Energy Market

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

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance for the first six months of 2014, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM Energy Market results were competitive in the first six months of 2014.

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 six months of 2014 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1138 with a minimum of 891 and a maximum of 1407 in the first six months of 2014.
- 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, although the behavior of some participants during periods of high demand raises concerns about economic withholding.
- 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. The expanding role of UTCs in the Day-Ahead Energy Market continues to cause concerns. Issues related to the definition of gas costs includable in offers and the impact of the uncertainty around gas costs during high demand periods also need to be addressed.

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

1 Analysis of 2014 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 *2013 State of the Market Report for PJM*, Appendix A, "PJM Geography."

2 OATT Attachment M.

basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs only in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[3] There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are extremely tight.

Overview

Market Structure

- **Supply.** Supply includes physical generation and imports and virtual transactions. Average offered real-time generation decreased by 1,011 MW, or 0.6 percent, from 171,274 MW in the first six months of 2013 to 170,262 MW in the first six months of 2014.[4] In 2014, 1,030 MW of new capacity were added to PJM. This new generation was more than offset by the deactivation of 11 units (1,179 MW) since January 1, 2014. The decrease in offered generation in the first six months of 2014 was in part a result of a 2,189 MW reduction in net capacity between July 2013 and June 2014.[5]

  PJM average real-time generation in the first six months of 2014 increased by 5.1 percent from the first six months of 2013, from 87,974 MW to 92,458 MW. The PJM average real-time generation in the first six months of 2014 would have increased by 4.3 percent from the first six months of 2013, from 87,974 MW to 91,722 MW, if the EKPC Transmission Zone had not been included.[6]

  PJM average day-ahead supply in the first six months of 2014, including INCs and up-to congestion transactions, increased by 11.6 percent from the first six months of 2013, from 148,381 MW to 165,620 MW. The PJM average day-ahead supply, including INCs and up-to congestion transactions, would have increased by 11.1 percent from the first six months of 2013, from 148,381 MW to 164,822 MW, if the EKPC Transmission Zone had not been included. The day-ahead supply growth was 127.5 percent higher than the real-time generation growth as a result of the continued growth of up-to congestion transactions.

- **Market Concentration.** Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload and intermediate segments, but high concentration in the peaking segment.

- **Generation Fuel Mix.** During the first six months of 2014, coal units provided 45.9 percent, nuclear units 33.1 percent and gas units 15.7 percent of total generation. Compared to the first six months of 2013, generation from coal units increased 9.1 percent, generation from nuclear units decreased 0.7 percent, and generation from gas units increased 5.4 percent.

- **Marginal Resources.** In the PJM Real-Time Energy Market, during the first six months of 2014, coal units were 47.6 percent of marginal resources and natural gas units were 40.9 percent of marginal resources. In the first six months of 2013, coal units were 57.6 percent and natural gas units were 33.3 percent of the marginal resources.

  In the PJM Day-Ahead Energy Market, during the first six months of 2014, up-to congestion transactions were 94.2 percent of marginal resources, INCs were 1.4 percent of marginal resources, DECs were 2.1 percent of marginal resources, and generation resources were 2.2 percent of marginal resources in the first six months of 2014.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM system peak load during the first six months of 2014 was 141,673 MW in the HE 1700 on June 17, 2014, which was 1,895

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 3, "Energy Market," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.
5 The net capacity additions are calculated by taking the difference between the new generation (1,622 MW) and the retired generation (3,808 MW) after July 1, 2013.
6 The EKPC Zone was integrated on June 1, 2013.

MW, or 1.4 percent, higher than the PJM peak load for the first six months of 2013, which was 139,779 MW in the HE 1600 on June 25, 2013.

PJM average real-time load in the first six months of 2014 increased by 4.2 percent from the first six months of 2013, from 86,897 MW to 90,529 MW. The PJM average real-time load in the first six months of 2014 would have increased by 3.4 percent from the first six months of 2013, from 86,897 MW to 89,881 MW, if the EKPC Transmission Zone had not been included.

PJM average day-ahead demand in the first six months of 2014, including DECs and up-to congestion transactions, increased by 10.7 percent from the first six months of 2013, from 145,280 MW to 160,805 MW. The PJM average day-ahead demand, including DECs and up-to congestion transactions, would have increased by 10.1 percent from the first six months of 2013, from 145,280 MW to 159,959 MW, if the EKPC Transmission Zone had not been included. The day-ahead demand growth was 154.8 percent higher than the real-time load growth as a result of the continued growth of up-to congestion transactions.

- **Supply and Demand: 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. For the first six months of 2014, 9.6 percent of real-time load was supplied by bilateral contracts, 28.3 percent by spot market purchases and 62.1 percent by self-supply. Compared with 2013, reliance on bilateral contracts decreased 1.0 percentage points, reliance on spot market purchases increased by 3.3 percentage points and reliance on self-supply decreased by 2.3 percentage points.

- **Supply and Demand: Scarcity.** In the first six months of 2014, shortage pricing was triggered on two days in PJM. On January 6, shortage pricing was triggered by a voltage reduction action that was issued at 1950 EPT and terminated at 2045. On January 7, shortage pricing was triggered by shortage of primary and synchronized reserves starting in the hour beginning 0700 EPT and was in effect until 1220 during the morning peak as well as between 1755 and 1810 during the evening peak.

Market Behavior

- **Offer Capping for Local Market Power.** 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 six months 2013 to 0.2 percent in the first six months of 2014. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 0.3 percent in the first six months of 2013 to 0.7 percent in the first six months of 2014.

  In the first six months of 2014, 14 control zones experienced congestion resulting from one or more constraints binding for 50 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.

- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, specifically for black start service and reactive service. In the Day-Ahead Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 2.9 percent in the first six months of 2013 to 0.5 percent in the first six months of 2014. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 2.3 percent in the first six months of 2013 to 0.4 percent in the first six months of 2014.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the PJM Real-Time Energy Market in the first six months of 2014, 70.0 percent of marginal units had an average markup index less than or equal to 0.0. Nonetheless, some marginal units do have substantial markups. In the first six months of 2014, 11.4 percent of units had average dollar markups greater than or equal to $150. Only 4.0 percent of units had average dollar markups greater than or equal to $150 in the first six months of 2013. Markups increased during the high demand days in January.

In the PJM Day-Ahead Energy Market in the first six months of 2014, 92.0 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.02. Nonetheless, some marginal units do have substantial markups.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 93 units eligible for FMU or AU status in at least one month during the first six months of 2014, 62 units (66.7 percent) were FMUs or AUs for all six months, and 5 units (5.3 percent) qualified in only one month.
- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up-to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. In the first six months of 2014, up-to congestion transactions continued to displace increment offers and decrement bids.
- **Generator Offers.** Generator offers are categorized as dispatchable and self scheduled. Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are categorized as self scheduled must run. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are categorized as self scheduled and dispatchable. Of all generator offers in the first six months of 2014, 55.1 percent were offered as available for economic dispatch, 23.1 percent were offered as self scheduled, and 21.8 percent were offered as self scheduled and dispatchable.

Market Performance

- **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 Market prices in the first six months of 2014 were between $800 and $900 for 4 hours, between $900 and $1,000 for one hour, greater than $1,000 for six hours, and greater than $1,800 for one hour.

  PJM Real-Time Energy Market prices increased in the first six months of 2014 compared to the first six months of 2013. The load-weighted average LMP was 84.2 percent higher in the first six months of 2014 than in the first six months of 2013, $69.92 per MWh versus $37.96 per MWh.

  PJM Day-Ahead Energy Market prices increased in the first six months of 2014 compared to the first six months of 2013. The load-weighted average LMP was 84.8 percent higher in the first six months of 2014 than in the first six months of 2013, $70.67 per MWh versus $38.23 per MWh.[7]

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

  In the PJM Real-Time Energy Market, for the first six months of 2014, 23.4 percent of the load-weighted LMP was the result of coal costs, 39.1 percent was the result of gas costs and 0.47 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market, for the first six months of 2014, 24.7 percent of the load-weighted LMP was the result of the cost of gas, 16.0 percent was the result of the cost of up-to congestion transactions and 15.2 percent was the result of the cost of DECs.

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

  In the PJM Real-Time Energy Market in for the first six months of 2014, the adjusted markup component of LMP was positive, $2.88 per MWh

7 Tables reporting zonal and jurisdictional load and prices are in the *2013 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

or 4.1 percent of the PJM real-time, load-weighted average LMP. The real-time load-weighted average LMP for the month of January had the highest markup component, $9.10 per MWh using adjusted cost offers, or 7.18 percent of the real-time load-weighted average LMP in January, a substantial increase over 2013. For the first six months of 2013, the adjusted markup was $0.30 per MWh or 0.8 percent of the PJM real-time load-weighted average LMP.

In the PJM Day-Ahead Energy Market, marginal INC, DEC and up-to congestion transactions have zero markups. In the first six months of 2014, the adjusted markup component of LMP resulting from generation resources was -$0.59 per MWh.

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, although the behavior of some participants during the high demand periods in January raises concerns about economic withholding.

- **Price Convergence.** Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. The difference between the average day-ahead and real-time prices was -$0.55 per MWh in the first six months of 2013 and -$1.38 per MWh in the first six months of 2014. The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

Scarcity

- In the first six months of 2014, shortage pricing was triggered on two days in January. On January 6, shortage pricing was triggered by a voltage reduction action that was issued at 1950 EPT and terminated at 2045. On January 7, shortage pricing was triggered by a shortage of primary and synchronized reserves starting in the hour beginning 0700 EPT and was in effect until 1220 during the morning peak as well as between 1755 and 1810 during the evening peak.
- The performance of the PJM markets under scarcity conditions raised a number of concerns including concerns related to capacity market incentives, participant offer behavior under tight market conditions, natural gas availability and pricing, demand response and interchange transactions.

Recommendations

- The MMU recommends the elimination of FMU and AU adders. Since the implementation of FMU adders, 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.

  The MMU and PJM have proposed a compromise that would maintain the ability of certain generating units to qualify for FMU adders but limit FMU adders to units with net revenues less than unit going forward costs or ACR.
- The MMU recommends that PJM require all generating units to identify the fuel type associated with each of their offered schedules.
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[8]
- The MMU recommends that PJM not use the ATSI closed loop interface or create similar interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product.
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice.

8 PJM OATT, 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.

- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013.
- The MMU recommends that the roles of PJM and the transmission owners in the decision making process to control for local contingencies be clarified, that PJM's role be strengthened and that the process be made transparent.
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that removes the need for market participants to schedule physical power.
- There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[9] 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.[10]
- 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.
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters.
- The LMPs in excess of $1,800 per MWh on January 7, 2014, were potentially a result of the way in which PJM modeled zonal (not nodal) demand response as a marginal resource. The MMU recommends that PJM explain how LMPs are calculated when demand response is marginal.
- The MMU recommends that PJM create and implement clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources.

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first six months of 2014, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand response programs, loads and prices.

Average real-time offered generation decreased by 1,011 MW in the first six months of 2014 compared to the first six months of 2013, while peak load increased by 1,895 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 the impact of the price elasticity of demand on prices. Energy market results for the first six months of 2014 generally reflected supply-

9 The general definition of a hub can be found in "Manual 35: Definitions and Acronyms," Revision 23 (April 11, 2014).
10 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.

demand fundamentals, although the behavior of some participants during the high demand periods in January raises concerns about economic withholding. These issues relate to the ability to increase markups substantially in tight market conditions, to the uncertainties about the pricing and availability of natural gas, and to the lack of adequate incentives for unit owners to take all necessary actions to acquire fuel and operate rather than take an outage.

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.

PJM also offer caps units that are committed for reliability reasons in addition to units committed to provide constraint relief. Specifically, units that are committed to provide reactive support and black start service are offer capped in the energy market. These units are committed manually in both the Day-Ahead and Real-Time Energy Markets. Before 2011, these units were generally economic in the energy market. Since 2011, the percentage of hours when these units were not economic in the Real-Time Energy Market has steadily increased. In the Day-Ahead Energy Market, PJM started to commit these units as offer capped in September 2012, as part of a broader effort to maintain consistency between Real-Time and Day-Ahead Energy Markets.

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

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

The overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units operating at, or close to, their marginal costs, although this was not always the case during the high demand hours in January. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants during the high demand periods in January raises concerns about economic withholding. Given the structure of the Energy Market, the tighter markets and the change in some participants' behavior are sources of concern in the Energy Market. The MMU concludes that the PJM energy market results were competitive in the first six months of 2014.

Market Structure

Market Concentration

Analyses of supply curve segments of the PJM Energy Market for the first six months of 2014 indicate moderate concentration in the base load and intermediate segments, but high concentration in the peaking segment.[12] 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 six months of 2014.

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 3-2).

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.[13]

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during the first six months of 2014 was moderately concentrated (Table 3-2).

Table 3-2 PJM hourly Energy Market HHI: January through June, 2013 and 2014[14]

	Hourly Market HHI (Jan - Jun, 2013)	Hourly Market HHI (Jan - Jun, 2014)
Average	1204	1138
Minimum	947	891
Maximum	1610	1407
Highest market share (One hour)	31%	29%
Average of the highest hourly market share	22%	21%
# Hours	4,343	4,343
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-3 includes HHI values by supply curve segment, including base, intermediate and peaking plants for the first six months of 2013 and 2014.

Table 3-3 PJM hourly Energy Market HHI (By supply segment): 2013 and 2014

	Jan - Jun, 2013			Jan - Jun, 2014		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	1038	1225	1679	1029	1174	1454
Intermediate	1046	2327	5484	727	1719	5693
Peak	608	6297	10000	713	6119	10000

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

13 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).

14 This analysis includes all hours in the first six months of 2014, regardless of congestion.

Figure 3-1 shows the number of units in the baseload, intermediate and peaking segments by fuel source in the first six months of 2014.

Figure 3-1 Fuel source distribution in unit segments: January through June, 2014

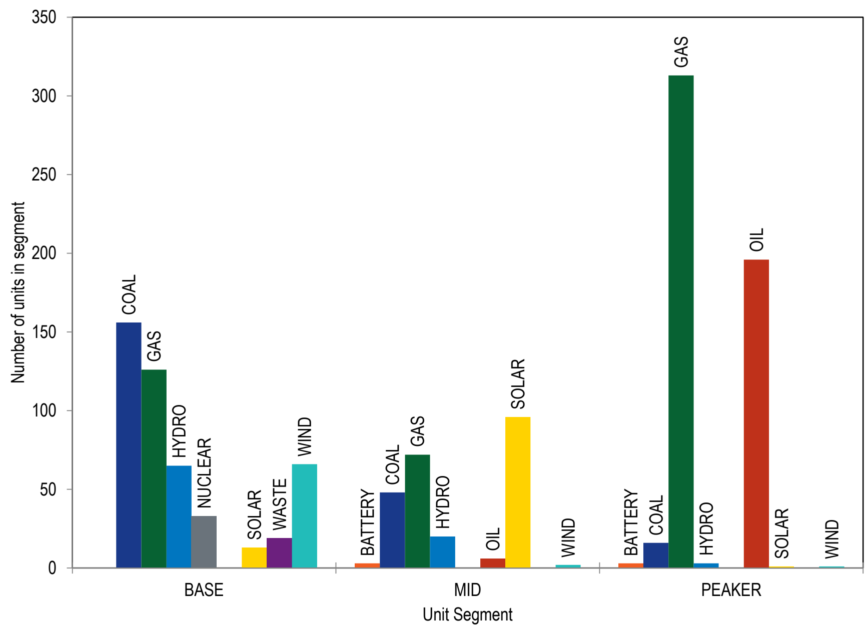
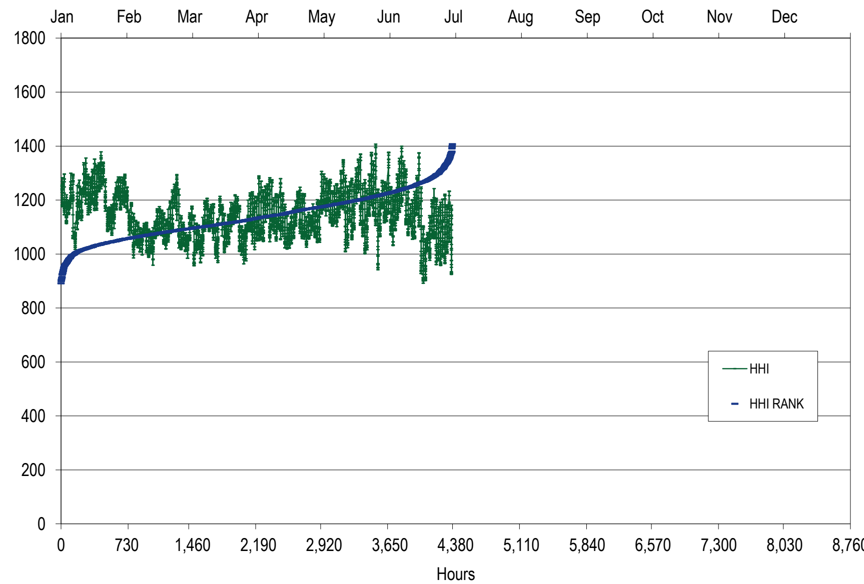


Figure 3-2 presents the hourly HHI values in chronological order and an HHI duration curve for the first six months of 2014.

Figure 3-2 PJM hourly Energy Market HHI: January through June, 2014



Ownership of Marginal Resources

Table 3-4 shows the contribution to PJM real-time, load-weighted LMP by individual marginal resource owner.[15] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of the first six months of 2014, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. The results show that in the first six months of 2014, the offers of one company contributed 18.2. percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies contributed 52.1 percent of the real-time, load-weighted, average PJM system LMP. During the first six months of 2013, the offers of one company contributed 23.1 percent of the real time, load-

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

weighted PJM system LMP and offers of the top four companies contributed 63.3 percent of the real-time, load-weighted, average PJM system LMP.

Table 3-4 Marginal unit contribution to PJM real-time, load-weighted LMP (By parent company): January through June 2013 and 2014

2013 (Jan-Jun)		2014 (Jan-Jun)	
Company	Percent of Price	Company	Percent of Price
1	23.1%	1	18.2%
2	22.5%	2	14.5%
3	10.5%	3	12.2%
4	7.3%	4	7.2%
5	4.3%	5	6.6%
6	4.1%	6	6.3%
7	4.1%	7	4.7%
8	3.4%	8	3.8%
9	3.0%	9	3.4%
Other (51 companies)	17.7%	Other (58 companies)	23.1%

Table 3-5 shows the contribution to PJM day-ahead, load-weighted LMP by individual marginal resource owners.[16] The contribution of each marginal resource to price at each load bus is calculated hourly and summed by company. The marginal resource owner with the largest impact on PJM day-ahead, load-weighted LMP (16.6 percent), in the first six months of 2013 also had the largest impact (10.8 percent) in the first six months of 2014.

