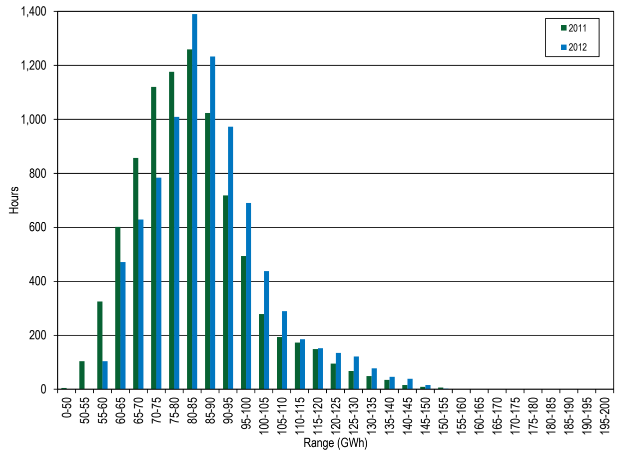
36 The ATSI zone was integrated on June 1, 2011. The DEOK zone was integrated on January 1, 2012. The ATSI zone was not included in this comparison for January through May 2011, and January through May 2012. The DEOK zone was not included in this comparison.

Real-Time Load

PJM Real-Time Load Duration

Figure 2-7 shows the hourly distribution of PJM real-time load for 2011 and 2012.[37]

Figure 2-7 PJM real-time accounting load: 2011 and 2012[38]



PJM Real-Time, Average Load

Table 2-30 presents summary real-time load statistics 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.[39]

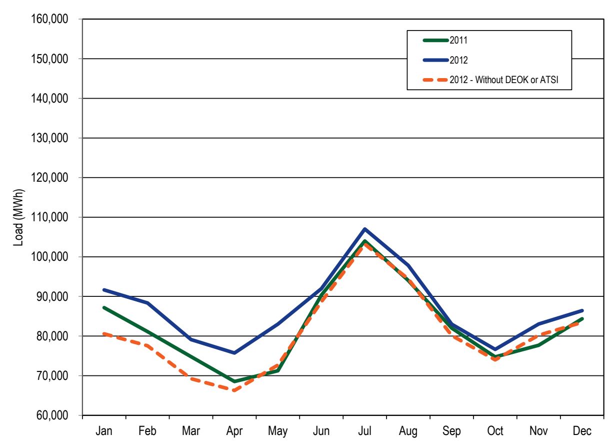
Table 2-30 PJM real-time average hourly load: 1998 through 2012[40]

	PJM Real-Time Load (MWh)		Year-to-Year Change	
Year	Average Load	Load Standard Deviation	Average Load	Load Standard Deviation
1998	28,578	5,511	NA	NA
1999	29,641	5,955	3.7%	8.1%
2000	30,113	5,529	1.6%	(7.2%)
2001	30,297	5,873	0.6%	6.2%
2002	35,776	7,976	18.1%	35.8%
2003	37,395	6,834	4.5%	(14.3%)
2004	49,963	13,004	33.6%	90.3%
2005	78,150	16,296	56.4%	25.3%
2006	79,471	14,534	1.7%	(10.8%)
2007	81,681	14,618	2.8%	0.6%
2008	79,515	13,758	(2.7%)	(5.9%)
2009	76,034	13,260	(4.4%)	(3.6%)
2010	79,611	15,504	4.7%	16.9%
2011	82,546	16,156	3.7%	4.2%
2012	87,011	16,213	5.4%	0.3%

PJM Real-Time, Monthly Average Load

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

Figure 2-8 PJM real-time monthly average hourly load: 2011 and 2012



PJM real-time load is significantly affected by temperature. PJM uses the Temperature-Humidity Index (THI), the Winter Weather Parameter (WWP) and the average temperature as weather variables in the PJM load forecast model for different seasons.[41] Table

37 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.

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

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

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

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

2-31 shows the load weighted THI, WWP and average temperature for cooling, heating and shoulder seasons.[42]

Table 2-31 PJM annual Summer THI, Winter WWP and average temperature (Degrees F): Cooling, heating and shoulder months of 2007 through 2012

	Summer THI	Winter WWP	Shoulder Average Temperature
2007	74.84	24.99	53.87
2008	74.48	26.93	51.13
2009	73.15	24.02	52.80
2010	76.09	24.47	54.73
2011	75.14	25.20	53.19
2012	74.92	30.26	54.64

Day-Ahead Load

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

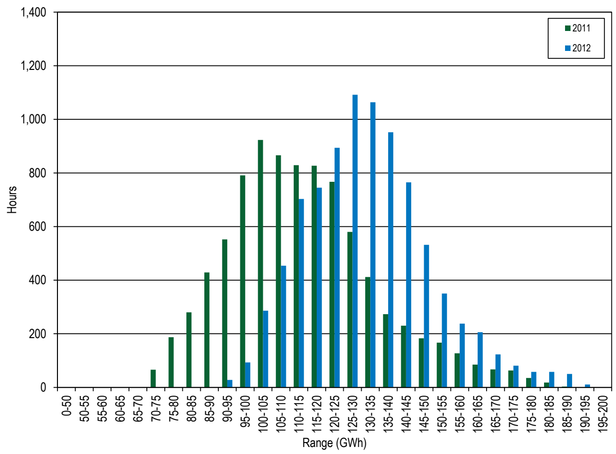
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of 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.[43] In the PJM Day-Ahead Market, an up-to congestion transaction is evaluated and clears as a matched pair of injections and withdrawals analogous to a matched pair of INC offers and DEC bids. The DEC (sink) portion of each up-to congestion transaction is load in the Day-Ahead Energy Market. The INC (source) of each up-to congestion transaction is generation in the Day-Ahead Energy Market.

PJM day-ahead load is the hourly total of the four types of cleared demand bids.[44]

PJM Day-Ahead Load Duration

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

Figure 2-9 PJM day-ahead load: 2011 and 2012



PJM Day-Ahead, Average Load

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

42 The Summer THI is calculated by taking average of daily maximum THI in June, July, August and September. The Winter WWP is calculated by taking average of daily minimum WWP in January and February (December of each year is not included). Average temperature is used for the remaining months. For additional information on the calculation of these weather variables, see PJM "Manual 19: Load Forecasting and Analysis," Revision 21 (October 1, 2012), Section 3, pp. 15-16. Load weighting using real-time zonal accounting load.

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

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

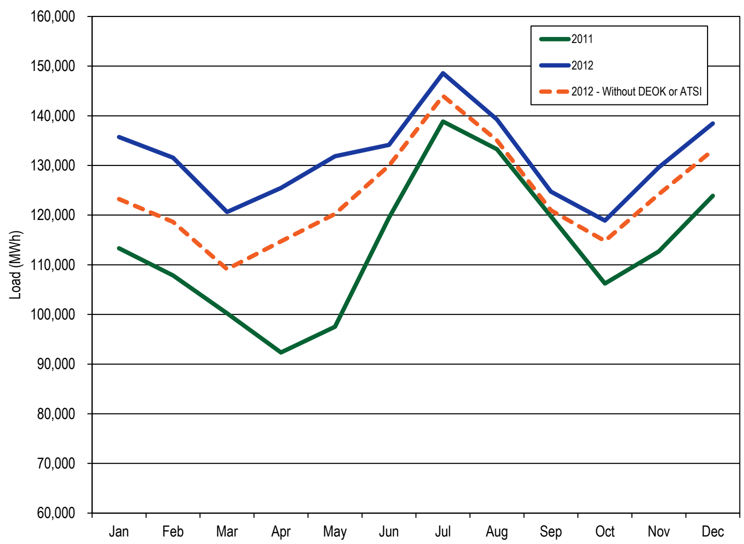
Table 2-32 PJM day-ahead average load: 2001 through 2012[45]

	PJM Day-Ahead Load (MWh)						Year-to-Year Change		
	Average			Standard Deviation			Average		
Year	Load	Up-to Congestion	Total Load	Load	Up-to Congestion	Total Load	Load	Up-to Congestion	Total Load
2001	33,303	67	33,370	6,526	200	6,562	NA	NA	NA
2002	42,131	174	42,305	10,130	303	10,161	26.5%	161.2%	26.8%
2003	44,328	346	44,674	7,877	310	7,841	5.2%	98.6%	5.6%
2004	61,034	1,068	62,101	16,318	905	16,654	37.7%	208.9%	39.0%
2005	92,002	1,532	93,534	17,381	886	17,643	50.7%	43.5%	50.6%
2006	94,793	3,734	98,527	16,048	1,555	16,723	3.0%	143.8%	5.3%
2007	100,912	4,591	105,503	16,190	1,567	16,686	6.5%	23.0%	7.1%
2008	95,522	6,381	101,903	15,439	1,889	15,871	(5.3%)	39.0%	(3.4%)
2009	88,707	6,234	94,941	14,896	2,133	15,869	(7.1%)	(2.3%)	(6.8%)
2010	90,985	12,952	103,937	17,014	7,778	21,358	2.6%	107.8%	9.5%
2011	91,713	22,153	113,866	17,830	5,767	20,708	0.8%	71.0%	9.6%
2012	93,267	38,344	131,612	17,121	7,978	17,421	1.7%	73.1%	15.6%

PJM Day-Ahead, Monthly Average Load

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

Figure 2-10 PJM day-ahead monthly average hourly load: 2011 and 2012



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

Real-Time and Day-Ahead Load

Table 2-33 presents summary statistics for 2011 and 2012 day-ahead and real-time loads.

Table 2-33 Cleared day-ahead and real-time load (MWh): 2011 and 2012

		Day Ahead					Real Time	Average Difference	
	Year	Cleared Fixed Demand	Cleared Price Sensitive	Cleared DEC Bids	Cleared Up-to Congestion	Total Load	Total Load	Total Load	Total Load Minus Cleared DEC Bids Minus Up-to Congestion
Average	2011	79,553	879	11,282	22,153	113,866	82,546	31,320	(2,114)
	2012	84,112	720	8,435	38,344	131,612	87,011	44,600	(2,179)
Median	2011	77,556	880	11,086	21,488	111,650	80,870	30,781	(1,793)
	2012	82,422	692	8,169	37,015	130,461	85,011	45,450	267
Standard Deviation	2011	15,931	181	2,441	5,767	20,708	16,156	4,551	(3,657)
	2012	15,855	143	1,818	7,978	17,421	16,213	1,208	(8,588)
Peak Average	2011	88,273	956	12,971	23,194	125,395	91,413	33,981	(2,184)
	2012	93,339	771	9,421	37,347	140,878	96,187	44,691	(2,076)
Peak Median	2011	84,791	972	12,747	22,802	122,634	87,930	34,705	(844)
	2012	89,430	741	9,174	36,899	138,153	92,187	45,966	(108)
Peak Standard Deviation	2011	14,784	176	1,979	5,862	18,775	14,836	3,939	(3,902)
	2012	13,984	145	1,671	5,663	14,870	14,406	464	(6,870)
Off-Peak Average	2011	71,950	812	9,809	21,245	103,815	74,815	29,000	(2,053)
	2012	76,049	676	7,574	39,215	123,515	78,994	44,521	(2,269)
Off-Peak Median	2011	70,247	819	9,571	20,472	102,274	72,658	29,617	(427)
	2012	73,982	656	7,260	37,142	121,293	76,895	44,398	(3)
Off-Peak Standard Deviation	2011	12,667	158	1,755	5,525	16,688	12,978	3,710	(3,570)
	2012	12,680	125	1,472	9,467	15,328	13,168	2,160	(8,778)

