Energy Market

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

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance for the first nine months of 2013, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM Energy Market results were competitive in the first nine months of 2013.

Table 3-1 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 the first nine months of 2013 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1180 with a minimum of 871 and a maximum of 1610 in the first nine months of 2013.
- 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,

1 Analysis of 2013 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. In June 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC). By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the control zones, the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2012 State of the Market Report for PJM*, Appendix A, "PJM Geography."

2 OATT Attachment M.

applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[3]

Overview

Market Structure

- **Supply.** Average offered supply increased by 2,646, or 1.5 percent, from 173,414 MW in the first nine months of 2012 to 176,060 MW in the first nine months of 2013.[4] The increase in offered supply was in part the result of the integration of the East Kentucky Power Cooperative (EKPC) Transmission Zone in the second quarter of 2013. In 2013, 731 MW of new capacity were added to PJM. This new supply was partially offset by the deactivation of 7 units (476.9 MW) since January 1, 2013.
- **Demand.** The PJM system peak load for the first nine months of 2013 was 157,508 MW in the HE 1700 on July 18, 2013, which was 3,165 MW, or 2.1 percent, higher than the PJM peak load for the first nine months of 2012, which was 154,344 MW in the HE 1700 on July 17, 2012.[5]
- **Market Concentration.** Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.
- **Local Market Structure and Offer Capping for Energy.** 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 continued to apply a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in the first nine months of 2013. PJM offer caps units 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, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 0.1 percent in the first nine months of 2012 to 0.2 percent in the first nine months of 2013. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 1.1 percent in the first nine months of 2012 to 0.5 percent in the first nine months of 2013.
- **Reliability and Offer Capping.** PJM also offer caps units that are committed for reliability reasons, specifically for black start service and reactive service. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours increased from 0.5 percent in the first nine months of 2012 to 3.0 percent in the first nine months of 2013. In the Day-Ahead Energy Market, for units committed to provide energy for reliability reasons, offer-capped unit hours increased from 0.2 percent in the first nine months of 2012 to 3.8 percent in the first nine months of 2013.
- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 81 units eligible for FMU or AU status in at least one month during the first nine months of 2013, 24 units (29.6 percent) were FMUs or AUs for all nine months, and 16 units (19.8 percent) qualified in only one month of 2013.
- **Local Market Structure.** In the first nine months of 2013, 10 Control Zones experienced congestion resulting from one or more constraints binding for 75 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.

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

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

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).

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

  In the first nine months of 2013, the unadjusted markup was negative, -$1.21 per MWh, primarily as a result of competitive behavior by coal units and the competitive removal of the 10 percent adder. The adjusted markup was positive, $0.27 per MWh or 0.7 percent of the PJM real-time, load-weighted average LMP.

  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 the first nine months of 2013 increased by 0.5 percent from the first nine months of 2012, from 88,687 MW to 89,123 MW. The PJM average real-time load in 2013 would have decreased by 0.2 percent from the first nine months of 2012, from 88,687 MW to 88,522 MW, if the EKPC Transmission Zone had not been included in this comparison for the months prior to its integration to PJM.[6]

  PJM average day-ahead load in the first nine months of 2013, including DECs and up-to congestion transactions, increased by 9.5 percent from the first nine months of 2012, from 132,494 MW to 145,139 MW. The PJM average day-ahead load, including DECs and up-to congestion transactions, would have increased 9.1 percent from the first nine months of 2012, from 132,494 MW to 144,501 MW, if the EKPC Transmission Zone had not been included. The day-ahead load growth was 1,800.0 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 the first nine months of 2013 increased by 0.1 percent from the first nine months of 2012, from 90,367 MW to 90,432 MW. The PJM average real-time generation in the first nine months of 2013 would have decreased by 0.5 percent from the first nine months of 2012, from 90,367 MW to 89,910 MW, if the EKPC Transmission Zone had not been included.

  PJM average day-ahead generation in the first nine months of 2013, including INCs and up-to congestion transactions, increased by 9.8 percent from the first nine months of 2012, from 135,213 MW to 148,489 MW. The PJM average day-ahead generation, including INCs and up-to congestion transactions, would have increased by 9.4 percent from the first nine months of 2012, from 135,213 MW to 147,895 MW, if the EKPC Transmission Zone had not been included. The day-ahead generation growth was 9,700.0 percent higher than the real-time generation growth as a result of the continued growth of up-to congestion transactions.

- **Generation Fuel Mix.** During the first nine months of 2013, coal units provided 44.5 percent, nuclear units 34.5 percent and gas units 16.5 percent of total generation. Compared to the first nine months of 2012, generation from coal units increased 6.2 percent, generation from nuclear units increased 0.9 percent, and generation from gas units decreased 16.1 percent. This represents a reversal of the recent trend of decreasing coal-fired output and increasing gas-fired output. The change is primarily a result of increased natural gas prices in the first nine months of 2013, particularly in eastern zones, and lower or constant coal prices.

6 The EKPC zone was integrated on June 1, 2013 and was not included in this comparison for January through May of 2013.

- **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 increased in the first nine months of 2013 compared to the first nine months of 2012. The system average LMP was 15.0 percent higher in the first nine months of 2013 than in the first nine months of 2012, $37.30 per MWh versus $32.45 per MWh. The load-weighted average LMP was 13.5 percent higher in the first nine months of 2013 than in the first nine months of 2012, $39.75 per MWh versus $35.02 per MWh.

  PJM Day-Ahead Energy Market prices increased in the first nine months of 2013 compared to the first nine months of 2012. The system average LMP was 16.6 percent higher in the first nine months of 2013 than in the first nine months of 2012, $37.50 per MWh versus $32.16 per MWh. The load-weighted average LMP was 15.1 percent higher in the first nine months of 2013 than in the first nine months of 2012, $39.49 per MWh versus $34.29 per MWh.[7]

- **Load and Spot Market.** Companies that serve load in PJM can do so using a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. For the first nine months of 2013, 10.5 percent of real-time load was supplied by bilateral contracts, 24.1 percent by spot market purchases and 65.4 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased 1.4 percentage points, reliance on spot market purchases increased by 0.9 percentage points and reliance on self-supply decreased by 2.3 percentage points. For the first nine months of 2013, 7.5 percent of day-ahead load was supplied by bilateral contracts, 23.4 percent by spot market purchases, and 69.1 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased by 0.9 percentage points, reliance on spot market purchases increased by 1.1 percentage points, and reliance on self-supply decreased by 1.9 percentage points.

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

Scarcity

- **Scarcity Pricing Events in 2013.** PJM's market did not experience any reserve-based scarcity events in the first nine months of 2013.

Recommendations

The zonal load-weighted LMP is calculated by weighting the zone's load bus LMPs by the zone's load bus accounting load. The definition of injections and withdrawals of energy as generation or load affects PJM's calculation of zonal load-weighted LMP.

PJM sums all negative (injections) and positive (withdrawals) load at each designated load bus when calculating net load (accounting load). PJM sums all of the negative (withdrawals) and positive (injections) generation at each generation bus when calculating net generation. Netting withdrawals and injections by bus type (generation or load) affects the measurement of total load and total generation. Energy withdrawn at a generation bus to provide, for example, auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps, is actually load, not negative generation. Energy injected at load buses by behind the meter generation is actually generation, not negative load.

- The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load weighted LMP. The MMU also recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load weighted LMP.
- There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[8]

8 The general definition of a hub can be found in "Manual 35: Definitions and Acronyms," Revision 22 (February 28, 2013).

The MMU recommends that PJM include in the appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[9]

- 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 changes to the scarcity pricing rules in 2012. The reasons that FMU and AU adders were implemented no longer exist. FMU and AU adders are no longer required to serve the purpose for which they were created, and the adders now interfere with the efficient operation of PJM markets. This recommendation is currently scheduled to be evaluated through the PJM stakeholder process in the fourth quarter of 2013.
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during Maximum Emergency Events.[10]

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in the first nine months of 2013, 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 2,646 MW in the first nine months of 2013 compared to the first nine months of 2012, while peak load increased by 3,165 MW, modifying the general supply demand balance with a corresponding impact on energy market prices. Market concentration levels remained moderate. This relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive for most hours.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load in each hour. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price. Energy Market results for the first nine months of 2013 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.[11] This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. A generation owner or group of generation owners is pivotal for a local market if the output of the owners' generation facilities is required in order to relieve a transmission constraint. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests. The result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and specific owners had structural market power. The analysis of the application of the three pivotal supplier test demonstrates that it is working successfully to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and

9 According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

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

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

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 the first nine months of 2013.

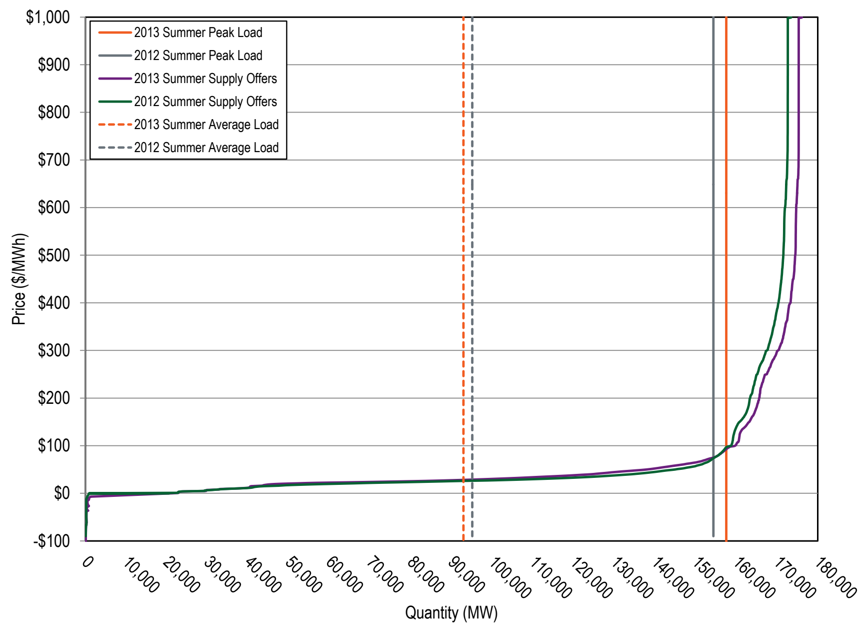
Market Structure

Supply

Average offered supply increased by 2,646 MW, or 1.5 percent, from 173,414 MW in the first nine months of 2012 to 176,060 MW in the first nine months of 2013.[12] The increase in offered supply was in part the result of the integration of the East Kentucky Power Cooperative (EKPC) Transmission Zone in the second quarter of 2013. In 2013, 731 MW of new capacity were added to PJM. This new supply was partially offset by the deactivation of 7 units (476.9 MW) since January 1, 2013.

Figure 3-1 shows the average PJM aggregate supply curves, peak load and average load for the summers of 2012 and 2013.

Figure 3-1 Average PJM aggregate supply curves: Summer of 2012 and 2013



Energy Production by Fuel Source

Compared to the first nine months of 2012, generation from coal units increased 6.2 percent and generation from natural gas units decreased 16.4 percent (Table 3-2). This represents a reversal of the recent trend of decreasing

12 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.

coal-fired output and increasing gas-fired output. The change is primarily a result of increased natural gas prices in the first nine months of 2013, particularly in eastern zones, and lower or constant coal prices.

Table 3-2 PJM generation (By fuel source (GWh)): January through September 2012 and 2013[13]

	Jan-Sep 2012		Jan-Sep 2013		Change in
	GWh	Percent	GWh	Percent	Output
Coal	251,591.7	41.8%	267,112.3	44.5%	6.2%
Standard Coal	244,258.0	40.5%	259,835.6	43.2%	6.2%
Waste Coal	7,333.6	1.2%	7,276.7	1.2%	(0.0%)
Nuclear	205,503.9	34.1%	207,254.4	34.5%	0.9%
Gas	118,328.2	19.6%	99,264.9	16.5%	(16.1%)
Natural Gas	116,649.9	19.4%	97,550.2	16.2%	(16.4%)
Landfill Gas	1,678.0	0.3%	1,713.1	0.3%	2.1%
Biomass Gas	0.4	0.0%	1.7	0.0%	328.5%
Hydroelectric	9,768.1	1.6%	11,144.7	1.9%	14.1%
Wind	8,944.7	1.5%	10,379.3	1.7%	16.0%
Waste	3,894.1	0.6%	3,719.2	0.6%	(4.5%)
Solid Waste	3,156.5	0.5%	3,111.9	0.5%	(1.4%)
Miscellaneous	737.6	0.1%	607.2	0.1%	(17.7%)
Oil	4,337.1	0.7%	1,620.5	0.3%	(62.6%)
Heavy Oil	4,122.7	0.7%	1,440.3	0.2%	(65.1%)
Light Oil	201.3	0.0%	152.4	0.0%	(24.3%)
Diesel	8.2	0.0%	14.1	0.0%	71.3%
Kerosene	4.9	0.0%	13.6	0.0%	179.3%
Jet Oil	0.0	0.0%	0.1	0.0%	215.0%
Solar	192.7	0.0%	288.4	0.0%	49.7%
Battery	0.2	0.0%	0.4	0.0%	124.4%
Total	602,560.9	100.0%	600,784.1	100.0%	(0.3%)

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

Table 3-3 Monthly PJM Generation (By fuel source (GWh)): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Coal	31,689.2	28,886.8	29,680.4	24,637.5	25,824.6	30,722.3	34,879.0	31,619.9	29,172.7	267,112.3
Standard Coal	30,814.3	28,102.4	28,670.2	24,060.8	24,962.6	29,884.0	33,916.0	30,862.6	28,562.7	259,835.6
Waste Coal	874.9	784.4	1,010.2	576.7	862.0	838.3	962.9	757.4	610.0	7,276.7
Nuclear	25,610.7	22,563.1	23,854.9	19,614.0	21,106.9	23,109.3	24,458.0	24,985.8	21,951.7	207,254.4
Gas	10,261.4	10,319.8	10,055.6	9,276.0	10,240.2	10,594.4	14,788.8	13,356.2	10,372.6	99,264.9
Natural Gas	10,072.4	10,143.6	9,859.7	9,096.1	10,047.2	10,404.5	14,593.7	13,158.1	10,174.8	97,550.2
Landfill Gas	189.0	176.2	195.9	179.9	193.0	189.8	195.1	198.1	196.2	1,713.1
Biomass Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.7	1.7
Hydroelectric	1,234.0	1,127.0	1,215.8	1,273.0	1,250.7	1,401.7	1,609.2	1,167.5	865.7	11,144.7
Wind	1,784.4	1,397.5	1,606.2	1,639.6	1,271.3	862.5	588.2	510.4	719.2	10,379.3
Waste	414.4	385.2	391.5	358.2	421.3	428.7	447.1	465.4	407.4	3,719.2
Solid Waste	324.8	301.5	325.2	323.9	349.9	368.6	385.3	382.3	350.4	3,111.9
Miscellaneous	89.6	83.7	66.2	34.3	71.4	60.2	61.8	83.0	57.0	607.2
Oil	62.5	23.8	50.3	79.1	220.3	190.7	629.8	154.8	209.2	1,620.5
Heavy Oil	55.8	21.9	27.9	66.8	206.1	179.4	575.0	139.9	167.6	1,440.3
Light Oil	4.2	1.5	17.7	11.7	13.2	10.7	43.6	13.0	36.7	152.4
Diesel	0.6	0.1	0.0	0.5	1.1	0.4	8.2	0.2	3.0	14.1
Kerosene	1.9	0.3	4.7	0.1	0.0	0.2	3.0	1.7	1.8	13.6
Jet Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
Solar	15.6	17.6	26.7	38.1	39.6	38.4	37.9	35.6	39.0	288.4
Battery	0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.1	0.4
Total	71,072.0	64,720.7	66,881.4	56,915.4	60,374.9	67,348.2	77,438.0	72,295.8	63,737.6	600,784.1

Generator Offers

Generator offers are categorized as dispatchable and self scheduled.[14,15] Table 3-4 shows the average hourly distribution of MW offers by dispatchable units by offer prices for the first nine months of 2013. Table 3-5 shows the average hourly distribution of MW offers by self-scheduled units by offer prices for the first nine months of 2013. Of the dispatchable MW offered by combustion turbines (CT), 23.0 percent were dispatchable at an offered range of $600 to $800. Only wind and solar units have negative offer prices.

Table 3-4 Distribution of MW for dispatchable unit offer prices: January through September, 2013

	Dispatchable (Range)						
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Total
CC	0.0%	64.5%	11.7%	2.7%	4.1%	0.8%	83.8%
CT	0.0%	49.1%	15.8%	9.4%	23.0%	2.3%	99.6%
Diesel	0.0%	8.0%	50.1%	6.3%	1.2%	0.8%	66.4%
Hydro	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.2%
Nuclear	0.0%	10.2%	0.0%	0.0%	0.0%	0.0%	10.2%
Pumped Storage	0.0%	51.6%	0.0%	0.0%	0.0%	0.0%	51.6%
Solar	0.0%	58.3%	0.0%	0.0%	0.0%	0.0%	58.3%
Steam	0.0%	49.4%	10.3%	0.6%	0.1%	0.0%	60.5%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	27.4%	28.2%	0.0%	0.0%	0.0%	0.0%	55.6%
All Dispatchable Offers	0.8%	43.1%	9.2%	2.5%	5.1%	0.6%	61.1%

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

Table 3-5 Distribution of MW for self-scheduled unit offer prices: January through September, 2013

	Self Scheduled (Range)						
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Total
CC	0.0%	14.2%	1.9%	0.0%	0.0%	0.0%	16.2%
CT	0.0%	0.4%	0.0%	0.0%	0.0%	0.0%	0.4%
Diesel	0.0%	32.6%	0.2%	0.0%	0.0%	0.8%	33.6%
Hydro	0.0%	98.7%	0.0%	0.0%	0.0%	1.0%	99.8%
Nuclear	0.0%	89.8%	0.0%	0.0%	0.0%	0.0%	89.8%
Pumped Storage	0.0%	48.4%	0.0%	0.0%	0.0%	0.0%	48.4%
Solar	0.6%	41.1%	0.0%	0.0%	0.0%	0.0%	41.7%
Steam	0.0%	26.6%	12.6%	0.0%	0.1%	0.1%	39.5%
Transaction	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Wind	16.3%	28.2%	0.0%	0.0%	0.0%	0.0%	44.4%
All Self-Scheduled Offers	0.5%	32.6%	5.6%	0.0%	0.0%	0.1%	38.9%

Demand

The PJM system peak load for the first nine months 2013 was 157,508 MW in the HE 1700 on July 18, 2013, which was 3,165 MW, or 2.1 percent, higher than the PJM peak load for the first nine months of 2012, which was 154,344 MW in the HE 1700 on July 17, 2012. The EKPC Transmission Zone accounted for 2,175 MW in the peak hour of the first nine months of 2013. The peak load excluding the EKPC transmission zone was 155,333 MW, also occurring on July 18, 2013, HE 1700, an increase of 990 MW, or 0.6 percent.

Table 3-6 shows the coincident peak loads for the first nine months of 1999 through 2013.

Table 3-6 Actual PJM footprint peak loads: January through September, 1999 to 2013[16]

(Jan - Sep)	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	Tue, July 17	17	154,344	(3,672)	(2.3%)
2013 (with EKPC)	Thu, July 18	17	157,508	3,165	2.1%
2013 (without EKPC)	Thu, July 18	17	155,333	990	0.6%

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

Figure 3-2 shows the peak loads for the first nine months of 1999 through 2013.