Table 3-5 Marginal resource contribution to PJM day-ahead, load-weighted LMP (By parent company): January through June 2013 and 2014

2013 (Jan - Jun)		2014 (Jan - Jun)	
Company	Percent of Price	Company	Percent of Price
1	16.6%	1	10.8%
2	15.6%	2	7.1%
3	6.7%	3	7.0%
4	6.4%	4	6.2%
5	5.1%	5	6.1%
6	4.7%	6	3.8%
7	4.1%	7	3.4%
8	3.3%	8	3.3%
9	2.9%	9	3.2%
Other (124 companies)	34.7%	Other (133 companies)	49.0%

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

Type of Marginal Resources

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. Marginal resource designation is not limited to physical resources in the Day-Ahead Energy Market. INC offers, DEC bids and up-to congestion transactions are dispatchable injections and withdrawals in the Day-Ahead Energy Market that can set price via their offers and bids.

Table 3-6 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 six months of 2014, coal units were 47.59 percent and natural gas units were 40.97 percent of marginal resources. In the first six months of 2013, coal units were 57.63 percent and natural gas units were 33.26 percent of the total marginal resources.

The results reflect the dynamics of an LMP market. When there is a single constraint, there are two marginal units. For example, a significant west to east constraint could be binding with a gas unit marginal in the east and a coal unit marginal in the west. As a result, although the dispatch of natural gas units has increased and gas units set price for more hours as marginal resources in the Real-Time Energy Market, this does not necessarily reduce the proportion of hours in which coal units are marginal.[17] In the first six months of 2014, 75.71 percent of the wind marginal units had negative offer prices, 22.85 percent had zero offer prices and 1.44 percent had positive offer prices.

17 For the generation units that are capable of using multiple fuel types, PJM does not require the participants to disclose the fuel type associated with their offer schedule. For these units, the cleared offer schedules on a given day were compared to the cost associated with each fuel to determine the fuel type most likely to have been the basis for the cleared schedule.

Table 3-6 Type of fuel used (By real-time marginal units): January through June 2013 and January through June 2014

Type/Fuel	2013 (Jan-Jun)	2014 (Jan-Jun)
Coal	57.63%	47.59%
Gas	33.26%	40.97%
Oil	3.08%	5.73%
Wind	5.86%	5.11%
Other	0.15%	0.43%
Uranium	0.02%	0.09%
Emergency DR	0.00%	0.08%
Municipal Waste	0.01%	0.01%

Table 3-7 shows the type and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In the first six months of 2014, up-to congestion transactions were 94.17 percent of the total marginal resources. Up-to congestion transactions were 95.78 percent of the total marginal resources in the first six months of 2013.[18]

Table 3-7 Day-ahead marginal resources by type/fuel: January through June 2013 and 2014

Type/Fuel	2013 (Jan - Jun)	2014 (Jan - Jun)
Up-to Congestion Transaction	95.78%	94.17%
Coal	1.26%	1.16%
DEC	1.22%	2.07%
INC	0.98%	1.38%
Gas	0.54%	0.93%
Wind	0.15%	0.11%
Dispatchable Transaction	0.07%	0.10%
Price Sensitive Demand	0.01%	0.01%
Municipal Waste	0.00%	0.01%
Oil	0.00%	0.06%
Import	0.00%	0.01%
Total	100.00%	100.00%

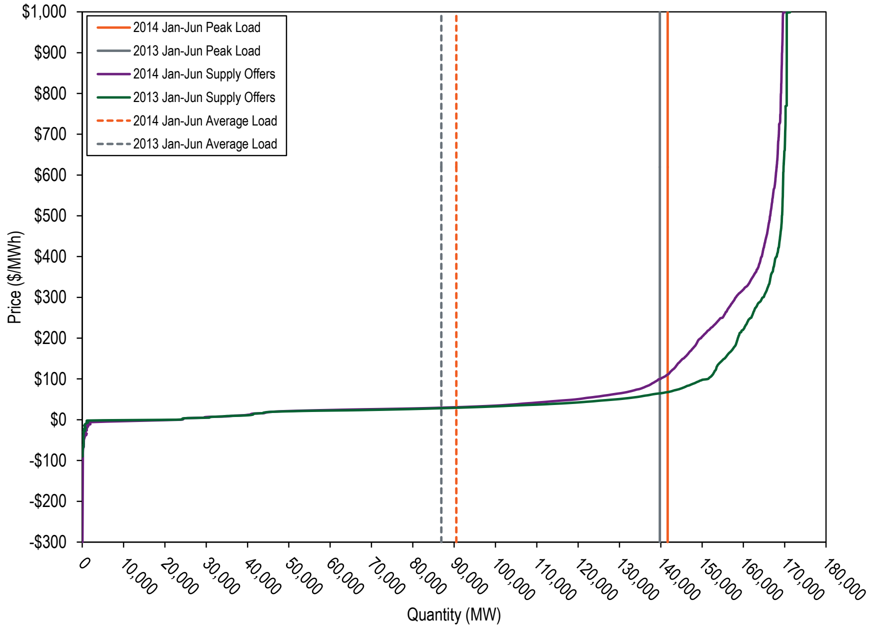
18 PJM acknowledged an error in identifying marginal up-to congestion transactions following April 2013 changes to the day-ahead solution software. The software incorrectly increased the volume of marginal up-to congestion transactions. The fix to the problem is expected to be in place in 2014.

Supply

Supply includes physical generation and imports and virtual transactions.

Figure 3-3 shows the average PJM aggregate real-time generation supply curves, peak load and average load for the first six months of 2013 and the first six months of 2014.

Figure 3-3 Average PJM aggregate real-time generation supply curves: January through June of 2013 and 2014



Energy Production by Fuel Source

Compared to the first six months of 2013, generation from coal units increased 9.1 percent and generation from natural gas units increased 5.3 percent (Table 3-8).[19] Natural gas prices increased and coal prices remained relatively constant in the first six months of 2014. Natural gas prices in the second quarter of 2014 were lower than the second quarter of 2013.

Table 3-8 PJM generation (By fuel source (GWh)): January through June of 2013 and 2014[20]

	2013 (Jan - Jun)		2014 (Jan - Jun)		Change in Output
	GWh	Percent	GWh	Percent	
Coal	171,440.7	44.3%	187,104.6	45.9%	9.1%
Standard Coal	166,494.3	43.0%	181,912.8	44.7%	9.0%
Waste Coal	4,946.4	1.3%	5,191.8	1.3%	0.1%
Nuclear	135,858.8	35.1%	134,954.5	33.1%	(0.7%)
Gas	60,747.3	15.7%	64,021.8	15.7%	5.4%
Natural Gas	59,623.6	15.4%	62,757.8	15.4%	5.3%
Landfill Gas	1,123.7	0.3%	1,183.0	0.3%	5.3%
Biomass Gas	0.0	0.0%	81.1	0.0%	NA
Hydroelectric	7,502.2	1.9%	8,241.9	2.0%	9.9%
Pumped Storage	3,189.6	0.8%	3,451.6	0.8%	8.2%
Run of River	4,312.7	1.1%	4,790.3	1.2%	11.1%
Wind	8,561.5	2.2%	8,678.0	2.1%	1.4%
Waste	2,399.3	0.6%	2,509.9	0.6%	4.6%
Solid Waste	1,993.9	0.5%	2,043.7	0.5%	2.5%
Miscellaneous	405.4	0.1%	466.2	0.1%	15.0%
Oil	626.7	0.2%	1,564.9	0.4%	149.7%
Heavy Oil	557.8	0.1%	1,158.1	0.3%	107.6%
Light Oil	59.0	0.0%	339.4	0.1%	474.7%
Diesel	2.7	0.0%	49.4	0.0%	1,761.1%
Kerosene	7.2	0.0%	18.1	0.0%	151.8%
Jet Oil	0.0	0.0%	0.1	0.0%	186.5%
Solar	175.9	0.0%	197.7	0.0%	12.4%
Battery	0.2	0.0%	5.4	0.0%	2,082.9%
Total	387,312.7	100.0%	407,278.5	100.0%	5.2%

Table 3-9 Monthly PJM generation (By fuel source (GWh)): January through June of 2014

	Jan	Feb	Mar	Apr	May	Jun	Total
Coal	37,833.4	34,845.0	34,350.8	25,940.4	24,165.0	29,969.9	187,104.6
Standard Coal	36,809.3	33,985.5	33,460.1	25,162.7	23,406.8	29,088.3	181,912.8
Waste Coal	1,024.1	859.5	890.7	777.7	758.2	881.6	5,191.8
Nuclear	25,189.6	21,737.8	22,504.1	20,862.6	21,331.1	23,329.3	134,954.5
Gas	11,597.9	9,772.2	11,053.4	8,392.8	10,715.9	12,489.6	64,021.8
Natural Gas	11,377.7	9,566.6	10,845.4	8,185.5	10,508.5	12,274.2	62,757.8
Landfill Gas	207.0	181.3	194.5	197.3	206.4	196.4	1,183.0
Biomass Gas	13.2	24.3	13.5	10.1	1.0	19.0	81.1
Hydroelectric	1,391.3	1,074.4	1,371.9	1,448.9	1,575.4	1,380.0	8,241.9
Pumped Storage	536.0	530.6	551.0	433.3	606.2	794.5	3,451.6
Run of River	855.3	543.7	821.0	1,015.6	969.2	585.5	4,790.3
Wind	1,918.4	1,342.1	1,661.4	1,697.7	1,238.1	820.3	8,678.0
Waste	407.6	336.6	433.7	421.9	445.8	464.3	2,509.9
Solid Waste	324.2	270.0	342.0	350.6	375.0	381.9	2,043.7
Miscellaneous	83.4	66.6	91.7	71.3	70.8	82.4	466.2
Oil	840.7	69.2	199.3	31.8	173.6	250.2	1,564.9
Heavy Oil	585.2	39.0	132.2	25.1	145.4	231.1	1,158.1
Light Oil	193.4	28.7	64.4	6.4	27.8	18.6	339.4
Diesel	47.3	0.5	1.0	0.0	0.2	0.2	49.4
Kerosene	14.9	1.0	1.6	0.3	0.1	0.2	18.1
Jet Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Solar	16.0	20.2	31.5	42.8	41.4	45.8	197.7
Battery	0.2	0.1	0.2	4.6	0.2	0.1	5.4
Total	79,195.1	69,197.7	71,606.3	58,843.5	59,686.5	68,749.5	407,278.5

Net Generation and Load

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.

19 Generation data are the sum of MWh for each fuel by source at every generation bus in PJM with positive output and reflect gross generation without offset for station use of any kind.

20 All generation is total gross generation output and does not net out the MWh withdrawn at a generation bus to provide auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps.

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.

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.

Real-Time Supply

Average offered real-time generation decreased by 1,011 MW, or 0.6 percent, from 171,274 MW in the first six months of 2013 to 170,262 MW in the first six months of 2014.[21] The decrease in offered supply was partly offset by the integration of the East Kentucky Power Cooperative (EKPC) Transmission Zone in the second quarter of 2013. In the first six months of 2014, 1,030 MW of new capacity were added to PJM. This new generation was more than offset by the deactivation of 11 units (1,179 MW) since January 1, 2014. The decrease in offered supply in the first six months of 2014 was in part a result of a 2,189 MW reduction in net capacity between July 2013 and June 2014.[22]

PJM average real-time generation in the first six months of 2014 increased by 5.1 percent from the first six months of 2013, from 87,974 MW to 92,458 MW. PJM average real-time generation in the first six months of 2014 would have increased by 4.3 percent from the first six months of 2013, from 87,974 MW to 91,722 MW, if the EKPC Transmission Zone had not been included in the comparison.[23] [24]

21 Calculated values shown in Section 3, "Energy Market," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.
22 The net capacity additions are calculated by taking the difference between the new generation (1,622 MW) and the retired generation (3,808 MW) after July 1, 2013.
23 The EKPC Transmission Zone was integrated on June 1, 2013 and was not included in this comparison for January through May of 2013 and 2014.
24 Generation data are the net MWh injections and withdrawals MWh at every generation bus in PJM.

PJM average real-time supply, including imports, in the first six months of 2014 increased by 5.4 percent from the first six months of 2013, from 93,166 MW to 98,186 MW. PJM average real-time supply, including imports, in the first six months of 2014 would have increased by 4.6 percent from the first six months of 2013, from 93,166 MW to 97,452 MW, if the EKPC Transmission Zone had not been included in the comparison.

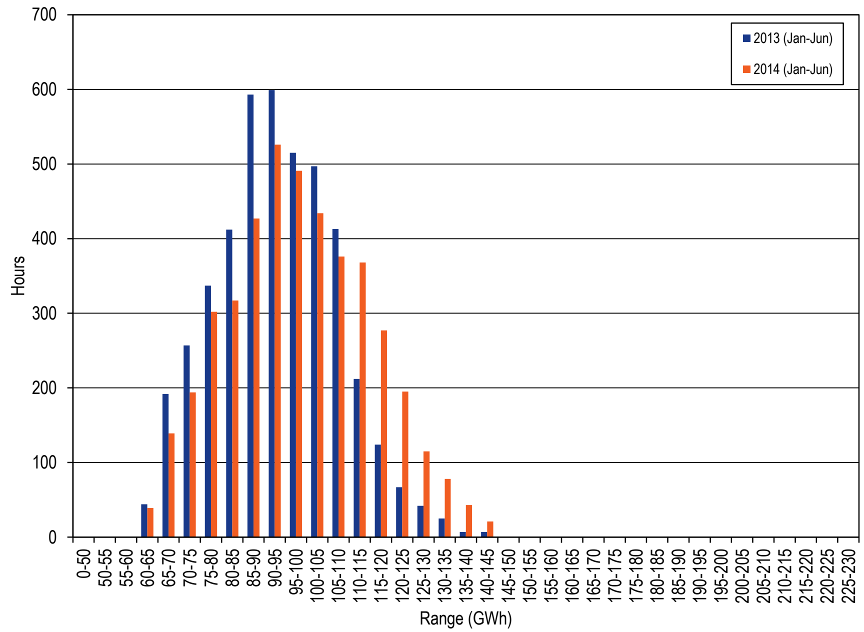
In the PJM Real-Time Energy Market, there are three types of supply offers:

- **Self-Scheduled Generation Offer.** Offer to supply a fixed block of MWh, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MWh and corresponding offer prices from a specific unit.
- **Import.** An import is an external energy transaction scheduled to PJM from another balancing authority. A real-time import must have a valid OASIS reservation when offered, must have available ramp room to support the import, must be accompanied by a NERC e-Tag, and must pass the neighboring balancing authority checkout process.

PJM Real-Time Supply Duration

Figure 3-4 shows the hourly distribution of PJM real-time generation plus imports for the first six months of 2013 and the first six months of 2014.

Figure 3-4 Distribution of PJM real-time generation plus imports: January through June of 2013 and 2014[25]



PJM Real-Time, Average Supply

Table 3-10 presents summary real-time supply statistics for each year for the first six months of the 15-year period from 2000 through 2014.[26]

Table 3-10 PJM real-time average hourly generation and real-time average hourly generation plus average hourly imports: January through June of 2000 through 2014

	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
Jan - Jun	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2000	31,523	5,560	34,190	6,329	NA	NA	NA	NA
2001	29,428	4,679	32,412	4,813	(6.6%)	(15.8%)	(5.2%)	(24.0%)
2002	30,967	5,770	34,730	6,238	5.2%	23.3%	7.2%	29.6%
2003	36,034	6,008	39,644	6,021	16.4%	4.1%	14.1%	(3.5%)
2004	41,430	9,435	45,597	9,699	15.0%	57.0%	15.0%	61.1%
2005	74,365	12,661	79,693	13,242	79.5%	34.2%	74.8%	36.5%
2006	80,249	11,011	84,819	11,574	7.9%	(13.0%)	6.4%	(12.6%)
2007	83,478	12,105	88,150	13,192	4.0%	9.9%	3.9%	14.0%
2008	83,294	12,458	88,824	12,778	(0.2%)	2.9%	0.8%	(3.1%)
2009	77,508	12,961	82,928	13,580	(6.9%)	4.0%	(6.6%)	6.3%
2010	80,702	13,968	85,575	14,455	4.1%	7.8%	3.2%	6.4%
2011	81,483	13,677	86,268	14,428	1.0%	(2.1%)	0.8%	(0.2%)
2012	86,310	13,695	91,526	14,279	5.9%	0.1%	6.1%	(1.0%)
2013	87,974	13,528	93,166	14,277	1.9%	(1.2%)	1.8%	(0.0%)
2014	92,458	15,722	98,186	16,710	5.1%	16.2%	5.4%	17.0%

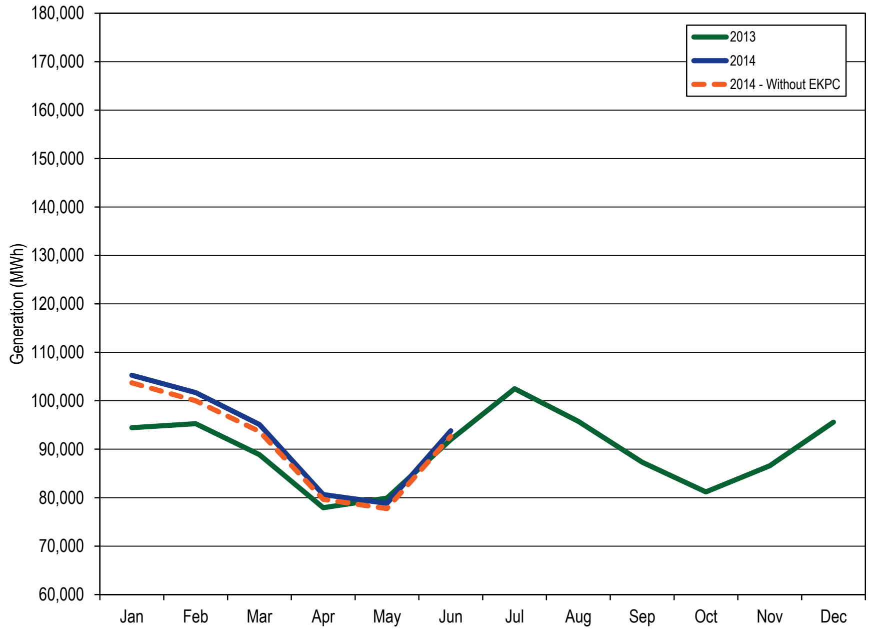
25 Each range on the horizontal axis excludes the start value and includes the end value.

26 The import data in this table is not available before June 1, 2000. The data that includes imports in 2000 is calculated from the last six months of that year.

PJM Real-Time, Monthly Average Generation

Figure 3-5 compares the real-time, monthly average hourly generation in 2013 to the first six months of 2014 with and without EKPC.