Figure 2-11 shows the 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): 2012

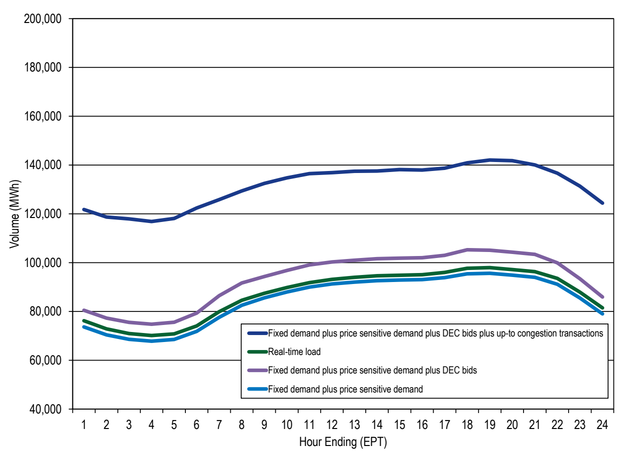
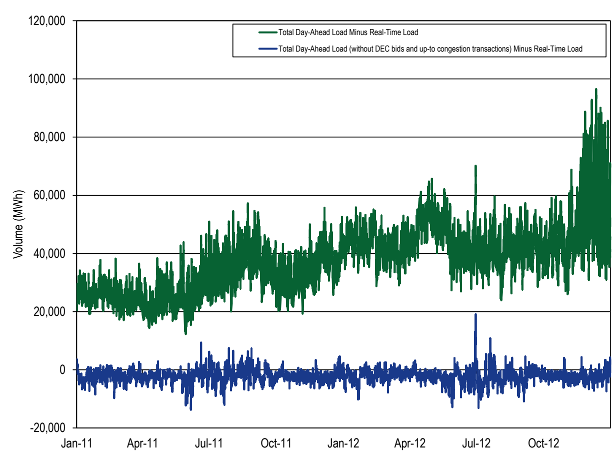


Figure 2-12 shows the difference between the day-ahead and real-time average daily loads in 2011 and 2012.

Figure 2-12 Difference between day-ahead and real-time loads (Average daily volumes): 2011 and 2012



Real-Time and Day-Ahead Generation

PJM average real-time generation in 2012 increased by 3.4 percent from 2011, from 85,775 MW to 88,708 MW. PJM average real-time generation in 2012 would have decreased 2.5 percent from 2011, from 85,755 MW to

83,630 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison.[46]

PJM average day-ahead generation in 2012, including INCs and up-to congestion transactions, increased by 14.8 percent from 2011, from 117,130 MW to 134,479 MW. PJM average day-ahead generation in 2012, including INCs and up-to congestion transactions, would have increased 4.7 percent from 2011, from 117,130 MW to 122,599 MW, if the DEOK and ATSI transmission zones were excluded from the comparison.

The day-ahead generation growth was 335.3 percent higher than the real-time generation growth because of the continued growth of up-to congestion transactions. If 2012 up-to congestion transactions had been held to 2011 levels, the day-ahead generation, including INCs and up-to congestion transactions, would have increased 1.0 percent instead of 14.8 percent and day-ahead generation growth would have been 70.6 percent lower than the real-time generation growth.

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

In the Day-Ahead Energy Market, four types of financially binding generation offers are made and cleared:[47]

- **Self-Scheduled.** Offer to supply a fixed block of MWh that must run from a specific unit, including a minimum amount of MWh that must run from a specific unit that also has a dispatchable component above the minimum.[48]
- **Generator Offer.** Offer to supply a schedule of MWh and the corresponding offer prices from a specific unit.
- **Increment Offer (INC).** Financial offer to supply specified MWh and the 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.[49] In the PJM Day-Ahead Market, an up-to congestion transaction is evaluated and clears as a matched pair of injections and withdrawals analogous to a matched pair of INC offers and DEC bids. The DEC (sink) portion of each up-to congestion transaction is load in the Day-Ahead Energy Market. The INC (source) of each up-to congestion transaction is generation in the Day-Ahead Energy Market.

Table 2-34 presents summary real-time generation statistics for the 10-year period from 2003 through 2012.

Table 2-34 PJM real-time average hourly generation: 2003 through 2012

	PJM Real-Time Generation (MWh)		Year-to-Year Change	
Year	Average Generation	Generation Standard Deviation	Average Generation	Generation Standard Deviation
2003	36,628	6,165	NA	NA
2004	51,068	13,790	39.4%	123.7%
2005	81,127	15,452	58.9%	12.0%
2006	82,780	13,709	2.0%	(11.3%)
2007	85,860	14,018	3.7%	2.3%
2008	83,476	13,787	(2.8%)	(1.7%)
2009	78,026	13,647	(6.5%)	(1.0%)
2010	82,585	15,556	5.8%	14.0%
2011	85,775	15,932	3.9%	2.4%
2012	88,708	15,701	3.4%	(1.4%)

Table 2-35 presents summary day-ahead generation statistics for the 10-year period from 2003 through 2012.

46 The ATSI zone was integrated on June 1, 2011. The DEOK zone was integrated on January 1, 2012. The ATSI zone was not included in this comparison for January through May 2011, and January through May 2012. The DEOK zone was not included in this comparison.

47 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 2012 State of the Market Report for PJM, Volume II, Section 2, "Energy Market."

48 The definition of self-scheduled is based on the PJM "eMKT User Guide" (October, 2012), pp. 41-44.

49 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 2-35 PJM day-ahead average hourly generation: 2003 through 2012[50]

	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	40,296	346	40,642	8,303	310	8,292	NA	NA	NA
2004	61,687	1,068	62,755	16,791	905	17,141	53.1%	208.9%	54.4%
2005	92,906	1,532	94,438	16,932	886	17,204	50.6%	43.5%	50.5%
2006	96,322	3,734	100,056	15,860	1,555	16,543	3.7%	143.8%	5.9%
2007	104,116	4,591	108,707	16,071	1,567	16,549	8.1%	23.0%	8.6%
2008	99,105	6,381	105,485	15,558	1,889	15,994	(4.8%)	39.0%	(3.0%)
2009	91,154	6,234	97,388	15,406	2,133	16,364	(8.0%)	(2.3%)	(7.7%)
2010	94,355	12,952	107,307	17,297	7,778	21,655	3.5%	107.8%	10.2%
2011	94,977	22,153	117,130	18,069	5,767	20,977	0.7%	71.0%	9.2%
2012	96,135	38,344	134,479	17,527	7,978	17,905	1.2%	73.1%	14.8%

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

Table 2-36 Day-ahead and real-time generation (MWh): 2011 and 2012

		Day Ahead				Real Time	Average Difference	
	Year	Cleared Generation	Cleared INC Offers	Cleared Up-to Congestion	Cleared Generation Plus INC Offers Plus Up-to Congestion	Generation	Cleared Generation	Cleared Generation Plus INC Offers Plus Up-to Congestion
Average	2011	86,966	8,010	22,153	117,130	85,775	1,191	31,354
	2012	90,134	6,000	38,344	134,479	88,708	1,426	45,771
Median	2011	85,218	8,006	21,488	114,938	83,986	1,232	30,952
	2012	88,404	5,976	37,015	133,376	86,513	1,891	46,863
Standard Deviation	2011	17,353	1,313	5,767	20,977	15,932	1,421	5,045
	2012	17,301	922	7,978	17,905	15,701	1,600	2,203
Peak Average	2011	96,750	8,859	23,194	128,803	94,275	2,475	34,528
	2012	100,130	6,348	37,347	143,825	97,134	2,996	46,691
Peak Median	2011	93,363	8,753	22,802	126,036	90,828	2,535	35,208
	2012	96,163	6,291	36,899	141,076	93,361	2,802	47,716
Peak Standard Deviation	2011	15,502	1,048	5,862	18,954	14,683	819	4,272
	2012	15,068	753	5,663	15,219	14,272	796	947
Off-Peak Average	2011	78,437	7,271	21,245	106,953	78,365	72	28,588
	2012	81,400	5,697	39,215	126,313	81,346	55	44,967
Off-Peak Median	2011	76,403	7,217	20,472	105,400	76,383	20	29,017
	2012	79,555	5,618	37,142	124,215	79,350	205	44,865
Off-Peak Standard Deviation	2011	14,071	1,047	5,525	16,975	13,011	1,060	3,963
	2012	14,103	950	9,467	15,979	12,951	1,152	3,028

Figure 2-13 shows the 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.[51]

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

51 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): 2012

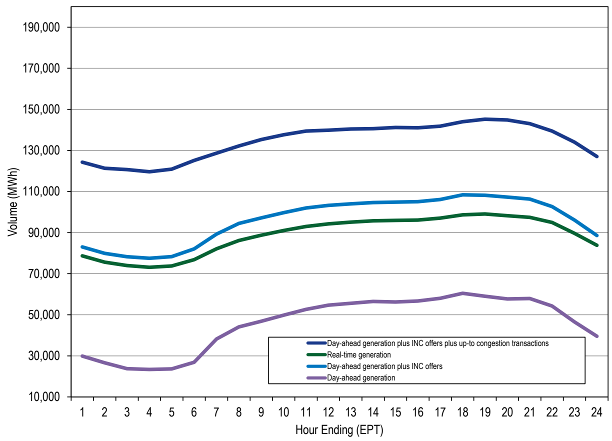
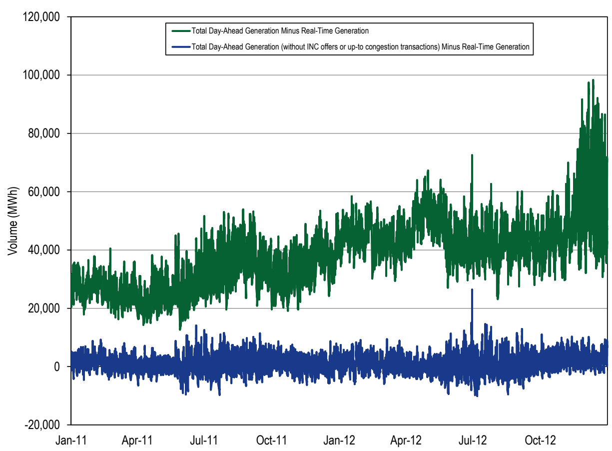


Figure 2-14 shows the difference between the day-ahead and real-time average daily generation in 2011 and 2012.

Figure 2-14 Difference between day-ahead and real-time generation (Average daily volumes): 2011 and 2012



Locational Marginal Price (LMP)

The conduct of individual market entities within a market structure is reflected in market prices.[52] PJM LMPs are a direct measure of market performance. Price level is a good, general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses and local price differences caused by congestion. Real-Time and Day-Ahead Energy Market load-weighted prices were 23.3 percent and 23.5 percent lower than in 2011 as a result of lower fuel costs and relatively low demand.[53]

PJM Real-Time Energy Market prices decreased in 2012 compared to 2011. The system average LMP was 22.7 percent lower in 2012 than in 2011, $33.11 per MWh versus $42.84 per MWh. The load-weighted average LMP was 23.3 percent lower in 2012 than in 2011, $35.23 per MWh versus $45.94 per MWh.