Figure 3-2 PJM footprint calendar year peak loads: January through September of 1999 to 2013

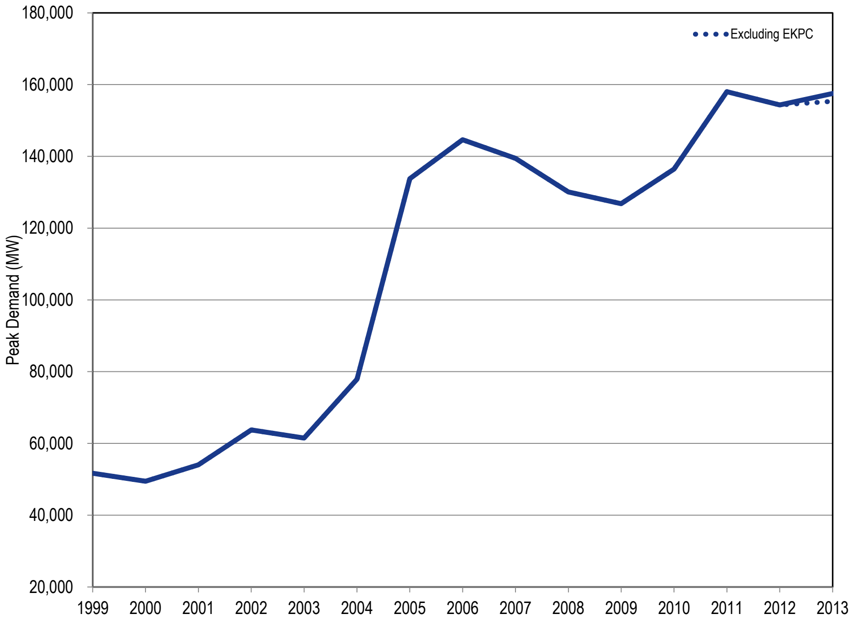
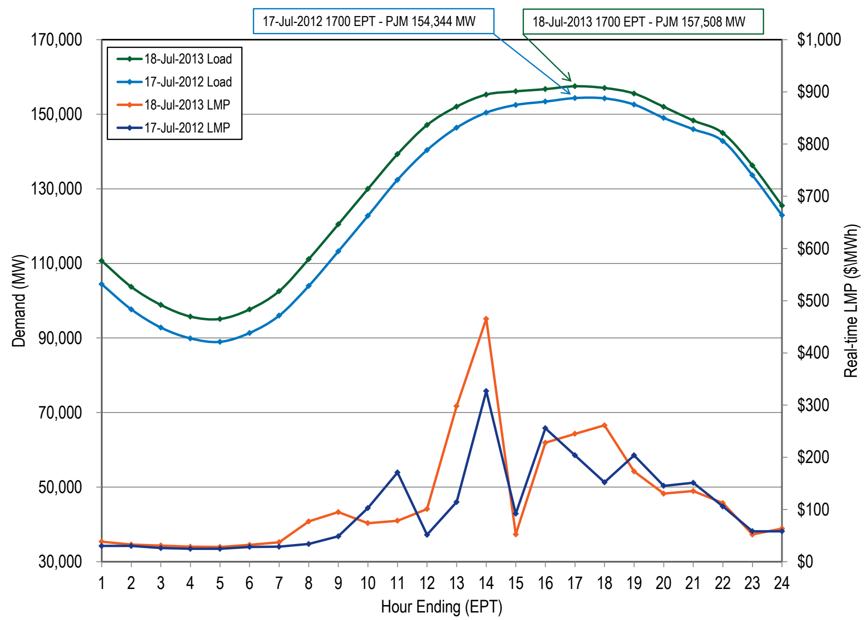


Figure 3-3 compares the peak load days in the first nine months of 2012 and 2013. In every hour on July 18, 2013, the average hourly real-time load was higher than the average hourly real-time load on July 17, 2012. The average hourly real-time LMP peaked at $465.18 on July 18, 2013 and peaked at $326.72 on July 17, 2012.

Figure 3-3 PJM peak-load comparison: Thursday, July 18, 2013, and Tuesday, July 17, 2012



Market Concentration

Analyses of supply curve segments of the PJM Energy Market for the first nine months of 2013 indicate moderate concentration in the base load segment, but high concentration in the intermediate and peaking segments.[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 were generally effective in preventing the exercise of market power in these areas during the first nine months of 2013.

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.

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 3-7).

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

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

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

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during the first nine months of 2013 was moderately concentrated (Table 3-7).

Table 3-7 PJM hourly Energy Market HHI: January through September, 2012 and 2013[19]

	Hourly Market HHI (Jan - Sep, 2012)	Hourly Market HHI (Jan - Sep, 2013)
Average	1234	1180
Minimum	927	871
Maximum	1657	1610
Highest market share (One hour)	32%	31%
Average of the highest hourly market share	23%	22%
# Hours	6,575	6,551
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-8 includes 2013 HHI values by supply curve segment, including base, intermediate and peaking plants.

Table 3-8 PJM hourly Energy Market HHI (By supply segment): January through September, 2012 and 2013

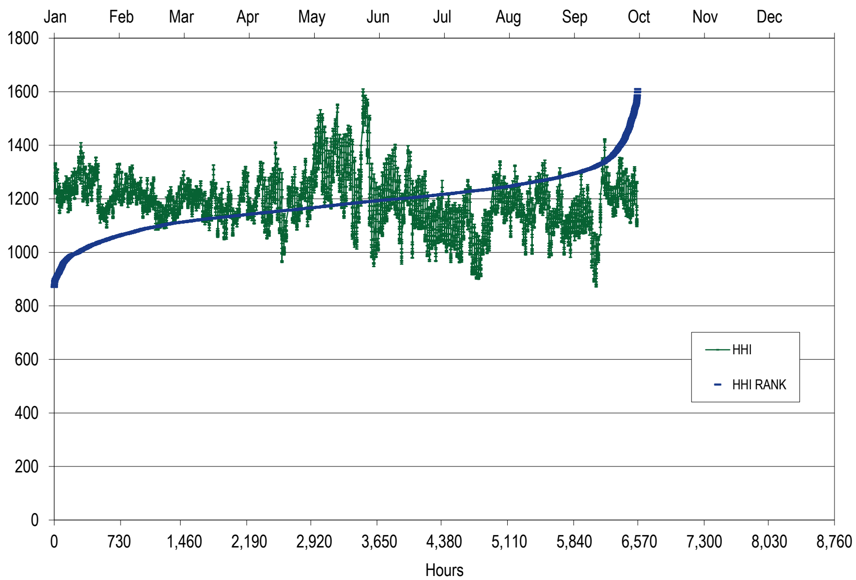
	Jan - Sep, 2012			Jan - Sep, 2013		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	1082	1268	1691	901	1095	1484
Intermediate	849	1919	8301	835	2266	8429
Peak	619	5699	10000	694	6329	10000

18 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)

19 This analysis includes all hours in the first nine months of 2013, regardless of congestion.

Figure 3-4 presents the 2013 hourly HHI values in chronological order and an HHI duration curve.

Figure 3-4 PJM hourly Energy Market HHI: January through September, 2013



Local Market Structure and Offer Capping

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

Levels of offer capping have historically been low in PJM, as shown in Table 3-9. The offer capping percentages shown in Table 3-9 include units that are committed to provide constraint relief whose owners failed the TPS test in the energy market, excluding offer capping for reliability reasons.

Table 3-9 Offer-capping statistics – Energy only: January through September, 2009 to 2013

	Real Time		Day Ahead	
(Jan - Sep)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2009	0.5%	0.1%	0.1%	0.0%
2010	1.2%	0.3%	0.3%	0.1%
2011	0.7%	0.3%	0.0%	0.0%
2012	1.1%	0.6%	0.1%	0.1%
2013	0.5%	0.2%	0.2%	0.1%

Table 3-10 shows the offer capping percentages including units committed to provide constraint relief as well as units committed to provide reactive support. The units that are committed and offer capped for reactive support have been steadily increasing since 2011. Before 2011, the units that ran to provided reactive support were generally economic in the energy market. Since 2011, the percentage of hours when these units were out of the money (and are therefore committed on their cost schedule to provide reactive) has steadily increased. Black start service is not considered a transmission constraint and is therefore not included in the statistics presented in this section.

Table 3-10 Offer-capping statistics for energy and reactive support: January through September, 2009 to 2013

	Real Time		Day Ahead	
(Jan - Sep)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2009	0.5%	0.1%	0.1%	0.0%
2010	1.2%	0.3%	0.3%	0.1%
2011	0.8%	0.3%	0.0%	0.0%
2012	1.1%	0.7%	0.2%	0.1%
2013	2.2%	1.9%	2.4%	1.8%

Table 3-11 presents data on the frequency with which units were offer capped in the first nine months of 2012 and 2013 for failing the TPS test to provide energy for constraint relief in the real time energy market.

Table 3-11 Real-time offer-capped unit statistics: January through September, 2012 and 2013[20]

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	(Jan - Sep)	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2013	0	0	0	0	0	0
	2012	0	0	1	0	1	1
80% and < 90%	2013	0	0	0	1	1	1
	2012	0	0	1	0	1	4
75% and < 80%	2013	0	0	0	1	1	3
	2012	0	0	1	0	0	0
70% and < 75%	2013	0	0	0	0	0	3
	2012	0	0	0	0	1	3
60% and < 70%	2013	0	0	0	0	0	6
	2012	0	0	0	1	1	8
50% and < 60%	2013	0	0	0	0	0	9
	2012	1	0	1	0	1	6
25% and < 50%	2013	0	0	6	0	5	50
	2012	2	0	1	2	2	43
10% and < 25%	2013	2	0	0	0	3	45
	2012	0	0	0	1	3	57

Table 3-11 shows that a small number of units are offer capped for 90 percent or more of their run hours in the first nine months of 2013.

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

Local Market Structure

In the first nine months of 2013, the AEP, ATSI, BGE, ComEd, Dominion, DPL, PECO, Pepco, PPL and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 75 or more hours. Actual competitive conditions in the Real-Time Energy Market associated with each of these frequently binding constraints were analyzed using the three pivotal supplier results for the first nine months of 2013.[21] The AECO, AP, DAY, DEOK, DLCO, JCPL, Met-Ed, PENELEC and RECO Control Zones were not affected by constraints binding for 75 or more hours.

The MMU analyzed the results of the three pivotal supplier tests conducted by PJM for the Real-Time Energy Market for the period January 1, 2013, through September 30, 2013. 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.

Table 3-12 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 transfer interface constraints.

20 This table was modified from the previous State of the Market report to include only units that are offer capped for failing the TPS test in the real time energy market.

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

Table 3-12 Three pivotal supplier test details for interface constraints: January through September, 2013

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	270	312	13	2	11
	Off Peak	206	288	12	3	9
AEP - DOM	Peak	156	89	6	0	6
	Off Peak	0	0	0	0	0
AP South	Peak	307	470	10	1	9
	Off Peak	336	507	10	1	9
ATSI	Peak	321	717	15	12	3
	Off Peak	0	0	0	0	0
Bedington - Black Oak	Peak	156	139	11	2	10
	Off Peak	152	106	10	0	10
Cleveland	Peak	100	112	2	0	2
	Off Peak	0	0	0	0	0
Eastern	Peak	463	619	16	2	14
	Off Peak	0	0	0	0	0
PL North	Peak	0	0	0	0	0
	Off Peak	151	321	2	0	2
Western	Peak	463	754	16	5	11
	Off Peak	1,438	2,068	21	8	14

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 3-13 provides, for the identified interface constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping uncommitted units.

Table 3-13 Summary of three pivotal supplier tests applied for interface constraints: January through September, 2013

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	684	53	8%	17	2%	32%
	Off Peak	617	51	8%	15	2%	29%
AEP - DOM	Peak	38	0	0%	0	0%	0%
	Off Peak	0	0	0%	0	0%	0%
AP South	Peak	4,826	213	4%	46	1%	22%
	Off Peak	3,319	101	3%	23	1%	23%
ATSI	Peak	144	4	3%	0	0%	0%
	Off Peak	0	0	0%	0	0%	0%
Bedington - Black Oak	Peak	11	0	0%	0	0%	0%
	Off Peak	145	5	3%	4	3%	80%
Cleveland	Peak	108	6	6%	3	3%	50%
	Off Peak	0	0	0%	0	0%	0%
Eastern	Peak	8	0	0%	0	0%	0%
	Off Peak	0	0	0%	0	0%	0%
PL North	Peak	0	0	0%	0	0%	0%
	Off Peak	212	0	0%	0	0%	0%
Western	Peak	316	14	4%	7	2%	50%
	Off Peak	253	7	3%	5	2%	71%

Ownership of Marginal Resources

Table 3-14 shows the contribution to PJM real-time, nine month, load-weighted LMP by individual marginal resource owner.[22] The contribution of each marginal resource to price at each load bus is calculated for the first nine months of 2013, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. The results show that in the first nine months of 2013, the offers of one company contributed 20.8 percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies contributed 54.2 percent of the real-time, load-weighted, average PJM system LMP. In comparison, during the first nine months of 2012, the offers of one company contributed 21.4 percent of the real time, load-weighted PJM system LMP and offers of the top four companies contributed 54.0 percent of the real-time, load-weighted, average PJM system LMP.

Table 3-14 Marginal unit contribution to PJM real-time, load-weighted LMP (By parent company): January through September 2012 and 2013

2012 (Jan - Sep)		2013 (Jan - Sep)	
Company	Percent of Price	Company	Percent of Price
1	21.4%	1	20.8%
2	13.1%	2	13.6%
3	11.2%	3	10.4%
4	8.3%	4	9.5%
5	8.0%	5	7.3%
6	6.0%	6	5.2%
7	5.6%	7	3.9%
8	5.6%	8	3.8%
9	3.9%	9	3.4%
Other (52 companies)	16.9%	Other (58 companies)	22.1%

Table 3-15 shows the contribution to PJM day-ahead, load-weighted LMP by individual marginal resource owner.[23] The contribution of each marginal resource to price at each load bus is calculated for the first nine months of 2013, period and summed by the company that offers the marginal resource into the Day-Ahead Energy Market.

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

Table 3-15 Marginal resource contribution to PJM day-ahead, load-weighted LMP (By parent company): January through September, 2012 and 2013

2012 (Jan - Sep)		2013 (Jan - Sep)	
Company	Percent of Price	Company	Percent of Price
1	15.2%	1	21.3%
2	6.6%	2	8.7%
3	6.4%	3	8.2%
4	6.2%	4	7.7%
5	6.0%	5	7.1%
6	4.8%	6	4.2%
7	4.8%	7	3.4%
8	4.1%	8	3.2%
9	3.8%	9	3.2%
Other (137 companies)	42.1%	Other (141 companies)	32.9%

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.

Table 3-16 shows the type of fuel used by marginal resources in the Real-Time Energy Market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In the first nine months of 2013, coal units were 58.54 percent and natural gas units were 32.51 percent of the total marginal resources. In the first nine months of 2012, coal units were 58.11 percent and natural gas units were 30.82 percent of the total marginal resources.[24]

24 The percentages of marginal fuel reported in the *2011 State of the Market Report for PJM*, were based on both Locational Pricing Algorithm (LPA) and dispatch (SCED) marginal resources. Starting from *2012 State of the Market Report for PJM*, 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."

Table 3-16 Type of fuel used (By real-time marginal units): January through September, 2012 and 2013

Fuel Type	2012 (Jan - Sep)	2013 (Jan - Sep)
Coal	58.11%	58.54%
Demand Response	0.00%	0.03%
Gas	30.82%	32.51%
Municipal Waste	0.14%	0.08%
Oil	6.04%	3.86%
Other	0.58%	0.21%
Uranium	0.01%	0.02%
Wind	4.30%	4.75%

Table 3-17 shows the type, and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In the first nine months of 2013, Up-to Congestion transactions were 96.2 percent of the total marginal resources. In comparison, Up-to Congestion transactions were 86.7 percent of the total marginal resources in the first nine months of 2012.

Table 3-17 Day-ahead marginal resources by type/fuel: January through September, 2012 and 2013

Type/Fuel	2012 (Jan - Sep)	2013 (Jan - Sep)
Up-to Congestion Transaction	86.7%	96.2%
DEC	5.2%	1.2%
INC	4.4%	1.0%
Coal	2.5%	1.0%
Gas	1.1%	0.4%
Dispatchable Transaction	0.1%	0.1%
Price Sensitive Demand	0.1%	0.0%
Wind	0.0%	0.0%
Oil	0.0%	0.0%
Municipal Waste	0.0%	0.0%
Diesel	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.[25] 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. The markup index does not measure the impact of unit markup on total LMP.

Real-Time Mark Up Conduct

Table 3-18 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category. For convenience, the marginal units are grouped into one of seven categories based on their respective offer prices. The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point. The data shows that despite the fact that markup had a negligible impact on LMP in the first nine months of 2013, some marginal units do have substantial markups.

Table 3-18 Average, real-time marginal unit markup index (By price category): January through September, 2012 and 2013

	2012 (Jan - Sep)			2013 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.09)	($3.43)	31.0%	0.02	($3.29)	17.4%
$25 to $50	(0.05)	($2.81)	48.9%	(0.02)	($1.84)	62.2%
$50 to $75	0.05	$1.12	4.4%	(0.02)	($5.86)	8.7%
$75 to $100	0.33	$28.81	0.6%	0.00	($5.86)	1.5%
$100 to $125	0.21	$21.28	0.6%	0.11	$10.77	0.7%
$125 to $150	0.17	$23.44	0.3%	0.08	$11.14	0.9%
>= $150	0.04	$9.59	5.5%	0.04	$8.63	4.5%

25 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.

Day-Ahead Mark Up Conduct

Table 3-19 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 3-19 Average marginal unit markup index (By offer price category): January through September, 2012 and 2013

	2012 (Jan - Sep)			2013 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.09)	($3.01)	32.2%	(0.06)	($1.76)	18.9%
$25 to $50	(0.05)	($2.56)	64.2%	(0.04)	($2.41)	75.4%
$50 to $75	0.09	$4.13	3.1%	0.00	($2.72)	4.6%
$75 to $100	0.45	$36.25	0.2%	0.08	$7.07	0.4%
$100 to $125	0.00	$0.00	0.0%	0.00	$0.00	0.1%
$125 to $150	(0.06)	($8.33)	0.1%	0.00	$0.00	0.0%
>= $150	0.03	$4.84	0.2%	0.75	$118.80	0.0%

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.[26]

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

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 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 the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units.

Table 3-20 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 3-20 on the system-wide load-weighted LMP. The negative markup components of LMP reflect the negative markups shown in the Table 3-18.

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, markup is simply the difference between the active offer of the marginal unit and the cost offer. In the second approach, the 10 percent markup is removed from the cost offers of coal units because coal units do not face the same cost uncertainty as gas-fired CTs. The adjusted markup is calculated as the difference between the active offer and the cost offer excluding the 10 percent adder. The unadjusted markup is calculated as the difference between the active offer and the cost offer including the 10 percent adder in the cost offer.

Table 3-20 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January through September, 2012 and 2013[27]

		2012 (Jan Sep)		2013 (Jan - Sep)	
Fuel Type	Unit Type	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($1.64)	$0.21	($0.42)	$1.06
Demand Response	Demand Response	$0.00	$0.00	$0.00	$0.00
Gas	CC	$0.55	$0.55	($0.28)	($0.28)
Gas	CT	($0.06)	($0.06)	$0.03	$0.03
Gas	Diesel	$0.03	$0.03	$0.02	$0.02
Gas	Steam	($0.04)	($0.04)	$0.00	$0.00
Municipal Waste	Diesel	$0.00	$0.00	$0.00	$0.00
Municipal Waste	Steam	$0.03	$0.03	($0.00)	($0.00)
Oil	CT	$0.01	$0.01	$0.00	$0.00
Oil	Diesel	$0.00	$0.00	$0.00	$0.00
Oil	Steam	($0.09)	($0.09)	($0.54)	($0.54)
Other	Solar	$0.00	$0.00	$0.00	$0.00
Other	Steam	($0.00)	($0.00)	($0.02)	($0.02)
Uranium	Steam	$0.00	$0.00	($0.00)	($0.00)
Wind		($0.01)	($0.01)	$0.00	$0.00
Total		($1.23)	$0.62	($1.21)	$0.27

27 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 3-20 shows mark-up component of the load weighted LMP by primary fuel and unit-type using unadjusted and adjusted offers.

Markup Component of Real-Time System Price

Table 3-21 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on-peak and off-peak prices. Table 3-22 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on-peak and off-peak prices. In the first nine months of 2013, when using unadjusted cost offers, - $ 1.21 per MWh of the PJM real-time load weighted average LMP was attributable to markup. Using adjusted cost-offers, $ 0.27 per MWh of the PJM real-time load weighted average LMP was attributable to markup. In the first nine months of 2013, the real time load-weighted average LMP for the month of July had the highest markup component.

Table 3-21 Monthly markup components of real-time load-weighted LMP (Unadjusted): January through September, 2012 and 2013

	2012 (Jan - Sep)			2013 (Jan - Sep)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($3.28)	($3.58)	($2.98)	($4.04)	($4.39)	($3.70)
Feb	($2.07)	($2.92)	($1.26)	($2.54)	($3.77)	($1.34)
Mar	($2.30)	($2.51)	($2.10)	($1.20)	($1.89)	($0.48)
Apr	($2.71)	($3.60)	($1.86)	($2.15)	($3.23)	($1.22)
May	($1.10)	($3.34)	$0.93	($0.87)	($2.03)	$0.10
Jun	($2.67)	($3.24)	($2.17)	($1.17)	($1.12)	($1.21)
Jul	$3.38	($2.36)	$8.82	$2.97	($1.43)	$6.85
Aug	($0.90)	($2.30)	$0.20	($1.58)	($1.73)	($1.45)
Sep	($0.70)	($1.89)	$0.60	($0.93)	($2.34)	$0.46
Total	($1.23)	($2.84)	$0.28	($1.21)	($2.42)	($0.09)

Table 3-22 Monthly markup components of real-time load-weighted LMP (Adjusted): January through September, 2012 and 2013

	2012 (Jan - Sep)			2013 (Jan - Sep)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($0.93)	($1.40)	($0.43)	($2.22)	($2.43)	($2.02)
Feb	($0.06)	($1.04)	$0.87	($0.75)	($1.87)	$0.33
Mar	($0.59)	($1.07)	($0.15)	$0.46	($0.13)	$1.08
Apr	($0.81)	($1.79)	$0.11	($0.91)	($1.61)	($0.31)
May	$0.64	($1.71)	$2.78	$0.43	($0.45)	$1.17
Jun	($1.14)	($1.92)	($0.45)	$0.21	$0.26	$0.16
Jul	$5.08	($0.47)	$10.34	$4.32	$0.09	$8.05
Aug	$1.07	($0.60)	$2.38	($0.30)	($0.36)	($0.25)
Sep	$1.01	($0.29)	$2.45	$0.56	($0.58)	$1.68
Total	$0.62	($1.11)	$2.25	$0.27	($0.76)	$1.24

Markup Component of Real-Time Zonal Prices

The average real-time price component of unit markup using unadjusted offers is shown for each zone for the first nine months of 2013 in Table 3-23 and for adjusted offers in Table 3-25. The smallest zonal all hours average markup component using unadjusted offers for the first nine months of 2013 was in the PPL Control Zone, -$1.67 per MWh, while the highest all hours average zonal markup component for the first nine months of 2013 was in the JCPL Control Zone, $1.42 per MWh. The smallest zonal on peak average markup was in the PPL Control Zone, -$0.97 per MWh, while the highest zonal on peak average markup was in the JCPL Control Zone, $4.79 per MWh.