Figure 3-5 PJM real-time average monthly hourly generation: January 2013 through June 2014



Day-Ahead Supply

PJM average day-ahead supply in the first six months of 2014, including INCs and up-to congestion transactions, increased by 11.6 percent from the first six months of 2013, from 148,381 MW to 165,620 MW. The PJM average day-ahead supply in the first six months of 2014, including INCs and up-to congestion transactions, would have increased by 11.1 percent in the first six months of 2014, from 148,381 MW to 164,822 MW, if the EKPC Transmission Zone had not been included in the comparison.

PJM average day-ahead supply in the first six months of 2014, including INCs, up-to congestion transactions, and imports, increased by 11.5 percent from the first six months of 2013, from 150,554 MW to 167,939 MW. PJM average day-ahead supply in the first six months of 2014, including INCs, up-to congestion transactions, and imports, would have increased by 11.0 percent from the first six months of 2013, from 150,554 MW to 167,141 MW, if the EKPC Transmission Zone had not been included in the comparison.

The day-ahead supply growth was 127.5 percent higher than the real-time generation growth in the first six months of 2014, because of the continued growth of up-to congestion transactions. If the first six months of 2014 up-to congestion transactions had been held to the first six months of 2013 levels, the day-ahead supply, including INCs and up-to congestion transactions, would have increased 2.2 percent instead of 11.6 percent and day-ahead supply growth would have been 56.9 percent lower than the real-time generation growth.

In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

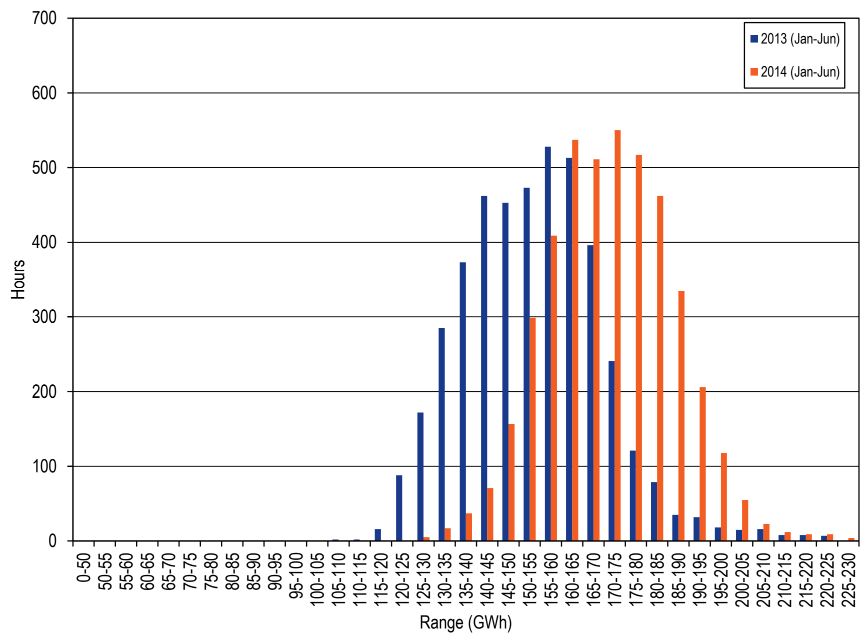
- **Self-Scheduled Generation Offer.** Offer to supply a fixed block of MWh, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MWh and corresponding offer prices from a unit.
- **Increment Offer (INC).** Financial offer to supply MWh and corresponding offer prices. INCs 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. 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.
- **Import.** An import is an external energy transaction scheduled to PJM from another balancing authority. An import must have a valid willing to

pay congestion (WPC) OASIS reservation when offered. An import energy transaction that clears the Day-Ahead Energy Market is financially binding. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an import energy transaction approved in the Day-Ahead Energy Market will not physically flow in real time unless it is also submitted through the real-time energy market scheduling process.

PJM Day-Ahead Supply Duration

Figure 3-6 shows the hourly distribution of PJM day-ahead supply, including increment offers, up-to congestion transactions, and imports for the first six months of 2013 and the first six months of 2014.

Figure 3-6 Distribution of PJM day-ahead supply plus imports: January through June of 2013 and 2014[27]



27 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Day-Ahead, Average Supply

Table 3-11 presents summary day-ahead supply statistics for the first six months of each year of the 15-year period from 2000 through 2014.[28]

Table 3-11 PJM day-ahead average hourly supply and day-ahead average hourly supply plus average hourly imports: January through June of 2000 through 2014

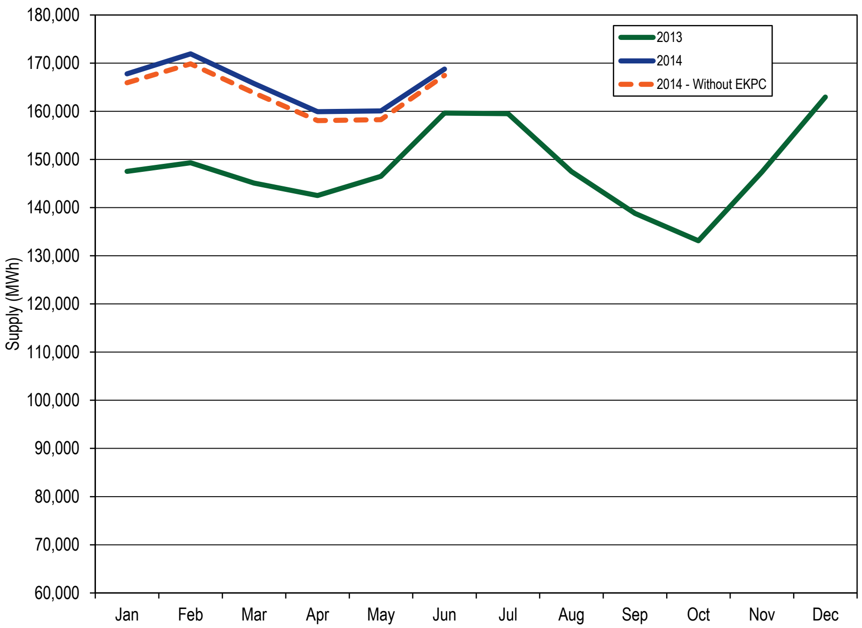
	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
Jan - Jun	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2000	29,474	5,648	29,645	5,766	NA	NA	NA	NA
2001	26,796	4,305	27,540	4,382	(9.1%)	(23.8%)	(7.1%)	(24.0%)
2002	25,840	10,011	26,398	10,021	(3.6%)	132.5%	(4.1%)	128.7%
2003	36,420	7,000	36,994	7,023	40.9%	(30.1%)	40.1%	(29.9%)
2004	50,089	10,108	50,836	10,171	37.5%	44.4%	37.4%	44.8%
2005	87,855	14,365	89,382	14,395	75.4%	42.1%	75.8%	41.5%
2006	95,562	12,620	97,796	12,615	8.8%	(12.1%)	9.4%	(12.4%)
2007	106,470	14,522	108,815	14,772	11.4%	15.1%	11.3%	17.1%
2008	104,705	14,124	107,169	14,190	(1.7%)	(2.7%)	(1.5%)	(3.9%)
2009	97,607	16,283	100,076	16,342	(6.8%)	15.3%	(6.6%)	15.2%
2010	102,626	18,206	105,463	18,378	5.1%	11.8%	5.4%	12.5%
2011	108,143	16,666	110,656	16,926	5.4%	(8.5%)	4.9%	(7.9%)
2012	132,326	15,710	134,747	15,841	22.4%	(5.7%)	21.8%	(6.4%)
2013	148,381	15,606	150,554	15,830	12.1%	(0.7%)	11.7%	(0.1%)
2014	165,620	13,930	167,939	14,119	11.6%	(10.7%)	11.5%	(10.8%)

28 Since the Day-Ahead Energy Market did not start until June 1, 2000, the day-ahead data for 2000 only includes data for the last six months of that year.

PJM Day-Ahead, Monthly Average Supply

Figure 3-7 compares the day-ahead, monthly average hourly supply, including increment offers and up-to congestion transactions, in 2013 to the first six months of 2014 with and without EKPC.

Figure 3-7 PJM day-ahead monthly average hourly supply: January 2013 through June 2014



Real-Time and Day-Ahead Supply

Table 3-12 presents summary statistics for the first six months of 2013 and the first six months of 2014, for day-ahead and real-time supply. The last two columns of Table 3-12 are the day-ahead supply minus the real-time supply. The first of these columns is the total day-ahead supply less the total real-time supply and the second of these columns is the total physical day-ahead generation less the total physical real-time generation. In the first six months of 2014, up-to congestion transactions were 39.9 percent of the total day-ahead supply compared to 35.2 percent in the first six months of 2013.

Figure 3-8 shows the average hourly cleared volumes of day-ahead supply and real-time supply. The day-ahead supply consists of day-ahead generation, imports, increment offers and up-to congestion transactions. The real-time generation includes generation and imports.

Table 3-12 Day-ahead and real-time supply (MWh): January through June of 2013 and 2014

		Day Ahead					Real Time		Day Ahead Less Real Time	
	Jan - Jun	Generation	INC Offers	Up-to Congestion	Imports	Total Supply	Generation	Total Supply	Total Supply	Total Generation
Average	2013	89,788	5,541	53,052	2,173	150,554	87,974	93,166	57,388	1,814
	2014	95,332	3,240	67,048	2,319	167,939	92,458	98,186	69,753	2,874
Median	2013	89,640	5,512	53,783	2,148	150,576	87,534	92,423	58,153	2,106
	2014	94,879	3,121	67,141	2,286	167,849	91,635	97,154	70,695	3,244
Standard Deviation	2013	14,687	737	10,043	407	15,830	13,528	14,277	1,552	1,159
	2014	16,262	857	10,018	385	14,119	15,722	16,710	(2,591)	540
Peak Average	2013	98,929	5,883	53,172	2,285	160,268	96,119	101,867	58,402	2,809
	2014	104,620	3,633	66,773	2,441	177,466	100,878	107,222	70,243	3,741
Peak Median	2013	98,280	5,875	54,255	2,294	159,026	95,623	101,132	57,894	2,657
	2014	103,967	3,548	67,716	2,375	176,835	100,317	106,500	70,334	3,650
Peak Standard Deviation	2013	11,297	553	9,738	351	13,214	10,591	11,289	1,925	706
	2014	13,288	828	9,565	366	10,818	13,101	13,952	(3,134)	188
Off-Peak Average	2013	81,751	5,241	52,947	2,074	142,013	80,812	85,516	56,497	939
	2014	87,165	2,894	67,291	2,213	159,563	85,054	90,240	69,322	2,111
Off-Peak Median	2013	80,916	5,129	53,268	1,977	140,769	80,220	84,671	56,098	696
	2014	86,694	2,798	66,558	2,220	159,087	84,042	89,083	70,004	2,652
Off-Peak Standard Deviation	2013	12,454	748	10,306	427	12,707	11,648	12,081	626	806
	2014	14,115	723	10,397	370	11,035	14,018	14,789	(3,754)	96

Figure 3-8 Day-ahead and real-time supply (Average hourly volumes): January through June of 2014

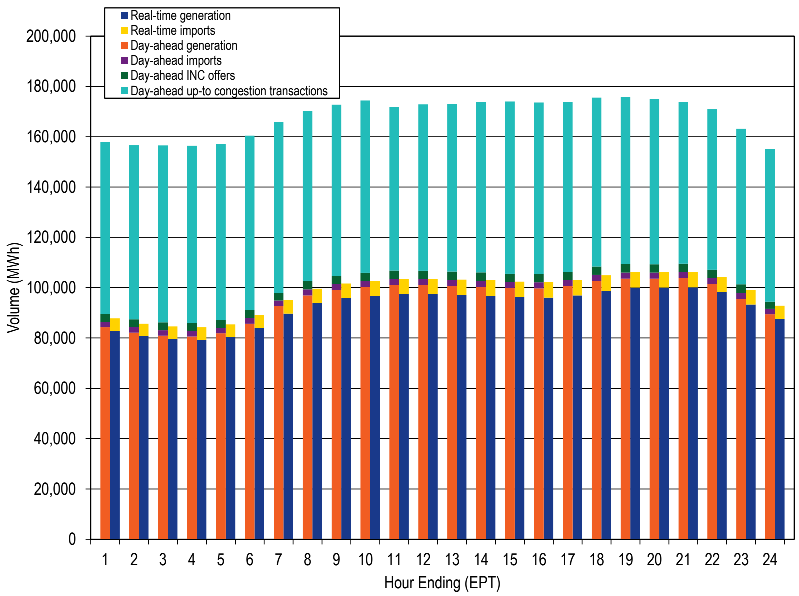


Figure 3-9 shows the difference between the day-ahead and real-time average daily supply in January 2013 through June of 2014.

Figure 3-9 Difference between day-ahead and real-time supply (Average daily volumes): January 2013 through June of 2014

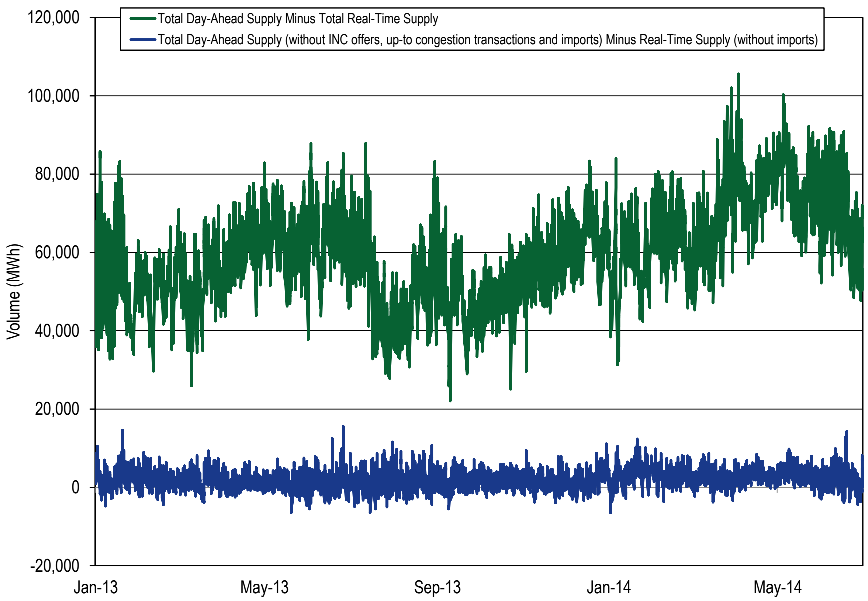
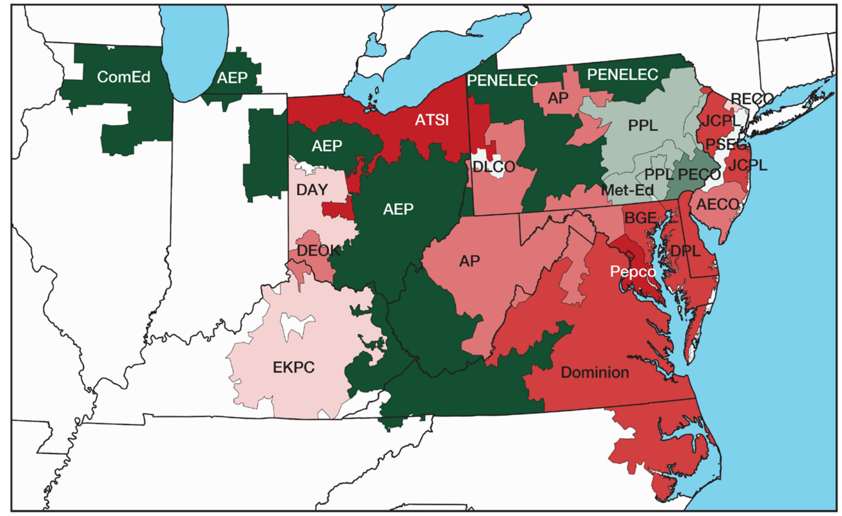


Figure 3-10 shows the difference between the PJM real-time generation and real-time load by zone in the first six months of 2014. Table 3-13 shows the difference between the PJM real-time generation and real-time load by zone in the first six months of 2013 and the first six months of 2014. Figure 3-10 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 3-10 Map of PJM real-time generation less real-time load by zone: January through June of 2014[29]



Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)
AECO	(3,559)	ComEd	13,407	DPL	(5,790)	PENELEC	15,274
AEP	13,990	DAY	(1,489)	EKPC	(950)	Pepco	(8,381)
AP	(2,634)	DEOK	(4,499)	JCPL	(5,157)	PPL	4,983
ATSI	(8,009)	DLCO	1,086	Met-Ed	2,635	PSEG	101
BGE	(5,083)	Dominion	(6,257)	PECO	9,428	RECO	(717)

29 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/markets-and-operations/energy/lmp-model-info/bus-model-updates.aspx>. (Accessed on 7/16/2014.)

Table 3-13 PJM real-time generation less real-time load by zone (GWh): January through June of 2013 and 2014

	Zonal Generation and Load (GWh)					
	2013 (Jan - Jun)			2014 (Jan - Jun)		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	942.9	4,891.5	(3,948.6)	1,392.9	4,952.0	(3,559.1)
AEP	64,822.7	65,047.3	(224.6)	79,566.2	65,576.1	13,990.0
AP	27,574.0	23,634.6	3,939.5	22,057.4	24,691.8	(2,634.4)
ATSI	27,317.5	32,901.3	(5,583.7)	26,162.3	34,171.4	(8,009.2)
BGE	9,983.0	15,769.2	(5,786.2)	11,110.2	16,193.1	(5,082.9)
ComEd	61,675.0	47,358.9	14,316.1	62,191.7	48,784.7	13,406.9
DAY	8,139.9	8,241.0	(101.1)	7,109.6	8,599.0	(1,489.4)
DEOK	12,073.2	13,053.9	(980.7)	9,079.3	13,578.2	(4,498.9)
DLCO	9,422.6	7,160.0	2,262.6	8,371.5	7,285.6	1,085.9
Dominion	39,002.8	46,175.4	(7,172.6)	41,837.2	48,093.9	(6,256.8)
DPL	3,449.6	9,057.2	(5,607.6)	3,453.4	9,243.4	(5,790.0)
EKPC	839.1	964.3	(125.1)	5,696.2	6,645.9	(949.7)
JCPL	4,984.7	10,934.2	(5,949.5)	5,950.4	11,107.4	(5,157.0)
Met-Ed	9,783.6	7,433.1	2,350.5	10,308.8	7,673.6	2,635.2
PECO	29,863.6	19,485.6	10,378.0	29,247.1	19,819.1	9,427.9
PENELEC	21,796.9	8,653.7	13,143.3	24,080.3	8,806.4	15,273.9
Pepco	4,317.2	14,852.3	(10,535.1)	6,958.7	15,339.9	(8,381.2)
PPL	23,940.2	20,209.0	3,731.2	25,990.2	21,007.3	4,982.9
PSEG	22,141.5	20,843.6	1,297.9	20,982.1	20,881.3	100.8
RECO	0.0	726.2	(726.2)	0.0	717.2	(717.2)

Demand

Demand includes physical load and exports and virtual transactions.