PJM Day-Ahead Energy Market prices decreased in 2012 compared to 2011. The system average LMP was 22.9 percent lower in 2012 than in 2011, $32.79 per MWh versus $42.52 per MWh. The load-weighted average LMP was 23.5 percent lower in 2012 than in 2011, $34.55 per MWh versus $45.19 per MWh.[54]

Real-Time LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[55] 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 hourly distribution of PJM real-time average LMP for 2011 and 2012.

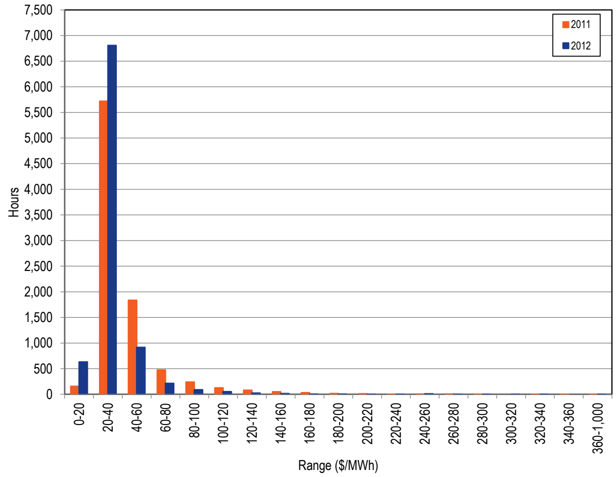
52 See the *2012 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market," for methodological background, detailed price data and the *Technical Reference for PJM Markets*, Section 4, "Calculating Locational Marginal Price" for more information on how bus LMPs are aggregated to system LMPs.

53 There was an average reduction of 1.2 heating degree days and an average increase of 0.1 cooling degree days in 2012 which meant overall reduced demand.

54 Tables reporting zonal and jurisdictional load and prices are in Appendix C. See the *2012 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

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

Figure 2-15 Average LMP for the PJM Real-Time Energy Market: 2011 and 2012



PJM Real-Time, Average LMP

Table 2-37 shows the PJM real-time, annual, average LMP for the 15-year period 1998 to 2012.[56]

Table 2-37 PJM real-time, average LMP (Dollars per MWh): 1998 through 2012

	Real-Time LMP			Year-to-Year Change		
Year	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.72	$16.60	$31.45	NA	NA	NA
1999	$28.32	$17.88	$72.42	30.4%	7.7%	130.3%
2000	$28.14	$19.11	$25.69	(0.6%)	6.9%	(64.5%)
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.41	(12.6%)	(8.3%)	(50.2%)
2003	$38.28	$30.79	$24.71	35.2%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	(15.2%)	(12.1%)	(8.9%)
2007	$57.58	$49.92	$34.60	16.9%	20.4%	5.8%
2008	$66.40	$55.53	$38.62	15.3%	11.2%	11.6%
2009	$37.08	$32.71	$17.12	(44.1%)	(41.1%)	(55.7%)
2010	$44.83	$36.88	$26.20	20.9%	12.7%	53.1%
2011	$42.84	$35.38	$29.03	(4.4%)	(4.1%)	10.8%
2012	$33.11	$29.53	$20.67	(22.7%)	(16.5%)	(28.8%)

Real-Time, Load-Weighted, Average LMP

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

56 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, Load-Weighted, Average LMP

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

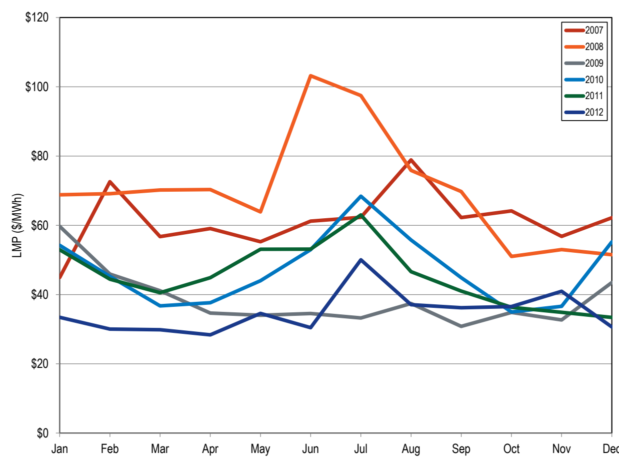
Table 2-38 PJM real-time, load-weighted, average LMP (Dollars per MWh): 1998 through 2012

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
Year	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.7%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	15.4%	8.9%	10.9%
2009	$39.05	$34.23	$18.21	(45.1%)	(42.5%)	(55.6%)
2010	$48.35	$39.13	$28.90	23.8%	14.3%	58.7%
2011	$45.94	$36.54	$33.47	(5.0%)	(6.6%)	15.8%
2012	$35.23	$30.43	$23.66	(23.3%)	(16.7%)	(29.3%)

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

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

Figure 2-16 PJM real-time, monthly, load-weighted, average LMP: 2007 through 2012



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 2012. Comparing prices in 2012 to prices in 2011, the price of Northern Appalachian coal was 16.5 percent lower; the price of Central Appalachian coal was 18.4 percent lower; the price of Powder River Basin coal was 31.5 percent lower; the price of eastern natural gas was 36.2 percent lower; and the price of western natural gas was 31.9 percent lower. Figure 2-17 shows monthly average spot fuel prices for 2011 and 2012.[57] Natural gas prices were below eastern coal prices in the months of March and April, with prices below $2/MMBtu for some days. Natural gas prices increased during summer months but remained competitive with coal on a $/MWh basis. Coal prices decreased during the year but remained relatively flat during the second half of 2012 while natural gas increased to above $3/MMBtu in the fourth quarter of 2012.

Figure 2-17 Spot average fuel price comparison: 2011 and 2012 ($/MMBtu)

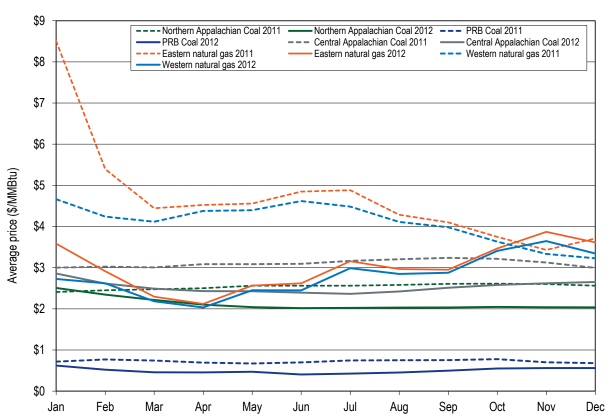


Figure 2-18 shows the average spot fuel cost of generation, comparing the fuel cost of a coal plant, combined cycle, and combustion turbine in dollars per MWh. The spot fuel cost of a new entrant combined cycle was below the spot fuel cost of a new entrant coal plant for February through June but greater for January and July through December. The average spot fuel cost of a new entrant combined cycle unit was $20.95/MWh, higher than the spot fuel cost of a new entrant coal plant, $19.60/MWh, in 2012.

57 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.

In the market, new combined cycles are competing with older coal plants. Most coal plants in PJM are 20 years or older, with heat rates greater than a new coal plant. Using average heat rates for existing sub-critical coal units, the spot fuel cost of existing coal units is $23.11. Thus the spot fuel cost of new combined cycle units remains below the spot fuel cost of existing coal plants.

Figure 2-18 Average spot fuel cost of generation of CP, CT, and CC: 2011 and 2012

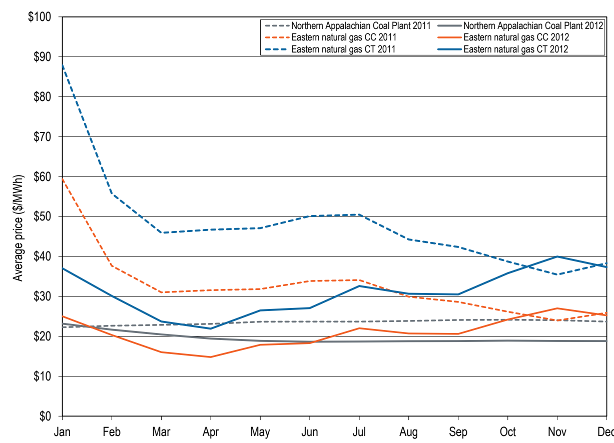


Table 2-39 compares the 2012 PJM real-time fuel cost adjusted, load weighted, average LMP to 2012 load-weighted, average LMP. The fuel cost adjusted, load weighted, average LMP for 2012 was 16.9 percent higher than the load weighted, average LMP for 2012. The real-time, fuel cost adjusted, load weighted, average LMP for 2012 was 10.4 percent lower than the load weighted LMP for 2011. If fuel costs in 2012 had been the same as in 2011, the 2012 load weighted LMP would have been higher, $41.17 per MWh instead of the observed $35.23 per MWh. The mix of fuel types and fuel costs in 2012 resulted in lower prices in 2012 than would have occurred if fuel prices had remained at their 2011 levels.

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

	2012 Load-Weighted LMP	2012 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$35.23	$41.17	16.9%
	2011 Load-Weighted LMP	2012 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$45.94	$41.17	(10.4%)
	2011 Load-Weighted LMP	2012 Load-Weighted LMP	Change
Average	$45.94	$35.23	(23.3%)

Components of Real-Time, Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, economic (least-cost) dispatch (SCED) in which marginal units determine system LMPs, based on their offers and five-minute-ahead forecast of the system conditions. Those offers can be decomposed into fuel costs, emission costs, variable operation and maintenance costs, markup, FMU adder and the 10 percent cost adder. As a result, it is possible to decompose PJM system's load-weighted LMP using the components of unit offers and sensitivity factors.

The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal. Cost offers of marginal units are broken into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs were calculated using spot prices for NO_x, SO_2 and CO_2 emission credits, fuel-specific emission rates for NO_x and unit-specific emission rates for SO_2. The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware, Maryland and New Jersey.[58]

Prior to the implementation of scarcity pricing on October 1, 2012, LMPs calculated based on SCED were modified ex-post to account for realized system conditions. This is sometimes referred to as an ex-post LMP calculation. The extent to which the ex-post LMP in a five-minute interval deviated from the LMP calculated by SCED (ex-ante LMP) reflected the change in system conditions between the time when the dispatch was solved, and the end of the five-minute interval. The contribution of this deviation to real-time LMPs is shown as the LPA-SCED differential. Starting with the October 1, 2012, implementation of scarcity pricing, PJM eliminated ex-post pricing and relies entirely on ex-ante pricing. After October 1, 2012, real-time LMPs are based solely on the interval's most recent SCED solution.

The components of LMP are shown in Table 2-40, including markup using unadjusted cost offers.[59] (Numbers in parentheses in the table are negative.) Table 2-40 shows that 53.8 percent of the annual, load-weighted LMP was the result of coal costs, 23.8 percent was the result of gas costs and 0.6 percent was the result of the cost of emission allowances. Markup was -$1.38 per MWh. In 2011, 42.2 percent of the annual, load-weighted LMP was the result of coal costs, 41.0 percent was the result of gas costs and 1.3 percent was the result of the cost of emission allowances. Markup was -$ 4.35. The fuel-related components of LMP reflect the degree to which the cost of the identified fuel affects LMP rather than all of the components of the offers of units burning that fuel.