Table 3-23 Average real-time zonal markup component (Unadjusted): January through September, 2012 and 2013

	2012 (Jan - Sep)			2013 (Jan - Sep)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	($1.09)	($2.67)	$0.42	($0.82)	($2.18)	$0.47
AEP	($1.48)	($2.86)	($0.14)	($1.48)	($2.53)	($0.48)
APS	($1.29)	($2.84)	$0.19	($1.55)	($2.65)	($0.52)
ATSI	($1.44)	($3.04)	$0.04	($1.42)	($2.46)	($0.46)
BGE	($0.88)	($2.33)	$0.50	($1.37)	($2.39)	($0.42)
ComEd	($1.28)	($3.07)	$0.37	($1.25)	($2.40)	($0.21)
DAY	($1.54)	($3.03)	($0.17)	($1.47)	($2.54)	($0.51)
DEOK	($1.51)	($2.92)	($0.18)	($1.41)	($2.48)	($0.42)
DLCO	($1.23)	($2.87)	$0.30	($1.50)	($2.41)	($0.66)
DPL	($1.52)	($3.45)	$0.34	($1.41)	($2.28)	($0.58)
Dominion	($0.77)	($2.35)	$0.75	($1.22)	($2.48)	($0.02)
EKPC	$0.00	$0.00	$0.00	($0.43)	($1.91)	$0.96
JCPL	($0.82)	($2.87)	$1.03	$1.42	($2.36)	$4.79
Met-Ed	($1.40)	($3.05)	$0.12	($0.79)	($2.35)	$0.63
PECO	($1.23)	($2.84)	$0.27	($1.38)	($2.17)	($0.64)
PENELEC	($1.49)	($3.11)	$0.02	($1.38)	($2.58)	($0.27)
PPL	($1.47)	($3.06)	$0.01	($1.67)	($2.43)	($0.97)
PSEG	($1.09)	($2.94)	$0.61	($0.17)	($1.94)	$1.45
Pepco	($0.68)	($2.39)	$0.90	($1.31)	($2.46)	($0.26)
RECO	($0.92)	($3.02)	$0.86	$0.65	($1.68)	$2.63

Table 3-24 Average real-time zonal markup component (Adjusted): January through September, 2012 and 2013

	2012 (Jan - Sep)			2013 (Jan - Sep)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$0.62	($1.12)	$2.29	$0.66	($0.53)	$1.80
AEP	$0.37	($1.13)	$1.82	$0.04	($0.85)	$0.88
APS	$0.65	($1.10)	$2.32	($0.04)	($0.96)	$0.83
ATSI	$0.39	($1.34)	$2.01	$0.12	($0.77)	$0.94
BGE	$1.27	($0.30)	$2.77	$0.16	($0.63)	$0.91
ComEd	$0.55	($1.32)	$2.27	$0.21	($0.82)	$1.14
DAY	$0.36	($1.28)	$1.87	$0.08	($0.84)	$0.91
DEOK	$0.31	($1.23)	$1.77	$0.08	($0.84)	$0.94
DLCO	$0.52	($1.26)	$2.19	($0.01)	($0.78)	$0.71
DPL	$0.26	($1.77)	$2.21	$0.06	($0.67)	$0.75
Dominion	$1.17	($0.52)	$2.78	$0.26	($0.79)	$1.25
EKPC	$0.00	$0.00	$0.00	$0.99	($0.35)	$2.25
JCPL	$0.93	($1.25)	$2.89	$2.74	($0.75)	$5.85
Met-Ed	$0.31	($1.49)	$1.96	$0.63	($0.76)	$1.89
PECO	$0.48	($1.24)	$2.09	$0.07	($0.59)	$0.69
PENELEC	$0.31	($1.43)	$1.94	$0.13	($0.91)	$1.09
PPL	$0.23	($1.50)	$1.84	($0.17)	($0.80)	$0.41
PSEG	$0.69	($1.31)	$2.51	$1.21	($0.37)	$2.66
Pepco	$1.33	($0.49)	$2.99	$0.17	($0.75)	$1.02
RECO	$0.92	($1.30)	$2.82	$2.01	($0.07)	$3.77

Markup by Real Time System Price Levels

Table 3-25 show the average markup component of observed prices, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system LMP was in the identified price range.

Table 3-25 Average real-time markup component (By price category, unadjusted): January through September, 2012 and 2013

	2012 (Jan - Sep)		2013 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.91)	28.0%	($0.41)	12.8%
$25 to $50	($1.81)	62.0%	($1.33)	72.8%
$50 to $75	$0.37	4.4%	($0.13)	7.4%
$75 to $100	$0.27	1.4%	$0.03	1.6%
$100 to $125	$0.15	0.7%	$0.09	0.7%
$125 to $150	$0.13	0.2%	$0.05	0.3%
>= $150	$0.57	0.6%	$0.48	0.5%

Table 3-26 Average real-time markup component (By price category, adjusted): January through September, 2012 and 2013

	2012 (Jan - Sep)		2013 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.62)	28.0%	($0.26)	12.8%
$25 to $50	($0.41)	62.0%	($0.09)	72.8%
$50 to $75	$0.46	4.4%	($0.06)	7.4%
$75 to $100	$0.30	1.4%	$0.05	1.6%
$100 to $125	$0.16	0.7%	$0.10	0.8%
$125 to $150	$0.14	0.2%	$0.06	0.3%
>= $150	$0.58	0.6%	$0.49	0.5%

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 3-27.

Table 3-27 Markup component of the overall PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through September, 2012 and 2013

		2012 (Jan - Sep)		2013 (Jan - Sep)	
Fuel Type	Unit Type	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($1.68)	($0.70)	($0.51)	($0.19)
Gas	Steam	($0.20)	($0.15)	($0.46)	($0.46)
Oil	Steam	($0.08)	($0.08)	($0.00)	($0.00)
Municipal Waste	Steam	($0.00)	($0.00)	($0.00)	($0.00)
Wind	Wind	($0.00)	($0.00)	$0.00	$0.00
Gas	CT	$0.09	$0.09	($0.02)	($0.02)
Total		($1.87)	($0.85)	($1.00)	($0.67)

Markup Component of Day-Ahead System Price

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units. Only hours when generating units were marginal on either priced based offers or on cost based offers were included in the markup calculation.

Table 3-28 shows the markup component of average prices and of average monthly on-peak and off-peak prices using unadjusted offers. Table 3-29 shows the markup component of average prices and of average monthly on-peak and off-peak prices using adjusted offers.

Table 3-28 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: January through September, 2012 and 2013

	2012 (Jan - Sep)			2013 (Jan - Sep)		
	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)	($3.77)	($3.99)	($3.54)
Feb	($3.01)	($3.61)	($2.38)	($2.53)	($1.43)	($3.67)
Mar	($2.30)	($1.99)	($2.63)	($1.84)	($0.18)	($3.45)
Apr	($2.67)	($2.36)	($2.98)	($0.11)	($0.01)	($0.22)
May	($1.52)	($1.11)	($1.97)	($0.10)	($0.04)	($0.17)
Jun	($1.93)	($1.09)	($2.88)	($0.06)	$0.03	($0.14)
Jul	$0.35	$2.60	($2.07)	($0.08)	($0.01)	($0.15)
Aug	($1.86)	($0.95)	($3.05)	($0.06)	($0.01)	($0.11)
Sep	($1.75)	($1.36)	($2.10)	($0.27)	($0.13)	($0.42)
Annual	($1.87)	($1.20)	($2.59)	($1.00)	($0.66)	($1.37)

Table 3-29 Monthly markup components of day-ahead (Adjusted), load-weighted LMP: January through September, 2012 and 2013

	2012 (Jan - Sep)			2013 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($1.43)	($1.00)	($1.84)	($2.66)	($3.01)	($2.28)
Feb	($1.74)	($2.21)	($1.25)	($1.67)	($0.67)	($2.70)
Mar	($1.37)	($1.05)	($1.72)	($1.28)	$0.08	($2.61)
Apr	($1.49)	($1.18)	($1.81)	($0.03)	$0.04	($0.11)
May	($0.76)	($0.33)	($1.23)	($0.04)	($0.02)	($0.06)
Jun	($0.92)	($0.04)	($1.91)	($0.02)	$0.04	($0.07)
Jul	$1.24	$3.35	($1.03)	($0.03)	$0.02	($0.09)
Aug	($0.93)	($0.11)	($2.01)	($0.02)	$0.01	($0.05)
Sep	($0.82)	($0.44)	($1.17)	($0.17)	($0.08)	($0.26)
Annual	($0.85)	($0.20)	($1.54)	($0.67)	($0.42)	($0.95)

Markup Component of Day-Ahead Zonal Prices

The markup component of annual average day-ahead price using unadjusted offers is shown for each zone in Table 3-30. The markup component of annual average day-ahead price using adjusted offers is shown for each zone in Table 3-31.

Table 3-30 Day-ahead, average, zonal markup component (Unadjusted): January through September, 2012 and 2013

	2012 (Jan - Sep)			2013 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($1.48)	($0.55)	($2.48)	($1.00)	($0.71)	($1.30)
AEP	($1.95)	($1.35)	($2.57)	($1.01)	($0.62)	($1.42)
AP	($1.83)	($1.38)	($2.31)	($1.10)	($0.71)	($1.50)
ATSI	($2.00)	($1.44)	($2.62)	($1.01)	($0.63)	($1.42)
BGE	($1.86)	($1.22)	($2.55)	($1.00)	($0.71)	($1.33)
ComEd	($1.83)	($1.29)	($2.41)	($0.91)	($0.55)	($1.31)
DAY	($1.89)	($1.25)	($2.60)	($1.02)	($0.62)	($1.47)
DEOK	($1.83)	($1.22)	($2.48)	($0.96)	($0.56)	($1.39)
DLCO	($1.79)	($1.17)	($2.47)	($0.95)	($0.60)	($1.34)
DPL	($1.61)	($0.78)	($2.50)	($1.05)	($0.65)	($1.46)
Dominion	($1.80)	($1.06)	($2.58)	($0.98)	($0.67)	($1.32)
EKPC	NA	NA	NA	($0.10)	($0.02)	($0.20)
JCPL	($1.45)	($0.55)	($2.48)	($1.18)	($1.05)	($1.34)
Met-Ed	($1.86)	($1.16)	($2.64)	($1.09)	($0.78)	($1.43)
PECO	($1.67)	($0.96)	($2.44)	($1.01)	($0.67)	($1.38)
PENELEC	($2.15)	($1.70)	($2.63)	($1.02)	($0.67)	($1.39)
PPL	($2.11)	($1.55)	($2.71)	($1.14)	($0.83)	($1.48)
PSEG	($1.54)	($0.53)	($2.69)	($0.96)	($0.64)	($1.33)
Pepco	($1.88)	($1.31)	($2.49)	($1.00)	($0.71)	($1.31)
RECO	($1.42)	($0.43)	($2.61)	($0.92)	($0.58)	($1.32)

Table 3-31 Day-ahead, average, zonal markup component (Adjusted): January through September, 2012 and 2013

	2012 (Jan - Sep)			2013 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($0.52)	$0.38	($1.49)	($0.68)	($0.47)	($0.92)
AEP	($0.90)	($0.31)	($1.52)	($0.66)	($0.37)	($0.97)
AP	($0.78)	($0.34)	($1.25)	($0.73)	($0.45)	($1.03)
ATSI	($0.93)	($0.36)	($1.54)	($0.66)	($0.37)	($0.98)
BGE	($0.75)	($0.15)	($1.40)	($0.70)	($0.50)	($0.92)
ComEd	($0.86)	($0.32)	($1.44)	($0.61)	($0.32)	($0.92)
DAY	($0.83)	($0.19)	($1.52)	($0.68)	($0.37)	($1.02)
DEOK	($0.80)	($0.21)	($1.45)	($0.63)	($0.33)	($0.96)
DLCO	($0.82)	($0.20)	($1.50)	($0.62)	($0.36)	($0.91)
DPL	($0.65)	$0.13	($1.49)	($0.72)	($0.42)	($1.03)
Dominion	($0.78)	($0.10)	($1.51)	($0.67)	($0.45)	($0.91)
EKPC	NA	NA	NA	($0.05)	$0.00	($0.11)
JCPL	($0.48)	$0.38	($1.47)	($0.81)	($0.70)	($0.94)
Met-Ed	($0.90)	($0.23)	($1.65)	($0.76)	($0.54)	($1.01)
PECO	($0.71)	($0.03)	($1.46)	($0.69)	($0.44)	($0.97)
PENELEC	($1.10)	($0.64)	($1.59)	($0.66)	($0.40)	($0.94)
PPL	($1.13)	($0.61)	($1.71)	($0.80)	($0.57)	($1.04)
PSEG	($0.56)	$0.41	($1.67)	($0.65)	($0.42)	($0.92)
Pepco	($0.83)	($0.30)	($1.41)	($0.70)	($0.50)	($0.91)
RECO	($0.43)	$0.52	($1.58)	($0.64)	($0.38)	($0.93)

Markup by Day-Ahead System Price Levels

Table 3-32 and Table 3-33 show the average markup component of observed prices, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system LMP was in the identified price range.

Table 3-32 Average, day-ahead markup (By LMP category, unadjusted): January through September, 2012 and 2013

	2012 (Jan - Sep)		2013 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($3.43)	24.9%	($1.89)	5.1%
$25 to $50	($2.75)	70.8%	($2.97)	83.9%
$50 to $75	$2.52	2.8%	$0.75	8.9%
$75 to $100	$6.96	0.7%	$0.03	1.2%
$100 to $125	$18.93	0.3%	$0.01	0.4%
$125 to $150	$4.54	0.1%	$0.00	0.1%
>= $150	$16.80	0.3%	($0.30)	0.4%

Table 3-33 Average, day-ahead markup (By LMP category, adjusted): January through September, 2012 and 2013

	2012 (Jan - Sep)		2013 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($2.46)	24.9%	($1.06)	5.1%
$25 to $50	($1.35)	70.8%	($2.06)	83.9%
$50 to $75	$2.94	2.8%	$0.83	8.9%
$75 to $100	$7.19	0.7%	$0.10	1.2%
$100 to $125	$19.30	0.3%	($0.03)	0.4%
$125 to $150	$4.91	0.1%	$0.00	0.1%
>= $150	$16.85	0.3%	($0.30)	0.4%

Frequently Mitigated Units and Associated Units

An FMU is a frequently mitigated unit. The results reported here include units that were mitigated for any reason, including both structural market power in the energy market and units called on for reliability reasons, including reactive. FMUs were first provided additional compensation as a form of scarcity pricing in 2005.[28] 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 for 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 for 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.[29] These categories are designated Tier 1, Tier 2 and Tier 3, respectively.[30,31]

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 with identical electrical impacts on the system, one of which was offer capped for more than 80 percent of its run hours, that unit would be designated a Tier 3 FMU. If the second unit were capped for 30 percent of its run hours, that unit would be an AU and receive the same Tier 3 adder as the FMU at the site. The AU designation was implemented to ensure that the associated unit is not dispatched in place of the FMU, resulting in no effective adder for the FMU. In the absence of the AU designation, the associated unit would be an FMU after its dispatch and the FMU would be dispatched in its place after losing its FMU designation.

The MMU recommends the elimination of FMU and AU adders. FMU and AU adders were added to the market rules in 2006 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 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. This recommendation is currently scheduled to be evaluated through the PJM stakeholder process in the fourth quarter of 2013.

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.[32]

Table 3-34 shows, by month, the number of FMUs and AUs in 2012 and 2013. For example, in January 2013, there were 18 FMUs and AUs in Tier 1, 17 FMUs and AUs in Tier 2, and 10 FMUs and AUs in Tier 3.

Table 3-34 Number of frequently mitigated units and associated units (By month): 2012 and January through September, 2013

	FMUs and AUs							
	2012				2013			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	26	21	52	99	18	17	10	45
February	26	22	47	95	18	11	12	41
March	25	17	47	89	18	8	12	38
April	23	17	46	86	16	5	15	36
May	23	14	47	84	11	5	15	31
June	22	13	48	83	24	8	12	44
July	25	11	50	86	19	15	19	53
August	25	23	43	91	14	25	20	59
September	17	6	33	56	11	22	31	64
October	10	18	14	42				
November	9	21	10	40				
December	14	17	10	41				

28 110 FERC ¶ 61,053 (2005).
29 OA, Schedule 1 § 6.4.2.
30 114 FERC ¶ 61, 076 (2006).
31 See "Settlement Agreement," Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).

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

Figure 3-5 shows the total number of FMUs and AUs that qualified for an adder since the inception of the business rule in February, 2006.

Figure 3-5 Frequently mitigated units and associated units (By month): February, 2006 through September, 2013

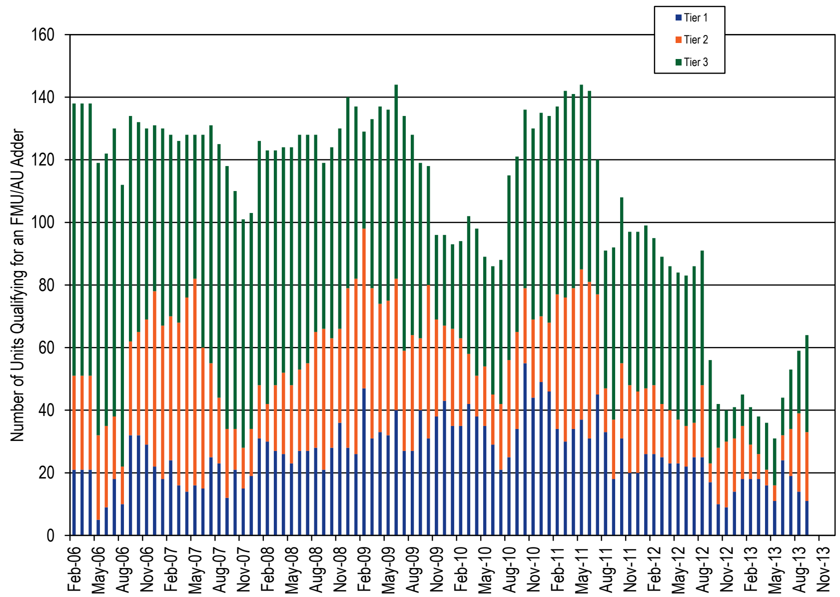


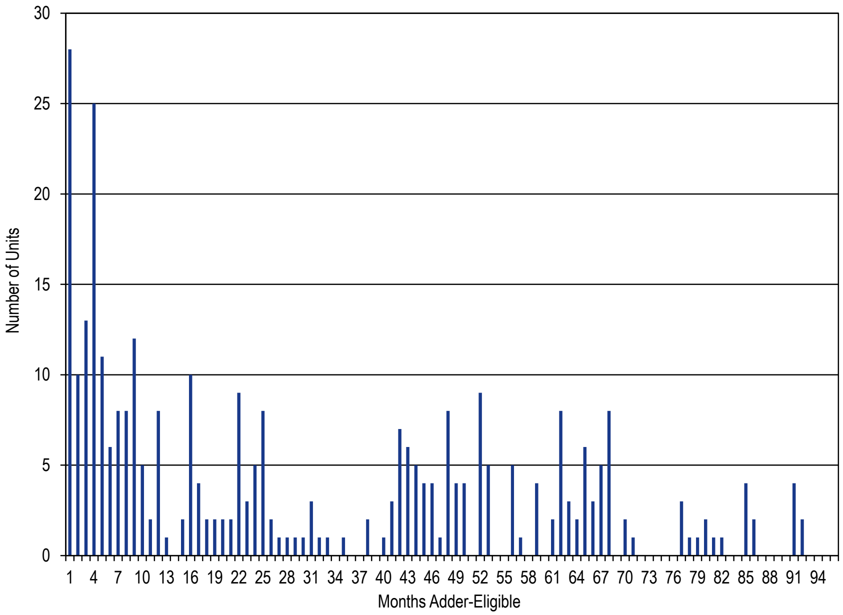
Table 3-35 shows the number of units that were eligible for an FMU or AU adder (Tier 1, Tier 2 or Tier 3) by the number of months they were eligible in 2012 and during the first nine months of 2013. Of the 81 units eligible in at least one month during the first nine months of 2013, 24 units (29.6 percent) were FMUs or AUs for all nine months, and 16 units (19.8 percent) qualified in only one month of 2013. The reduction in the total number of units qualifying for an FMU or AU adder resulted from the decrease in congestion, which was in turn the result of changes in fuel costs and changes in system topology.