Peak Demand

The PJM system load reflects the entire RTO. The PJM Energy Market includes the Real-Time Energy Market and the Day-Ahead Energy Market. In this section, demand refers to physical load and exports and in the Day-Ahead Energy Market also includes virtual transactions, which include decrement bids and up-to congestion transactions.

The PJM system real-time peak load for the first six months of 2014 was 141,673 MW in the HE 1700 on June 17, 2014, which was 1,895 MW, or 1.4 percent, higher than the peak load for the first six months of 2013, which was 139,779 MW in the HE 1600 on June 25, 2013. The EKPC Transmission Zone accounted for 2,128 MW in the peak hour of the first six months of 2014. The peak load excluding the EKPC Transmission Zone was 139,545 MW, also occurring on June 17, 2014, HE 1700, a decrease of 234 MW, or 0.2 percent from the first six months of 2013.

Table 3-14 shows the peak loads for the first six months of the years 1999 through 2014.

Table 3-14 Actual PJM footprint peak loads: January through June of 1999 to 2014[30]

Jan - Jun	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
1999	Tue, June 08	17	114,607	NA	NA
2000	Mon, June 26	16	112,028	(2,579)	(2.3%)
2001	Thu, June 28	17	115,808	3,780	3.4%
2002	Mon, June 24	17	122,105	6,297	5.4%
2003	Wed, June 25	17	119,378	(2,727)	(2.2%)
2004	Wed, June 09	17	120,218	840	0.7%
2005	Tue, June 28	16	124,052	3,833	3.2%
2006	Tue, May 30	17	121,165	(2,887)	(2.3%)
2007	Wed, June 27	16	130,971	9,806	8.1%
2008	Mon, June 09	17	130,100	(871)	(0.7%)
2009	Fri, January 16	19	117,169	(12,930)	(9.9%)
2010	Wed, June 23	17	126,188	9,019	7.7%
2011	Wed, June 08	17	144,350	18,162	14.4%
2012	Wed, June 20	18	147,913	3,563	2.5%
2013	Tue, June 25	16	139,779	(8,134)	(5.5%)
2014 (with EKPC)	Tue, June 17	17	141,673	1,895	1.4%
2014 (without EKPC)	Tue, June 17	17	139,545	(234)	(0.2%)

30 Peak loads shown are eMTR load. See the *MMU Technical Reference for the PJM Markets*, at "Load Definitions" for detailed definitions of load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Figure 3-11 shows the peak loads for the first six months of the years 1999 through 2014.

Figure 3-11 PJM footprint calendar year peak loads: January through June of 1999 to 2014

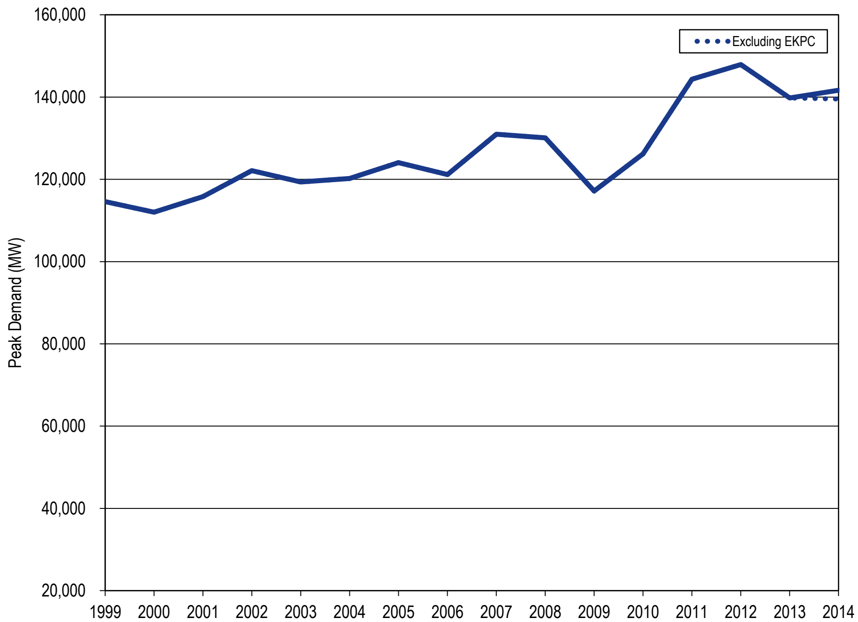
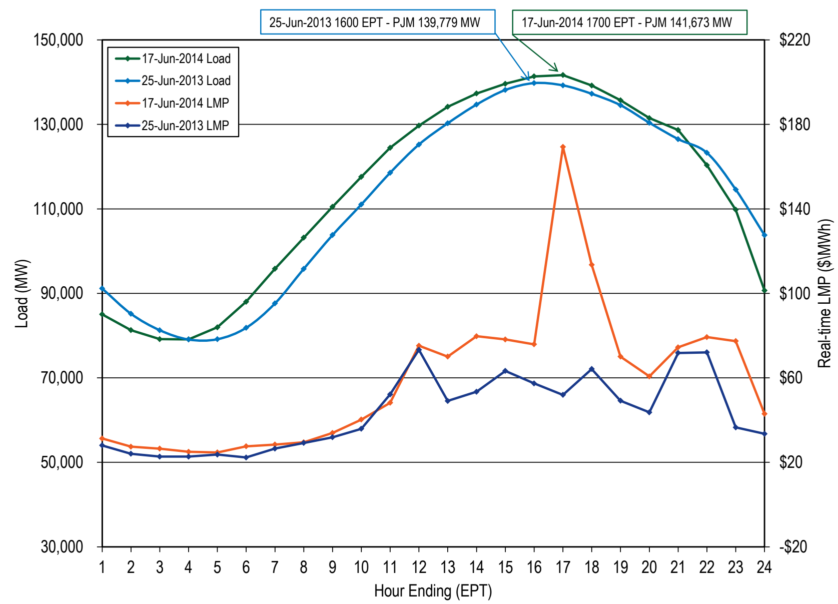


Figure 3-12 compares the peak load days in the first six months of 2013 and the first six months of 2014. The average hourly real-time LMP peaked at $169.33 on June 17, 2014 and peaked at $73.30 on June 25, 2013.

Figure 3-12 PJM peak-load comparison: Tuesday, June 17, 2014, and Tuesday, June 25, 2013



Real-Time Demand

PJM average real-time load in the first six months of 2014 increased by 4.2 percent from the first six months of 2013, from 86,897 MW to 90,529 MW. PJM average real-time load in the first six months of 2014 would have increased by 3.4 percent from the first six months of 2013, from 86,897 MW to 89,881 MW, if the EKPC Transmission Zone had not been included in the comparison.[31 32]

PJM average real-time demand in the first six months of 2014 increased 5.5 percent from the first six months of 2013, from 91,199 MW to 96,189 MW. PJM average real-time demand in the first six months of 2014 would have increased by 4.8 percent from the first six months of 2013, from 91,199 MW to 95,541 MW, if the EKPC Transmission Zone had not been included in the comparison.

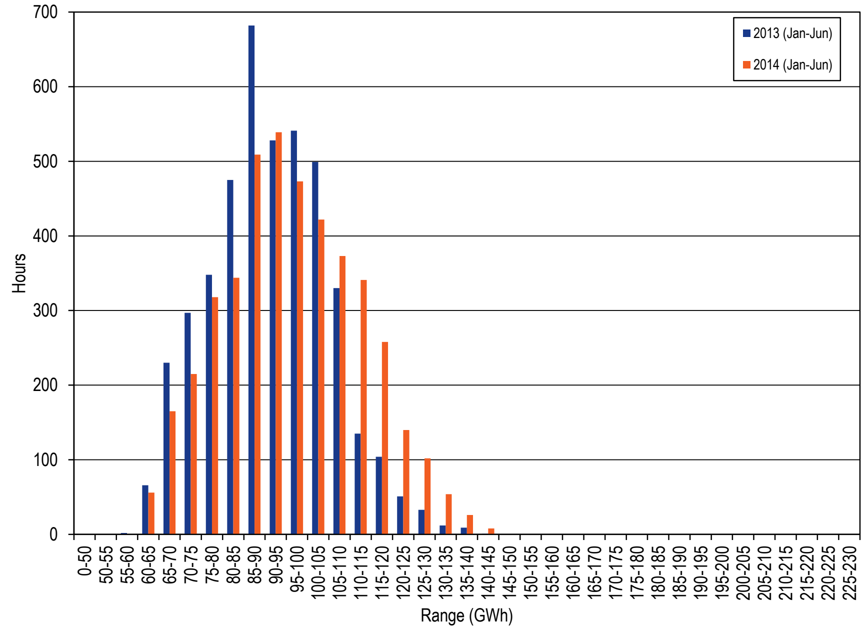
In the PJM Real-Time Energy Market, there are two types of demand:

- **Load.** The actual MWh level of energy used.
- **Export.** An export is an external energy transaction scheduled from PJM to another balancing authority. A real-time export must have a valid OASIS reservation when offered, must have available ramp room to support the export, must be accompanied by a NERC e-Tag, and must pass the neighboring balancing authority checkout process.

PJM Real-Time Demand Duration

Figure 3-13 shows the hourly distribution of PJM real-time load plus exports for the first six months of 2013 and the first six months of 2014.[33]

Figure 3-13 Distribution of PJM real-time accounting load plus exports: January through June of 2013 and 2014[34]



PJM Real-Time, Average Load

Table 3-15 presents summary real-time demand statistics for the first six months of each year during the 17-year period 1998 to 2014. 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.[35]

31 The EKPC Transmission Zone was integrated on June 1, 2013 and was not included in this comparison for January through May of 2013 and 2014.
32 Load data are the net MWh injections and withdrawals MWh at every load bus in PJM.
33 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*, "Load Definitions," for detailed definitions of accounting load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.
34 Each range on the horizontal axis excludes the start value and includes the end value.
35 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.

Table 3-15 PJM real-time average hourly load and real-time average hourly load plus average hourly exports: January through June of 1998 through 2014[36]

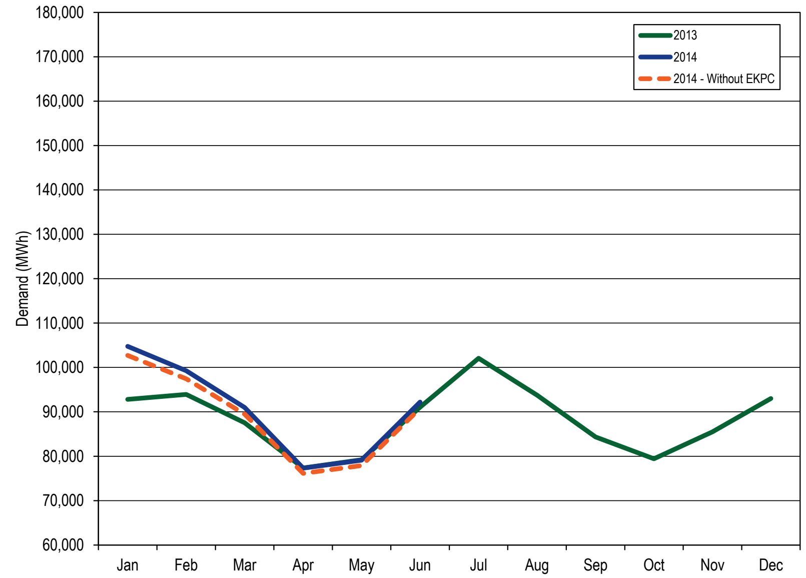
	PJM Real-Time Demand (MWh)				Year-to-Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
Jan - Jun	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
1998	27,662	4,703	27,662	4,703	NA	NA	NA	NA
1999	28,714	5,113	28,714	5,113	3.8%	8.7%	3.8%	8.7%
2000	29,649	5,382	29,902	5,511	3.3%	5.3%	4.1%	7.8%
2001	30,180	5,274	32,041	5,103	1.8%	(2.0%)	7.2%	(7.4%)
2002	32,678	6,457	33,969	6,557	8.3%	22.4%	6.0%	28.5%
2003	36,727	6,428	38,775	6,554	12.4%	(0.4%)	14.1%	(0.0%)
2004	41,787	8,999	44,808	10,033	13.8%	40.0%	15.6%	53.1%
2005	71,939	13,603	78,745	13,798	72.2%	51.2%	75.7%	37.5%
2006	77,232	12,003	83,606	12,377	7.4%	(11.8%)	6.2%	(10.3%)
2007	81,110	13,499	86,557	13,819	5.0%	12.5%	3.5%	11.6%
2008	78,685	12,819	85,819	13,242	(3.0%)	(5.0%)	(0.9%)	(4.2%)
2009	75,991	12,899	81,062	13,253	(3.4%)	0.6%	(5.5%)	0.1%
2010	78,106	13,643	83,758	14,227	2.8%	5.8%	3.3%	7.3%
2011	78,823	13,931	84,288	14,046	0.9%	2.1%	0.6%	(1.3%)
2012	84,946	13,941	89,638	13,848	7.8%	0.1%	6.3%	(1.4%)
2013	86,897	13,871	91,199	13,848	2.3%	(0.5%)	1.7%	0.0%
2014	90,529	16,266	96,189	16,147	4.2%	17.3%	5.5%	16.6%

PJM Real-Time, Monthly Average Load

Figure 3-14 compares the real-time, monthly average hourly loads in 2013 to the first six months of 2014 with and without EKPC.

36 The export data in this table are not available before June 1, 2000. The export data in 2000 are for the last six months of 2000.

Figure 3-14 PJM real-time monthly average hourly load: January 2013 through June 2014

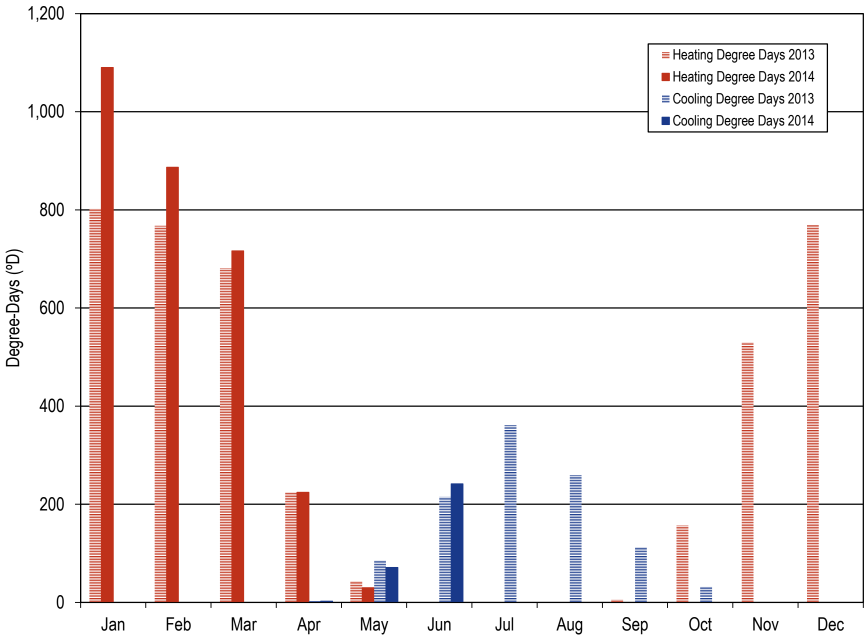


PJM real-time load is significantly affected by temperature. Figure 3-15 compares the PJM monthly heating and cooling degree days in the first six months of 2014 with those in the first six months of 2013.[37] The figure shows that in 2014, the heating degree days increased 35.8 percent in January, increased 15.6 percent in February, increased 5.2 percent in March, remained constant in April, and decreased 31.1 percent in May compared to 2013. The figure shows that in 2014, the cooling degree days decreased 20.5 percent in April, decreased 16.7 percent in May, and increased 12.5 percent in June compared to 2013.

37 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, LEX, ORD, ORF, PHL, PIT, RIC, ROA, TOL and WAL.

Figure 3-15 PJM heating and cooling degree days: January 2013 through June 2014



Day-Ahead Demand

PJM average day-ahead demand in the first six months of 2014, including DECs and up-to congestion transactions, increased by 10.7 percent from the first six months of 2013, from 145,280 MW to 160,805 MW. The PJM average day-ahead demand in the first six months of 2014, including DECs and up-to congestion transactions, would have increased 10.1 percent from the first six months of 2013, from 145,280 MW to 159,959 MW, if the EKPC Transmission Zone had not been included in the comparison.

PJM average day-ahead demand in the first six months of 2014, including DECs, up-to congestion transactions, and exports, increased by 11.0 percent from the first six months of 2013, from 148,414 MW to 164,740 MW. The PJM average day-ahead demand in the first six months of 2014, including DECs and up-to congestion transactions, and imports, would have increased 10.4 percent from the first six months of 2013, from 148,414 MW to 163,894 MW, if the EKPC Transmission Zone had not been included in the comparison.

The day-ahead demand growth was 154.8 percent higher than the real-time load growth in the first six months of 2014, because of the continued growth of up-to congestion transactions. If the first six months of 2014 up-to congestion transactions had been held to the first six months of 2013 levels, the day-ahead demand, including DECs and up-to congestion transactions, would have increased 1.1 percent instead of increasing 10.7 percent and day-ahead demand growth would have been 75.0 percent lower than the real-time load growth.