Table 2-40 Components of PJM real-time (Unadjusted), annual, load-weighted, average LMP: 2012 and 2011

	2012		2011	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$18.94	53.8%	$19.40	42.2%
Gas	$8.38	23.8%	$18.86	41.0%
Ten Percent Addder	$3.49	9.9%	$4.71	10.2%
VOM	$2.53	7.2%	$2.50	5.4%
Oil	$1.69	4.8%	$1.48	3.2%
NA	$1.17	3.3%	$1.99	4.3%
LPA Rounding Difference	$0.32	0.9%	($0.05)	(0.1%)
Increase Generation Adder	$0.12	0.3%	$0.21	0.5%
FMU Adder	$0.10	0.3%	$0.12	0.3%
NO_x Cost	$0.10	0.3%	$0.30	0.6%
CO_2 Cost	$0.09	0.3%	$0.29	0.6%
Market-to-Market Adder	$0.02	0.1%	($0.07)	(0.1%)
SO_2 Cost	$0.02	0.1%	$0.03	0.1%
Constraint Violation Adder	$0.02	0.1%	$0.01	0.0%
Other	$0.01	0.0%	$0.01	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%
Wind	($0.04)	(0.1%)	($0.05)	(0.1%)
LPA-SCED Differential	($0.12)	(0.3%)	$0.82	1.8%
Decrease Generation Adder	($0.21)	(0.6%)	($0.25)	(0.5%)
Markup	($1.38)	(3.9%)	($4.35)	(9.5%)
Total	$35.23	100.0%	$45.94	100.0%

All generating units, including coal units, are allowed to include a ten percent adder in their cost offer. The 10 percent adder was included in the definition of cost offers prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions.

In order to accurately assess the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach (Table 2-40 and Table 2-44), markup is simply the difference between the price offer and the cost offer. In the second approach (Table 2-41 and Table 2-45), the 10 percent markup is removed from the cost offers of coal units. Coal units do not face the same cost uncertainty as gas-fired CTs. Actual participant behavior support this view, as the owners of coal units, facing

58 New Jersey withdrew from RGGI, effective January 1, 2012.
59 These components are explained in the *Technical Reference for PJM Markets*, Section 7 "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

competition, typically remove the 10 percent adder from their actual offers. The adjusted markup is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder.

The components of LMP are shown in Table 2-41, including markup using adjusted cost offers.

Table 2-41 Components of PJM real-time (Adjusted), annual, load-weighted, average LMP: 2012 and 2011

	2012		2011	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$19.11	54.2%	$19.51	42.5%
Gas	$8.38	23.8%	$18.80	40.9%
VOM	$2.54	7.2%	$2.51	5.5%
Oil	$1.69	4.8%	$1.48	3.2%
Ten Percent Addder	$1.50	4.2%	$2.55	5.6%
NA	$1.17	3.3%	$2.15	4.7%
Markup	$0.43	1.2%	($2.42)	(5.3%)
LPA Rounding Difference	$0.32	0.9%	($0.05)	(0.1%)
Increase Generation Adder	$0.12	0.3%	$0.21	0.5%
FMU Adder	$0.10	0.3%	$0.11	0.2%
NOx Cost	$0.10	0.3%	$0.30	0.6%
CO2 Cost	$0.09	0.3%	$0.29	0.6%
Market-to-Market Adder	$0.02	0.1%	($0.07)	(0.1%)
SO2 Cost	$0.02	0.1%	$0.03	0.1%
Constraint Violation Adder	$0.02	0.1%	$0.01	0.0%
Other	$0.01	0.0%	$0.01	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%
Wind	($0.04)	(0.1%)	($0.05)	(0.1%)
LPA-SCED Differential	($0.12)	(0.3%)	$0.82	1.8%
Decrease Generation Adder	($0.21)	(0.6%)	($0.25)	(0.5%)
Total	$35.23	100.0%	$45.94	100.0%

Day-Ahead LMP

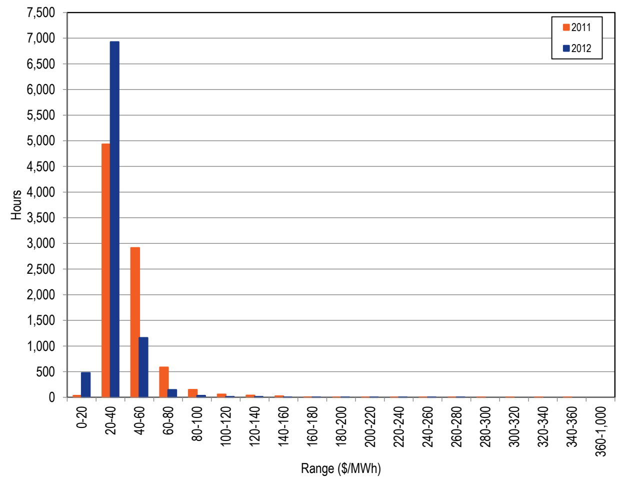
Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[60] This section discusses the day-ahead average LMP and the day-ahead load weighted average LMP. Average LMP is the unweighted average LMP.

Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

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

Figure 2-19 Price for the PJM Day-Ahead Energy Market: 2011 and 2012



PJM Day-Ahead, Average LMP

Table 2-42 shows the PJM day-ahead, average LMP for the 12 year period from 2001 to 2012.

Table 2-42 PJM day-ahead, average LMP (Dollars per MWh): 2001 through 2012

	Day-Ahead LMP			Year-to-Year Change		
Year	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$32.75	$27.05	$30.42	NA	NA	NA
2002	$28.46	$23.28	$17.68	(13.1%)	(14.0%)	(41.9%)
2003	$38.73	$35.22	$20.84	36.1%	51.3%	17.8%
2004	$41.43	$40.36	$16.60	7.0%	14.6%	(20.4%)
2005	$57.89	$50.08	$30.04	39.7%	24.1%	81.0%
2006	$48.10	$44.21	$23.42	(16.9%)	(11.7%)	(22.0%)
2007	$54.67	$52.34	$23.99	13.7%	18.4%	2.4%
2008	$66.12	$58.93	$30.87	20.9%	12.6%	28.7%
2009	$37.00	$35.16	$13.39	(44.0%)	(40.3%)	(56.6%)
2010	$44.57	$39.97	$18.83	20.5%	13.7%	40.6%
2011	$42.52	$38.13	$20.48	(4.6%)	(4.6%)	8.8%
2012	$32.79	$30.89	$13.27	(22.9%)	(19.0%)	(35.2%)

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 2-43 shows the PJM day-ahead, load-weighted, average LMP for the 12 year period from 2001 to 2012.

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

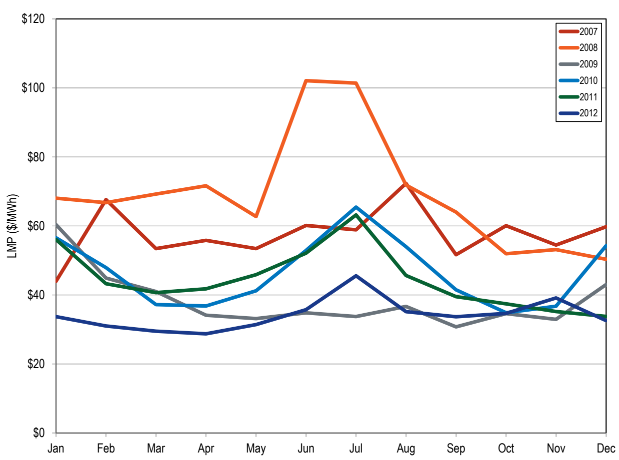
Table 2-43 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): 2001 through 2012

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
Year	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$36.01	$29.02	$37.48	NA	NA	NA
2002	$31.80	$26.00	$20.68	(11.7%)	(10.4%)	(44.8%)
2003	$41.43	$38.29	$21.32	30.3%	47.3%	3.1%
2004	$42.87	$41.96	$16.32	3.5%	9.6%	(23.4%)
2005	$62.50	$54.74	$31.72	45.8%	30.4%	94.3%
2006	$51.33	$46.72	$26.45	(17.9%)	(14.6%)	(16.6%)
2007	$57.88	$55.91	$25.02	12.8%	19.7%	(5.4%)
2008	$70.25	$62.91	$33.14	21.4%	12.5%	32.4%
2009	$38.82	$36.67	$14.03	(44.7%)	(41.7%)	(57.7%)
2010	$47.65	$42.06	$20.59	22.7%	14.7%	46.8%
2011	$45.19	$39.66	$24.05	(5.2%)	(5.7%)	16.8%
2012	$34.55	$31.84	$15.48	(23.5%)	(19.7%)	(35.6%)

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

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

Figure 2-20 Day-ahead, monthly, load-weighted, average LMP: 2007 through 2012



Components of Day-Ahead, Load-Weighted LMP

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

The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal. Day-Ahead Scheduling Reserve (DASR) lost opportunity cost (LOC) and DASR offer adders are the calculated contribution to LMP when redispatch of resources is needed in order to satisfy DASR requirements. Cost offers of marginal units are broken into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs were calculated using spot prices for NO_x, SO_2 and CO_2 emission credits, fuel-specific emission rates for NO_x and unit-specific emission rates for SO_2. The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware, Maryland and New Jersey.[61]

Table 2-44 shows the components of the PJM day ahead, annual, load-weighted average LMP, including markup, using unadjusted cost offers.

Table 2-44 Components of PJM day-ahead, (unadjusted) annual, load-weighted, average LMP (Dollars per MWh): 2012

	2012		2011	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$13.73	39.7%	$12.65	28.0%
DEC	$8.17	23.7%	$11.21	24.8%
Gas	$4.50	13.0%	$7.68	17.0%
INC	$3.33	9.7%	$7.27	16.1%
10% Cost Adder	$2.02	5.9%	$2.23	4.9%
Up-to Congestion Transaction	$1.69	4.9%	$1.70	3.8%
VOM	$1.54	4.5%	$1.35	3.0%
Dispatchable Transaction	$0.53	1.5%	$1.41	3.1%
Price Sensitive Demand	$0.45	1.3%	$1.85	4.1%
Oil	$0.32	0.9%	$0.28	0.6%
DASR Offer Adder	$0.15	0.4%	$0.09	0.2%
CO2	$0.06	0.2%	$0.16	0.4%
NOx	$0.06	0.2%	$0.17	0.4%
SO2	$0.01	0.0%	$0.02	0.0%
FMU Adder	$0.01	0.0%	$0.02	0.0%
Constrained Off	$0.00	0.0%	$0.00	0.0%
Diesel	$0.00	0.0%	$0.00	(0.0%)
Wind	($0.00)	(0.0%)	$0.00	(0.0%)
DASR LOC Adder	($0.31)	(0.9%)	$0.52	1.2%
Markup	($1.86)	(5.4%)	($3.60)	(8.0%)
NA	$0.14	0.4%	$0.19	0.4%
Total	$34.55	100.0%	$45.19	100.0%

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

Table 2-45 shows the components of the PJM day ahead, annual, load-weighted average LMP, including markup, using adjusted cost offers.