Table 3-35 Frequently mitigated units and associated units total months eligible: 2012 and January through September, 2013

Months Adder-Eligible	FMU & AU Count	
	2012	2013
1	25	16
2	12	10
3	4	11
4	9	7
5	2	1
6	4	1
7	14	1
8	16	10
9	15	24
10	5	
11	2	
12	25	
Total	188	81

Figure 3-6 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, 2013, there have been 332 unique units that have qualified for an FMU adder in at least one month. Of these 332 units, no unit qualified for an adder in all potential months. Two units qualified in 92 of the 93 possible months, and 102 of the 332 units (30.7 percent) have qualified for an adder in more than half of the possible months.

Figure 3-6 Frequently mitigated units and associated units total months eligible: February, 2006 through September, 2013



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 the first nine months of 2013 increased by 0.5 percent from the first nine months of 2012, from 88,687 MW to 89,123 MW. The PJM average real-time load in the first nine months of 2013 would have decreased by 0.2 percent from the first nine months of 2012, from 88,687 MW to 88,522 MW, if the EKPC Transmission Zone had not been included in the comparison.[33]

33 The EKPC Transmission Zone was integrated on June 1, 2013 and was not included in this comparison for January through May of 2013.

PJM average day-ahead load, including DECs and up-to congestion transactions, in the first nine months of 2013 increased by 9.5 percent from the first nine months of 2012, from 132,494 MW to 145,139 MW. The PJM average day-ahead load, including DECs and up-to congestion transactions, would have increased 9.1 percent from the first nine months of 2012, from 132,494 MW to 144,501 MW, if the EKPC Transmission Zone had not been included in the comparison.

The day-ahead load growth was 1,800.0 percent higher than the real-time load growth because of the continued growth of up-to congestion transactions. If the first nine months of 2013 up-to congestion transactions had been held to the first nine months of 2012 levels, the day-ahead load, including DECs and up-to congestion transactions, would have decreased 0.5 percent instead of increasing 9.5 percent. The day-ahead load growth would have been 200.0 percent lower than the real-time load growth.

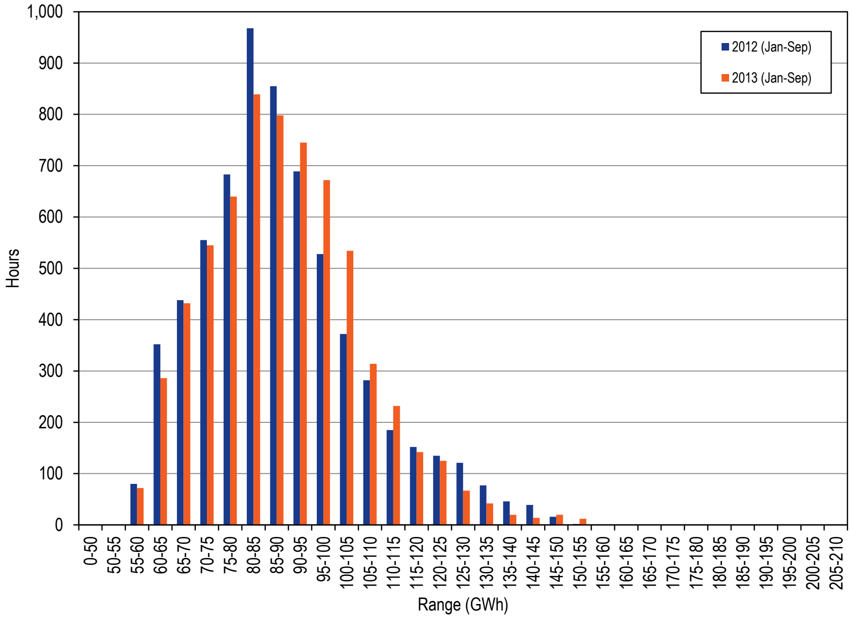
Real-Time Load

PJM Real-Time Load Duration

Figure 3-7 shows the hourly distribution of PJM real-time load for the first nine months of 2012 and 2013.[34]

34 All real-time load data in Section 3, "Energy Market," "Market Performance: Load and LMP" are based on PJM accounting load. See the *Technical Reference for PJM Markets*, Section 5, "Load Definitions," for detailed definitions of accounting load.

Figure 3-7 Distribution of PJM real-time accounting load: January through September of 2012 and 2013[35]



PJM Real-Time, Average Load

Table 3-36 presents summary real-time load statistics for the first nine months of each year during the 16 year period 1998 to 2013. 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.[36]

Table 3-36 PJM real-time average hourly load: January through September of 1998 through 2013[37]

	PJM Real-Time Load (MWh)		Year-to-Year Change	
(Jan-Sep)	Average Load	Load Standard Deviation	Average Load	Load Standard Deviation
1998	29,112	5,780	NA	NA
1999	30,236	6,306	3.9%	9.1%
2000	30,266	5,765	0.1%	(8.6%)
2001	31,060	6,156	2.6%	6.8%
2002	35,715	8,688	15.0%	41.1%
2003	37,996	7,187	6.4%	(17.3%)
2004	45,294	10,512	19.2%	46.3%
2005	78,235	17,541	72.7%	66.9%
2006	80,717	15,568	3.2%	(11.2%)
2007	83,114	15,386	3.0%	(1.2%)
2008	80,611	14,389	(3.0%)	(6.5%)
2009	76,954	13,879	(4.5%)	(3.5%)
2010	81,068	16,209	5.3%	16.8%
2011	83,762	17,604	3.3%	8.6%
2012	88,687	17,431	5.9%	(1.0%)
2013	89,123	16,384	0.5%	(6.0%)

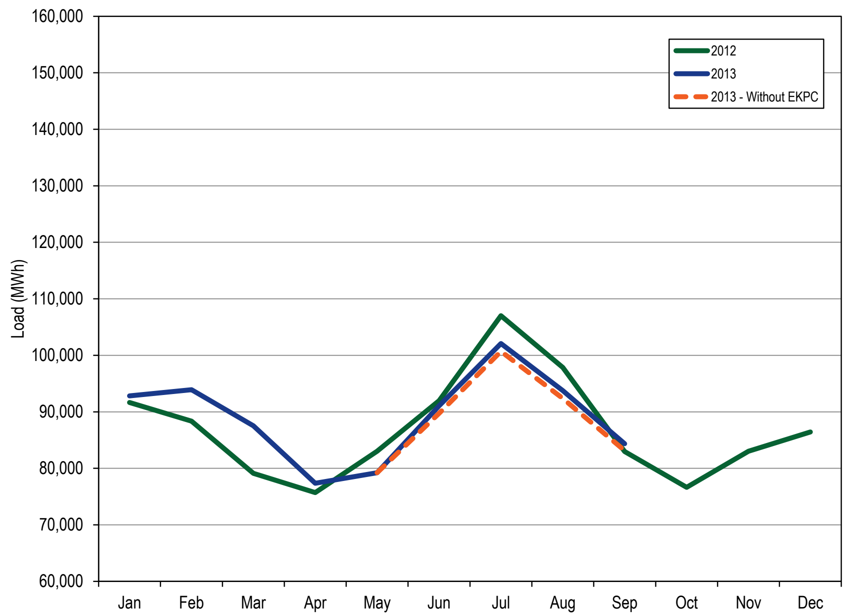
PJM Real-Time, Monthly Average Load

Figure 3-7 compares the real-time, monthly average hourly loads in 2013 with those in 2012.

35 Each range on the vertical axis includes the start value and excludes the end value.
36 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.

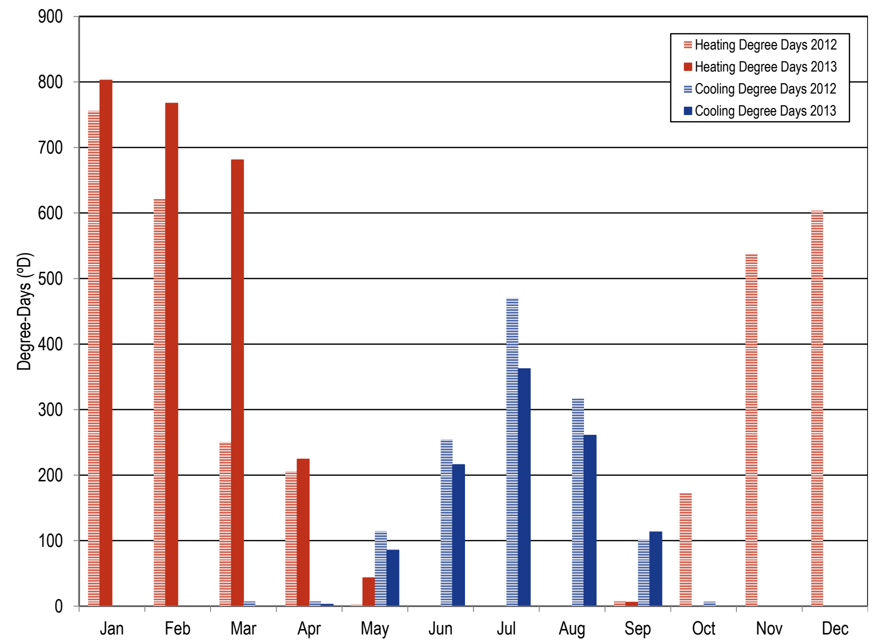
37 The data used in the version of this table in the *2012 State of the Market Report for PJM: January through September* have been updated by PJM and the updates are included in this table.

Figure 3-8 PJM real-time monthly average hourly load: January 2012 through September 2013



PJM real-time load is significantly affected by temperature. Figure 3-9 compares the total PJM monthly heating and cooling degree days in the first nine months of 2013 with those in 2012.[38] The figure shows that in the first nine months of 2013, the heating degree days were higher and the cooling degree days were lower than in the corresponding months of 2012, except for September.

Figure 3-9 PJM Heating and Cooling Degree Days: January of 2012 through September of 2013



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.

38 A heating degree day is defined as the number of degrees that a day's average temperature is below 65 degrees F (the temperature below which buildings need to be heated). A cooling degree day is the number of degrees that a day's average temperature is above 65 degrees F (the temperature when people will start to use air conditioning to cool buildings).
Heating and cooling degree days are calculated by weighting the temperature at each weather station in the individual transmission zones using weights provided by PJM in Manual 19. Then the temperature is weighted by the real-time zonal accounting load for each transmission zone. After calculating an average daily temperature across PJM, the heating and cooling degree formulas are used to calculate the daily heating and cooling degree days, which are summed for monthly reporting.
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, SDF, TOL and WAL.

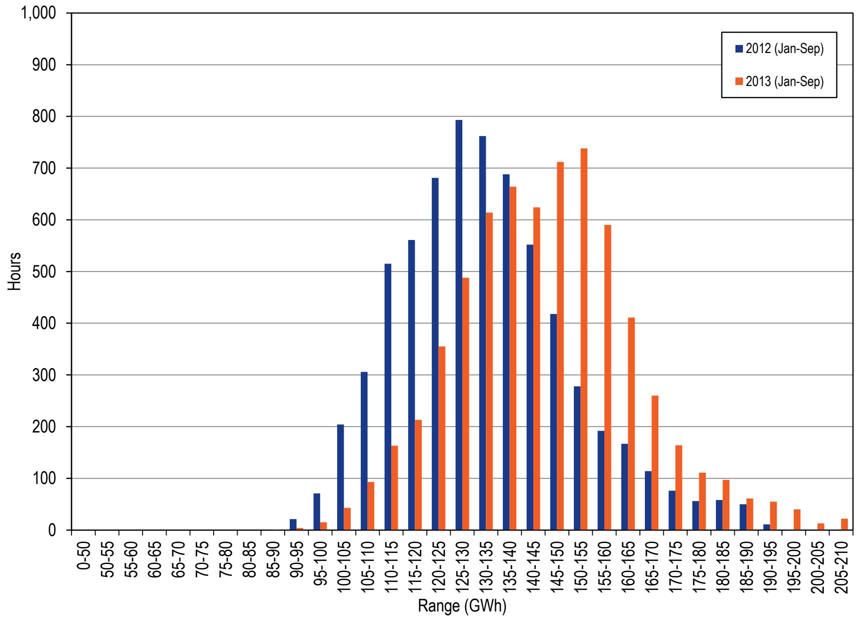
- **Up-to Congestion Transaction.** An up-to congestion transaction is a conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink. In the PJM Day-Ahead Market, an up-to congestion transaction is evaluated as a matched pair of an injection and a withdrawal analogous to a matched pair of an INC offer and a DEC bid. 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.[39]

PJM Day-Ahead Load Duration

Figure 3-10 shows the hourly distribution of PJM day-ahead load for the first nine months of 2012 and 2013.

Figure 3-10 Distribution of PJM day-ahead load: January through September of 2012 and 2013



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

PJM Day-Ahead, Average Load

Table 3-37 presents summary day-ahead load statistics for the first nine months of each year of the 13-year period 2001 to 2013.

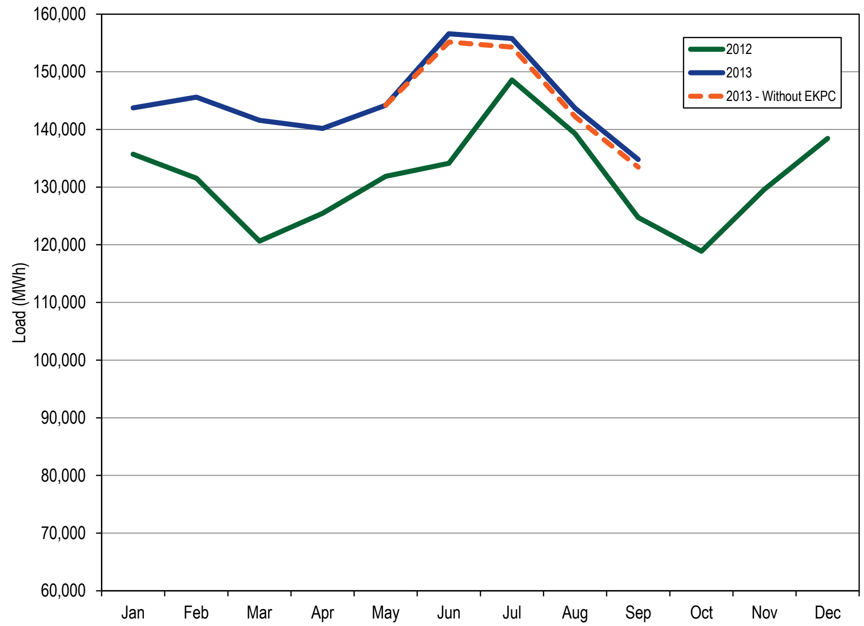
Table 3-37 PJM day-ahead average load: January through September of 2001 through 2013

	PJM Real-Time Load (MWh)						Year-to-Year Change		
	Average			Standard Deviation			Average		
(Jan-Sep)	Load	Up-to congestion	Total Load	Load	Up-to congestion	Total Load	Load	Up-to congestion	Total Load
2000	34,064	0	34,064	7,649	0	7,649	NA	NA	NA
2001	33,878	66	33,944	6,978	199	7,016	(0.5%)	NA	(0.4%)
2002	41,547	87	41,634	11,053	202	11,073	22.6%	32.2%	22.7%
2003	45,083	288	45,371	8,409	287	8,377	8.5%	230.4%	9.0%
2004	54,997	833	55,830	13,103	584	13,319	22.0%	189.4%	23.1%
2005	92,162	1,363	93,525	18,867	851	19,126	67.6%	63.6%	67.5%
2006	95,572	3,831	99,403	17,415	1,657	18,165	3.7%	181.1%	6.3%
2007	102,742	4,553	107,295	17,075	1,535	17,580	7.5%	18.8%	7.9%
2008	97,506	6,080	103,586	16,051	1,830	16,618	(5.1%)	33.6%	(3.5%)
2009	89,680	6,340	96,020	15,756	2,018	16,995	(8.0%)	4.3%	(7.3%)
2010	92,683	12,335	105,018	17,769	8,637	22,972	3.3%	94.5%	9.4%
2011	92,828	20,896	113,724	19,456	5,481	22,444	0.2%	69.4%	8.3%
2012	94,857	37,637	132,494	18,419	5,706	18,115	2.2%	80.1%	16.5%
2013	94,252	50,888	145,139	16,674	10,509	18,667	(0.6%)	35.2%	9.5%

PJM Day-Ahead, Monthly Average Load

Figure 3-11 compares the day-ahead, monthly average hourly loads of 2013 with those of 2012.

Figure 3-11 PJM day-ahead monthly average hourly load: January 2012 through September 2013



Real-Time and Day-Ahead Load

Table 3-38 presents summary statistics for the first nine months of 2012 and 2013 day-ahead and real-time loads.

Table 3-38 Cleared day-ahead and real-time load (MWh): January through September of 2012 and 2013[40]

		Day Ahead					Real Time	Average Difference	
	(Jan-Sep)	Cleared Fixed Demand	Cleared Price Sensitive	Cleared DEC Bids	Cleared Up-to Congestion	Total Load	Total Load	Total Load	Total Load Minus Cleared DEC Bids Minus Up-to Congestion
Average	2012	85,748	756	8,354	37,637	132,494	88,687	43,807	(2,184)
	2013	85,893	1,156	7,204	50,888	145,139	89,123	56,016	(2,075)
Median	2012	83,361	725	8,019	36,844	130,970	86,125	44,845	(18)
	2013	84,729	1,184	6,925	51,045	144,982	87,586	57,396	(574)
Standard Deviation	2012	17,044	142	1,856	5,706	18,115	17,431	684	(6,879)
	2013	15,592	254	1,505	10,509	18,667	16,384	2,284	(9,730)
Peak Average	2012	95,511	810	9,347	37,608	143,276	98,401	44,875	(2,080)
	2013	95,790	1,248	7,956	51,272	156,266	99,025	57,241	(1,987)
Peak Median	2012	91,277	781	9,084	36,899	139,945	93,938	46,007	24
	2013	93,964	1,306	7,582	52,023	154,283	97,004	57,279	(2,325)
Peak Standard Deviation	2012	15,176	143	1,750	5,551	15,563	15,601	(38)	(7,339)
	2013	12,954	272	1,467	9,793	15,569	13,993	1,576	(9,684)
Off-Peak Average	2012	77,186	708	7,483	37,663	123,039	80,169	42,870	(2,275)
	2013	77,238	1,075	6,546	50,552	135,411	80,465	54,946	(2,152)
Off-Peak Median	2012	74,624	684	7,138	36,794	121,287	77,560	43,727	(205)
	2013	75,784	1,104	6,308	50,254	134,578	78,761	55,816	(747)
Off-Peak Standard Deviation	2012	13,653	123	1,469	5,840	14,567	14,198	369	(6,940)
	2013	12,184	206	1,199	11,087	15,440	13,087	2,353	(9,934)

40 The data used in the version of this table in the *2012 State of the Market Report for PJM: January through June* have been updated by PJM and the updates are accounted for in this table.

Figure 3-12 shows the average hourly cleared volumes of day-ahead load (fixed-demand bids and price-sensitive bids), and day-ahead load plus each component of day-ahead demand, including decrement bids, up-to congestion transactions and exports.

Figure 3-12 Day-ahead and real-time loads (Average hourly volumes): January through September of 2013

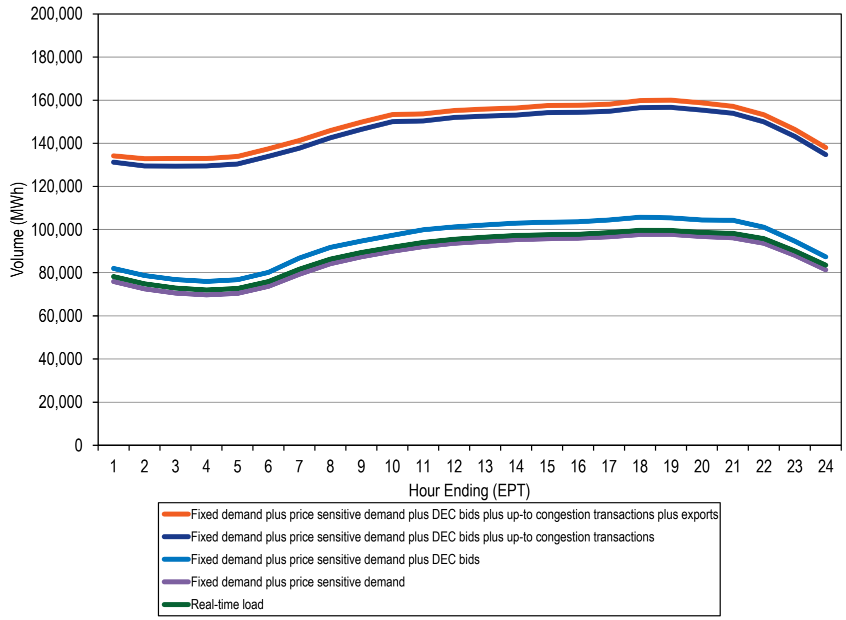
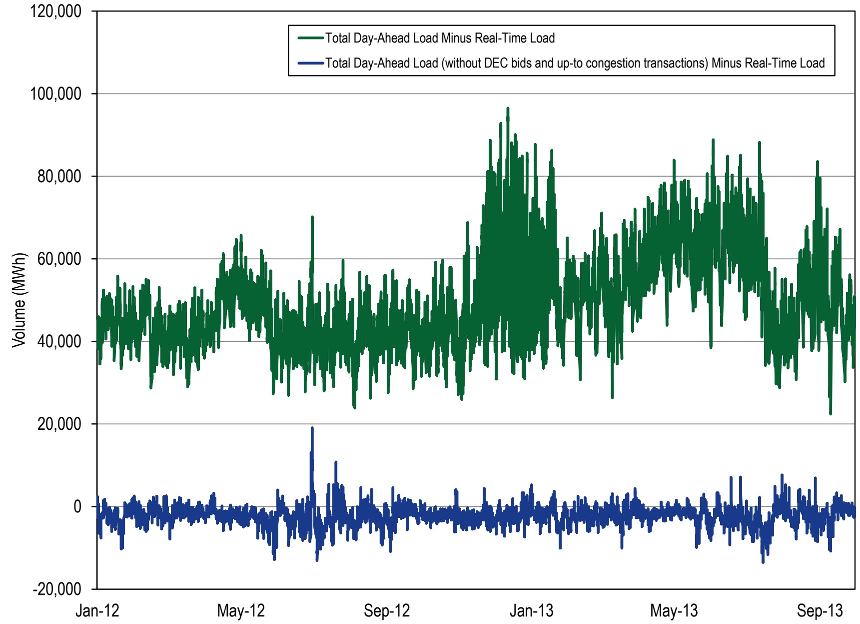


Figure 3-13 shows the difference between the day-ahead and real-time average daily loads in 2012 through the first nine months of 2013.