In the PJM Day-Ahead Energy Market, five 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 DEC 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. 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.
- **Export.** An export is an external energy transaction scheduled from PJM to another balancing authority. An export must have a valid willing to pay congestion (WPC) OASIS reservation when offered. An export energy transaction that clears the Day-Ahead Energy Market is financially binding. There is no link between transactions submitted in the PJM

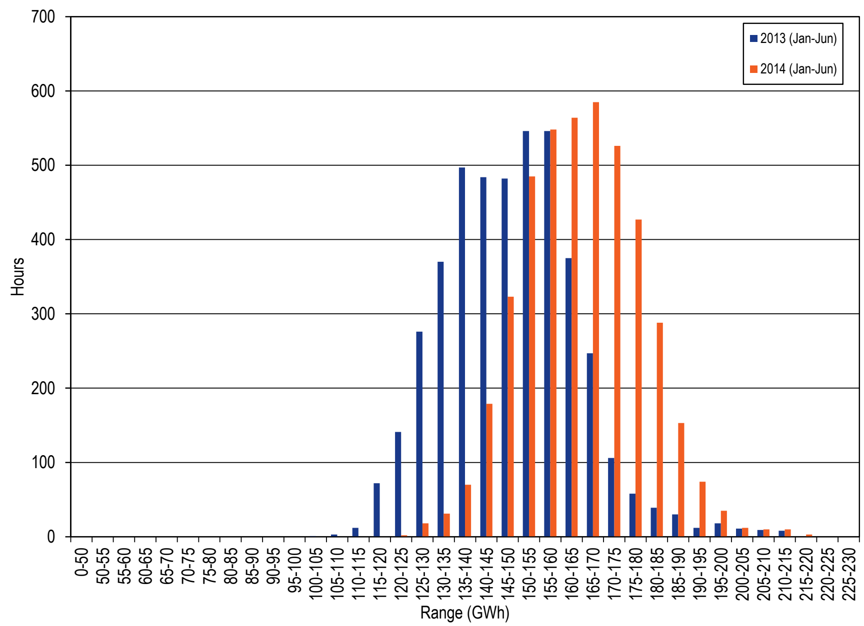
Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an export energy transaction approved in the Day-Ahead Energy Market will not physically flow in real time unless it is also submitted through the Real-Time Energy Market scheduling process.

PJM day-ahead demand is the hourly total of the five types of cleared demand bids.

PJM Day-Ahead Demand Duration

Figure 3-16 shows the hourly distribution of PJM day-ahead demand, including decrement bids, up-to congestion transactions, and exports for the first six months of 2013 and the first six months of 2014.

Figure 3-16 Distribution of PJM day-ahead demand plus exports: January through June of 2013 and 2014[38]



PJM Day-Ahead, Average Demand

Table 3-16 presents summary day-ahead demand statistics for the first six months of each year of the 15-year period 2000 to 2014.[39]

Table 3-16 PJM day-ahead average demand and day-ahead average hourly demand plus average hourly exports: January through June of 2000 through 2014

	PJM Day-Ahead Demand (MWh)				Year-to-Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
Jan - Jun	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2000	35,448	8,138	35,623	7,982	NA	NA	NA	NA
2001	32,425	6,014	33,075	5,857	(8.5%)	(26.1%)	(7.2%)	(26.6%)
2002	37,561	8,293	37,607	8,311	15.8%	37.9%	13.7%	41.9%
2003	44,391	7,717	44,503	7,704	18.2%	(6.9%)	18.3%	(7.3%)
2004	50,161	10,304	50,596	10,557	13.0%	33.5%	13.7%	37.0%
2005	86,890	14,677	89,388	14,827	73.2%	42.4%	76.7%	40.4%
2006	94,470	12,925	97,460	13,303	8.7%	(11.9%)	9.0%	(10.3%)
2007	104,737	15,019	107,647	15,269	10.9%	16.2%	10.5%	14.8%
2008	100,948	14,255	104,499	14,461	(3.6%)	(5.1%)	(2.9%)	(5.3%)
2009	95,130	15,878	98,001	15,972	(5.8%)	11.4%	(6.2%)	10.4%
2010	99,691	18,097	103,573	18,366	4.8%	14.0%	5.7%	15.0%
2011	105,071	16,452	108,756	16,578	5.4%	(9.1%)	5.0%	(9.7%)
2012	129,881	15,268	133,046	15,436	23.6%	(7.2%)	22.3%	(6.9%)
2013	145,280	15,552	148,414	15,588	11.9%	1.9%	11.6%	1.0%
2014	160,805	13,872	164,740	13,800	10.7%	(10.8%)	11.0%	(11.5%)

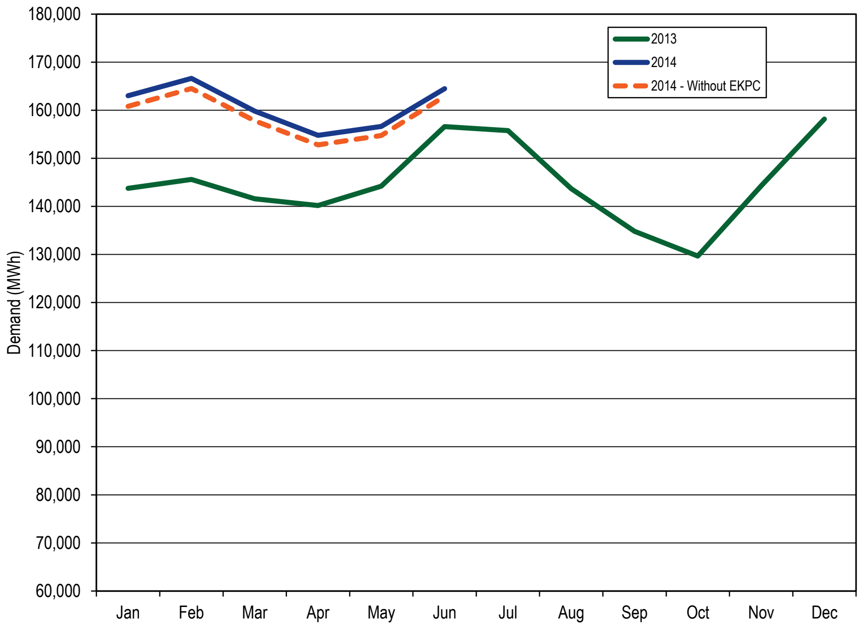
38 Each range on the horizontal axis excludes the start value and includes the end value.

39 Since the Day-Ahead Energy Market did not start until June 1, 2000, the day-ahead data for 2000 only includes data for the last six months of that year.

PJM Day-Ahead, Monthly Average Demand

Figure 3-17 compares the day-ahead, monthly average hourly demand, including decrement bids and up-to congestion transactions, in 2013 to the first six months of 2014 with and without EKPC.

Figure 3-17 PJM day-ahead monthly average hourly demand: January 2013 through June 2014



Real-Time and Day-Ahead Demand

Table 3-17 presents summary statistics for the first six months of 2013 and the first six months of 2014 day-ahead and real-time demand. The last two columns of Table 3-17 are the day-ahead demand minus the real-time demand. The first such column is the total day-ahead demand less the total real-time demand and the second such column is the total physical day-ahead load (fixed demand plus price sensitive demand) less the physical real-time load.

Table 3-17 Cleared day-ahead and real-time demand (MWh): January through June of 2013 and 2014

		Day Ahead						Real Time		Day Ahead Less Real Time	
	Jan - Jun	Fixed Demand	Price Sensitive	DEC Bids	Up-to Congestion	Exports	Total Demand	Load	Total Demand	Total Demand	Total Load
Average	2013	83,854	1,074	7,300	53,052	3,134	148,414	86,897	91,199	57,215	(1,968)
	2014	86,321	1,270	6,165	67,048	3,935	164,740	90,529	96,189	68,551	(2,938)
Median	2013	83,413	1,098	7,021	53,783	3,109	148,365	86,231	90,502	57,863	(1,720)
	2014	84,903	1,257	5,961	67,141	3,823	164,502	89,103	95,269	69,232	(2,943)
Standard Deviation	2013	13,293	238	1,612	10,043	561	15,588	13,871	13,848	1,740	(340)
	2014	15,392	173	1,270	10,018	1,081	13,800	16,266	16,147	(2,348)	(702)
Peak Average	2013	92,416	1,165	8,144	53,172	3,110	158,006	95,564	99,688	58,318	(1,983)
	2014	95,297	1,351	6,756	66,773	3,886	174,063	99,513	104,987	69,076	(2,865)
Peak Median	2013	91,916	1,251	7,720	54,255	3,100	156,841	94,737	99,061	57,781	(1,570)
	2014	94,153	1,354	6,569	67,716	3,811	173,368	98,350	104,292	69,076	(2,843)
Peak Standard Deviation	2013	10,099	251	1,534	9,738	569	13,051	10,753	10,913	2,137	(404)
	2014	12,781	162	1,235	9,565	1,082	10,643	13,664	13,478	(2,835)	(721)
Off-Peak Average	2013	76,327	994	6,557	52,947	3,155	139,980	79,276	83,735	56,245	(1,955)
	2014	78,428	1,200	5,646	67,291	3,978	156,543	82,629	88,453	68,090	(3,001)
Off-Peak Median	2013	75,657	1,034	6,290	53,268	3,121	138,721	78,519	82,945	55,776	(1,828)
	2014	77,333	1,191	5,473	66,558	3,837	156,189	81,095	87,373	68,816	(2,571)
Off-Peak Standard Deviation	2013	11,014	193	1,279	10,306	552	12,446	11,653	11,689	756	(447)
	2014	12,979	149	1,055	10,397	1,078	10,708	14,132	14,228	(3,520)	(1,004)

Figure 3-18 shows the average hourly cleared volumes of day-ahead demand and real-time demand. The day-ahead demand includes day-ahead load, day-ahead exports, decrement bids and up-to congestion transactions. The real-time demand includes real-time load and real-time exports.

Figure 3-18 Day-ahead and real-time demand (Average hourly volumes): January through June of 2014

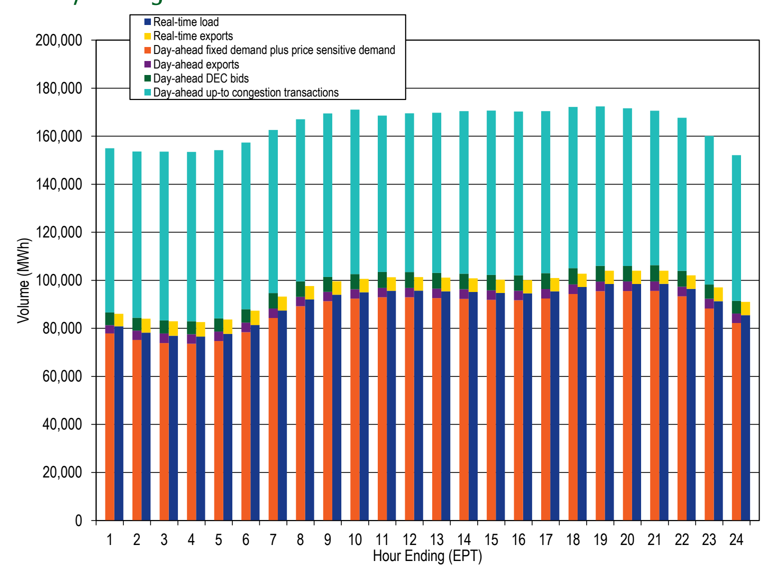
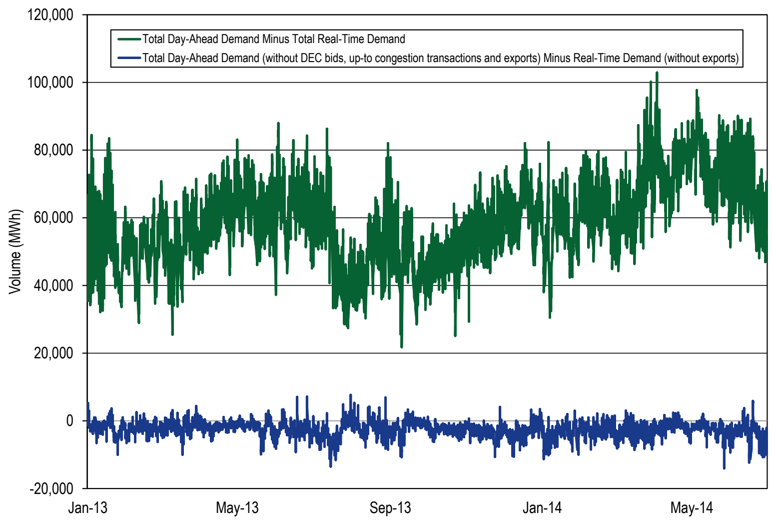


Figure 3-19 shows the difference between the day-ahead and real-time average daily demand in January 2013 through June 2014.

Figure 3-19 Difference between day-ahead and real-time demand (Average daily volumes): January 2013 through June 2014



Supply and Demand: 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 3-18 shows the monthly average share of real-time load served by self-supply, bilateral contracts and spot purchase in 2013 and 2014 based on parent company. For the first six months of 2014, 9.6 percent of real-time load was supplied by bilateral contracts, 28.3 percent by spot market purchase and 62.1 percent by self-supply. Compared with 2013, reliance on bilateral contracts decreased 1.0 percentage points, reliance on spot supply increased by 3.3 percentage points and reliance on self-supply decreased by 2.3 percentage points.

Table 3-18 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: 2013 through 2014

	2013			2014			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	10.4%	22.3%	67.3%	9.5%	27.9%	62.6%	(0.9%)	5.7%	(4.7%)
Feb	10.5%	22.0%	67.5%	9.2%	27.3%	63.5%	(1.4%)	5.3%	(4.0%)
Mar	10.4%	24.2%	65.4%	9.7%	27.2%	63.0%	(0.7%)	3.1%	(2.4%)
Apr	10.7%	24.2%	65.1%	9.1%	29.7%	61.2%	(1.6%)	5.5%	(3.9%)
May	10.9%	25.4%	63.6%	9.7%	28.8%	61.5%	(1.2%)	3.4%	(2.1%)
Jun	10.7%	25.0%	64.3%	10.6%	29.0%	60.4%	(0.1%)	4.0%	(3.8%)
Jul	10.2%	25.2%	64.7%						
Aug	10.2%	24.5%	65.3%						
Sep	10.1%	24.2%	65.7%						
Oct	11.1%	28.2%	60.7%						
Nov	10.6%	27.2%	62.2%						
Dec	11.3%	27.1%	61.7%						
Annual	10.6%	25.0%	64.4%	9.6%	28.3%	62.1%	(1.0%)	3.3%	(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 supply 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 demand (cleared fixed-demand, price-sensitive load and decrement bids) is calculated by summing across all the parent companies of PJM billing organizations that serve demand in the Day-Ahead Energy Market for each hour. Table 3-19 shows the monthly average share of day-ahead demand served by self-supply, bilateral contracts and spot purchases in 2013 and 2014, based on parent companies. For the first six months of 2014, 8.9 percent of day-ahead demand was supplied by bilateral contracts, 28.4 percent by spot market purchases, and 62.7 percent by self-supply. Compared with 2013, reliance on bilateral contracts increased by 0.8 percentage points, reliance on spot supply increased by 3.9 percentage points, and reliance on self-supply decreased by 4.8 percentage points.

Table 3-19 Monthly average percentage of day-ahead self-supply demand, bilateral supply demand, and spot-supply demand based on parent companies: 2013 through 2014

	2013			2014			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	6.8%	22.1%	71.1%	10.9%	28.7%	60.4%	4.1%	6.7%	(10.7%)
Feb	7.0%	22.1%	71.0%	7.9%	27.0%	65.0%	1.0%	5.0%	(5.9%)
Mar	7.0%	23.6%	69.4%	8.6%	27.7%	63.7%	1.6%	4.1%	(5.7%)
Apr	7.1%	23.1%	69.8%	7.9%	29.9%	62.3%	0.7%	6.8%	(7.6%)
May	7.8%	23.5%	68.7%	8.0%	29.0%	63.0%	0.2%	5.5%	(5.7%)
Jun	8.2%	23.8%	68.0%	9.4%	28.5%	62.1%	1.2%	4.7%	(5.9%)
Jul	8.0%	24.1%	67.9%						
Aug	8.1%	23.9%	68.0%						
Sep	7.8%	23.9%	68.3%						
Oct	9.8%	29.0%	61.3%						
Nov	9.3%	29.1%	61.7%						
Dec	9.9%	25.6%	64.5%						
Annual	8.0%	24.5%	67.5%	8.9%	28.4%	62.7%	0.8%	3.9%	(4.8%)

Market Behavior

Offer Capping for Local Market Power

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 as well as for conservative operations. 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 3-20. The offer capping percentages shown in Table 3-20 include units that are committed to provide constraint relief whose owners failed the TPS test in the Energy Market as well as units committed as part of conservative operations, excluding units that were committed for providing black start and reactive service. In January 2014, due to an increase in constrained hours, there was an increase in the offer capping percentages for units failing the TPS test and units committed for conservative operations while the number of units committed as offer capped for providing black start and reactive service decreased. In the first six months of 2014, the percentage of hours in which black start and reactive service units were economic increased compared to the first six months of 2013 and the percentage of hours they were committed as offer capped decreased as a result.

Table 3-20 Offer-capping statistics – Energy only: January through June, 2010 to 2014

	Real Time		Day Ahead	
(Jan-Jun)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2010	0.9%	0.3%	0.3%	0.1%
2011	0.7%	0.3%	0.0%	0.0%
2012	1.0%	0.5%	0.1%	0.1%
2013	0.3%	0.1%	0.1%	0.0%
2014	0.7%	0.3%	0.2%	0.1%

Table 3-21 shows the offer capping percentages including units committed to provide constraint relief and units committed to provide black start service and reactive support. The units that are committed and offer capped for reliability reasons have been increasing since 2011. Before 2011, the units that ran to provide black start service and reactive support were generally economic in the energy market. Since 2011, the percentage of hours when these units were not economic (and are therefore committed on their cost schedule for reliability reasons) has steadily increased. This trend reversed in the first six months of 2014 because higher LMPs resulted in the increased economic dispatch of black start and reactive service resources to be economic.

Table 3-21 Offer-capping statistics for energy and reliability: January through June, 2010 to 2014

	Real Time		Day Ahead	
(Jan-Jun)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2010	0.9%	0.3%	0.3%	0.1%
2011	0.7%	0.3%	0.0%	0.0%
2012	1.4%	0.8%	0.1%	0.1%
2013	2.6%	2.1%	3.0%	2.0%
2014	1.1%	0.7%	0.7%	0.5%

Table 3-22 presents data on the frequency with which units were offer capped in the first six months of 2013 and the first six months of 2014, for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market.

Table 3-22 Real-time offer-capped unit statistics: January through June, 2013 and 2014

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	(Jan - Jun)	Offer-Capped Hours: Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2014	0	0	0	0	0	1
	2013	0	0	0	0	1	17
80% and < 90%	2014	0	0	1	0	1	2
	2013	0	0	0	0	1	7
75% and < 80%	2014	0	0	1	1	1	2
	2013	0	0	0	0	0	2
70% and < 75%	2014	0	0	0	0	1	1
	2013	0	0	0	0	0	1
60% and < 70%	2014	1	0	0	0	10	6
	2013	0	0	0	4	0	10
50% and < 60%	2014	0	0	0	0	2	15
	2013	0	0	0	2	0	17
25% and < 50%	2014	0	0	4	7	10	51
	2013	0	0	0	0	4	18
10% and < 25%	2014	0	0	0	0	1	36
	2013	0	0	0	0	0	22

Table 3-22 shows that one unit was offer capped for 90 percent or more of its run hours in the first six months of 2014 compared to 18 units in the first six months of 2013.