Table 2-45 Components of PJM day-ahead, (adjusted) annual, load-weighted, average LMP (Dollars per MWh): Calendar year 2012

	2012		2011	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$13.73	39.7%	$12.65	28.0%
DEC	$8.17	23.7%	$11.21	24.8%
Gas	$4.50	13.0%	$7.68	17.0%
INC	$3.33	9.7%	$7.27	16.1%
Up-to Congestion Transaction	$1.69	4.9%	$1.70	3.8%
VOM	$1.54	4.5%	$1.35	3.0%
10% Cost Adder	$1.02	2.9%	$1.19	2.6%
Dispatchable Transaction	$0.53	1.5%	$1.41	3.1%
Price Sensitive Demand	$0.45	1.3%	$1.85	4.1%
Oil	$0.32	0.9%	$0.28	0.6%
DASR Offer Adder	$0.15	0.4%	$0.09	0.2%
CO2	$0.06	0.2%	$0.16	0.4%
NOx	$0.06	0.2%	$0.17	0.4%
SO2	$0.01	0.0%	$0.02	0.0%
FMU Adder	$0.01	0.0%	$0.02	0.0%
Constrained Off	$0.00	0.0%	$0.00	0.0%
Diesel	$0.00	0.0%	$0.00	(0.0%)
Wind	($0.00)	(0.0%)	$0.00	(0.0%)
DASR LOC Adder	($0.31)	(0.9%)	$0.52	1.2%
Markup	($0.85)	(2.5%)	($2.56)	(5.7%)
NA	$0.14	0.4%	$0.19	0.4%
Total	$34.55	100.0%	$45.19	100.0%

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.[62]

Table 2-46 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 2-21 PJM day-ahead aggregate supply curves: 2012 example day

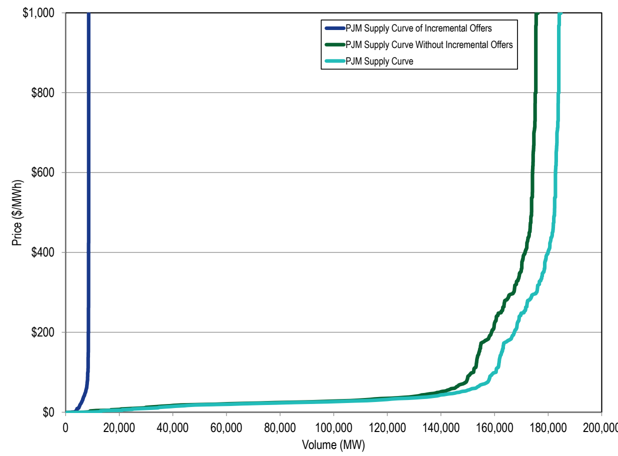


Table 2-46 shows the average volume of trading in increment offers and decrement bids per hour and the average total MW values of all bids per hour. Table 2-47 shows the average volume of up-to congestion transactions per hour and the average total MW values of all bids per hour. In 2012, the average submitted and cleared increment bid MW decreased 34.8 and 23.0 percent, and the average submitted and cleared decrement bid MW decreased 32.8 and 24.1 percent, compared to 2011. The 2012 average up-to congestion submitted and cleared MW increased 116.4 and 73.8 percent, compared to 2011. The increase in up-to congestion transactions displaced increment and decrement transactions.

62 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. Internal up-to congestion transactions may source or sink at any of the eligible hubs, transmission zones, aggregates, or single buses for which LMP is calculated. For a complete list of eligible locations for up-to congestion source and sink transactions see the following link from the PJM website: <http://www.pjm.com/~/media/etools/oasis/references/oasis-source-sink-link.ashx>.

Table 2-46 Hourly average volume of cleared and submitted INCs, DECs by month: 2011 and 2012

		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	1,077	11,135	17,917	224	963
2011	Feb	8,530	16,263	215	1,672	11,071	17,355	230	1,034
2011	Mar	7,230	13,164	201	1,059	10,435	16,343	219	982
2011	Apr	7,222	12,516	185	984	10,211	16,199	202	846
2011	May	7,443	12,161	220	835	10,250	15,956	243	800
2011	Jun	8,405	14,171	238	1,084	11,648	17,542	279	1,015
2011	Jul	8,595	14,006	185	1,234	12,196	17,567	213	1,140
2011	Aug	7,540	12,349	120	1,034	10,992	15,368	161	847
2011	Sep	7,092	10,071	114	591	12,171	16,268	147	648
2011	Oct	7,726	10,242	104	351	10,983	14,550	116	396
2011	Nov	8,290	11,545	105	382	10,936	15,204	118	416
2011	Dec	8,914	12,159	107	409	11,964	15,515	114	404
2011	Annual	7,792	12,924	180	992	11,109	16,507	203	867
2012	Jan	6,781	10,341	91	455	9,031	12,562	111	428
2012	Feb	6,428	10,930	96	591	7,641	11,043	108	511
2012	Mar	5,969	9,051	90	347	7,193	10,654	112	362
2012	Apr	6,355	9,368	87	298	7,812	10,811	105	329
2012	May	6,224	8,447	80	271	8,785	11,141	109	316
2012	Jun	6,415	8,360	79	234	9,030	11,124	97	270
2012	Jul	6,485	8,270	81	285	8,981	11,121	112	349
2012	Aug	5,809	7,873	74	291	8,471	10,507	100	320
2012	Sep	5,274	7,509	78	313	8,192	10,814	109	381
2012	Oct	5,231	6,953	82	275	8,901	11,526	110	361
2012	Nov	5,423	6,944	67	190	8,678	11,758	102	289
2012	Dec	5,622	7,090	69	183	8,456	10,007	84	207
2012	Annual	6,001	8,428	81	311	8,431	11,089	105	343

Table 2-47 Hourly average of cleared and submitted up-to congestion bids by month: 2011 and 2012

		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	1,013	2,519
2012	May	43,468	119,374	1,052	2,541
2012	Jun	35,052	101,065	915	2,193
2012	Jul	35,179	118,294	981	2,710
2012	Aug	35,515	122,458	986	2,787
2012	Sep	35,199	112,731	946	2,801
2012	Oct	35,365	106,819	990	2,692
2012	Nov	40,499	143,853	1,329	3,934
2012	Dec	45,536	176,660	1,681	5,145
2012	Annual	38,343	119,744	1,033	2,801

Table 2-48 shows the frequency with which generation offers, import or export transactions, up-to congestion transactions, decrement bids, increment offers and price-sensitive demand are marginal for each month.[63]

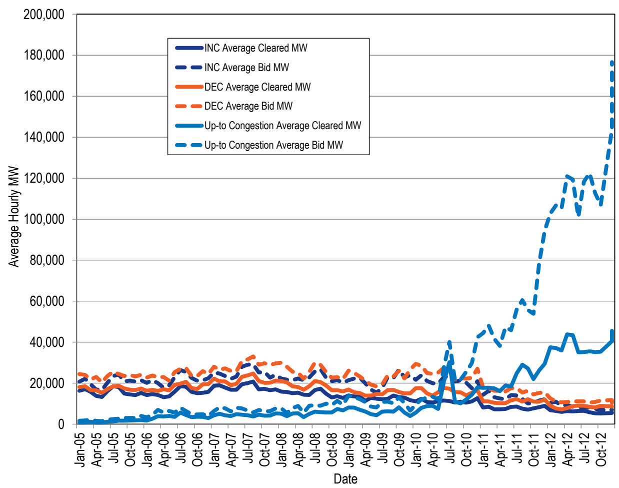
Table 2-48 Type of day-ahead marginal units: 2012

	Generation	Dispatchable Transaction	Up-to Congestion Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	3.8%	0.1%	87.3%	5.7%	3.1%	0.1%
Feb	3.7%	0.1%	83.8%	5.4%	6.9%	0.1%
Mar	3.5%	0.1%	83.2%	6.2%	6.9%	0.1%
Apr	3.5%	0.1%	85.3%	5.2%	5.9%	0.0%
May	3.1%	0.1%	87.9%	4.6%	4.4%	0.0%
Jun	4.3%	0.0%	88.7%	4.3%	2.6%	0.0%
Jul	3.3%	0.1%	88.0%	6.1%	2.5%	0.1%
Aug	4.0%	0.1%	89.4%	4.1%	2.3%	0.0%
Sep	3.7%	0.1%	86.8%	4.5%	5.0%	0.0%
Oct	3.4%	0.1%	88.2%	4.0%	4.3%	0.0%
Nov	2.8%	0.1%	92.9%	2.0%	2.2%	0.0%
Dec	2.4%	0.0%	95.0%	1.3%	1.4%	0.0%
Annual	3.4%	0.1%	88.4%	4.3%	3.8%	0.0%

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

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

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



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 2-49 shows, for 2011 and 2012, the total increment offers and decrement bids by the type of parent organization: financial or physical. Table 2-50 shows for 2011 and 2012, the total up-to congestion transactions by the type of parent organization.

The top five companies with cleared up-to congestion bids are financial and account for 65.0 percent of all the cleared up-to congestion MW in PJM in 2012.

Table 2-49 PJM INC and DEC bids by type of parent organization (MW): 2011 and 2012

	2011		2012	
Category	Total Virtual Bids MW	Percentage	Total Virtual Bids MW	Percentage
Financial	125,432,065	43.0%	59,843,681	34.9%
Physical	166,308,872	57.0%	111,507,235	65.1%
Total	291,740,937	100.0%	171,350,915	100.0%

Table 2-50 PJM up-to congestion transactions by type of parent organization (MW): 2011 and 2012

	2011		2012	
Category	Total Up-to Congestion MW	Percentage	Total Up-to Congestion MW	Percentage
Financial	187,509,868	96.8%	318,217,668	94.7%
Physical	6,113,860	3.2%	17,660,315	5.3%
Total	193,623,729	100.0%	335,877,984	100.0%

Table 2-51 shows increment offers and decrement bids bid by top ten locations for 2011 and 2012.