Figure 3-13 Difference between day-ahead and real-time loads (Average daily volumes): January 2012 through September of 2013



Real-Time and Day-Ahead Generation

PJM average real-time generation in the first nine months of 2013 increased by 0.1 percent from the first nine months of 2012, from 90,367 MW to 90,432 MW. The PJM average real-time generation in the first nine months of 2013 would have decreased by 0.5 percent from the first nine months of 2012, from 90,367 MW to 89,910 MW, if the EKPC Transmission Zone had not been included in the comparison.[41]

41 The EKPC Transmission Zone was integrated on June 1, 2013 and was not included in this comparison for January through May of 2013.

PJM average day-ahead generation in the first nine months of 2013, including INCs and up-to congestion transactions, increased by 9.8 percent from the first nine months of 2012, from 135,213 MW to 148,489 MW. The PJM average day-ahead generation in the first nine months of 2013, including INCs and up-to congestion transactions, would have increased 9.4 percent from the first nine months of 2012, from 135,213 MW to 147,895 MW, if the EKPC Transmission Zone had not been included in the comparison.

The day-ahead generation growth was 9,700.0 percent higher in the first nine months of 2013 than the real-time generation growth in the first nine months of 2012 because of the continued growth of up-to congestion transactions. If the first nine months of 2013 up-to congestion transactions had been held to first nine months of 2012 levels, the day-ahead generation, including INCs and up-to congestion transactions, would have increased 0.0 percent instead of 9.8 percent and day-ahead generation growth would have been 80.0 percent lower than the real-time generation growth.

PJM sums all negative (injections) and positive (withdrawals) load at each designated load bus when calculating net load (accounting load). PJM sums all of the negative (withdrawals) and positive (injections) generation at each generation bus when calculating net generation. Netting withdrawals and injections by bus type (generation or load) affects the measurement of total load and total generation. Energy withdrawn at a generation bus to provide, for example, auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps, is actually load, not negative generation. Energy injected at load buses by behind the meter generation is actually generation, not negative load.

The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load weighted LMP. The MMU also recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load weighted LMP.

In the Day-Ahead Energy Market, four types of financially binding generation offers are made and cleared:[42]

- **Self-Scheduled Generation Offer.** Offer to supply a fixed block of MWh from a specific unit, including a minimum MWh level from a specific unit that also has a dispatchable component above the minimum.[43]
- **Dispatchable Generation Offer.** Offer to supply a schedule of MWh and corresponding offer prices from a specific unit.
- **Increment Offer (INC).** Financial offer to supply MWh and corresponding offer prices. An increment offer is a financial offer that can be submitted by any market participant.
- **Up-to Congestion Transaction.** 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. In the PJM Day-Ahead Market, an up-to congestion transaction is evaluated as a matched pair of an injection and a withdrawal analogous to a matched pair of an INC offer and a DEC bid. 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 3-39 presents summary real-time generation statistics for the first nine months of each year for the 11-year period from 2003 through 2013.

42 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 *2013 Quarterly State of the Market Report for PJM: January through September*, Section 3, "Energy Market."
43 The definition of self-scheduled is based on the PJM "eMKT User Guide" (July, 2013), pp. 47-51.

Table 3-39 PJM real-time average hourly generation: January through September of 2003 through 2013

	PJM Real-Time Generation (MWh)		Year-to-Year Change	
(Jan-Sep)	Average Generation	Generation Standard Deviation	Average Generation	Generation Standard Deviation
2003	37,211	6,556	NA	NA
2004	45,888	11,035	23.3%	68.3%
2005	81,095	16,710	76.7%	51.4%
2006	84,260	14,696	3.9%	(12.1%)
2007	87,297	14,853	3.6%	1.1%
2008	85,241	14,203	(2.4%)	(4.4%)
2009	78,850	14,242	(7.5%)	0.3%
2010	84,086	16,346	6.6%	14.8%
2011	86,966	17,369	3.4%	6.3%
2012	90,367	16,893	3.9%	(2.7%)
2013	90,432	15,792	0.1%	(6.5%)

Table 3-40 presents summary day-ahead generation statistics for the first nine months of each year of the 11-year period from 2003 through 2013.

Table 3-40 PJM day-ahead average hourly generation: January through September of 2003 through 2013

	PJM Day-Ahead Generation (MWh)						Year-to-Year Change		
	Average			Standard Deviation			Average		
(Jan-Sep)	Generation (Cleared Gen. and INC Offers)	Up-to Congestion	Total Generation	Generation (Cleared Gen. and INC Offers)	Up-to Congestion	Total Generation	Generation (Cleared Gen. and INC Offers)	Up-to Congestion	Total Generation
2003	39,736	288	40,024	9,113	287	9,079	NA	NA	NA
2004	55,270	833	56,103	13,158	584	13,380	39.1%	189.4%	40.2%
2005	93,074	1,363	94,437	18,401	851	18,671	68.4%	63.6%	68.3%
2006	97,056	3,831	100,888	17,304	1,657	18,061	4.3%	181.1%	6.8%
2007	105,748	4,553	110,300	17,092	1,535	17,561	9.0%	18.8%	9.3%
2008	101,287	6,080	107,367	16,015	1,830	16,601	(4.2%)	33.6%	(2.7%)
2009	92,187	6,340	98,527	16,220	2,018	17,462	(9.0%)	4.3%	(8.2%)
2010	95,974	12,335	108,309	18,086	8,637	23,295	4.1%	94.5%	9.9%
2011	96,092	20,896	116,988	19,705	5,481	22,722	0.1%	69.4%	8.0%
2012	97,576	37,637	135,213	18,929	5,706	18,553	1.5%	80.1%	15.6%
2013	97,602	50,888	148,489	17,044	10,509	18,858	0.0%	35.2%	9.8%

Table 3-41 presents summary statistics for the first nine months of 2012 and 2013 for day-ahead and real-time generation.

Table 3-41 Day-ahead and real-time generation (MWh): January through September of 2012 and 2013

		Day Ahead				Real Time	Average Difference	
	(Jan-Sep)	Cleared Generation	Cleared INC Offers	Cleared Up-to Congestion	Cleared Generation Plus INC Offers Plus Up-to Congestion	Generation	Cleared Generation	Cleared Generation Plus INC Offers Plus Up-to Congestion
Average	2012	91,382	6,194	37,637	135,213	90,367	1,015	44,846
	2013	92,323	5,279	50,888	148,489	90,432	1,891	58,057
Median	2012	88,873	6,191	36,844	133,659	87,665	1,207	45,993
	2013	91,378	5,292	51,045	148,344	89,341	2,037	59,002
Standard Deviation	2012	18,736	906	5,706	18,553	16,893	1,843	1,659
	2013	16,953	868	10,509	18,858	15,792	1,160	3,066
Peak Average	2012	102,016	6,547	37,608	146,171	99,382	2,635	46,789
	2013	102,879	5,551	51,272	159,702	99,804	3,075	59,898
Peak Median	2012	97,816	6,477	36,899	142,800	95,406	2,410	47,393
	2013	100,661	5,620	52,023	157,635	98,051	2,610	59,584
Peak Standard Deviation	2012	16,523	721	5,551	15,938	15,366	1,157	572
	2013	13,985	776	9,793	15,691	13,518	467	2,173
Off-Peak Average	2012	82,057	5,884	37,663	125,604	82,461	(405)	43,142
	2013	83,093	5,040	50,552	138,686	82,238	856	56,448
Off-Peak Median	2012	79,731	5,810	36,794	123,948	80,263	(532)	43,685
	2013	81,594	5,001	50,254	137,872	80,728	866	57,144
Off-Peak Standard Deviation	2012	15,277	939	5,840	15,023	13,960	1,318	1,064
	2013	13,604	874	11,087	15,662	12,797	808	2,866

Figure 3-14 shows the average hourly cleared volumes of day-ahead generation, and day-ahead generation plus each component of day-ahead supply, including increment offers, up-to congestion transactions and imports, and the real-time generation.[44]

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

Figure 3-14 Day-ahead and real-time generation (Average hourly volumes): January through September of 2013

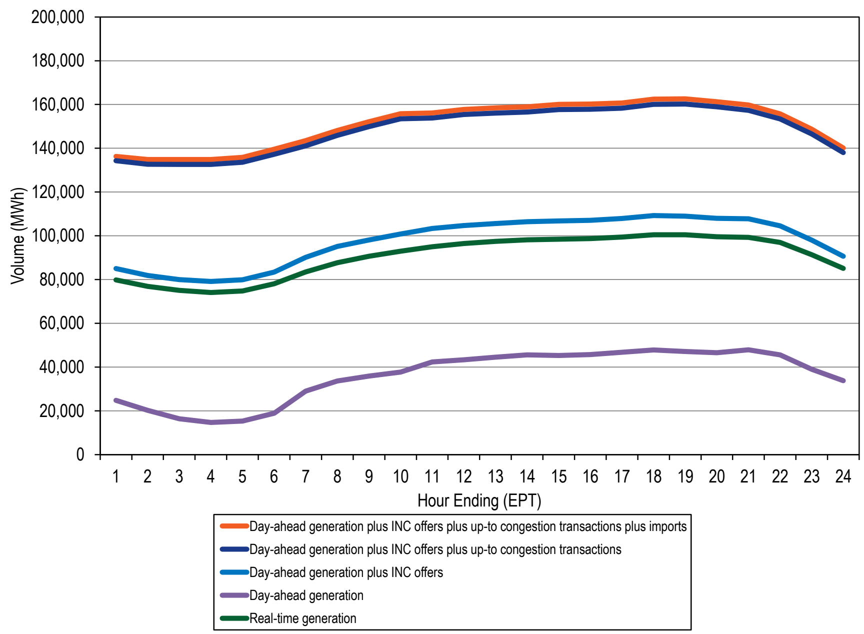


Figure 3-15 shows the difference between the day-ahead and real-time average daily generation in 2012 through the first nine months of 2013.

Figure 3-15 Difference between day-ahead and real-time generation (Average daily volumes): January 2012 through September of 2013

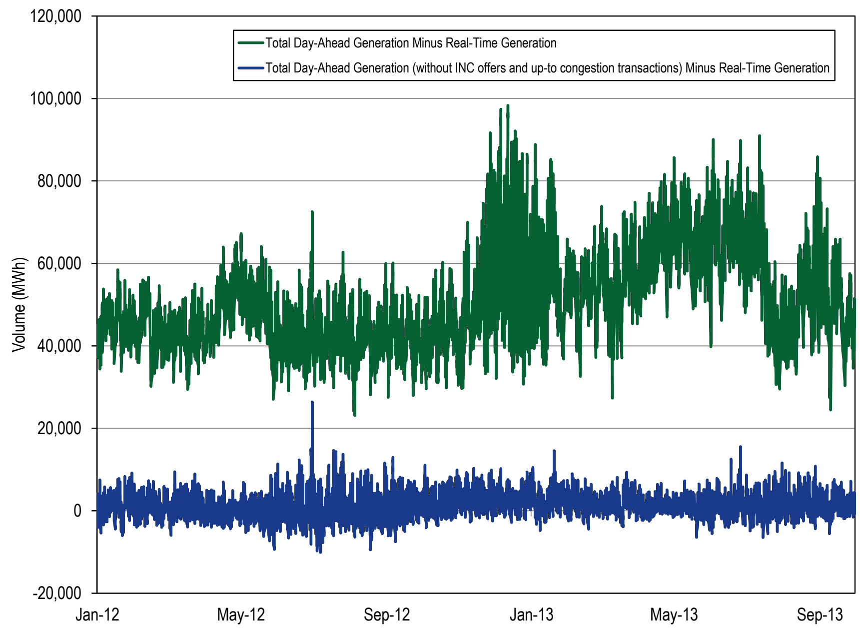


Figure 3-16 shows the difference between the PJM real-time generation and real-time load by zone in the first nine months of 2013. Table 3-42 shows the difference between the PJM real-time generation and real-time load by zone in the first nine months of 2012 and 2013. Figure 3-16 is color coded on a scale on which red shades represent zones that have less generation than load and green shades represent zones that have more generation than load, with darker shades meaning greater amounts of net generation or load. For example, the Pepco Control Zone has less generation than load, while the PENELEC Control Zone has more generation than load.

Figure 3-16 Map of PJM real-time generation less real-time load by zone: January through September of 2013[45]

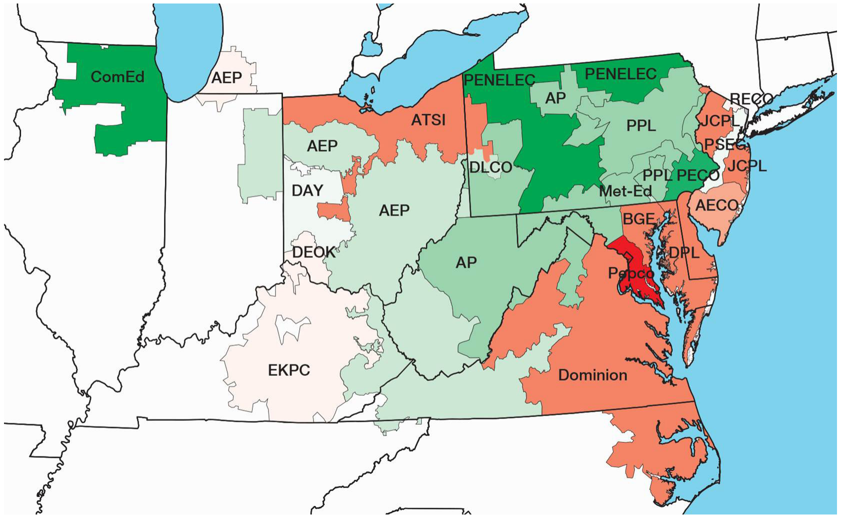


Table 3-42 PJM real-time generation less real-time load by zone (GWh): January through September of 2013

	Zonal Generation and Load (GWh)					
	2012 (Jan-Sep)			2013 (Jan-Sep)		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	1,551.2	8,304.5	(6,753.3)	1,720.2	8,013.9	(6,293.7)
AEP	107,865.8	99,065.9	8,799.8	99,790.3	97,582.4	2,207.9
AP	36,952.7	34,638.2	2,314.5	42,595.9	35,282.2	7,313.7
ATSI	45,187.6	50,733.4	(5,545.8)	41,393.9	50,220.1	(8,826.2)
BGE	15,591.1	24,915.2	(9,324.1)	15,944.6	24,500.6	(8,556.0)
ComEd	97,385.1	76,462.7	20,922.4	94,423.0	74,585.7	19,837.4
DAY	11,907.1	12,780.4	(873.3)	12,891.4	12,587.0	304.4
DEOK	14,484.4	20,326.6	(5,842.2)	18,602.4	20,209.2	(1,606.8)
DLCO	13,486.1	11,452.9	2,033.2	13,962.7	11,109.6	2,853.1
Dominion	60,066.3	69,863.7	(9,797.4)	61,604.3	71,237.2	(9,632.9)
DPL	6,679.8	13,936.0	(7,256.2)	5,874.7	14,084.8	(8,210.2)
EKPC	NA	NA	NA	3,420.7	3,937.2	(516.5)
JCPL	10,533.5	17,595.2	(7,061.7)	8,523.9	17,636.1	(9,112.2)
Met-Ed	15,887.5	11,398.2	4,489.2	15,490.1	11,332.1	4,158.0
PECO	45,863.5	30,393.7	15,469.8	45,148.4	30,480.7	14,667.8
PENELEC	28,821.9	12,818.4	16,003.5	32,773.1	12,889.7	19,883.4
Pepco	8,842.0	23,600.3	(14,758.4)	6,993.3	23,260.3	(16,266.9)
PPL	37,283.8	29,900.5	7,383.3	36,462.3	30,328.6	6,133.7
PSEG	35,773.7	33,754.0	2,019.7	34,804.9	33,390.7	1,414.2
RECO	0.0	1,179.3	(1,179.3)	0.0	1,177.6	(1,177.6)

Locational Marginal Price (LMP)

The conduct of individual market entities within a market structure is reflected in market prices.[46] 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 13.5 percent and 15.1 percent higher in the first nine months of 2013 than in the first nine months of 2012 as a result of higher fuel costs and higher demand.[47] Natural

45 Zonal real-time generation data for the map and corresponding table is based on the zonal designation for every bus listed in the most current PJM LMP bus model, which can be found at <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20130601-lmp-bus-model.ashx>.

46 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.

47 There was an average increase of 2.5 heating degree days and an average reduction of 0.8 cooling degree days in the first nine months of 2013 compared to the first nine months of 2012 which meant overall increased demand.

gas prices were higher, particularly in eastern zones, while coal prices were relatively constant. The fuel-cost-adjusted, load weighted LMP in the first nine months of 2013 shows that the mix of fuel types and fuel costs was the primary driver of higher prices than would have occurred if fuel prices had remained at the same levels as in the first nine months of 2012.

PJM Real-Time Energy Market prices increased in the first nine months of 2013 compared to the first nine months of 2012. The system average LMP was 15.0 percent higher in the first nine months of 2013 than in the first nine months of 2012, $37.30 per MWh versus $32.45 per MWh. The load-weighted average LMP was 13.5 percent higher in the first nine months of 2013 than in the first nine months of 2012, $39.75 per MWh versus $35.02 per MWh.

The fuel cost adjusted, load weighted, average LMP for the first nine months of 2013 was 14.2 percent lower than the load weighted, average LMP for the first nine months of 2013. If fuel costs in 2013 had been the same as in 2012, holding everything else constant, the 2013 load weighted LMP would have been lower, $34.12 per MWh instead of the observed $39.75 per MWh.

PJM Day-Ahead Energy Market prices increased in the first nine months of 2013 compared to the first nine months of 2012. The system average LMP was 16.6 percent higher in the first nine months of 2013 than in the first nine months of 2012, $37.50 per MWh versus $32.16 per MWh. The load-weighted average LMP was 15.1 percent higher in the first nine months of 2013 than in the first nine months of 2012, $39.49 per MWh versus $34.29 per MWh.[48]

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

Real-Time LMP

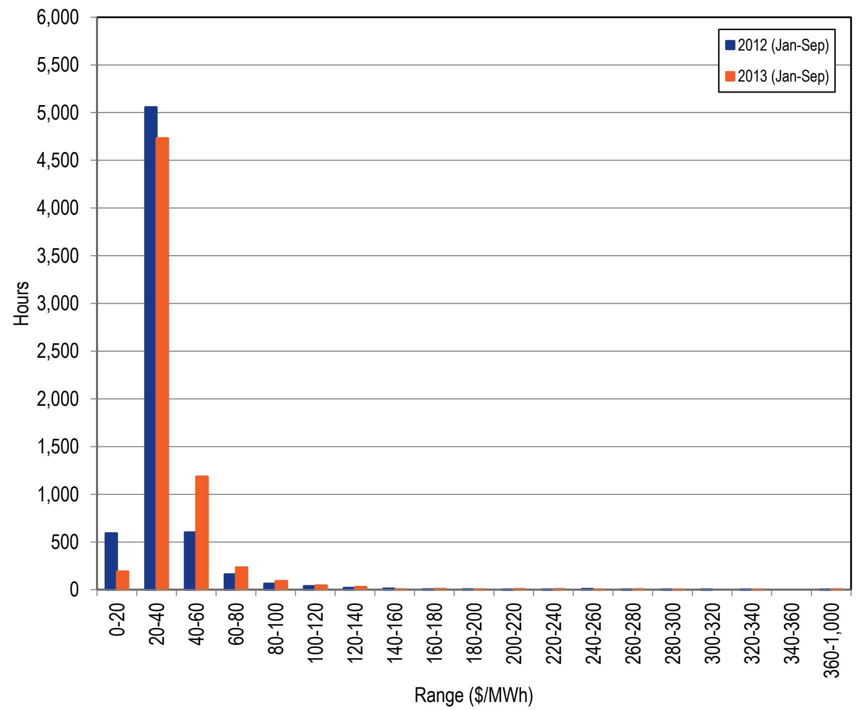
Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[49]

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 3-17 shows the hourly distribution of PJM real-time average LMP for the first nine months of 2012 and 2013.