Offer Capping for Local Market Power

In the first six months of 2014, the AEP, AP, ATSI, BGE, ComEd, DLCO, Dominion, DPL, EKPC, PECO, PENELEC, Pepco, PPL and PSEG control zones experienced congestion resulting from one or more constraints binding for 50 or more hours. The AECO, DAY, DEOK, JCPL, Met-Ed and RECO control zones did not have constraints binding for 50 or more hours in the first six months of 2014. Table 3-23 shows that AEP, AP, BGE, ComEd, Dominion, and PSEG were the only control zones with 50 or more hours of congestion or with an interface constraint that was binding for one or more hours in every year in the first six months of 2009 through 2014. In the first six months of 2014, the BGE Pepco interface (BCPEP) constraint was binding in Pepco for 39 hours.

Table 3-23 Numbers of hours when control zones experienced congestion for 50 or more hours: January through June, 2009 through 2014

	2009 (Jan - Jun)	2010 (Jan - Jun)	2011 (Jan - Jun)	2012 (Jan - Jun)	2013 (Jan - Jun)	2014 (Jan - Jun)
AECO	149	69	88	NA	NA	NA
AEP	932	355	1,228	322	553	1,534
AP	598	1,292	1,117	173	51	170
ATSI	101	NA	NA	1	70	403
BGE	90	154	184	1,556	316	1,142
ComEd	576	1,406	153	845	1,678	1,729
DEOK	NA	NA	NA	58	NA	NA
DLCO	156	342	NA	209	NA	281
Dominion	310	589	718	200	124	137
DPL	NA	NA	NA	126	142	560
EKPC	NA	NA	NA	NA	NA	65
Met-Ed	NA	NA	NA	123	NA	NA
PECO	59	NA	130	53	256	944
PENELEC	55	NA	NA	NA	NA	1,441
Pepco	NA	NA	59	203	85	39
PPL	176	NA	52	146	261	147
PSEG	438	479	605	316	1,462	2,023

The local market structure in the Real-Time Energy Market associated with each of the frequently binding constraints were analyzed using the three pivotal supplier results for the first six months of 2014.[40] The three pivotal supplier (TPS) 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 3-24 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.

40 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 3-24 Three pivotal supplier test details for interface constraints: January through June, 2014

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	354	349	13	1	12
	Off Peak	396	399	12	1	11
AEP - DOM	Peak	423	274	8	0	8
	Off Peak	323	211	7	0	7
AP South	Peak	413	467	9	0	9
	Off Peak	432	521	9	0	9
BC/PEPCO	Peak	603	614	7	0	6
	Off Peak	482	468	6	0	6
Bedington - Black Oak	Peak	175	206	13	3	11
	Off Peak	203	165	11	1	10
Central	Peak	422	63	6	0	6
	Off Peak	1,070	657	11	0	11
Eastern	Peak	426	295	8	0	8
	Off Peak	457	400	9	1	8
PL North	Peak	0	0	0	0	0
	Off Peak	83	303	1	0	1
Seneca	Peak	83	96	1	0	1
	Off Peak	97	115	1	0	1
Western	Peak	951	886	14	1	13
	Off Peak	894	937	13	1	12

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 3-25 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 3-25 Summary of three pivotal supplier tests applied for interface constraints: January through June, 2014

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	781	73	9%	1	0%	1%
	Off Peak	887	82	9%	2	0%	2%
AEP - DOM	Peak	68	5	7%	0	0%	0%
	Off Peak	238	29	12%	0	0%	0%
AP South	Peak	4171	181	4%	0	0%	0%
	Off Peak	3374	165	5%	2	0%	1%
BC/PEPCO	Peak	229	26	11%	0	0%	0%
	Off Peak	112	8	7%	0	0%	0%
Bedington - Black Oak	Peak	975	93	10%	6	1%	6%
	Off Peak	348	39	11%	0	0%	0%
Central	Peak	2	0	0%	0	0%	0%
	Off Peak	6	0	0%	0	0%	0%
Eastern	Peak	48	2	4%	0	0%	0%
	Off Peak	60	4	7%	0	0%	0%
PL North	Peak	0	0	0%	0	0%	0%
	Off Peak	402	0	0%	0	0%	0%
Seneca	Peak	1800	0	0%	0	0%	0%
	Off Peak	3539	0	0%	0	0%	0%
Western	Peak	1156	132	11%	2	0%	2%
	Off Peak	627	35	6%	0	0%	0%

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.[41] 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 Markup

Table 3-26 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category. The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point. In the first six months of 2014, 80.3 percent of marginal units had average dollar markups less than zero and 70.0 percent of units had an average markup index less than or equal to 0.0. The data show that some marginal units did have substantial markups. The average data do not show the high markups that occurred for the very high load days in January. Using the unadjusted cost offers, the highest markup in the first six months of 2014 was $922.3 whereas the highest markup in the first six months of 2013 was $286.9.

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

Table 3-26 Average, real-time marginal unit markup index (By offer price category): January through June 2013 and 2014

	2013 (Jan - Jun)			2014 (Jan - Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.11)	($3.06)	21.4%	(0.17)	($2.95)	11.8%
$25 to $50	(0.01)	($1.47)	64.0%	(0.02)	($1.77)	58.2%
$50 to $75	0.00	($1.85)	7.8%	0.02	($2.22)	10.4%
$75 to $100	0.03	$0.88	1.4%	0.07	$3.66	3.3%
$100 to $125	0.10	$9.98	0.8%	0.06	$5.79	3.4%
$125 to $150	0.07	$9.45	0.6%	0.10	$11.52	1.6%
>= $150	0.02	$4.19	4.0%	0.12	$30.13	11.4%

Day-Ahead Markup

Table 3-27 shows the average markup index of marginal units in Day-Ahead Energy Market, by offer price category. In the first six months of 2014, 92.0 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.02. The data show that some marginal units did have substantial markups. The average markup index increased significantly, for example, from 0.00 in the first six months of 2013, to 0.14 in the first six months of 2014 in the offer price category from $100 to $125. There were 36 hours when generating resources were marginal in this category in the first six months of 2013. However, in the first six months of 2014, there were 436 hours when the marginal units had offer prices of $100 or above and the highest markup was $392 per MWh.

Table 3-27 Average day-ahead marginal unit markup index (By offer price category): January through June of 2013 and 2014

	2013 (Jan - Jun)			2014 (Jan - Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.05)	($1.51)	16.8%	(0.09)	($2.42)	8.2%
$25 to $50	(0.05)	($2.67)	77.1%	(0.02)	($1.77)	68.2%
$50 to $75	0.00	($2.91)	5.1%	0.02	($1.89)	13.9%
$75 to $100	0.08	$7.07	0.4%	0.05	$2.89	2.3%
$100 to $125	0.00	$0.00	0.1%	0.14	$15.32	1.7%
$125 to $150	0.00	$0.00	0.0%	0.02	($2.02)	1.7%
>= $150	0.00	$0.00	0.0%	0.06	$12.56	3.8%

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 and black start service.

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.[42] These categories are designated Tier 1, Tier 2 and Tier 3.[43] [44]

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 based on the number of run-hours the unit is offer capped. 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.

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.[45]

42 OA, Schedule 1 § 6.4.2.
43 114 FERC ¶ 61, 076 (2006).
44 See "Settlement Agreement," Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).
45 OA, Schedule 1 § 6.4.2. In 2007, the FERC approved OA revisions to clarify the AU criteria.

Table 3-28 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 2013 and the first six months of 2014. Of the 93 units eligible in at least one month during the first six months of 2014, 62 units (66.7 percent) were FMUs or AUs for all six months, and 5 units (5.3 percent) qualified in only one month in the first quarter of 2014.

Table 3-28 Frequently mitigated units and associated units total months eligible: 2013 and January through June, 2014

Months Adder-Eligible	2013	2014
1	10	5
2	22	7
3	14	0
4	10	10
5	5	9
6	8	62
7	7	
8	3	
9	1	
10	2	
11	8	
12	22	
Total	112	93

Figure 3-20 shows the number of months FMUs and AUs were eligible for any adder (Tier 1, Tier 2 or Tier 3) since the inception of FMUs effective February 1, 2006. From February 1, 2006, through June 30, 2014, there have been 349 unique units that have qualified for an FMU adder in at least one month. Of these 349 units, no unit qualified for an adder in all potential months. Two units qualified in 101 of the 102 possible months, and 92 of the 349 units (26.4 percent) have qualified for an adder in more than half of the possible months.

Figure 3-20 Frequently mitigated units and associated units total months eligible: February, 2006 through June, 2014

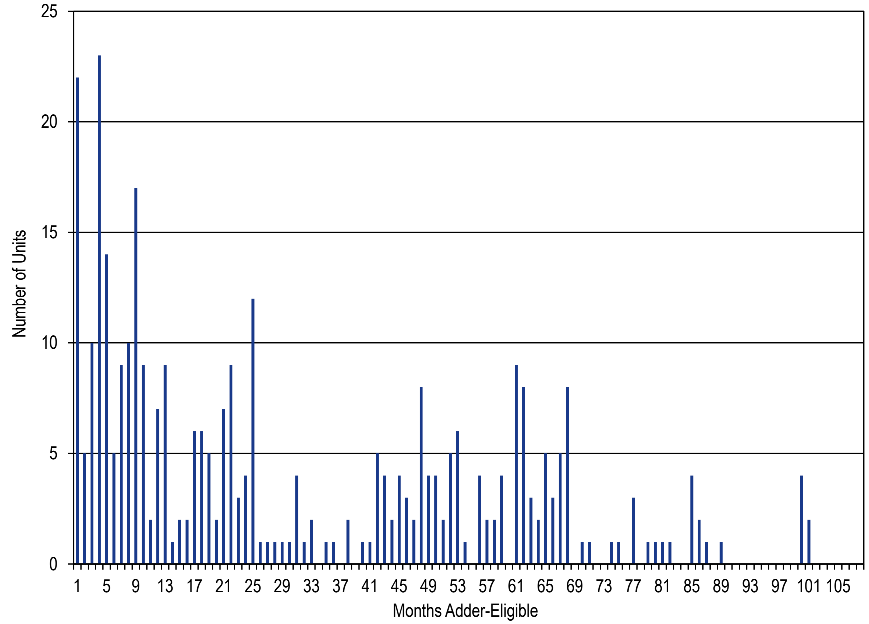


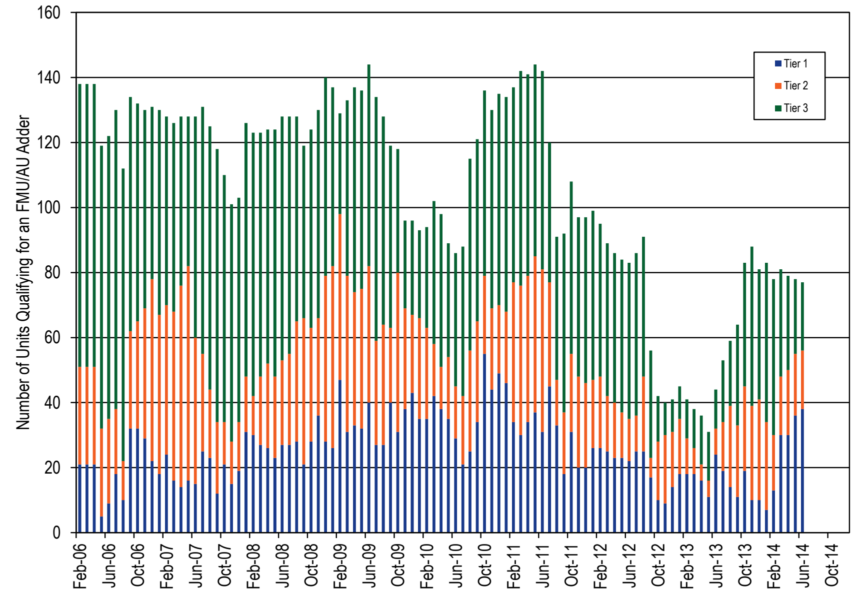
Table 3-29 shows, by month, the number of FMUs and AUs in 2013 and the first six months of 2014. For example, in January 2014, there were 7 FMUs and AUs in Tier 1, 27 FMUs and AUs in Tier 2, and 49 FMUs and AUs in Tier 3.

Table 3-29 Number of frequently mitigated units and associated units (By month): 2013 and January through June, 2014

	FMUs and AUs							
	2013				2014			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	18	17	10	45	7	27	49	83
February	18	11	12	41	13	17	48	78
March	18	8	12	38	30	18	33	81
April	16	5	15	36	30	20	29	79
May	11	5	15	31	36	19	23	78
June	24	8	12	44	38	18	21	77
July	19	15	19	53				
August	14	25	20	59				
September	11	22	31	64				
October	19	26	38	83				
November	10	29	49	88				
December	10	31	40	81				

Figure 3-21 shows the total number of FMUs and AUs that qualified for an adder since the inception of the business rule in February 2006. The reduction in the total number of units qualifying for an FMU or AU adder in 2012 resulted from the decrease in congestion, which was in turn the result of changes in fuel costs, changes in the generation mix and changes in system topology. The increase in the total number of units qualifying for an FMU or AU adder in the first quarter of 2013 was the result of modifications to commitment of black start and reactive units in the Day-Ahead Energy Market. In September 2012, PJM began to schedule units in the Day-Ahead Energy Market for black start and reactive that otherwise would not clear the market based on economics. Whenever these units are scheduled in the Day-Ahead Energy Market for black start and reactive, they are offer capped for all run hours in day ahead and real time. As FMU status is determined on a rolling 12-month period, this change started to affect the number of eligible FMU units in the first six months of 2013.

Figure 3-21 Frequently mitigated units and associated units (By month): February, 2006 through June, 2014



The PJM Tariff defines offer capped units as those capped to maintain system reliability as a result of limits on transmission capability.[46] Offer capping for providing black start service does not meet this criterion. The MMU recommends that black start units not be given FMU status under the current rules.

The goal of the FMU adders was to ensure that units that were offer capped for most of their run hours could cover their going forward or avoidable costs (also known as ACR in the capacity market). The relevant units were all CTs, typically running less than 500 hours per year and the adders were specifically designed to cover ACR for such units. The FMU adders were not designed for baseload units like those providing reactive service. If the FMU adders are not eliminated, adders must be specifically designed for such baseload units.

46 PJM OATT. Attachment K – Appendix §6.4 Offer Price Caps., (Effective Date August 9, 2013), p. 1912.

The FMU adder was filed with FERC in 2005, and approved effective February 2006.[47] The goal, in 2005, was to ensure that units that were offer capped for most of their run hours could cover their going forward or avoidable costs (also known as ACR in the capacity market). That function became unnecessary with the introduction of the RPM capacity market design in 2007. Under the RPM design, units can make offers in the capacity market that include their ACR net of net revenues. Thus if there is a shortfall in ACR recovery, that shortfall is included in the RPM offer. If the unit clears in RPM, it covers its shortfall in ACR costs. If the unit does not clear, then the market result means that PJM can provide reliability without the unit and no additional revenue is needed.

The MMU recommends the elimination of FMU and AU adders. Since the implementation of FMU adders, 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. The MMU and PJM proposed a compromise that maintained the ability of certain generating units to qualify for FMU adders but limiting FMU adders to units with net revenues less than unit going forward costs or ACR.

In 2013, of the 112 units that received FMU payments in 2013, 28 units did not cover ACR. Of those 28 units, 22 units are scheduled to retire (Table 3-30).

Table 3-30 Frequently mitigated units at risk of retirement: 2013

	No. of Units	MW
Units that received FMU payments in 2013	112	14,763
FMUs that did not cover ACR in 2013	28	5,342
FMUs that did not cover ACR in 2013 that are scheduled to retire	22	3,908
FMUs that did not cover ACR in 2013 that are not scheduled to retire	6	1,434

47 10 FERC ¶ 61,053 (2005).

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, up-to congestion transactions, import transactions and export 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 on a list of 438 buses, eligible for up-to congestion transaction bidding.[48] Financial Transaction Rights (FTRs) bids may be submitted at any bus on a list of 1,915 buses, eligible for FTRs. Import and export transactions may be submitted at any interface pricing point, where an import is equivalent to a virtual offer that is injected into PJM and an export is equivalent to a virtual bid that is withdrawn from PJM.

Figure 3-22 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve of imports, the system aggregate supply curve without increment offers and imports, the system aggregate supply curve with increment offers, and the system aggregate supply curve with increment offers and imports for an example day in the first six months of 2014.

48 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>.

Figure 3-22 PJM day-ahead aggregate supply curves: 2014 example day

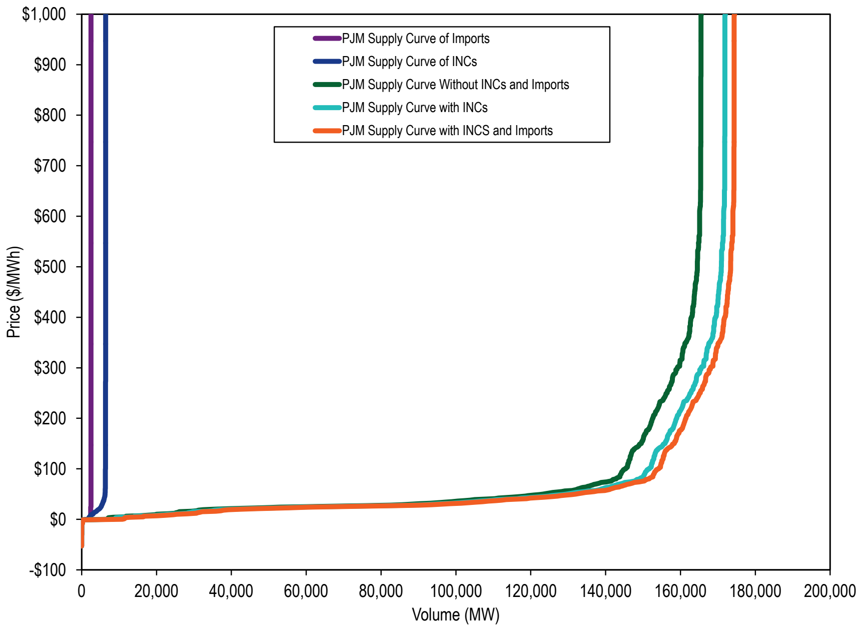


Table 3-31 shows the average hourly number of increment offers and decrement bids and the average hourly MW for 2013 and the first six months of 2014. In the first six months of 2014, the average hourly submitted and cleared increment offer MW decreased 33.6 and 41.5 percent, and the average hourly submitted and cleared decrement bid MW increased 1.8 and decreased 15.5 percent, compared to the first six months of 2013.