Table 2-51 PJM virtual offers and bids by top ten locations (MW): 2011 and 2012

2011					2012				
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	34,784,275	39,727,544	74,511,819	WESTERN HUB	HUB	30,251,322	34,038,502	64,289,824
N ILLINOIS HUB	HUB	10,740,204	17,271,222	28,011,425	AEP-DAYTON HUB	HUB	5,095,250	6,203,179	11,298,428
AEP-DAYTON HUB	HUB	8,161,997	9,878,692	18,040,689	N ILLINOIS HUB	HUB	2,523,882	6,051,839	8,575,721
SOUTHIMP	INTERFACE	11,363,163	0	11,363,163	SOUTHIMP	INTERFACE	8,243,907	0	8,243,907
MISO	INTERFACE	292,005	8,755,249	9,047,254	MISO	INTERFACE	311,129	7,046,379	7,357,509
PECO	ZONE	2,080,316	5,855,528	7,935,844	PPL	ZONE	327,795	5,785,740	6,113,535
PPL	ZONE	318,717	4,727,485	5,046,202	PECO	ZONE	889,065	4,026,280	4,915,345
COMED	ZONE	3,208,552	243,813	3,452,365	IMO	INTERFACE	3,665,471	73,627	3,739,098
IMO	INTERFACE	2,754,598	108,998	2,863,597	BGE	ZONE	173,888	2,161,310	2,335,198
PSEG	ZONE	544,733	1,740,038	2,284,771	METED	ZONE	153,851	1,421,991	1,575,842
Top ten total		74,248,561	88,308,567	162,557,128			51,635,560	66,808,846	118,444,406
PJM total		130,593,253	161,147,684	291,740,937			73,945,975	97,404,941	171,350,915
Top ten total as percent of PJM total		56.9%	54.8%	55.7%			69.8%	68.6%	69.1%

Table 2-52 shows up-to congestion transactions by import bids for the top ten locations for 2011 and 2012.[64]

Table 2-52 PJM cleared up-to congestion import bids by top ten source and sink pairs (MW): 2011 and 2012

2011				
Imports				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	N ILLINOIS HUB	HUB	3,763,388
MISO	INTERFACE	112 WILTON	EHVAGG	2,649,235
OVEC	INTERFACE	CONESVILLE 6	AGGREGATE	2,419,245
NORTHWEST	INTERFACE	ZION 1	AGGREGATE	2,205,202
OVEC	INTERFACE	CONESVILLE 4	AGGREGATE	2,103,635
NYIS	INTERFACE	MARION	AGGREGATE	1,674,479
OVEC	INTERFACE	CONESVILLE 5	AGGREGATE	1,645,825
NYIS	INTERFACE	PSEG	ZONE	1,158,004
OVEC	INTERFACE	JEFFERSON	EHVAGG	1,043,124
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	986,945
Top ten total				19,649,082
PJM total				104,786,982
Top ten total as percent of PJM total				18.8%
2012				
Imports				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	112 WILTON	EHVAGG	9,190,395
OVEC	INTERFACE	DEOK	ZONE	2,413,946
MISO	INTERFACE	N ILLINOIS HUB	HUB	2,381,726
OVEC	INTERFACE	JEFFERSON	EHVAGG	2,143,300
NYIS	INTERFACE	HUDSON BC	AGGREGATE	2,111,405
OVEC	INTERFACE	MARYSVILLE	EHVAGG	1,864,666
MISO	INTERFACE	COOK	EHVAGG	1,841,613
OVEC	INTERFACE	COOK	EHVAGG	1,785,331
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	1,784,828
OVEC	INTERFACE	BIG SANDY CT1	AGGREGATE	1,686,217
Top ten total				27,203,428
PJM total				146,428,449
Top ten total as percent of PJM total				18.6%

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

Table 2-53 shows up-to congestion transactions by export bids for the top ten locations for 2011 and 2012.

Table 2-53 PJM cleared up-to congestion export bids by top ten source and sink pairs (MW): 2011 and 2012

2011				
Exports				
Source	Source Type	Sink	Sink Type	MW
LUMBERTON	AGGREGATE	SOUTHEAST	AGGREGATE	6,076,609
WESTERN HUB	HUB	MISO	INTERFACE	3,932,018
23 COLLINS	EHVAGG	MISO	INTERFACE	1,684,900
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	1,591,281
FE GEN	AGGREGATE	SOUTHWEST	AGGREGATE	1,363,004
167 PLANO	EHVAGG	MISO	INTERFACE	1,166,857
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	AGGREGATE	1,157,710
BELMONT	EHVAGG	OVEC	INTERFACE	992,732
FOWLER 34.5 KV FWLR1AWF	AGGREGATE	OVEC	INTERFACE	969,853
RECO	ZONE	IMO	INTERFACE	847,660
Top ten total				19,782,624
PJM total				85,627,554
Top ten total as percent of PJM total				23.1%
2012				
Exports				
Source	Source Type	Sink	Sink Type	MW
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	3,715,287
ROCKPORT	EHVAGG	OVEC	INTERFACE	3,343,889
23 COLLINS	EHVAGG	MISO	INTERFACE	3,085,476
STUART 1	AGGREGATE	OVEC	INTERFACE	2,386,394
GAVIN	EHVAGG	OVEC	INTERFACE	1,932,567
ROCKPORT	EHVAGG	MISO	INTERFACE	1,854,904
QUAD CITIES 1	AGGREGATE	NORTHWEST	INTERFACE	1,841,009
SPORN 5	AGGREGATE	OVEC	INTERFACE	1,803,365
SPORN 3	AGGREGATE	OVEC	INTERFACE	1,792,405
WESTERN HUB	HUB	MISO	INTERFACE	1,661,684
Top ten total				23,416,981
PJM total				150,988,394
Top ten total as percent of PJM total				15.5%

Table 2-54 shows up-to congestion transactions by wheel bids for the top ten locations for 2011 and 2012.

Table 2-54 PJM cleared up-to congestion wheel bids by top ten source and sink pairs (MW): 2011 and 2012

		2011		
		Wheels		
Source	Source Type	Sink	Sink Type	MW
CPLEIMP	INTERFACE	NCMPAEXP	INTERFACE	397,775
CPLEIMP	INTERFACE	DUKEXP	INTERFACE	287,643
NORTHWEST	INTERFACE	MISO	INTERFACE	239,020
NORTHWEST	INTERFACE	SOUTHWEST	AGGREGATE	204,835
SOUTHWEST	AGGREGATE	OVEC	INTERFACE	174,891
NYIS	INTERFACE	MICHFE	INTERFACE	115,574
MISO	INTERFACE	NIPSCO	INTERFACE	114,199
NIPSCO	INTERFACE	OVEC	INTERFACE	93,186
NIPSCO	INTERFACE	MISO	INTERFACE	73,321
NCMPAIMP	INTERFACE	OVEC	INTERFACE	62,459
Top ten total				1,762,903
PJM total				3,209,193
Top ten total as percent of PJM total				54.9%
		2012		
		Wheels		
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	540,158
MISO	INTERFACE	NIPSCO	INTERFACE	198,665
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	192,006
NYIS	INTERFACE	IMO	INTERFACE	167,433
SOUTHIMP	INTERFACE	MISO	INTERFACE	149,798
SOUTHEAST	INTERFACE	SOUTHEXP	INTERFACE	149,407
MISO	INTERFACE	OVEC	INTERFACE	147,574
IMO	INTERFACE	NYIS	INTERFACE	138,041
NORTHWEST	INTERFACE	MISO	INTERFACE	131,420
OVEC	INTERFACE	IMO	INTERFACE	118,486
Top ten total				1,932,987
PJM total				2,974,891
Top ten total as percent of PJM total				65.0%

On November 1, 2012, PJM eliminated the requirement for market participants to specify an interface pricing point as either the source or sink of an up-to congestion transaction.[65] Up-to congestion transactions can now be made at internal buses. The top ten internal up-to congestion transaction locations were only 4.9 percent of the PJM total internal up-to congestion transactions in 2012.

65 For more information, see the *2012 State of the Market Report for PJM*, Section 8, "Interchange Transactions," Up-to Congestion.

Table 2-55 shows up-to congestion transactions by internal bids for the top ten locations for November through December of 2012.

Table 2-55 PJM cleared up-to congestion internal bids by top ten source and sink pairs (MW): November through December of 2012

2012 (November - December)				
Internal				
Source	Source Type	Sink	Sink Type	MW
NAPERVILLE	AGGREGATE	ZION 1	AGGREGATE	213,928
MARQUIS	EHVAGG	STUART DIESEL	AGGREGATE	205,066
JOLIET 8	AGGREGATE	JOLIET 7	AGGREGATE	189,609
WESTERN HUB	HUB	BGE	ZONE	174,710
SULLIVAN-AEP	EHVAGG	AK STEEL	AGGREGATE	166,152
RENO 138 KV T1	AGGREGATE	OAKGROVE 1	AGGREGATE	160,935
TANNERS CRK 4	AGGREGATE	SPORN 3	AGGREGATE	159,006
ROCKPORT	EHVAGG	JEFFERSON	EHVAGG	156,568
CONEMAUGH	EHVAGG	HUNTERSTOWN	EHVAGG	153,698
N ILLINOIS HUB	HUB	AEP-DAYTON HUB	HUB	152,976
Top ten total				1,732,647
PJM total				35,486,249
Top ten total as percent of PJM total				4.9%

Table 2-56 shows the number of source-sink pairs that were offered and cleared monthly in 2012. The increase in average offered and cleared source-sink pairs in November and December illustrates that PJM's modification of the rules governing the location of up-to congestion transactions bids resulted in a significant increase in the number of offered and cleared up-to congestion transactions. The increase in source-sink pairs available for up-to congestion transactions has also led to more dispersion in the number of cleared up-to congestion transaction internal bids by location.

Table 2-56 Number of PJM offered and cleared source and sink pairs: 2012

2012				
Daily Number of Source-Sink Pairs				
Month	Average Offered	Max Offered	Average Cleared	Max Cleared
Jan	1,771	2,182	1,126	1,568
Feb	1,816	2,198	1,156	1,414
Mar	1,746	2,004	1,128	1,353
Apr	1,753	2,274	1,117	1,507
May	1,866	2,257	1,257	1,491
Jun	2,145	2,581	1,425	1,897
Jul	2,168	2,800	1,578	2,078
Aug	2,541	3,043	1,824	2,280
Sep	2,140	3,032	1,518	2,411
Oct	2,344	3,888	1,569	2,625
Nov	4,102	8,142	2,829	5,811
Dec	9,424	13,009	5,025	8,071
Jan-Oct	2,031	3,888	1,371	2,625
Nov-Dec	6,806	13,009	3,945	8,071

Table 2-57 and Figure 2-23 shows the spike in internal up-to congestion transactions in November and December, following the November 1, 2012, rule change permitting such transactions.

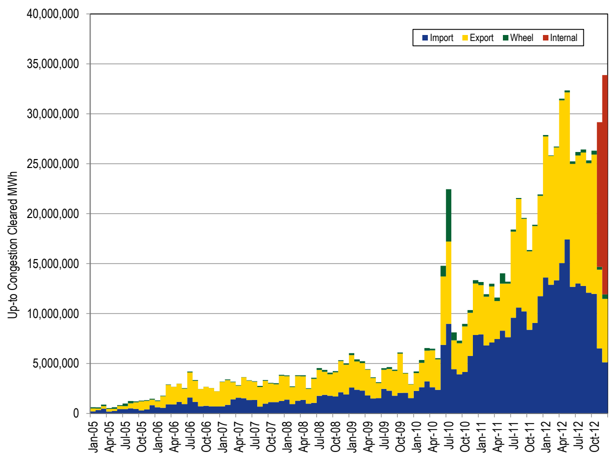
Figure 2-23 show total cleared up-to congestion transactions by type for 2011 and 2012. Internal up-to congestion transactions in just November and December of 2012, were 10.6 percent of all up-to congestion transactions for the year 2012.

Table 2-57 PJM cleared up-to congestion transactions by type (MW): 2011 and 2012

	2011				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	19,649,082	19,782,624	1,762,903	NA	20,850,203
PJM total (MW)	104,786,982	85,627,554	3,209,193	NA	193,623,729
Top ten total as percent of PJM total	18.8%	23.1%	54.9%	NA	10.8%
PJM total as percent of all up-to congestion transactions	54.1%	44.2%	1.7%	NA	100.0%
	2012				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	27,203,428	23,416,981	1,932,987	1,732,647	32,704,386
PJM total (MW)	146,428,449	150,988,394	2,974,891	35,486,249	335,877,984
Top ten total as percent of PJM total	18.6%	15.5%	65.0%	4.9%	9.7%
PJM total as percent of all up-to congestion transactions	43.6%	45.0%	0.9%	10.6%	100.0%

Figure 2-23 shows the spike in internal up-to congestion transactions in November and December, following the November 1, 2012, rule change permitting such transactions.