Figure 3-17 Average LMP for the PJM Real-Time Energy Market: January through September of 2012 and 2013



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

PJM Real-Time, Average LMP

Table 3-43 shows the PJM real-time, average LMP for the first nine months of each year of the 16-year period 1998 to 2013.[50]

Table 3-43 PJM real-time, average LMP (Dollars per MWh): January through September of 1998 through 2013

	Real-Time LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$23.18	$16.86	$36.00	NA	NA	NA
1999	$31.65	$18.77	$83.28	36.6%	11.3%	131.3%
2000	$25.88	$18.22	$23.70	(18.2%)	(2.9%)	(71.5%)
2001	$36.00	$25.48	$51.30	39.1%	39.9%	116.4%
2002	$28.13	$20.70	$23.92	(21.9%)	(18.8%)	(53.4%)
2003	$40.42	$33.68	$26.00	43.7%	62.7%	8.7%
2004	$43.85	$39.99	$21.82	8.5%	18.7%	(16.1%)
2005	$54.69	$44.53	$33.67	24.7%	11.4%	54.3%
2006	$51.79	$43.50	$34.93	(5.3%)	(2.3%)	3.7%
2007	$57.34	$49.40	$35.52	10.7%	13.6%	1.7%
2008	$71.94	$61.33	$41.64	25.4%	24.2%	17.2%
2009	$37.42	$33.00	$17.92	(48.0%)	(46.2%)	(57.0%)
2010	$46.13	$37.89	$26.99	23.3%	14.8%	50.6%
2011	$45.79	$37.05	$32.25	(0.7%)	(2.2%)	19.5%
2012	$32.45	$28.78	$21.94	(29.1%)	(22.3%)	(32.0%)
2013	$37.30	$32.44	$22.84	15.0%	12.7%	4.1%

Real-Time, Load-Weighted, Average LMP

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

PJM Real-Time, Load-Weighted, Average LMP

Table 3-44 shows the PJM real-time, load-weighted, average LMP for the first nine months of each year of the 16-year period 1998 to 2013.

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

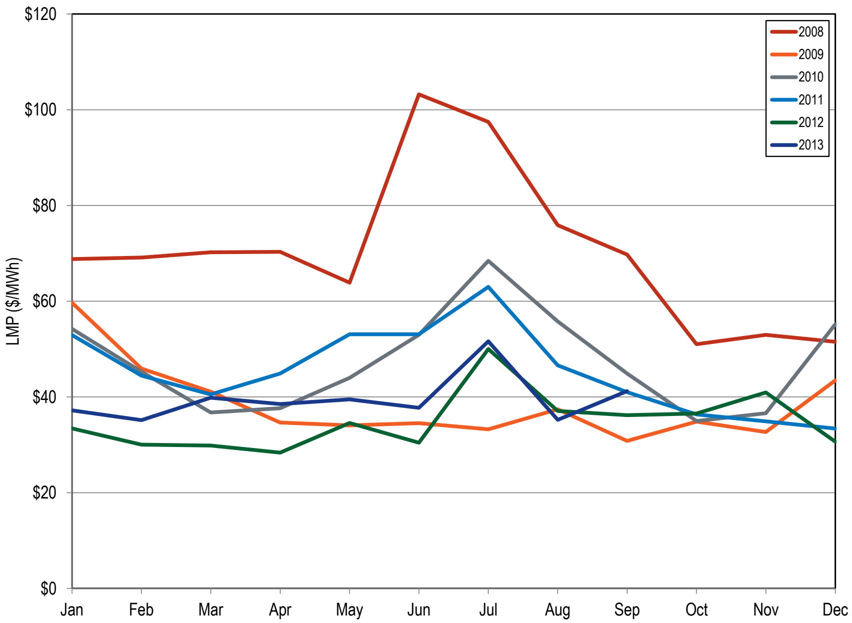
Table 3-44 PJM real-time, load-weighted, average LMP (Dollars per MWh): January through September of 1998 through 2013

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$26.06	$18.20	$44.65	NA	NA	NA
1999	$38.65	$20.02	$104.17	48.3%	10.0%	133.3%
2000	$28.49	$19.30	$26.89	(26.3%)	(3.6%)	(74.2%)
2001	$40.96	$28.18	$64.57	43.8%	46.0%	140.1%
2002	$31.95	$23.09	$29.14	(22.0%)	(18.1%)	(54.9%)
2003	$43.57	$38.17	$26.53	36.3%	65.3%	(9.0%)
2004	$46.44	$43.03	$21.89	6.6%	12.7%	(17.5%)
2005	$60.44	$50.10	$36.52	30.2%	16.4%	66.9%
2006	$56.39	$46.82	$40.70	(6.7%)	(6.5%)	11.4%
2007	$61.83	$55.12	$37.98	9.7%	17.7%	(6.7%)
2008	$77.27	$66.73	$43.80	25.0%	21.1%	15.3%
2009	$39.57	$34.57	$19.04	(48.8%)	(48.2%)	(56.5%)
2010	$49.91	$40.33	$29.65	26.2%	16.7%	55.7%
2011	$49.48	$38.72	$37.02	(0.9%)	(4.0%)	24.8%
2012	$35.02	$29.84	$25.44	(29.2%)	(22.9%)	(31.3%)
2013	$39.75	$33.61	$26.47	13.5%	12.6%	4.0%

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

Figure 3-18 shows the PJM real-time, monthly, load-weighted LMP from 2008 through the first nine months of 2013.

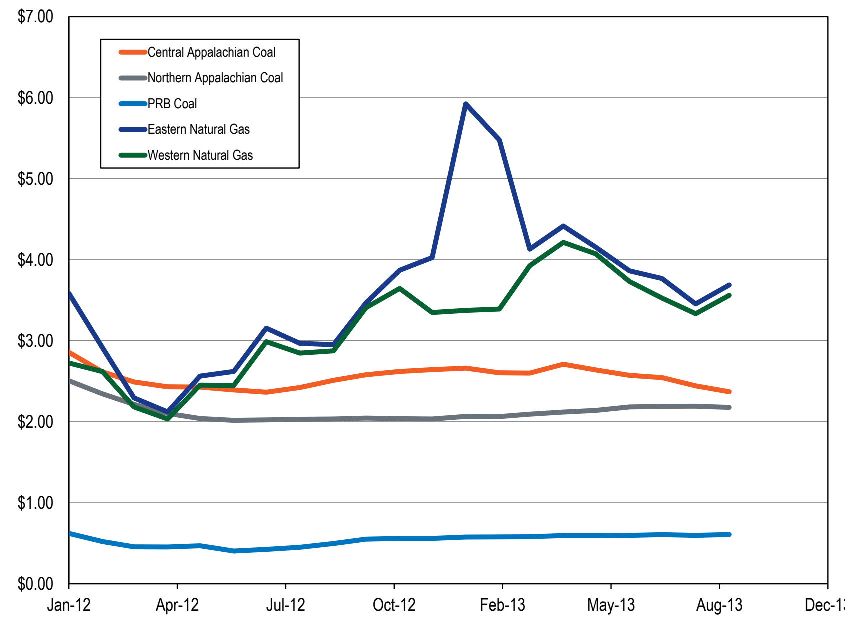
Figure 3-18 PJM real-time, monthly, load-weighted, average LMP: January 2008 through September of 2013



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. Natural gas, especially in the eastern part of PJM increased in price in the first nine months of 2013. Comparing prices in the first nine months of 2013 to the first nine months of 2012, the price of Northern Appalachian coal was 0.4 percent lower; the price of Central Appalachian coal was 2.8 percent higher; the price of Powder River Basin coal was 24.1 percent higher; the price of eastern natural gas was 54.0 percent higher; and the price of western natural gas was 43.0 percent higher. Figure 3-19 shows monthly average spot fuel prices for 2012 and the first nine months of 2013.[51] Natural gas prices were above coal prices in the first nine months of 2013, with prices above $10/MMBtu for some days.

Figure 3-19 Spot average fuel price comparison with fuel delivery charges: 2012 and January through September 2013 ($/MMBtu)



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

Figure 3-20 shows the marginal cost of generation in dollars per MWh. Marginal costs consist of fuel costs, fuel transportation costs, variable operations and maintenance adders, and emissions costs. The marginal cost of generation from a new entrant combined cycle was above the cost of a new entrant coal plant, but below the marginal cost of the average existing PJM sub-critical coal plant.

Figure 3-20 Marginal cost of generation of CP, CT, CC, and PJM average heat rate sub-critical coal plant: 2009 through September 2013 ($/MWh)

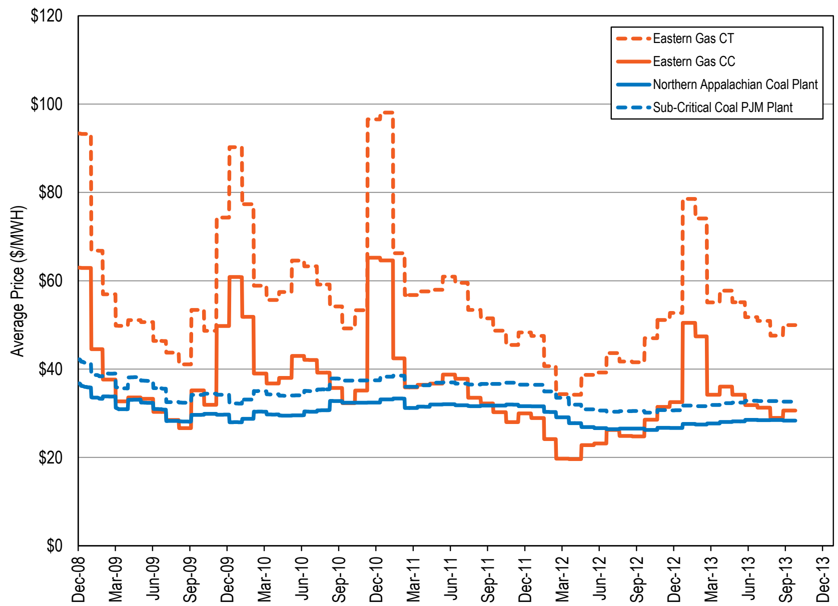


Table 3-45 compares the first nine months of 2013 PJM real-time fuel cost adjusted, load weighted, average LMP to the first nine months of 2012 load-weighted, average LMP. The fuel cost adjusted, load weighted, average LMP for the first nine months of 2013 was 14.2 percent lower than the load weighted, average LMP for the first nine months of 2013. The real-time, fuel cost adjusted, load weighted, average LMP for the first nine months of 2013 was 2.6 percent lower than the load weighted LMP for the first nine months of 2012. If fuel costs in 2013 had been the same as in 2012, holding everything else constant, the 2013 load weighted LMP would have been lower, $34.12 per MWh instead of the observed $39.75 per MWh. The mix of fuel types and fuel costs in 2013 were the primary driver of higher prices in 2013.

Table 3-45 PJM real-time annual, fuel-cost-adjusted, load-weighted average LMP (Dollars per MWh): Year-over-year method

	2013 Load-Weighted LMP	2013 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$39.75	$34.12	(14.2%)
	2012 Load-Weighted LMP	2013 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$35.02	$34.12	(2.6%)
	2012 Load-Weighted LMP	2013 Load-Weighted LMP	Change
Average	$35.02	$39.75	13.5%

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.[52]

Prior to the implementation of scarcity pricing on October 1, 2012, LMPs calculated based on SCED were modified ex-post (five minutes) 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.

Since the implementation of scarcity pricing on October 1, 2012, PJM jointly optimizes energy and ancillary services. In periods when generators providing energy have to be dispatched down from their economic operating level to meet reserve requirements, the joint optimization of energy and reserves takes into account the lost opportunity cost of the lowered generation and the associated incremental cost to maintain reserves. The cost of dispatching energy resources down to provide reserves is the Ancillary Service redispatch cost.

The components of LMP are shown in Table 3-46, including markup using unadjusted cost offers.[53] (Numbers in parentheses in the table are negative.) Table 3-46 shows that for the first nine months of 2013, 46.1 percent of the load-weighted LMP was the result of coal costs, 28.3 percent was the result of gas costs and 0.65 percent was the result of the cost of emission allowances. Markup was -$1.21 per MWh. In the first nine months of 2012, 54.3 percent of the load-weighted LMP was the result of coal costs, 23.4 percent was the result of gas costs and 0.59 percent was the result of the cost of emission allowances. Markup was -$1.23. 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.

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

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

Table 3-46 Components of PJM real-time (Unadjusted), annual, load-weighted, average LMP: January through September 2013 and 2012

	2012 (Jan - Sep)		2013 (Jan - Sep)	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$19.01	54.3%	$18.33	46.1%
Gas	$8.20	23.4%	$11.24	28.3%
Ten Percent Adder	$3.49	10.0%	$3.67	9.2%
VOM	$2.57	7.3%	$2.34	5.9%
NA	$0.80	2.3%	$2.07	5.2%
Oil	$1.97	5.6%	$1.61	4.0%
FMU Adder	$0.12	0.3%	$0.98	2.5%
LPA Rounding Difference	$0.11	0.3%	$0.48	1.2%
Emergency DR Adder	$0.00	0.0%	$0.22	0.6%
Ancillary Service Redispatch cost	$0.00	0.0%	$0.17	0.4%
CO_2 Cost	$0.10	0.3%	$0.15	0.4%
NO_x Cost	$0.09	0.3%	$0.10	0.2%
SO_2 Cost	$0.02	0.1%	$0.01	0.0%
Market-to-Market Adder	$0.03	0.1%	$0.00	0.0%
Increase Generation Adder	$0.07	0.2%	$0.00	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%
Other	$0.01	0.0%	$0.00	0.0%
Constraint Violation Adder	$0.02	0.1%	$0.00	0.0%
Wind	($0.06)	(0.2%)	($0.00)	(0.0%)
Decrease Generation Adder	($0.27)	(0.8%)	($0.14)	(0.4%)
LPA-SCED Differential	($0.05)	(0.1%)	($0.27)	(0.7%)
Markup	($1.23)	(3.5%)	($1.21)	(3.0%)
Total	$35.02	100.0%	$39.75	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 3-46 and Table 3-50), markup is simply the difference between the price offer and the cost offer. In the second approach

(Table 3-47 and Table 3-51), 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 supports 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. The unadjusted markup is calculated as the difference between the price offer and the cost offer including the 10 percent adder in the cost offer.

The components of LMP are shown in Table 3-47, including markup using adjusted cost offers.

Table 3-47 Components of PJM real-time (Adjusted), annual, load-weighted, average LMP: January through September 2013 and 2012

	2012 (Jan-Sep)		2013 (Jan-Sep)	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$19.17	54.8%	$18.58	46.8%
Gas	$8.20	23.4%	$11.25	28.3%
VOM	$2.59	7.4%	$2.36	5.9%
Ten Percent Adder	$1.46	4.2%	$2.06	5.2%
NA	$0.80	2.3%	$1.85	4.6%
Oil	$1.97	5.6%	$1.61	4.0%
FMU Adder	$0.12	0.3%	$0.86	2.2%
LPA Rounding Difference	$0.11	0.3%	$0.70	1.8%
Markup	$0.62	1.8%	$0.27	0.7%
Emergency DR Adder	$0.00	0.0%	$0.22	0.6%
Ancillary Service Redispatch cost	$0.00	0.0%	$0.17	0.4%
CO_2 Cost	$0.10	0.3%	$0.15	0.4%
NO_x Cost	$0.09	0.3%	$0.10	0.2%
SO_2 Cost	$0.02	0.1%	$0.01	0.0%
Market-to-Market Adder	$0.03	0.1%	$0.00	0.0%
Increase Generation Adder	$0.07	0.2%	$0.00	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%
Other	$0.01	0.0%	$0.00	0.0%
Constraint Violation Adder	$0.02	0.1%	$0.00	0.0%
Wind	($0.06)	(0.2%)	($0.00)	(0.0%)
Decrease Generation Adder	($0.27)	(0.8%)	($0.14)	(0.4%)
LPA-SCED Differential	($0.05)	(0.1%)	($0.31)	(0.8%)
Total	$35.02	100.0%	$39.75	100.0%

Day-Ahead LMP

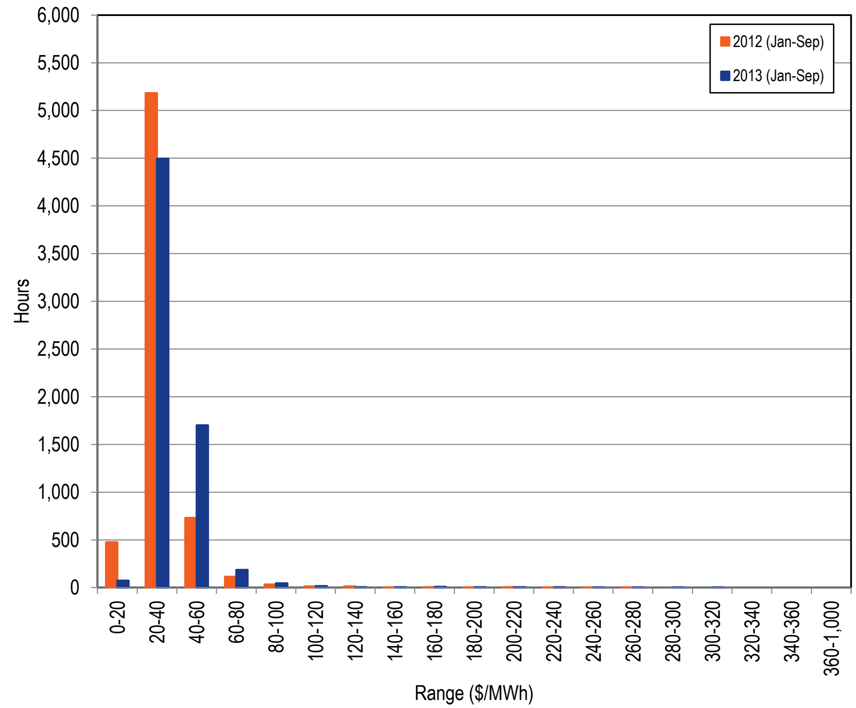
Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[54]

Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 3-21 shows the hourly distribution of PJM day-ahead average LMP for the first nine months of 2012 and 2013.

Figure 3-21 Average LMP for the PJM Day-Ahead Energy Market: January through September of 2012 and 2013



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

PJM Day-Ahead, Average LMP

Table 3-48 shows the PJM day-ahead, average LMP for the first nine months of each year of the 13-year period 2001 to 2013.

Table 3-48 PJM day-ahead, average LMP (Dollars per MWh): January through September of 2001 through 2013

	Day-Ahead LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$36.07	$30.02	$34.25	NA	NA	NA
2002	$28.29	$22.54	$19.09	(21.6%)	(24.9%)	(44.3%)
2003	$41.20	$38.24	$22.02	45.6%	69.7%	15.4%
2004	$42.64	$42.07	$17.47	3.5%	10.0%	(20.7%)
2005	$54.48	$46.67	$28.83	27.8%	10.9%	65.1%
2006	$50.45	$46.32	$24.93	(7.4%)	(0.8%)	(13.5%)
2007	$54.24	$51.40	$24.95	7.5%	11.0%	0.1%
2008	$71.43	$66.38	$33.11	31.7%	29.2%	32.7%
2009	$37.35	$35.29	$14.32	(47.7%)	(46.8%)	(56.8%)
2010	$45.81	$41.03	$19.59	22.7%	16.3%	36.8%
2011	$45.14	$40.20	$22.68	(1.5%)	(2.0%)	15.7%
2012	$32.16	$30.10	$14.54	(28.8%)	(25.1%)	(35.9%)
2013	$37.50	$34.70	$16.96	16.6%	15.3%	16.6%

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 3-49 shows the PJM day-ahead, load-weighted, average LMP for the first nine months of each year of the 13-year period 2001 to 2013.

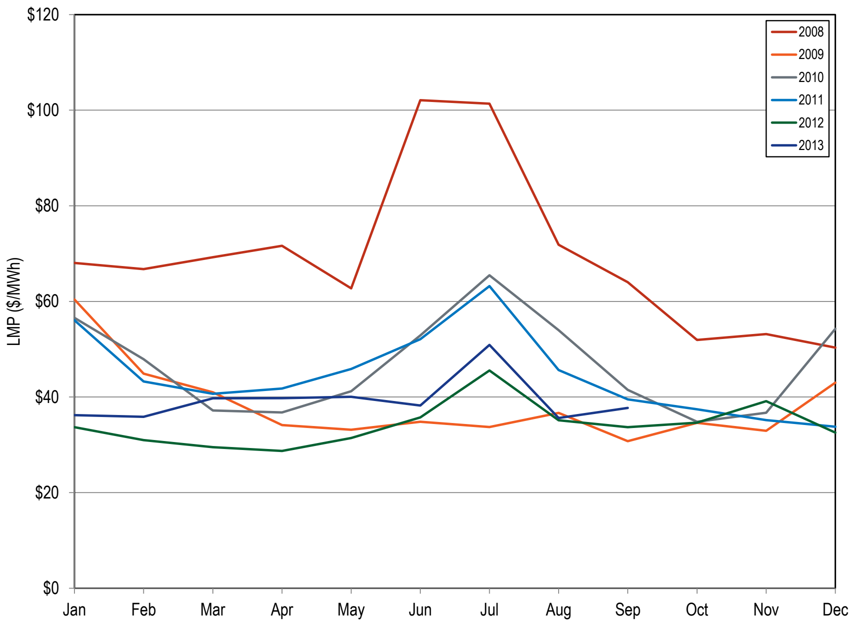
Table 3-49 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January through September of 2001 through 2013

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$39.88	$32.68	$42.01	NA	NA	NA
2002	$32.29	$25.22	$22.81	(19.0%)	(22.8%)	(45.7%)
2003	$44.11	$41.51	$22.34	36.6%	64.6%	(2.1%)
2004	$44.59	$44.47	$17.40	1.1%	7.1%	(22.1%)
2005	$59.51	$51.33	$31.13	33.5%	15.4%	78.9%
2006	$54.19	$48.87	$28.35	(8.9%)	(4.8%)	(8.9%)
2007	$57.79	$55.62	$26.07	6.6%	13.8%	(8.0%)
2008	$75.96	$70.35	$35.19	31.5%	26.5%	35.0%
2009	$39.35	$36.92	$14.98	(48.2%)	(47.5%)	(57.4%)
2010	$49.12	$43.33	$21.35	24.8%	17.4%	42.6%
2011	$48.34	$42.35	$26.54	(1.6%)	(2.3%)	24.3%
2012	$34.29	$31.17	$17.12	(29.1%)	(26.4%)	(35.5%)
2013	$39.49	$35.96	$19.90	15.1%	15.4%	16.3%

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

Figure 3-22 shows the PJM day-ahead, monthly, load-weighted LMP from 2008 through the first nine months of 2013.