Table 3-31 Hourly average number of cleared and submitted INCs, DECs by month: January 2013 through June of 2014

		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
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	6,595	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	6,819	8,295	78	195
2013	Sep	4,262	5,464	60	191	6,646	8,400	82	233
2013	Oct	4,375	5,642	70	215	6,694	8,899	93	287
2013	Nov	4,906	6,803	81	304	7,202	10,200	105	386
2013	Dec	4,803	6,123	75	278	7,700	10,650	98	393
2013	Annual	5,131	6,451	65	182	7,202	9,088	83	239
2014	Jan	3,086	4,165	69	214	5,844	8,372	81	322
2014	Feb	3,085	3,985	64	171	5,981	9,108	82	286
2014	Mar	2,942	3,890	66	179	6,702	9,455	96	291
2014	Apr	2,837	3,722	69	181	5,693	7,720	86	279
2014	May	3,981	6,008	73	248	6,042	10,238	104	418
2014	Jun	3,486	5,101	62	219	6,716	8,806	105	324
2014	Annual	3,240	4,488	67	203	6,165	8,955	93	321

In the first six months of 2014, up-to congestion transactions continued to displace increment offers and decrement bids. Table 3-32 shows the average hourly number of up-to congestion transactions and the average hourly MW for 2013 and the first six months of 2014. In the first six months of 2014, the average hourly up-to congestion submitted MW increased 26.7 percent and cleared MW increased 26.4 percent, compared to the first six months of 2013.

Table 3-32 Hourly average of cleared and submitted up-to congestion bids by month: January 2013 through June of 2014

		Up-to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2013	Jan	44,844	157,229	1,384	4,205
2013	Feb	46,351	144,066	1,419	3,862
2013	Mar	49,003	163,178	1,467	3,745
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	Oct	45,918	145,026	1,705	4,267
2013	Nov	54,643	171,439	2,108	5,365
2013	Dec	60,588	197,092	2,204	5,948
2013	Annual	51,598	175,255	1,682	4,596
2014	Jan	55,969	199,708	2,436	7,056
2014	Feb	64,123	229,256	3,262	9,020
2014	Mar	65,829	243,469	3,521	10,920
2014	Apr	73,453	224,924	3,216	8,390
2014	May	73,853	251,463	3,057	8,860
2014	Jun	69,050	235,590	2,781	8,221
2014	Annual	67,048	230,762	3,042	8,744

Table 3-33 shows the average hourly number of import and export transactions and the average hourly MW for 2013 and the first six months of 2014. In the first six months of 2014, the average hourly submitted and cleared import transaction MW increased 4.5 and 6.7 percent, and the average hourly submitted and cleared export transaction MW increased 27.8 and 23.9 percent, compared to the first six months of 2013.[49]

49 For more information about imports and exports, see the *2014 Quarterly State of the Market Report for PJM: January through June, Section 9, "Interchange Transactions,"* Interchange Transaction Activity.

Table 3-33 Hourly average number of cleared and submitted import and export transactions by month: January 2013 through June of 2014

		Imports				Exports			
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
2013	Jan	2,071	2,177	10	11	3,278	3,293	21	21
2013	Feb	2,098	2,244	11	13	3,275	3,288	19	19
2013	Mar	1,997	2,097	12	13	3,326	3,329	18	18
2013	Apr	2,004	2,097	12	13	2,691	2,691	16	16
2013	May	2,160	2,316	12	13	2,824	2,838	18	19
2013	Jun	2,712	2,818	15	16	3,420	3,507	19	20
2013	Jul	2,930	3,019	15	16	3,621	3,720	19	20
2013	Aug	2,577	2,656	13	15	3,734	3,766	20	20
2013	Sep	2,089	2,135	9	10	3,561	3,567	19	19
2013	Oct	2,191	2,216	10	10	3,215	3,225	18	18
2013	Nov	2,182	2,196	10	11	2,531	2,564	16	16
2013	Dec	2,243	2,315	10	10	3,774	3,889	21	22
2013	Annual	2,273	2,359	12	13	3,273	3,309	19	19
2014	Jan	2,347	2,515	14	15	3,495	3,887	21	24
2014	Feb	2,419	2,616	13	15	4,299	4,584	24	26
2014	Mar	2,450	2,496	15	15	5,069	5,293	27	29
2014	Apr	2,017	2,045	13	13	4,164	4,171	22	22
2014	May	2,162	2,168	13	13	2,664	2,674	18	18
2014	Jun	2,527	2,536	13	14	3,643	3,645	22	22
2014	Annual	2,319	2,394	13	14	3,882	4,034	22	23

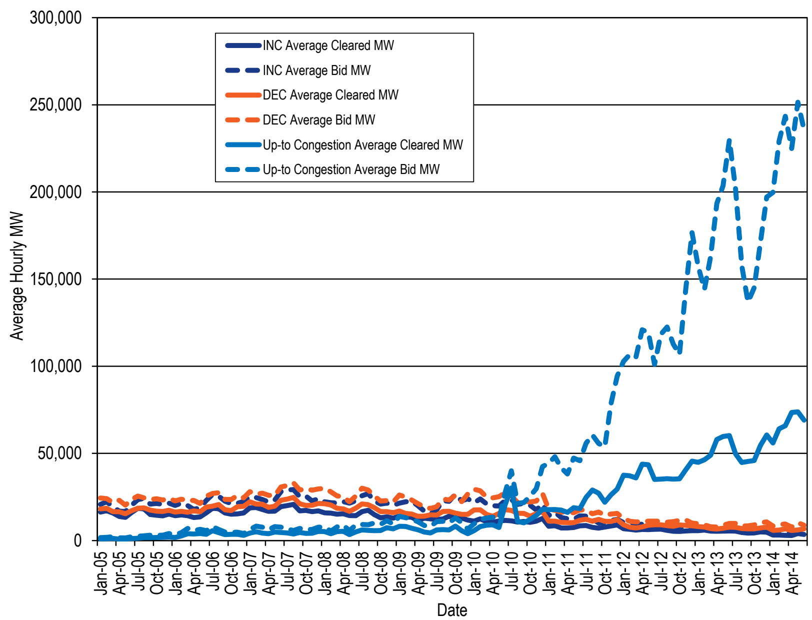
Table 3-34 shows the frequency with which generation offers, import or export transactions, up-to congestion transactions, decrement bids, increment offers and price-sensitive demand are marginal for each month.

Table 3-34 Type of day-ahead marginal units: January through June of 2014

	Generation	Dispatchable Transaction	Up-to Congestion Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	2.9%	0.1%	94.4%	1.4%	1.1%	0.0%
Feb	2.0%	0.3%	94.8%	1.9%	1.1%	0.0%
Mar	2.6%	0.2%	94.7%	1.5%	1.0%	0.0%
Apr	2.3%	0.0%	95.1%	1.4%	1.2%	0.0%
May	1.6%	0.0%	92.0%	4.0%	2.4%	0.0%
Jun	2.0%	0.0%	94.6%	2.0%	1.4%	0.0%
Annual	2.2%	0.1%	94.2%	2.1%	1.4%	0.0%

Figure 3-23 shows the hourly volume of bid and cleared INC, DEC and up-to congestion bids by month.

Figure 3-23 Hourly number of bid and cleared INC, DEC and Up-to Congestion bids (MW) by month: January 2005 through June 2014



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 3-35 shows, for the first six months of 2013 and the first six months of 2014, the total increment offers and decrement bids by whether the parent organization is financial or physical. Table 3-36 shows, for the first six months of 2013 and the first six months of 2014, the total up-to congestion transactions by the type of parent organization. Table 3-37 shows, for the first six months of 2013 and the first six months of 2014, the total import and export transactions by whether the parent organization is financial or physical.

The top five companies with cleared up-to congestion transactions are financial and account for 65.8 percent of all the cleared up-to congestion MW in PJM in the first six months of 2014, which is 2.2 percent higher than 63.6 percent in the first six months of 2013. The cleared up-to congestion MW from financial companies increased 29.9 percent in the first six months of 2014 compared to the first six months of 2013. At the same time, the cleared up-to congestion MW from physical companies decreased by 36.5 percent decrease in the first six months of 2014 compared to the first six months for 2013. The average hourly price difference between day-ahead and real-time markets increased from $0.55 in the first six months of 2013 to $1.38 in the first six months of 2014. On average, real-time prices were lower than day-ahead prices.

Table 3-35 PJM INC and DEC bids by type of parent organization (MW): January through June of 2013 and 2014

	2013 (Jan - Jun)		2014 (Jan - Jun)	
Category	Total Virtual Bids MW	Percentage	Total Virtual Bids MW	Percentage
Financial	16,564,288	24.5%	24,106,225	41.3%
Physical	50,975,729	75.5%	34,273,129	58.7%
Total	67,540,016	100.0%	58,379,354	100.0%

Table 3-36 PJM up-to congestion transactions by type of parent organization (MW): January through June of 2013 and 2014

	2013 (Jan - Jun)		2014 (Jan - Jun)	
Category	Total Up-to Congestion MW	Percentage	Total Up-to Congestion MW	Percentage
Financial	218,167,286	94.7%	283,415,809	97.3%
Physical	12,237,587	5.3%	7,775,490	2.7%
Total	230,404,873	100.0%	291,191,299	100.0%

Table 3-37 PJM import and export transactions by type of parent organization (MW): January through June of 2013 and 2014

	2013 (Jan - Jun)		2014 (Jan - Jun)	
Category	Total Import and Export MW	Percentage	Total Import and Export MW	Percentage
Financial	9,824,038	42.6%	10,355,872	38.1%
Physical	13,222,593	57.4%	16,806,443	61.9%
Total	23,046,631	100.0%	27,162,315	100.0%

Table 3-38 shows increment offers and decrement bids bid by top ten locations for the first six months of 2013 and the first six months of 2014.

Table 3-38 PJM virtual offers and bids by top ten locations (MW): January through June of 2013 and 2014

2013 (Jan - Jun)					2014 (Jan - Jun)				
Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW	Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	12,988,250	14,451,505	27,439,756	WESTERN HUB	HUB	5,392,588	6,060,329	11,452,917
SOUTHIMP	INTERFACE	4,150,495	0	4,150,495	MISO	INTERFACE	293,286	4,007,374	4,300,660
N ILLINOIS HUB	HUB	1,304,118	2,474,710	3,778,828	PPL	ZONE	95,332	3,305,357	3,400,689
AEP-DAYTON HUB	HUB	1,777,832	1,879,048	3,656,880	SOUTHIMP	INTERFACE	3,336,133	0	3,336,133
IMO	INTERFACE	2,955,529	38,609	2,994,138	PECO	ZONE	94,450	2,718,398	2,812,848
PPL	ZONE	37,395	2,672,426	2,709,821	IMO	INTERFACE	2,226,609	137,034	2,363,643
PECO	ZONE	48,706	1,718,713	1,767,419	AEP-DAYTON HUB	HUB	990,986	1,206,700	2,197,686
MISO	INTERFACE	207,554	1,526,580	1,734,134	N ILLINOIS HUB	HUB	490,521	1,438,357	1,928,878
DOMINION HUB	HUB	199,382	918,597	1,117,979	BGE	ZONE	6,905	1,492,146	1,499,051
NYIS	INTERFACE	325,738	657,086	982,824	NYIS	INTERFACE	458,402	357,044	815,446
Top ten total		23,994,999	26,337,274	50,332,274			13,385,210	20,722,740	34,107,950
PJM total		29,332,449	38,207,567	67,540,016			19,489,623	38,889,731	58,379,354
Top ten total as percent of PJM total		81.8%	68.9%	74.5%			68.7%	53.3%	58.4%

Table 3-39 shows up-to congestion transactions by import bids for the top ten locations for the first six months of 2013 and the first six months of 2014.[50]

Table 3-39 PJM cleared up-to congestion import bids by top ten source and sink pairs (MW): January through June of 2013 and 2014

2013 (Jan - Jun)				
Imports				
Source	Source Type	Sink	Sink Type	MW
OVEC	INTERFACE	DEOK	ZONE	747,582
OVEC	INTERFACE	STUART 1	AGGREGATE	638,710
NYIS	INTERFACE	HUDSON BC	AGGREGATE	633,803
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	632,639
NORTHWEST	INTERFACE	ZION 1	AGGREGATE	457,848
OVEC	INTERFACE	BECKJORD 6	AGGREGATE	367,838
MISO	INTERFACE	112 WILTON	EHVAGG	355,225
OVEC	INTERFACE	CONESVILLE 5	AGGREGATE	338,322
OVEC	INTERFACE	SPORN 2	AGGREGATE	324,940
NORTHWEST	INTERFACE	BYRON 1	AGGREGATE	319,915
Top ten total				4,816,821
PJM total				23,795,591
Top ten total as percent of PJM total				20.2%
2014 (Jan - Jun)				
Imports				
Source	Source Type	Sink	Sink Type	MW
SOUTHEAST	INTERFACE	EDANVILL T1	AGGREGATE	668,476
HUDSONTP	INTERFACE	LEONIA 230 T-2	AGGREGATE	558,454
MISO	INTERFACE	COOK	EHVAGG	463,252
OVEC	INTERFACE	BIG SANDY CT1	AGGREGATE	424,636
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	370,917
NEPTUNE	INTERFACE	SOUTHRIV 230	AGGREGATE	323,163
MISO	INTERFACE	AEP-DAYTON HUB	HUB	311,956
OVEC	INTERFACE	DEOK	ZONE	285,971
HUDSONTP	INTERFACE	LEONIA 230 T-1	AGGREGATE	282,640
SOUTHEAST	INTERFACE	CLOVER	EHVAGG	272,144
Top ten total				3,961,610
PJM total				18,509,285
Top ten total as percent of PJM total				21.4%

Table 3-40 shows up-to congestion transactions by export bids for the top ten locations for the first six months of 2013 and the first six months of 2014.

Table 3-40 PJM cleared up-to congestion export bids by top ten source and sink pairs (MW): January through June of 2013 and 2014

2013 (Jan - Jun)				
Exports				
Source	Source Type	Sink	Sink Type	MW
JEFFERSON	EHVAGG	OVEC	INTERFACE	1,034,857
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	801,391
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	766,120
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	645,742
GAVIN	EHVAGG	OVEC	INTERFACE	614,094
TANNERS CRK 4	AGGREGATE	OVEC	INTERFACE	571,260
SPORN 3	AGGREGATE	OVEC	INTERFACE	450,427
F387 CHICAGOH	AGGREGATE	NIPSCO	INTERFACE	446,903
21 KINCA ATR24304	AGGREGATE	OVEC	INTERFACE	410,609
EAST BEND 2	AGGREGATE	OVEC	INTERFACE	364,120
Top ten total				6,105,523
PJM total				28,782,300
Top ten total as percent of PJM total				21.2%
2014 (Jan - Jun)				
Exports				
Source	Source Type	Sink	Sink Type	MW
JEFFERSON	EHVAGG	OVEC	INTERFACE	1,218,831
TANNERS CRK 4	AGGREGATE	SOUTHWEST	INTERFACE	1,203,791
TANNERS CRK 4	AGGREGATE	OVEC	INTERFACE	508,546
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	492,766
ROCKPORT	EHVAGG	OVEC	INTERFACE	405,904
LINDEN A	AGGREGATE	LINDENVFT	INTERFACE	383,560
JEFFERSON	EHVAGG	SOUTHWEST	INTERFACE	322,546
STUART 1	AGGREGATE	OVEC	INTERFACE	321,356
BECKJORD 6	AGGREGATE	OVEC	INTERFACE	320,690
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	310,744
Top ten total				5,488,734
PJM total				20,674,821
Top ten total as percent of PJM total				26.5%

50 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 3-41 shows up-to congestion transactions by wheel bids for the top ten locations for the first six months of 2013 and the first six months of 2014.

Table 3-41 PJM cleared up-to congestion wheel bids by top ten source and sink pairs (MW): January through June of 2013 and 2014

2013 (Jan - Jun)				
Wheels				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	559,697
NORTHWEST	INTERFACE	MISO	INTERFACE	267,006
IMO	INTERFACE	NYIS	INTERFACE	225,339
MISO	INTERFACE	NIPSCO	INTERFACE	224,005
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	192,900
MISO	INTERFACE	SOUTHEXP	INTERFACE	85,854
LINDENVFT	INTERFACE	NYIS	INTERFACE	77,442
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	73,043
OVEC	INTERFACE	IMO	INTERFACE	57,734
MISO	INTERFACE	OVEC	INTERFACE	56,278
Top ten total				1,819,298
PJM total				2,303,956
Top ten total as percent of PJM total				79.0%
2014 (Jan - Jun)				
Wheels				
Source	Source Type	Sink	Sink Type	MW
NORTHWEST	INTERFACE	MISO	INTERFACE	677,833
OVEC	INTERFACE	SOUTHEXP	INTERFACE	293,854
MISO	INTERFACE	NORTHWEST	INTERFACE	204,574
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	176,441
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	80,739
IMO	INTERFACE	NYIS	INTERFACE	71,471
MISO	INTERFACE	SOUTHEXP	INTERFACE	60,208
OVEC	INTERFACE	SOUTHWEST	INTERFACE	59,460
SOUTHEAST	INTERFACE	SOUTHEXP	INTERFACE	57,528
MISO	INTERFACE	NIPSCO	INTERFACE	54,605
Top ten total				1,736,715
PJM total				2,182,110
Top ten total as percent of PJM total				79.6%

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.[51] Up-to congestion transactions can now be made at internal buses. The top ten internal up-to congestion transaction locations were 9.6 percent of the PJM total internal up-to congestion transactions in the first six months of 2014.

Table 3-42 shows up-to congestion transactions by internal bids for the top ten locations for the first six months of 2013 and 2014.

Table 3-42 PJM cleared up-to congestion internal bids by top ten source and sink pairs (MW): January through June of 2013 and 2014

2013 (Jan - Jun)				
Internal				
Source	Source Type	Sink	Sink Type	MW
SUNBURY 1-3	AGGREGATE	CITIZENS	AGGREGATE	2,406,576
ATSI GEN HUB	HUB	ATSI	ZONE	1,597,254
CORDOVA	AGGREGATE	QUAD CITIES 2	AGGREGATE	1,491,949
FE GEN	AGGREGATE	ATSI	ZONE	1,116,651
DAY	ZONE	BUCKEYE - DPL	AGGREGATE	1,090,748
MT STORM	EHVAGG	GREENLAND GAP	EHVAGG	1,079,954
YADKIN	EHVAGG	FENTRESS	EHVAGG	1,022,931
AEP-DAYTON HUB	HUB	WESTERN HUB	HUB	962,854
NAPERVILLE	AGGREGATE	WINNETKA	AGGREGATE	954,143
NAPERVILLE	AGGREGATE	CHICAGO HUB	HUB	921,123
Top ten total				12,644,184
PJM total				175,523,026
Top ten total as percent of PJM total				7.2%
2014 (Jan - Jun)				
Internal				
Source	Source Type	Sink	Sink Type	MW
MOUNTAINEER	EHVAGG	GAVIN	EHVAGG	4,012,895
VERNON BK 4	AGGREGATE	AEC - JC	AGGREGATE	2,941,605
MOUNTAINEER	EHVAGG	FLATLICK	EHVAGG	2,875,685
DAY	ZONE	BUCKEYE - DPL	AGGREGATE	2,851,797
ATSI GEN HUB	HUB	ATSI	ZONE	2,505,826
FE GEN	AGGREGATE	ATSI	ZONE	2,296,169
WESTERN HUB	HUB	AEP-DAYTON HUB	HUB	1,803,219
DUMONT	EHVAGG	COOK	EHVAGG	1,604,519
JEFFERSON	EHVAGG	COOK	EHVAGG	1,542,406
SUNBURY 1-3	AGGREGATE	CITIZENS	AGGREGATE	1,440,225
Top ten total				23,874,346
PJM total				249,825,084
Top ten total as percent of PJM total				9.6%

51 For more information, see the *2013 State of the Market Report for PJM*, Volume II, Section 9, "Interchange Transactions," Up-to Congestion.