Figure 2-23 PJM cleared up-to congestion transactions by type (MW): 2005 through 2012



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. There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis (Figure 2-25).

Table 2-58 shows, day-ahead and real-time prices were relatively close, on average, in 2011 and 2012.

Table 2-58 Day-ahead and real-time average LMP (Dollars per MWh): 2011 and 2012[66]

	2011				2012			
	Day Ahead	Real Time	Difference	Difference as Percent of Real Time	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Average	$42.52	$42.84	$0.32	0.7%	$32.79	$33.11	$0.32	1.0%
Median	$38.13	$35.38	($2.75)	(7.8%)	$30.89	$29.53	($1.36)	(4.6%)
Standard deviation	$20.48	$29.03	$8.55	29.4%	$13.27	$20.67	$7.40	35.8%
Peak average	$50.45	$51.20	$0.74	1.4%	$38.46	$39.83	$1.37	3.4%
Peak median	$44.56	$40.25	($4.31)	(10.7%)	$34.71	$33.13	($1.58)	(4.8%)
Peak standard deviation	$24.60	$36.11	$11.51	31.9%	$15.86	$25.47	$9.61	37.7%
Off peak average	$35.61	$35.56	($0.05)	(0.1%)	$27.88	$27.29	($0.59)	(2.2%)
Off peak median	$32.43	$31.58	($0.85)	(2.7%)	$27.15	$26.18	($0.97)	(3.7%)
Off peak standard deviation	$12.44	$18.07	$5.63	31.2%	$7.66	$12.74	$5.08	39.9%

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 as well as conditions in real time that are difficult or impossible to predict.

Table 2-59 shows the difference between the Real-Time and the Day-Ahead Energy Market Prices for the 12-year period 2001 to 2012.

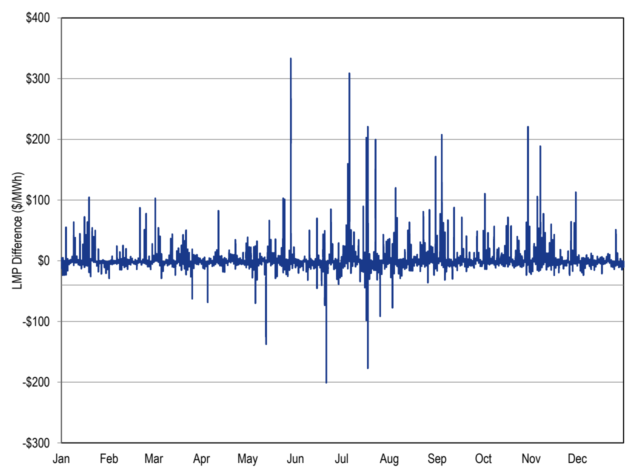
Table 2-59 Day-ahead and real-time average LMP (Dollars per MWh): 2001 through 2012

Year	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
2001	$32.75	$32.38	($0.37)	(1.1%)
2002	$28.46	$28.30	($0.16)	(0.6%)
2003	$38.73	$38.28	($0.45)	(1.2%)
2004	$41.43	$42.40	$0.97	2.3%
2005	$57.89	$58.08	$0.18	0.3%
2006	$48.10	$49.27	$1.17	2.4%
2007	$54.67	$57.58	$2.90	5.3%
2008	$66.12	$66.40	$0.28	0.4%
2009	$37.00	$37.08	$0.08	0.2%
2010	$44.57	$44.83	$0.26	0.6%
2011	$42.52	$42.84	$0.32	0.7%
2012	$32.79	$33.11	$0.32	1.0%

Table 2-60 provides frequency distributions of the differences between PJM real-time load-weighted hourly LMP and PJM day-ahead load-weighted hourly LMP for the years 2007 through 2012.

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

Figure 2-24 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: 2012



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

Table 2-60 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): 2007 through 2012

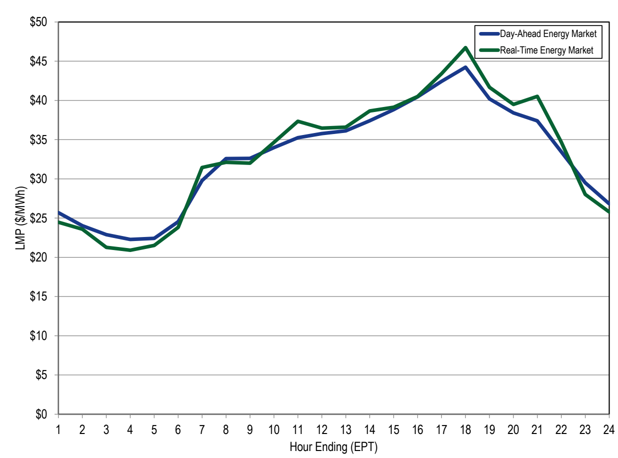
	2007		2008		2009		2010		2011		2012	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.01%	5	0.06%
($150) to ($100)	0	0.00%	1	0.01%	0	0.00%	0	0.00%	2	0.03%	6	0.13%
($100) to ($50)	33	0.38%	88	1.01%	3	0.03%	13	0.15%	49	0.59%	17	0.32%
($50) to $0	4,600	52.89%	5,120	59.30%	5,108	58.34%	5,543	63.42%	5,614	64.68%	5,576	63.80%
$0 to $50	3,827	96.58%	3,247	96.27%	3,603	99.47%	3,004	97.72%	2,880	97.56%	3,061	98.65%
$50 to $100	255	99.49%	284	99.50%	41	99.94%	164	99.59%	185	99.67%	82	99.58%
$100 to $150	31	99.84%	37	99.92%	5	100.00%	25	99.87%	21	99.91%	17	99.77%
$150 to $200	5	99.90%	4	99.97%	0	100.00%	9	99.98%	2	99.93%	12	99.91%
$200 to $250	1	99.91%	2	99.99%	0	100.00%	2	100.00%	3	99.97%	5	99.97%
$250 to $300	3	99.94%	0	99.99%	0	100.00%	0	100.00%	0	99.97%	1	99.98%
$300 to $350	2	99.97%	1	100.00%	0	100.00%	0	100.00%	0	99.97%	2	100.00%
$350 to $400	1	99.98%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%
$400 to $450	1	99.99%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%
$450 to $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%
>= $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%	0	100.00%

Figure 2-25 shows the monthly average differences between the day-ahead and real-time LMP in 2012. The figure shows a spike in the difference between the day-ahead and real-time LMP in June. A significant portion of this difference between day-ahead and real-time LMP in June was the result of relatively large differences on June 20, 21 and 29. On June 20, 21 and 29, the day-ahead market model solution required a redispatch of energy units to maintain day ahead synchronized reserves (DASR). The costs associated with the redispatch for DASR were reflected in the day-ahead energy price on these days. This cost was, in part, reflective of the lost opportunity cost (LOC) of units that were marginal for energy and DASR in the PJM market software. The LOCs caused higher than usual day-ahead versus real-time price spreads for some hours. On June 21, the day-ahead LMP was on average $50.83 more than the real-time LMP because DASR related redispatch caused day-ahead LMP to be $97.40 more than real-time LMP on average for the hours where an LOC was added to the day-ahead LMP. A similar shortage of reserves was not observed in the real-time market.

Figure 2-25 Monthly average of real-time minus day-ahead LMP: 2012

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

Figure 2-26 PJM system hourly average LMP: 2012



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 2-61 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, 9.0 percent of real-time load was supplied by bilateral contracts, 23.2 percent by spot market purchase and 67.8 percent by self-supply. Compared with 2011, reliance on bilateral contracts decreased 1.5 percentage points, reliance on spot supply decreased by 3.4 percentage points and reliance on self-supply increased by 4.9 percentage points.

Table 2-61 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: 2011 through 2012

	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%	8.9%	22.0%	69.1%	(0.4%)	(6.8%)	7.2%
Feb	10.9%	27.9%	61.2%	8.8%	21.2%	70.0%	(2.1%)	(6.7%)	8.7%
Mar	10.4%	29.3%	60.3%	9.4%	23.6%	67.1%	(1.0%)	(5.7%)	6.8%
Apr	10.7%	25.3%	64.1%	9.4%	23.8%	66.8%	(1.3%)	(1.4%)	2.7%
May	11.1%	25.7%	63.3%	8.6%	23.5%	67.9%	(2.6%)	(2.2%)	4.6%
Jun	10.5%	25.4%	64.1%	8.7%	22.3%	69.0%	(1.8%)	(3.1%)	4.9%
Jul	9.5%	24.7%	65.8%	8.0%	22.7%	69.3%	(1.5%)	(2.0%)	3.5%
Aug	10.3%	24.6%	65.1%	8.5%	23.6%	67.9%	(1.8%)	(1.0%)	2.8%
Sep	10.9%	26.7%	62.4%	9.1%	24.4%	66.5%	(1.9%)	(2.2%)	4.1%
Oct	12.2%	29.8%	58.0%	9.6%	25.5%	64.9%	(2.6%)	(4.3%)	6.9%
Nov	10.7%	28.3%	61.1%	9.9%	23.9%	66.3%	(0.8%)	(4.4%)	5.2%
Dec	10.1%	24.3%	65.5%	10.2%	22.6%	67.3%	0.0%	(1.7%)	1.7%
Annual	10.5%	26.6%	62.9%	9.0%	23.2%	67.8%	(1.5%)	(3.4%)	4.9%

Day-Ahead Load and Spot Market

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

The PJM system's reliance on self-supply, bilateral contracts, and spot purchases to meet day-ahead load (cleared fixed-demand, price-sensitive load and decrement bids) is calculated by summing across all the parent companies of PJM billing organizations that serve load in the Day-Ahead Energy Market for each hour. Table 2-62 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, 6.7 percent of day-ahead load was supplied by bilateral contracts, 22.3 percent by spot market purchases, and 71.0 percent by self-supply. Compared with 2011, reliance on bilateral contracts increased by 0.9 percentage points, reliance on spot supply decreased by 2.1 percentage points, and reliance on self-supply increased by 1.3 percentage points.

Table 2-62 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: 2011 through 2012

	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%	(3.7%)	2.4%
Mar	5.8%	24.3%	70.0%	6.7%	22.8%	70.5%	0.9%	(1.5%)	0.5%
Apr	6.1%	23.8%	70.1%	6.7%	22.8%	70.6%	0.6%	(1.0%)	0.5%
May	6.0%	24.0%	70.0%	6.6%	22.7%	70.7%	0.6%	(1.3%)	0.8%
Jun	6.0%	25.3%	68.8%	7.7%	20.7%	71.6%	1.8%	(4.5%)	2.8%
Jul	5.5%	23.4%	71.2%	5.9%	22.0%	72.0%	0.5%	(1.3%)	0.9%
Aug	5.7%	24.1%	70.1%	6.4%	22.5%	71.0%	0.7%	(1.6%)	0.9%
Sep	5.8%	25.2%	69.0%	6.5%	23.9%	69.6%	0.7%	(1.3%)	0.6%
Oct	5.7%	25.7%	68.5%	6.6%	25.2%	68.2%	0.8%	(0.5%)	(0.3%)
Nov	6.4%	25.3%	68.3%	6.9%	22.7%	70.5%	0.5%	(2.6%)	2.2%
Dec	6.6%	25.3%	68.1%	7.0%	21.2%	71.8%	0.3%	(4.1%)	3.8%
Annual	5.8%	24.4%	69.8%	6.7%	22.3%	71.0%	0.9%	(2.1%)	1.3%

Scarcity and Scarcity Pricing

In electricity markets, scarcity means that demand, plus reserve requirements, is nearing the limits of the available capacity of the system. Under the PJM rules that were in place through September 30, 2012, high prices, or scarcity pricing, resulted from high offers by individual generation owners for specific units when the system was close to its available capacity. These offers give the aggregate energy supply curve its steep upward sloping tail.[67] As demand increases and units with higher markups and higher offers are required to meet demand, prices increase. As a result, positive markups and associated high prices on high-load days may result in appropriate scarcity pricing. But this is not an efficient way to manage scarcity pricing and makes it difficult to distinguish between market power and scarcity pricing.