Figure 3-22 Day-ahead, monthly, load-weighted, average LMP: January 2008 through September of 2013



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. Such financial offers cannot be decomposed. Using identified marginal resource offers and the components of unit 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 are 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.[55]

The components of day ahead LMP are shown in Table 3-50, including markup using unadjusted cost offers. Table 3-50 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In the first nine months of 2013, 65.5 percent of the load-weighted LMP was the result of up-to congestion transactions, 15.0 percent was the result of the cost of coal and 7.1 percent was the result of the cost of gas. In the first nine months of 2012, 4.8 percent of the load-weighted LMP was the result of up-to congestion transactions, 38.9 percent was the result of the cost of coal and 12.9 percent was the result of the cost of gas.

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

Table 3-50 Components of PJM day-ahead, (unadjusted) annual, load-weighted, average LMP (Dollars per MWh): January through September 2012 and 2013[56]

	2012 (Jan - Sep)		2013 (Jan - Sep)	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$13.34	38.9%	$5.93	15.0%
DEC	$8.40	24.5%	$2.31	5.8%
Gas	$4.41	12.9%	$2.79	7.1%
INC	$3.41	10.0%	$1.50	3.8%
10% Cost Adder	$1.98	5.8%	$0.94	2.4%
Up-to Congestion Transaction	$1.66	4.8%	$25.87	65.5%
VOM	$1.52	4.4%	$0.64	1.6%
Price Sensitive Demand	$0.58	1.7%	$0.06	0.2%
Dispatchable Transaction	$0.51	1.5%	$0.17	0.4%
Oil	$0.42	1.2%	$0.00	0.0%
DASR Offer Adder	$0.19	0.6%	$0.00	0.0%
CO_2	$0.06	0.2%	$0.02	0.0%
NO_x	$0.06	0.2%	$0.02	0.1%
SO_2	$0.01	0.0%	$0.00	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	($0.41)	(1.2%)	$0.02	0.0%
Markup	($1.87)	(5.5%)	($1.00)	(2.5%)
FMU Adder	$0.00	0.0%	$0.06	0.2%
NA	$0.00	0.0%	$0.15	0.4%
Total	$34.29	100.0%	$39.49	100.0%

56 The NA in 2013 is $0.43. It is caused by bad savecase input files for March 5, 2013.

Table 3-51 shows the components of the PJM day ahead, annual, load-weighted average LMP.

Table 3-51 Components of PJM day-ahead, (adjusted) annual, load-weighted, average LMP (Dollars per MWh): January through September 2012 and 2013

	2012 (Jan - Sep)		2013 (Jan - Sep)	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$13.34	38.9%	$5.93	15.0%
DEC	$8.40	24.5%	$2.31	5.8%
Gas	$4.41	12.9%	$2.79	7.1%
INC	$3.41	10.0%	$1.50	3.8%
Up-to Congestion Transaction	$1.66	4.8%	$25.87	65.5%
VOM	$1.52	4.4%	$0.64	1.6%
10% Cost Adder	$0.96	2.8%	$0.61	1.6%
Price Sensitive Demand	$0.58	1.7%	$0.06	0.2%
Dispatchable Transaction	$0.51	1.5%	$0.17	0.4%
Oil	$0.42	1.2%	$0.00	0.0%
DASR Offer Adder	$0.19	0.6%	$0.00	0.0%
CO_2	$0.06	0.2%	$0.02	0.0%
NO_x	$0.06	0.2%	$0.02	0.1%
SO_2	$0.01	0.0%	$0.00	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	($0.41)	(1.2%)	$0.02	0.0%
Markup	($0.85)	(2.5%)	($0.67)	(1.7%)
FMU Adder	$0.00	0.0%	$0.06	0.2%
NA	$0.00	0.0%	$0.15	0.4%
Total	$34.29	100.0%	$39.49	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 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 and decrement bids may be submitted at any hub, transmission zone, aggregate, or single bus for which LMP is calculated. Up-to congestion transactions may be submitted between any two buses eligible for FTRs.[57]

Figure 3-23 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve without increment offers and the system aggregate supply curve with increment offers for an example day in August 2013.

Figure 3-23 PJM day-ahead aggregate supply curves: 2013 example day

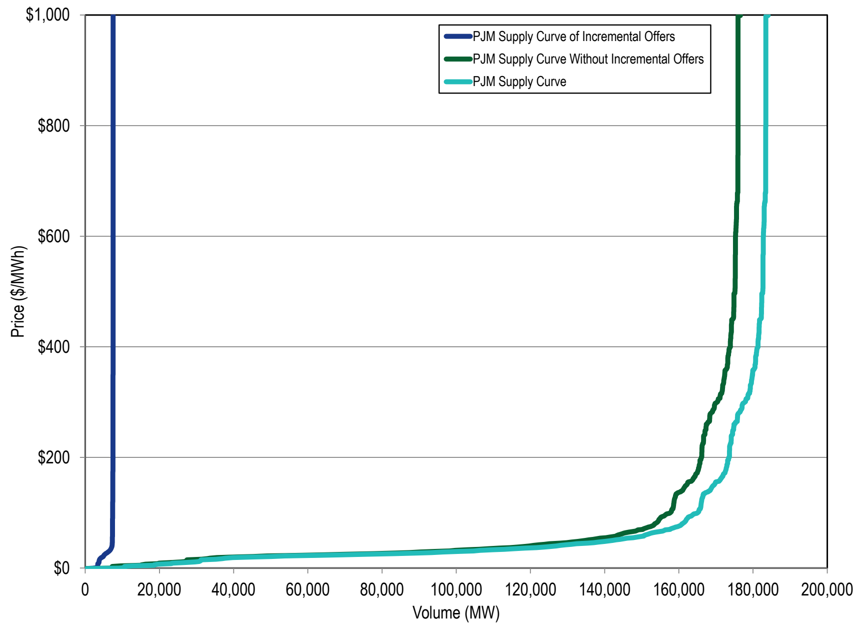


Table 3-52 shows the average volume of trading in increment offers and decrement bids per hour and the average total MW values of all bids per hour for 2012 through the first nine months of 2013. Table 3-53 shows the average volume of up-to congestion transactions per hour and the average total MW values of all bids per hour for 2012 through the first nine months of 2013. In the first nine months of 2013, the average submitted and cleared increment bid MW decreased 26.5 and 14.7 percent, and the average submitted and cleared decrement bid MW decreased 20.5 and 13.7 percent, compared to the first nine months of 2012. In the first nine months of 2013, the average up-to congestion submitted MW increased 57.2 percent and cleared MW increased 35.2 percent, compared to the first nine months of 2012. The increase in up-to congestion transactions displaced increment and decrement transactions.

Table 3-52 Hourly average volume of cleared and submitted INCs, DECs by month: January 2012 through September of 2013

		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
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
2013	Jan	5,682	7,271	80	195	7,944	9,653	81	211
2013	Feb	5,949	7,246	61	130	7,689	8,942	75	165
2013	Mar	5,414	6,192	50	94	6,890	7,907	65	140
2013	Apr	5,329	6,179	56	108	6,597	7,732	63	145
2013	May	5,415	6,651	57	130	7,036	8,803	74	185
2013	Jun	5,489	7,031	64	187	7,671	9,768	88	258
2013	Jul	5,374	6,710	60	173	7,566	9,786	89	267
2013	Aug	4,633	6,169	62	179	6,818	8,295	78	195
2013	Sep	4,262	5,464	60	191	6,646	8,400	82	233
2013	Annual	5,283	6,546	61	154	7,206	8,810	77	200

57 Market participants were required to specify an interface pricing point as the source for imports, an interface pricing point as the sink for exports or an interface pricing point as both the source and sink for transactions wheeling through PJM. On November 1, 2012, PJM eliminated this requirement. For the list of eligible sources and sinks for up-to congestion transactions, see www.pjm.com "*OASIS-Source-Sink-Link.xls*,"<<http://www.pjm.com/~/media/etools/oasis/references/oasis-source-sink-link.ashx>>

Table 3-53 Hourly average of cleared and submitted up-to congestion bids by month: January 2012 through September 2013

		Up-to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
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
2013	Jan	44,844	157,229	883	4,205
2013	Feb	46,351	144,066	893	3,862
2013	Mar	48,937	162,958	853	3,740
2013	Apr	57,938	193,366	1,683	4,229
2013	May	59,700	203,521	1,679	4,754
2013	Jun	60,210	229,912	1,984	5,997
2013	Jul	49,674	201,630	1,658	5,300
2013	Aug	44,765	157,748	1,477	3,923
2013	Sep	45,412	136,813	1,408	3,507
2013	Annual	50,870	176,360	1,391	4,391

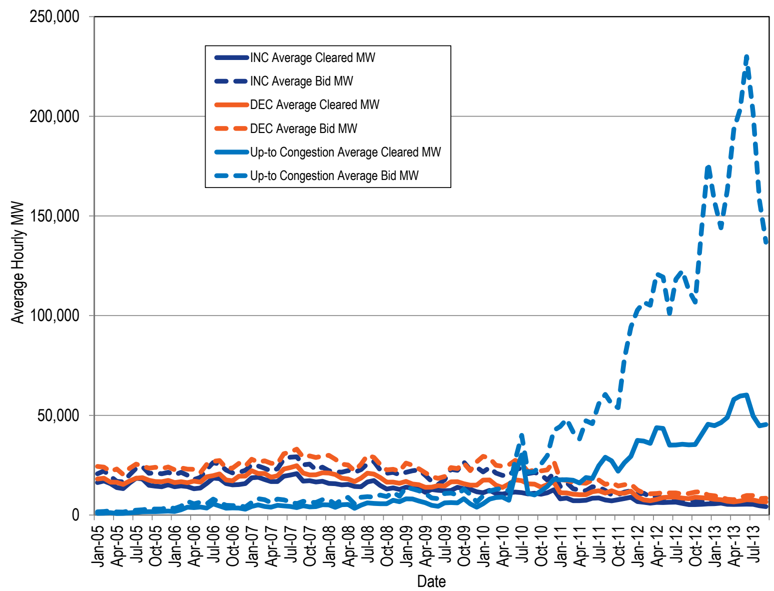
Table 3-54 shows the frequency with which generation offers, import or export transactions, up-to congestion transactions, decrement bids, increment offers and price-sensitive demand are marginal for each month.

Table 3-54 Type of day-ahead marginal units: January through September 2013

	Generation	Dispatchable Transaction	Up-to Congestion Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	3.8%	0.1%	91.7%	2.6%	1.8%	0.0%
Feb	3.4%	0.1%	92.9%	1.8%	1.8%	0.0%
Mar	2.5%	0.1%	95.8%	0.8%	0.8%	0.0%
Apr	0.4%	0.0%	98.5%	0.4%	0.6%	0.0%
May	0.6%	0.1%	98.4%	0.5%	0.4%	0.0%
Jun	0.6%	0.0%	97.5%	1.3%	0.7%	0.0%
Jul	0.8%	0.1%	97.0%	1.4%	0.7%	0.0%
Aug	0.4%	0.0%	97.6%	0.9%	1.1%	0.0%
Sep	0.6%	0.0%	96.2%	1.5%	1.6%	0.0%
Annual	1.5%	0.1%	96.2%	1.2%	1.0%	0.0%

Figure 3-24 shows the hourly volume of bid and cleared INC, DEC and up-to congestion bids by month.

Figure 3-24 Hourly volume of bid and cleared INC, DEC and Up-to Congestion bids (MW) by month: January, 2005 through September, 2013



In order to evaluate the ownership of virtual bids, the MMU categorizes 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 3-55 shows, for the first nine months of 2012 and 2013, the total increment offers and decrement bids by whether the parent organization is financial or physical. Table 3-56 shows for the first nine months of 2012 and 2013, the total up-to congestion transactions by the type of parent organization.

The top five companies with cleared up-to congestion transactions are financial and account for 62.4 percent of all the cleared up-to congestion MW in PJM in the first nine months of 2013.

Table 3-55 PJM INC and DEC bids by type of parent organization (MW): January through September of 2012 and 2013

	2012 (Jan - Sep)		2013 (Jan - Sep)	
Category	Total Virtual Bids MW	Percentage	Total Virtual Bids MW	Percentage
Financial	47,082,084	35.8%	26,283,017	26.1%
Physical	84,316,277	64.2%	74,273,099	73.9%
Total	131,398,361	100.0%	100,556,116	100.0%

Table 3-56 PJM up-to congestion transactions by type of parent organization (MW): January through September of 2012 and 2013

	2012 (Jan - Sep)		2013 (Jan - Sep)	
Category	Total Up-to Congestion MW	Percentage	Total Up-to Congestion MW	Percentage
Financial	235,531,919	95.2%	308,437,367	94.9%
Physical	11,950,279	4.8%	16,406,890	5.1%
Total	247,482,198	100.0%	324,844,257	100.0%

Table 3-57 shows increment offers and decrement bids bid by top ten locations for the first nine months of 2012 and 2013.

Table 3-57 PJM virtual offers and bids by top ten locations (MW): January through September of 2012 and 2013

2012 (Jan - Sep)					2013 (Jan - Sep)				
Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW	Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	22,645,383	25,448,690	48,094,072	WESTERN HUB	HUB	18,258,244	20,361,577	38,619,822
AEP-DAYTON HUB	HUB	3,906,488	4,420,709	8,327,197	N ILLINOIS HUB	HUB	2,021,644	3,654,208	5,675,852
SOUTHIMP	INTERFACE	7,038,188	0	7,038,188	SOUTHIMP	INTERFACE	5,630,343	0	5,630,343
N ILLINOIS HUB	HUB	2,059,281	4,605,627	6,664,908	AEP-DAYTON HUB	HUB	2,616,995	2,688,829	5,305,824
MISO	INTERFACE	248,793	5,303,608	5,552,401	IMO	INTERFACE	4,540,932	48,272	4,589,204
PPL	ZONE	286,342	4,331,684	4,618,026	PPL	ZONE	61,732	3,970,883	4,032,615
PECO	ZONE	858,512	3,219,905	4,078,417	MISO	INTERFACE	339,271	2,691,878	3,031,149
IMO	INTERFACE	2,591,173	45,924	2,637,097	PECO	ZONE	84,716	2,790,652	2,875,368
BGE	ZONE	167,525	1,542,604	1,710,129	BGE	ZONE	26,503	1,524,036	1,550,539
METED	ZONE	133,855	1,063,889	1,197,744	DOMINION HUB	HUB	241,152	1,292,010	1,533,161
Top ten total		39,935,538	49,982,640	89,918,178			33,821,532	39,022,345	72,843,878
PJM total		58,491,377	72,906,984	131,398,361			42,848,449	57,707,667	100,556,116
Top ten total as percent of PJM total		68.3%	68.6%	68.4%			78.9%	67.6%	72.4%

Table 3-58 shows up-to congestion transactions by import bids for the top ten locations for the first nine months of 2012 and 2013.[58]

Table 3-58 PJM cleared up-to congestion import bids by top ten source and sink pairs (MW): January through September of 2012 and 2013

2012 (Jan - Sep)				
Imports				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	112 WILTON	EHVAGG	8,832,551
MISO	INTERFACE	N ILLINOIS HUB	HUB	2,265,566
OVEC	INTERFACE	JEFFERSON	EHVAGG	1,958,932
OVEC	INTERFACE	DEOK	ZONE	1,795,528
OVEC	INTERFACE	COOK	EHVAGG	1,664,824
OVEC	INTERFACE	MARYSVILLE	EHVAGG	1,658,701
OVEC	INTERFACE	CONESVILLE 4	AGGREGATE	1,598,854
NYIS	INTERFACE	HUDSON BC	AGGREGATE	1,477,807
OVEC	INTERFACE	STUART 1	AGGREGATE	1,456,182
MISO	INTERFACE	COOK	EHVAGG	1,386,981
Top ten total				24,095,925
PJM total				122,824,468
Top ten total as percent of PJM total				19.6%
2013 (Jan - Sep)				
Imports				
Source	Source Type	Sink	Sink Type	MW
OVEC	INTERFACE	DEOK	ZONE	939,254
OVEC	INTERFACE	STUART 1	AGGREGATE	882,562
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	805,645
NYIS	INTERFACE	HUDSON BC	AGGREGATE	762,162
NORTHWEST	INTERFACE	ZION 1	AGGREGATE	656,470
NORTHWEST	INTERFACE	BYRON 1	AGGREGATE	496,011
OVEC	INTERFACE	BECKJORD 6	AGGREGATE	455,771
SOUTHEAST	INTERFACE	CLOVER	EHVAGG	452,895
OVEC	INTERFACE	SPORN 2	AGGREGATE	447,182
MISO	INTERFACE	112 WILTON	EHVAGG	399,528
Top ten total				6,297,480
PJM total				32,351,220
Top ten total as percent of PJM total				19.5%

Table 3-59 shows up-to congestion transactions by export bids for the top ten locations for the first nine months of 2012 and 2013.

Table 3-59 PJM cleared up-to congestion export bids by top ten source and sink pairs (MW): January through September of 2012 and 2013

2012 (Jan - Sep)				
Exports				
Source	Source Type	Sink	Sink Type	MW
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	3,403,395
ROCKPORT	EHVAGG	OVEC	INTERFACE	3,140,361
23 COLLINS	EHVAGG	MISO	INTERFACE	3,055,342
STUART 1	AGGREGATE	OVEC	INTERFACE	2,144,288
WESTERN HUB	HUB	MISO	INTERFACE	1,643,318
ROCKPORT	EHVAGG	MISO	INTERFACE	1,572,838
QUAD CITIES 1	AGGREGATE	NORTHWEST	INTERFACE	1,554,154
SPORN 3	AGGREGATE	OVEC	INTERFACE	1,472,620
STUART 4	AGGREGATE	OVEC	INTERFACE	1,292,612
SPORN 5	AGGREGATE	OVEC	INTERFACE	1,184,697
Top ten total				20,463,626
PJM total				122,815,948
Top ten total as percent of PJM total				16.7%
2013 (Jan - Sep)				
Exports				
Source	Source Type	Sink	Sink Type	MW
JEFFERSON	EHVAGG	OVEC	INTERFACE	1,901,810
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	1,074,478
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	1,055,665
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	949,703
TANNERS CRK 4	AGGREGATE	OVEC	INTERFACE	875,503
GAVIN	EHVAGG	OVEC	INTERFACE	641,654
ROCKPORT	EHVAGG	OVEC	INTERFACE	571,378
EAST BEND 2	AGGREGATE	OVEC	INTERFACE	556,385
SPORN 3	AGGREGATE	OVEC	INTERFACE	545,195
F387 CHICAGOH	AGGREGATE	NIPSCO	INTERFACE	533,133
Top ten total				8,704,904
PJM total				38,431,224
Top ten total as percent of PJM total				22.7%

58 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 3-60 shows up-to congestion transactions by wheel bids for the top ten locations for the first nine months of 2012 and 2013.

Table 3-60 PJM cleared up-to congestion wheel bids by top ten source and sink pairs (MW): January through September of 2012 and 2013

2012 (Jan - Sep)				
Wheels				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	252,804
NYIS	INTERFACE	IMO	INTERFACE	162,091
SOUTHIMP	INTERFACE	MISO	INTERFACE	147,801
SOUTHEAST	INTERFACE	SOUTHEXP	INTERFACE	120,035
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	112,478
MISO	INTERFACE	NIPSCO	INTERFACE	102,657
NORTHWEST	INTERFACE	MISO	INTERFACE	99,449
OVEC	INTERFACE	IMO	INTERFACE	72,960
MISO	INTERFACE	OVEC	INTERFACE	66,900
SOUTHWEST	INTERFACE	OVEC	INTERFACE	61,943
Top ten total				1,199,119
PJM total				1,841,782
Top ten total as percent of PJM total				65.1%
2013 (Jan - Sep)				
Wheels				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	685,232
NORTHWEST	INTERFACE	MISO	INTERFACE	396,607
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	300,204
IMO	INTERFACE	NYIS	INTERFACE	272,426
MISO	INTERFACE	NIPSCO	INTERFACE	259,584
OVEC	INTERFACE	IMO	INTERFACE	109,350
MISO	INTERFACE	SOUTHEXP	INTERFACE	104,052
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	88,280
MISO	INTERFACE	OVEC	INTERFACE	79,810
NORTHWEST	INTERFACE	OVEC	INTERFACE	78,419
Top ten total				2,373,962
PJM total				3,144,557
Top ten total as percent of PJM total				75.5%

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.[59] Up-to congestion transactions can now be made at internal buses. The top ten internal up-to congestion transaction locations were 7.9 percent of the PJM total internal up-to congestion transactions in the first nine months of 2013.

Table 3-61 shows up-to congestion transactions by internal bids for the top ten locations for the first nine months of 2013.

Table 3-61 PJM cleared up-to congestion internal bids by top ten source and sink pairs (MW): January through September of 2013

2013 (Jan - Sep)				
Internal				
Source	Source Type	Sink	Sink Type	MW
SUNBURY 1-3	AGGREGATE	CITIZENS	AGGREGATE	3,248,461
ATSI GEN HUB	HUB	ATSI	ZONE	3,180,687
MT STORM	EHVAGG	GREENLAND GAP	EHVAGG	3,060,670
FE GEN	AGGREGATE	ATSI	ZONE	1,778,421
AEP-DAYTON HUB	HUB	WESTERN HUB	HUB	1,690,443
CORDOVA	AGGREGATE	QUAD CITIES 2	AGGREGATE	1,519,249
WYOMING	EHVAGG	BROADFORD	EHVAGG	1,417,822
DAY	ZONE	BUCKEYE - DPL	AGGREGATE	1,371,354
WHITPAIN	EHVAGG	ELROY	EHVAGG	1,313,998
NAPERVILLE	AGGREGATE	WINNETKA	AGGREGATE	1,189,073
Top ten total				19,770,178
PJM total				250,917,257
Top ten total as percent of PJM total				7.9%

Table 3-62 shows the number of source-sink pairs that were offered and cleared monthly in 2012 and the first nine months of 2013. The increase in average offered and cleared source-sink pairs in November and December of 2012 and the first nine months of 2013 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 increased dispersion in cleared up-to congestion transaction internal bids by location.

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

Table 3-63 and Figure 3-25 show total cleared up-to congestion transactions by type for the first nine months of 2012 and 2013. Internal up-to congestion transactions in the first nine months of 2013 were 77.2 percent of all up-to congestion transactions for the first nine months of 2013.

Figure 3-25 shows the initial increase and continued rise of internal up-to congestion transactions in November and December of 2012 and the first nine months of 2013, following the November 1, 2012, rule change permitting such transactions.

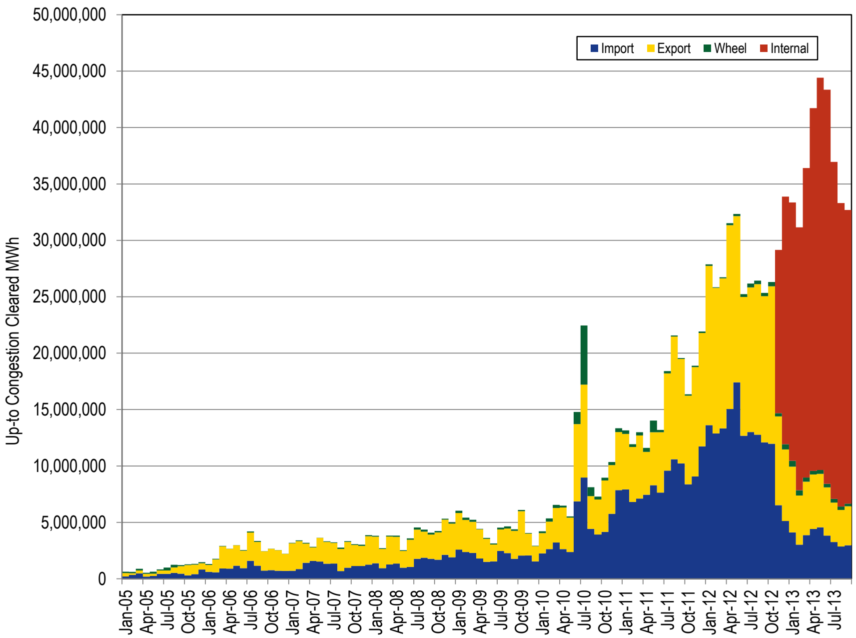
Table 3-62 Number of PJM offered and cleared source and sink pairs: January 2012 through September of 2013

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
2012	Jan	1,771	2,182	1,126	1,568
2012	Feb	1,816	2,198	1,156	1,414
2012	Mar	1,746	2,004	1,128	1,353
2012	Apr	1,753	2,274	1,117	1,507
2012	May	1,866	2,257	1,257	1,491
2012	Jun	2,145	2,581	1,425	1,897
2012	Jul	2,168	2,800	1,578	2,078
2012	Aug	2,541	3,043	1,824	2,280
2012	Sep	2,140	3,032	1,518	2,411
2012	Oct	2,344	3,888	1,569	2,625
2012	Nov	4,102	8,142	2,829	5,811
2012	Dec	9,424	13,009	5,025	8,071
2012	Jan-Oct	2,031	3,888	1,371	2,625
2012	Nov-Dec	6,806	13,009	3,945	8,071
2012	Annual	2,818	3,951	1,796	2,709
2013	Jan	6,580	10,548	3,291	5,060
2013	Feb	4,891	7,415	2,755	3,907
2013	Mar	4,858	7,446	2,868	4,262
2013	Apr	6,426	9,094	3,464	4,827
2013	May	5,729	7,914	3,350	4,495
2013	Jun	6,014	8,437	3,490	4,775
2013	Jul	5,955	9,006	3,242	4,938
2013	Aug	6,215	9,751	3,642	5,117
2013	Sep	3,496	4,222	2,510	3,082
2013	Annual	5,574	8,204	3,179	4,496

Table 3-63 PJM cleared up-to congestion transactions by type (MW): January through September of 2012 and 2013

	2012 (Jan - Sep)				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	24,095,925	20,463,626	1,199,119	NA	31,289,254
PJM total (MW)	122,824,468	122,815,948	1,841,782	NA	247,482,198
Top ten total as percent of PJM total	19.6%	16.7%	65.1%	NA	12.6%
PJM total as percent of all up-to congestion transactions	49.6%	49.6%	0.7%	NA	100.0%
	2013 (Jan - Sep)				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	6,297,480	8,704,904	2,373,962	19,770,178	20,482,915
PJM total (MW)	32,351,220	38,431,224	3,144,557	250,917,257	324,844,257
Top ten total as percent of PJM total	19.5%	22.7%	75.5%	7.9%	6.3%
PJM total as percent of all up-to congestion transactions	10.0%	11.8%	1.0%	77.2%	100.0%

Figure 3-25 PJM cleared up-to congestion transactions by type (MW): January 2005 through September of 2013



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 3-27).

Table 3-64 shows that the difference between average day-ahead and real-time prices was $0.29 per MWh in the first nine months of 2012 and -$0.20 per MWh in the first nine months of 2013. The difference between average on-peak day-ahead and real-time prices was $1.34 per MWh in the first nine months of 2012 and $0.16 per MWh in the first nine months of 2013.

Table 3-64 Day-ahead and real-time average LMP (Dollars per MWh): January through September of 2012 and 2013[60]

	2012 (Jan - Sep)				2013 (Jan - Sep)			
	Day Ahead	Real Time	Difference	Difference as Percent of Real Time	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Average	$32.16	$32.45	$0.29	0.9%	$37.50	$37.30	($0.20)	(0.5%)
Median	$30.10	$28.78	($1.32)	(4.6%)	$34.70	$32.44	($2.26)	(7.0%)
Standard deviation	$14.54	$21.94	$7.40	33.7%	$16.96	$22.84	$5.88	25.7%
Peak average	$38.16	$39.50	$1.34	3.4%	$44.58	$44.74	$0.16	0.4%
Peak median	$33.74	$32.19	($1.55)	(4.8%)	$40.32	$37.41	($2.91)	(7.8%)
Peak standard deviation	$17.76	$27.37	$9.60	35.1%	$21.37	$28.77	$7.40	25.7%
Off peak average	$26.95	$26.33	($0.62)	(2.4%)	$31.31	$30.80	($0.51)	(1.7%)
Off peak median	$25.95	$25.20	($0.74)	(2.9%)	$30.07	$28.44	($1.63)	(5.7%)
Off peak standard deviation	$7.92	$12.98	$5.06	39.0%	$7.58	$12.77	$5.19	40.7%

The price difference between the Real-Time and the Day-Ahead Energy Markets results, in part, from conditions in the Real-Time Energy Market that are difficult, or impossible, to anticipate in the Day-Ahead Energy Market.

Table 3-65 shows the difference between the Real-Time and the Day-Ahead Energy Market Prices for the first nine months of each year of the 13-year period 2001 to 2013.

Table 3-65 Day-ahead and real-time average LMP (Dollars per MWh): January through September of 2001 through 2013

(Jan - Sep)	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
2001	$36.07	$36.00	($0.07)	(0.2%)
2002	$28.29	$28.13	($0.16)	(0.6%)
2003	$41.20	$40.42	($0.77)	(1.9%)
2004	$42.64	$43.85	$1.22	2.9%
2005	$54.48	$54.69	$0.21	0.4%
2006	$50.45	$51.79	$1.34	2.7%
2007	$54.24	$57.34	$3.10	5.7%
2008	$71.43	$71.94	$0.51	0.7%
2009	$37.35	$37.42	$0.08	0.2%
2010	$45.81	$46.13	$0.32	0.7%
2011	$45.14	$45.79	$0.65	1.4%
2012	$32.16	$32.45	$0.29	0.9%
2013	$37.50	$37.30	($0.20)	(0.5%)

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

Table 3-66 provides frequency distributions of the differences between PJM real-time load-weighted hourly LMP and PJM day-ahead load-weighted hourly LMP for the first nine months of the years 2007 through 2013.

Table 3-66 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): January through September of 2007 through 2013

	2007		2008		2009		2010		2011		2012		2013	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.02%	5	0.08%	4	0.06%
($150) to ($100)	0	0.00%	1	0.02%	0	0.00%	0	0.00%	2	0.05%	6	0.17%	5	0.14%
($100) to ($50)	26	0.40%	88	1.35%	3	0.05%	13	0.20%	49	0.79%	17	0.43%	9	0.27%
($50) to $0	3,385	52.07%	3,730	58.08%	3,776	57.69%	4,091	62.65%	4,011	62.02%	4,112	62.97%	4,338	66.49%
$0 to $50	2,914	96.55%	2,448	95.32%	2,736	99.45%	2,288	97.57%	2,290	96.98%	2,343	98.60%	2,112	98.73%
$50 to $100	193	99.50%	264	99.33%	34	99.97%	130	99.56%	169	99.56%	61	99.53%	58	99.62%
$100 to $150	21	99.82%	37	99.89%	2	100.00%	20	99.86%	21	99.88%	14	99.74%	12	99.80%
$150 to $200	4	99.88%	4	99.95%	0	100.00%	8	99.98%	2	99.91%	10	99.89%	10	99.95%
$200 to $250	1	99.89%	2	99.98%	0	100.00%	1	100.00%	3	99.95%	4	99.95%	1	99.97%
$250 to $300	3	99.94%	0	99.98%	0	100.00%	0	100.00%	0	99.95%	1	99.97%	2	100.00%
$300 to $350	2	99.97%	1	100.00%	0	100.00%	0	100.00%	0	99.95%	2	100.00%	0	100.00%
$350 to $400	0	99.97%	0	100.00%	0	100.00%	0	100.00%	0	99.95%	0	100.00%	0	100.00%
$400 to $450	1	99.98%	0	100.00%	0	100.00%	0	100.00%	0	99.95%	0	100.00%	0	100.00%
$450 to $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.95%	0	100.00%	0	100.00%
>= $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%	0	100.00%	0	100.00%

Figure 3-26 shows the hourly differences between day-ahead and real-time load-weighted hourly LMP in the first nine months of 2013.

Figure 3-26 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: January through September of 2013

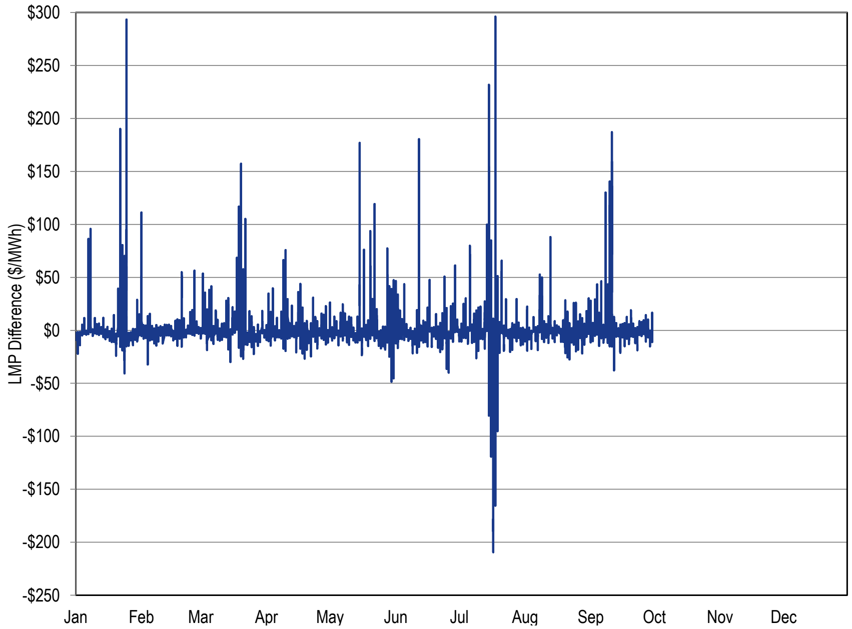


Figure 3-27 shows the monthly average differences between the day-ahead and real-time LMP in the first nine months of 2013.

Figure 3-27 Monthly average of real-time minus day-ahead LMP: January through September of 2013

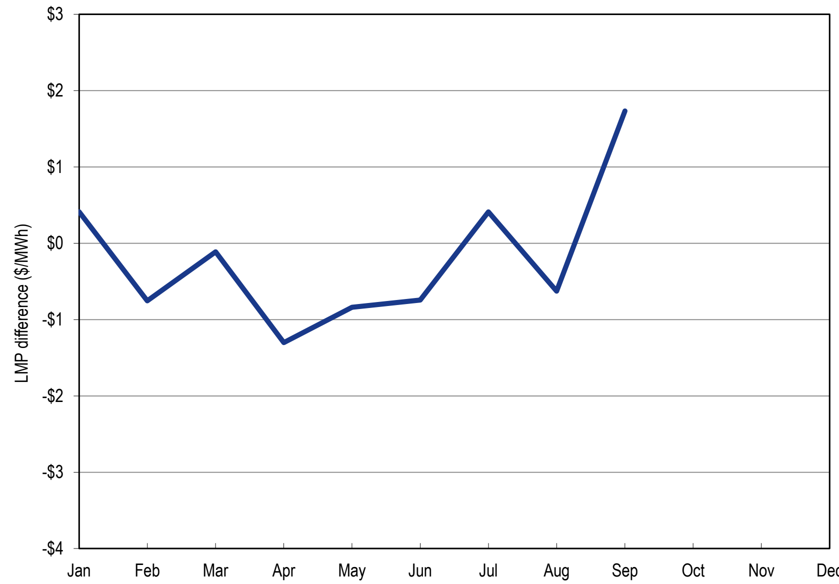
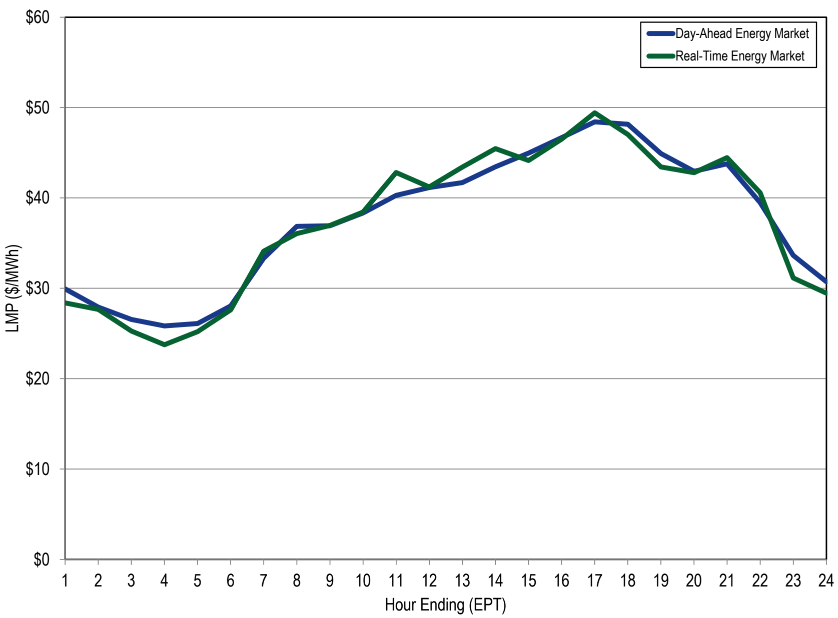


Figure 3-28 shows day-ahead and real-time LMP on an average hourly basis for the first nine months of 2013.

Figure 3-28 PJM system hourly average LMP: January through September of 2013



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 generating less power from owned plants and/or purchasing less power under bilateral contracts than required 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 3-67 shows the monthly average share of real-time load served by self-supply, bilateral contracts and spot purchase in 2012 and 2013 based on parent company. For the first nine months of 2013, 10.5 percent of real-time load was supplied by bilateral contracts, 24.1 percent by spot market purchase and 65.4 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased 1.4 percentage points, reliance on spot supply increased by 0.9 percentage points and reliance on self-supply decreased by 2.3 percentage points.

Table 3-67 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: 2012 through 2013

	2012			2013			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	8.9%	22.0%	69.1%	10.4%	22.3%	67.3%	1.5%	0.2%	(1.8%)
Feb	8.8%	21.2%	70.0%	10.5%	22.0%	67.5%	1.7%	0.8%	(2.4%)
Mar	9.4%	23.6%	67.1%	10.4%	24.2%	65.4%	1.1%	0.6%	(1.6%)
Apr	9.4%	23.8%	66.8%	10.7%	24.2%	65.1%	1.3%	0.4%	(1.6%)
May	8.6%	23.5%	67.9%	10.9%	25.4%	63.6%	2.4%	1.9%	(4.3%)
Jun	8.7%	22.3%	69.0%	10.7%	25.0%	64.3%	2.0%	2.7%	(4.8%)
Jul	8.0%	22.7%	69.3%	10.2%	25.2%	64.7%	2.2%	2.5%	(4.6%)
Aug	8.5%	23.6%	67.9%	10.2%	24.5%	65.3%	1.7%	0.8%	(2.6%)
Sep	9.1%	24.4%	66.5%	10.1%	24.2%	65.7%	1.1%	(0.2%)	(0.9%)
Oct	9.6%	25.5%	64.9%						
Nov	9.9%	23.9%	66.3%						
Dec	10.2%	22.6%	67.3%						
Annual	9.0%	23.2%	67.8%	10.5%	24.1%	65.4%	1.4%	0.9%	(2.3%)

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 3-68 shows the monthly average share of day-ahead load served by self-supply, bilateral contracts and spot purchases in 2012 and 2013, based on parent companies. For the first nine months of 2013, 7.5 percent of day-ahead load was supplied by bilateral contracts, 23.4 percent by spot market purchases, and 69.1 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased by 0.9 percentage points, reliance on spot supply increased by 1.1 percentage points, and reliance on self-supply decreased by 1.9 percentage points.

Table 3-68 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: 2012 through 2013

	2012			2013			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	6.6%	21.4%	72.0%	6.8%	22.1%	71.1%	0.2%	0.7%	(0.9%)
Feb	6.7%	20.0%	73.3%	7.0%	22.1%	71.0%	0.3%	2.1%	(2.3%)
Mar	6.7%	22.8%	70.5%	7.0%	23.6%	69.4%	0.3%	0.8%	(1.1%)
Apr	6.7%	22.8%	70.6%	7.1%	23.1%	69.8%	0.5%	0.3%	(0.8%)
May	6.6%	22.7%	70.7%	7.8%	23.5%	68.7%	1.2%	0.8%	(2.0%)
Jun	7.7%	20.7%	71.6%	8.2%	23.8%	68.0%	0.5%	3.1%	(3.5%)
Jul	5.9%	22.0%	72.0%	8.0%	24.1%	67.9%	2.0%	2.1%	(4.1%)
Aug	6.4%	22.5%	71.0%	8.1%	23.9%	68.0%	1.7%	1.4%	(3.1%)
Sep	6.5%	23.9%	69.6%	7.8%	23.9%	68.3%	1.3%	(0.0%)	(1.3%)
Oct	6.6%	25.2%	68.2%						
Nov	6.9%	22.7%	70.5%						
Dec	7.0%	21.2%	71.8%						
Annual	6.7%	22.3%	71.0%	7.5%	23.4%	69.1%	0.9%	1.1%	(1.9%)