The energy market alone frequently does not directly or sufficiently value some of the resources needed to provide for reliability. This is the rationale for administrative scarcity pricing mechanisms such as PJM's Reliability Pricing Model (RPM) market for capacity and PJM's administrative scarcity pricing mechanism in the energy market prior to October 1, 2012.

On October 1, 2012, PJM introduced a new administrative scarcity pricing regime. In times of reserve shortage, the cost of foregone reserves, reflected as a penalty factor in the optimization, is reflected in the price of energy.

PJM did not declare an administrative scarcity event in 2012. PJM's market did not experience any reserve-based shortage events in 2012.

Designation of Maximum Emergency MW

During extreme system conditions, when PJM declares Maximum Emergency Alerts the PJM tariff specifies that capacity can only be designated as maximum emergency if the capacity has limitations on its availability based on environmental limitations, short term fuel limitations, or emergency conditions at the unit, or the additional capacity is obtained by operating the unit past its normal limits.[68,69] The intent of the rule regarding maximum emergency designation is to ensure that only capacity with a clearly defined short term issue limiting its economic availability is defined as maximum emergency MW, which can be made available, at PJM direction, to maintain the system during emergency conditions.

67 See *2012 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market" at Figure 2-1, "Average PJM aggregate supply curves: Summers 2011 and 2012."

68 OA Schedule § 1.10.1A(d); See also PJM.

69 OA Schedule § 1.10.1A(d).

Declarations of Hot/Cold Weather Alerts also affect declarations of maximum emergency capacity under the rules. Hot Weather Alerts indicate that the system is expected to experience possible resource adequacy issues in the declared areas due to an expectation of multiple consecutive days with projected temperatures in excess of 90 degrees with high humidity.[70] Cold Weather Alerts indicate that the system is expected to experience possible resource adequacy issues in the declared areas due to an expectation that temperatures will fall below ten degrees Fahrenheit.[71] A Hot/Cold Weather Alert indicates conditions that require that combustion turbine (CT) and steam units with limited fuel availability need to be removed from economic availability and made available as emergency only capacity.[72] The Hot/Cold weather alert rule defines specific criteria to use to determine fuel limited generation, thereby classifying that part of the capacity of a unit as Maximum Emergency Generation. The Hot/Cold Weather Alert rule regarding Maximum emergency capacity declarations, as outlined in Manual 13, is consistent with the Maximum Emergency Alert rule and its intent.[73]

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

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

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

High Load Conditions

PJM's administrative scarcity pricing mechanism was designed to recognize real- time scarcity in the Energy Market and to increase prices to reflect the scarcity conditions. Prior to October 1, 2012 administrative scarcity pricing resulted when PJM took identified emergency actions to support identified scarcity constraints. The scarcity price was based on the highest offer of an operating unit. PJM takes emergency actions on a regional basis when the PJM system is running low on economic sources of energy and reserves. Such actions include voltage reductions, emergency power purchases, manual load dump, and loading of maximum emergency generation.[74,75] These do not represent all of the emergency actions that are available to PJM

70 The purpose of the Hot Weather Alert is to prepare personnel and facilities for extreme hot and/or humid weather conditions which may cause capacity requirements/unit unavailability to be substantially higher than forecast are expected to persist for an extended period. In general, a Hot Weather alert can be issued on a Control Zone basis, if projected temperatures are to exceed 90 degrees with high humidity for multiple days. See PJM. "Manual 13: Emergency Operations," Revision: 52 (Effective February 1, 2013), p 45.

71 The purpose of the Cold Weather Alert is to prepare personnel and facilities for expected extreme cold weather conditions. As a general guide when the forecasted weather conditions approach minimum or actual temperatures for the Control Zone fall near or below ten degrees Fahrenheit. PJM can initiate a Cold Weather Alert at higher temperatures if PJM anticipates increased winds or if PJM projects a portion of gas fired capacity is unable to obtain spot market gas during load pick-up periods (refer to Inter RTO Natural Gas Coordination Procedure below). PJM will generally initiate a Cold Weather Alert on a Control Zone basis. See PJM. "Manual 13: Emergency Operations," Revision: 52 (Effective February 1, 2013), p 42.

72 See PJM. "Manual 13: Emergency Operations," Revision: 52 (Effective February 1, 2013), pp 40-41. CTs burning oil, kerosene or diesel with less than 16 hours of remaining fuel are considered to be fuel limited during a Cold/Hot Weather Alert. CTs burning gas with less than 8 hours of daily fuel allowance are considered to be fuel limited during a Cold/Hot Weather Alert. Steam units with less than 32 hours of fuel in inventory are considered to be fuel limited during a Cold/Hot Weather Alert.

73 During Maximum Emergency Alert days, PJM rules limit maximum emergency declarations to capacity that falls into one of the following categories: environmentally limited, fuel limited, temporary emergency condition limited, or temporary megawatt additions. See PJM. "Manual 13: Emergency Operations," Revision: 52 (Effective February 1, 2013), p 75.

74 A voltage reduction warning (not an action) is evidence that the system is running out of available resources. A voltage reduction warning "is implemented when the available synchronized reserve capacity is less than the synchronized reserve requirement, after all available secondary and primary reserve capacity (except restricted maximum emergency capacity) is brought to a synchronized reserve status and emergency operating capacity is scheduled from adjacent systems." See PJM. "Manual 13: Emergency Operations," Revision: 52 (Effective February 1, 2013), p. 26.

75 "The PJM RTO is normally loaded according to bid prices; however, during periods of reserve deficiencies, other measures must be taken to maintain system reliability." See PJM. "Manual 13: Emergency Operations," Revision: 52 (Effective February 1, 2013), p. 19.

operators, but the listed steps that were defined in the PJM Tariff as the triggers for scarcity pricing events.[76]

PJM did not declare any scarcity pricing events in 2012 under PJM's emergency action based scarcity pricing rules. PJM's market did not experience any reserve-based shortage events in 2012.

Defining scarcity to exist when the demand for power exceeds the system-wide capacity available to provide both energy and 10 minute synchronized reserves, there were no scarcity events in 2012. Defining a high-load hour to exist when hourly real time demand plus the 30 minute reserve target is greater than or equal to the available within 30 minute economic supply (excluding maximum emergency MW), there were a total of 40 high-load hours in 2012. Defining a high-load day to exist when hourly total real time demand plus the 30 minute reserve target equals 96 percent or more of the within 30 minute supply (in the absence of non-market a dministrative intervention) on an hourly integrated basis over a two hour period,[77] there were seven high load days in 2012: July 5 - 7, 16 - 18 and 23.

2012 Results: High-Load Days

There was one Maximum Emergency Alert day in 2012, on July 18. Two days in 2012, July 17 and 18, had Maximum Emergency Actions which resulted in PJM direction to load maximum emergency capacity. Table 2-63 provides a description of PJM Maximum Emergency Alerts and Actions.

Table 2-64 shows the relationships among high load days, Hot Weather Alerts, Maximum Emergency Alerts and Maximum Emergency Actions in the May through September period. There were a total of 40 high-load hours in 2012. There were eight days with high load hours in 2012, one in June and seven in July. All seven days in July were high load days. In 2012, PJM declared twenty-eight Hot Weather Alerts.[78] Seven of the declared Hot Weather Alert days in July corresponded with the high load days. In 2012, PJM declared one maximum emergency alert day, which corresponded with one of the Hot Weather Alert days as well as one of the high load days, July 18.

Table 2-63 Maximum Emergency Alerts and Actions

Event	Purpose
Maximum Emergency Alert	Day ahead notice that maximum emergency generation has been called into day ahead operating capacity
Maximum Emergency Generation Action	Real time notice that maximum emergency generation may be required for system support
Emergency Mandatory Load Management Reductions (Long Lead Time)	Real time notice to participants registered in Demand Response(DR) program as Interruptible Load for Reliability(ILR) or DR resources that need between 1 to 2 hours lead time to provide load relief
Emergency Mandatory Load Management Reductions (Short Lead Time)	Real time notice to participants registered in Demand Response(DR) program as Interruptible Load for Reliability(ILR) or DR resources that need up to 1 hour lead time to provide load relief

76 See OA Schedule 1 § 2.5.

77 See PJM. "Manual 13: Emergency Operations," Revision: 52 (Effective February 1, 2013), p. 11. The thirty minute reserve target used in the study is the day-ahead operating reserve target based of a percentage of Day Ahead peak load.

78 "The purpose of the Hot Weather Alert is to prepare personnel and facilities for extreme hot and/or humid weather conditions which may cause capacity requirements/unit unavailability to be substantially higher than forecast are expected to persist for an extended period. In general, a Hot Weather alert can be issued on a Control Zone basis, if projected temperatures are to exceed 90 degrees with high humidity for multiple days." See PJM. "Manual 13: Emergency Operations," Revision: 52 (Effective February 1, 2013), p. 45.

Table 2-64 High Load Hour, Hot Weather Alerts and Maximum Emergency Related Events: 2012

Dates	High Load Day (High Load Hours)	Hot Weather Alert	Maximum Emergency Generation Alert	Maximum Emergency Generation Action
6/18/2012		ComEd		
6/19/2012		ComEd, Western		
6/20/2012		PJM		
6/21/2012		PJM except ComEd		
6/22/2012		Dominion, Mid-Atlantic		
6/28/2012		PJM		
6/29/2012		PJM		
6/30/2012		PJM		
7/1/2012		PJM		
7/2/2012		PJM		
7/3/2012		PJM		
7/4/2012		PJM		
7/5/2012	3	PJM		
7/6/2012	7	PJM		
7/7/2012	5	PJM		
7/8/2012		BGE, Pepco, Dominion		
7/15/2012		ComEd, Dominion		
7/16/2012	4	ComEd, Mid-Atlantic, Dominion		
7/17/2012	10	PJM		PJM
7/18/2012	6	PJM	Mid-Atlantic	Mid-Atlantic
7/19/2012		Dominion		
7/23/2012	4	ComEd, Dominion		
7/24/2012		Dominion		
7/25/2012		ComEd		
7/26/2012		PJM except ComEd		
7/27/2012		Dominion, Mid-Atlantic		
8/3/2012		PJM		
8/31/2012		Dominion, Mid-Atlantic		

In general, participant behavior in the summer of 2012 was consistent with the market incentives created by the Capacity Market and Energy Market. Maximum emergency generation declarations during maximum emergency generation periods were lower than the monthly average. During days when an emergency alert was not called or an emergency action was not taken, some economic capacity was inappropriately designated as emergency MW.

The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during Maximum Emergency Events.[79]

79 PJM Tariff, 6A.1.3 Maximum Emergency p. 1645, 1699-1700.