Table 3-43 shows the number of source-sink pairs that were offered and cleared monthly in January of 2012 through the first six months of 2014. The annual row in Table 3-43 is the average hourly number of offered and cleared source-sink pairs for the year for the average columns and the maximum hourly number of offered and cleared source-sink pairs for the year for the maximum columns. The increase in average offered and cleared source-sink pairs beginning in November and December of 2012 and continuing through the first six months of 2014 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.

Table 3-43 Number of PJM offered and cleared source and sink pairs: January 2012 through June 2014

		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	2,827	13,009	1,800	8,071
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	9,064	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	Oct	4,743	7,134	3,235	4,721
2013	Nov	8,605	14,065	5,419	8,069
2013	Dec	8,346	11,728	6,107	7,415
2013	Annual	5,996	14,065	3,620	8,069
2014	Jan	7,977	11,191	5,179	7,714
2014	Feb	10,087	11,688	7,173	8,463
2014	Mar	11,360	14,745	7,284	9,943
2014	Apr	11,487	14,106	8,589	10,253
2014	May	11,215	13,477	7,734	9,532
2014	Jun	10,613	14,112	7,374	10,143
2014	Annual	10,456	14,745	7,214	10,253

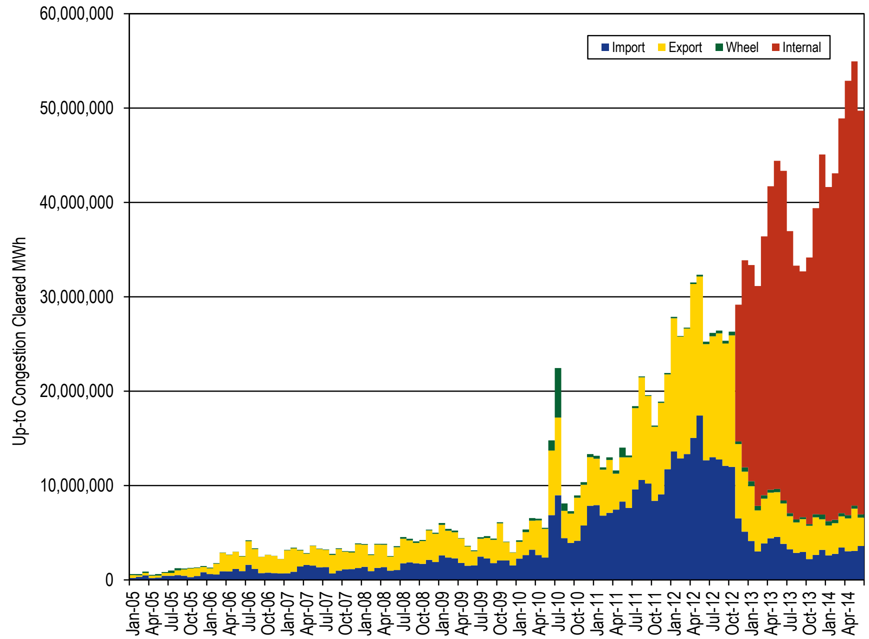
Table 3-44 and Figure 3-24 show total cleared up-to congestion transactions by type for the first six months of 2013 and the first six months of 2014. Internal up-to congestion transactions in the first six months of 2014 were 85.8 percent of all up-to congestion transactions for the first six months of 2014. In the first six months of 2014, the top ten internal up-to congestion transactions were the top ten total up-to congestion transactions in MW.

Table 3-44 PJM cleared up-to congestion transactions by type (MW): January through June of 2013 and 2014

2013 (Jan - Jun)					
Cleared Up-to Congestion Bids					
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	4,816,821	6,105,523	1,819,298	12,644,184	12,757,918
PJM total (MW)	23,795,591	28,782,300	2,303,956	175,523,026	230,404,873
Top ten total as percent of PJM total	20.2%	21.2%	79.0%	7.2%	5.5%
PJM total as percent of all up-to congestion transactions	10.3%	12.5%	1.0%	76.2%	100.0%
2014 (Jan - Jun)					
Cleared Up-to Congestion Bids					
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	3,961,610	5,488,734	1,736,715	23,874,346	23,874,346
PJM total (MW)	18,509,285	20,674,821	2,182,110	249,825,084	291,191,299
Top ten total as percent of PJM total	21.4%	26.5%	79.6%	9.6%	8.2%
PJM total as percent of all up-to congestion transactions	6.4%	7.1%	0.7%	85.8%	100.0%

Figure 3-24 shows the initial increase and continued rise of internal up-to congestion transactions in November and December of 2012, 2013, and the first six months of 2014, following the November 1, 2012 rule change permitting such transactions.

Figure 3-24 PJM cleared up-to congestion transactions by type (MW): January 2005 through June 2014



Generator Offers

Generator offers are categorized as dispatchable (Table 3-45) or self scheduled (Table 3-46).[52] Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are self scheduled and must run. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are self scheduled and dispatchable. Table 3-45 and Table 3-46 do not include units that did not indicate their offer status and units that were offered as available to run only during emergency events. The MW offered beyond the economic range of a unit, i.e. MW range between the specified economic maximum and

52 Each range in the tables is greater than or equal to the lower value and less than the higher value. The unit type battery is not included in these tables because batteries do not make energy offers. The unit type fuel cell is not included in these tables because of the small number owners and the small number of units of this type of generation.

emergency maximum, are categorized as emergency MW. The emergency MW are included in both tables.

Table 3-45 shows the proportion of MW offers by dispatchable units, by unit type and by offer price range, for the first six months of 2014. For example, 64.5 percent of CC offers were dispatchable and in the $0 to $200 per MWh price range. The Total column is the proportion of all MW offers by unit type that were dispatchable. For example, 80.7 percent of all CC MW offers were dispatchable, including the 7.8 percent of emergency MW offered by CC units. The All Dispatchable Offers row is the proportion of MW that were offered as available for economic dispatch within a given range by all unit types. For example, 39.5 percent of all dispatchable offers were in the $0 to $200 per MWh price range. The Total column in the All Dispatchable Offers row is the proportion of all MW offers that were offered as available for economic dispatch, including emergency MW. Among all the generator offers in the first six months of 2014, 55.1 percent were offered as available for economic dispatch.

Table 3-45 Distribution of MW for dispatchable unit offer prices: January through June of 2014

	Dispatchable (Range)							
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	0.0%	64.5%	4.7%	2.0%	0.6%	1.1%	7.8%	80.7%
CT	0.1%	48.0%	29.5%	7.2%	2.1%	1.2%	11.2%	99.3%
Diesel	1.9%	14.4%	25.0%	8.7%	2.2%	1.9%	15.2%	69.1%
Run of River	0.0%	10.9%	0.0%	0.0%	0.0%	0.0%	0.0%	10.9%
Nuclear	8.0%	34.1%	0.0%	0.0%	0.0%	0.0%	11.5%	53.6%
Pumped Storage	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
Solar	0.7%	5.4%	0.0%	0.0%	0.0%	0.0%	0.1%	6.2%
Steam	0.0%	44.3%	2.4%	0.4%	0.1%	0.2%	3.6%	50.9%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	39.1%	7.4%	0.0%	0.0%	0.0%	0.0%	0.5%	47.0%
All Dispatchable Offers	0.9%	39.5%	7.0%	1.8%	0.5%	0.5%	5.0%	55.1%

Table 3-46 shows the proportion of MW offers by unit type that were self scheduled to generate fixed output and by unit type and price range for self-scheduled and dispatchable units, for the first six months of 2014. For example, 16.2 percent of CC offers were self scheduled and dispatchable and in the $0 to $200 price range. The Total column is the proportion of all MW offers by unit type that were self scheduled to generate fixed output and are self scheduled and dispatchable. For example, 19.3 percent of all CC MW offers were either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum, including the 1.7 percent of emergency MW offered by CC units. The All Self-Scheduled Offers row is the proportion of MW that were offered as either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum within a given range by all unit types. For example, units that were self scheduled to generate at fixed output accounted for 20.7 percent of all offers and self-scheduled and dispatchable units accounted for 19.9 percent of all offers. The Total column in the All Self-Scheduled Offers row is the proportion of all MW offers that were either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum, including emergency MW. Among all the generator offers in the first six months of 2014, 23.1 percent were offered as self scheduled and 21.8 percent were offered as self scheduled and dispatchable.

Table 3-46 Distribution of MW for self scheduled offer prices: January through June of 2014

	Self Scheduled		Self Scheduled and Dispatchable (Range)							
Unit Type	Must Run	Emergency	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	0.7%	0.2%	0.1%	16.2%	0.4%	0.1%	0.1%	0.0%	1.5%	19.3%
CT	0.4%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%
Diesel	26.8%	4.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	30.9%
Hydro	82.4%	6.2%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.1%	89.1%
Nuclear	23.4%	10.1%	2.6%	2.6%	0.0%	0.0%	0.0%	0.0%	7.8%	46.4%
Pumped Storage	62.0%	15.7%	4.8%	11.4%	0.0%	0.0%	0.0%	1.6%	4.4%	99.9%
Solar	69.6%	23.5%	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	93.8%
Steam	4.7%	1.2%	0.2%	39.6%	0.1%	0.0%	0.0%	0.0%	3.1%	49.1%
Transaction	82.4%	17.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Wind	5.6%	4.7%	34.4%	2.8%	0.0%	0.0%	0.0%	0.0%	5.5%	53.0%
All Self-Scheduled Offers	20.7%	2.4%	0.8%	18.9%	0.1%	0.0%	0.0%	0.0%	1.9%	44.9%

Market Performance

The PJM average locational marginal price (LMP) reflects the configuration of the entire RTO. The PJM Energy Market includes the Real-Time Energy Market and the Day-Ahead Energy Market.

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.[53]

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.

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

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 3-47 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 3-47 on the system-wide load-weighted LMP. The negative markup components of LMP reflect the negative markups shown in the Table 3-26.

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 exclude 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. Even the adjusted markup underestimates the markup because coal units facing increased competitive pressure have excluded both the ten percent adder and some or all components of operating and maintenance cost. While both these elements are permitted under the definition of cost-based offers in the relevant PJM manual, they are not part of a competitive offer for a coal unit because they are not actually marginal costs, and market behavior reflected that fact.[54]

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 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 3-47 shows the mark-up component of the load-weighted LMP by fuel type and unit type using unadjusted and adjusted offers. The adjusted markup component of LMP increased from $0.30 in the first six months of 2013 to $2.88 in the first six months of 2014. The adjusted markup contribution of coal units in the first six months of 2014 was $2.38. The adjusted mark-up component of all gas-fired units in the first six months of 2014 was minus $0.24. Coal units accounted for 92 percent of the increased markup component of LMP in the first six months of 2014 while gas units accounted for minus nine percent.[55] The markup component of wind units is zero but this includes a range from negative to positive. If a price-based offer is negative but less negative than a cost-based offer, the markup is positive. In the first six of 2014, among the wind units that were marginal, 1.4 percent had positive offer prices.

54 See *PJM Manual 15: Cost Development Guidelines*, Revision: 23 (Effective August 1, 2013).

55 See the *2014 Quarterly State of the Market Report for PJM: January through March*, Section 3, "Real-Time Markup during Cold Weather Days in January."

Table 3-47 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January through June 2013 and 2014[56]

		2013 (Jan-Jun)		2014 (Jan-Jun)	
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	($0.78)	$0.78	$1.23	$2.38
Gas	CC	($0.28)	($0.28)	$0.51	$0.50
Gas	CT	$0.07	$0.07	$0.49	$0.49
Gas	Diesel	$0.00	$0.00	$0.14	$0.14
Gas	Steam	($0.35)	($0.35)	($1.37)	($1.37)
Municipal Waste	Steam	$0.00	$0.00	$0.30	$0.30
Oil	CC	$0.00	$0.00	$0.14	$0.14
Oil	CT	$0.02	$0.02	$0.14	$0.14
Oil	Diesel	$0.07	$0.07	$0.04	$0.04
Oil	Steam	($0.00)	($0.00)	$0.08	$0.08
Other	Steam	($0.02)	($0.02)	$0.00	$0.00
Total		($1.26)	$0.30	$1.73	$2.88

Markup Component of Real-Time Price

Table 3-48 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on-peak and off-peak prices. Table 3-49 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on-peak and off-peak prices. In the first six months of 2014, when using unadjusted cost offers, $1.73 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost-offers, $2.88 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In the first six months of 2014, the peak markup component was highest in January, $7.95 per MWh using unadjusted cost offers and $9.10 per MWh using adjusted cost offers. This corresponds to 6.27 percent and 7.18 percent of the real time load-weighted average LMP in January.

56 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 gas from municipal waste.

Table 3-48 Monthly markup components of real-time load-weighted LMP (Unadjusted): January through June 2013 and 2014

	2013			2014		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($2.82)	($3.28)	($2.38)	$5.84	$3.66	$7.95
Feb	($1.84)	($2.95)	($0.76)	$2.98	$0.88	$4.99
Mar	$0.67	($0.90)	$2.30	$6.85	$3.12	$10.76
Apr	($1.95)	($3.04)	($1.02)	($1.20)	($2.41)	($0.15)
May	($1.16)	($2.92)	$0.32	($0.59)	($1.66)	$0.44
Jun	($0.48)	($1.58)	$0.62	($5.04)	($0.93)	($8.59)
Total	($1.26)	($2.40)	($0.18)	$1.73	$0.72	$2.69

Table 3-49 Monthly markup components of real-time load-weighted LMP (Adjusted): January through June 2013 and 2014

	2013			2014		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($1.04)	($1.39)	($0.71)	$7.18	$5.19	$9.10
Feb	($0.05)	($1.04)	$0.91	$3.85	$1.93	$5.69
Mar	$2.28	$0.89	$3.71	$7.89	$4.43	$11.51
Apr	($0.69)	($1.39)	($0.10)	$0.09	($0.70)	$0.78
May	$0.22	($1.17)	$1.39	$0.55	($0.31)	$1.38
Jun	$0.98	($0.04)	$1.99	($3.82)	$0.57	($7.62)
Total	$0.30	($0.64)	$1.18	$2.88	$2.12	$3.60

Markup Component of Real-Time Zonal Prices

The unit markup component of average real-time price using unadjusted offers is shown for each zone for the first six months of 2014 and the first six months of 2013 in Table 3-50 and for adjusted offers in Table 3-51. The smallest zonal all hours average markup component using unadjusted offers for the first six months of 2014 was in the DLCO Zone, $0.28 per MWh, while the highest was in the Dominion Control Zone, $3.10 per MWh. The smallest zonal on peak average markup was in the DLCO Control Zone, -$0.20 per MWh, while the highest was in the Dominion Control Zone, $4.51 per MWh.

Table 3-50 Average real-time zonal markup component (Unadjusted): January through June, 2013 and 2014

	2013 (Jan - Jun)			2014 (Jan - Jun)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	($1.47)	($2.52)	($0.46)	$1.16	$0.31	$1.97
AEP	($1.29)	($2.33)	($0.28)	$1.70	$0.33	$3.02
APS	($1.36)	($2.48)	($0.28)	$1.39	$0.77	$1.99
ATSI	($1.31)	($2.41)	($0.28)	$0.57	$0.26	$0.87
BGE	($1.12)	($2.23)	($0.06)	$2.99	$1.94	$3.99
ComEd	($1.39)	($2.51)	($0.36)	$1.30	$0.46	$2.10
DAY	($1.35)	($2.41)	($0.38)	$1.18	$0.05	$2.22
DEOK	($1.36)	($2.40)	($0.40)	$1.07	($0.11)	$2.18
DLCO	($1.38)	($2.41)	($0.41)	$0.28	$0.79	($0.20)
DPL	($1.47)	($2.51)	($0.46)	$1.93	$1.11	$2.72
Dominion	($0.94)	($2.28)	$0.36	$3.10	$1.61	$4.51
EKPC	($0.22)	($1.80)	$1.36	$1.94	$0.41	$3.47
JCPL	($1.20)	($2.44)	($0.07)	$0.33	($0.16)	$0.77
Met-Ed	($1.44)	($2.49)	($0.47)	$1.01	$0.54	$1.46
PECO	($1.53)	($2.48)	($0.64)	$1.20	$0.40	$1.96
PENELEC	($1.63)	($2.58)	($0.73)	$2.42	$0.89	$3.85
PPL	($1.56)	($2.59)	($0.60)	$1.88	$0.72	$2.96
PSEG	($0.80)	($2.44)	$0.71	$2.46	$1.16	$3.66
Pepco	($0.99)	($2.24)	$0.16	$2.76	$1.69	$3.73
RECO	($0.55)	($2.32)	$0.96	$2.62	$1.16	$3.87

Table 3-51 Average real-time zonal markup component (Adjusted): January through June, 2013 and 2014

	2013 (Jan - Jun)			2014 (Jan - Jun)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$0.08	($0.74)	$0.88	$2.28	$1.63	$2.91
AEP	$0.30	($0.54)	$1.10	$2.90	$1.84	$3.94
APS	$0.21	($0.69)	$1.07	$2.52	$2.16	$2.87
ATSI	$0.31	($0.60)	$1.16	$1.76	$1.74	$1.78
BGE	$0.42	($0.43)	$1.24	$4.17	$3.38	$4.92
ComEd	$0.14	($0.84)	$1.03	$2.48	$1.87	$3.04
DAY	$0.28	($0.58)	$1.08	$2.40	$1.58	$3.16
DEOK	$0.20	($0.65)	$1.00	$2.25	$1.37	$3.10
DLCO	$0.19	($0.66)	$0.98	$1.56	$2.35	$0.82
DPL	$0.10	($0.72)	$0.91	$3.05	$2.40	$3.66
Dominion	$0.58	($0.53)	$1.66	$4.16	$2.92	$5.35
EKPC	$1.26	($0.20)	$2.72	$3.13	$1.87	$4.40
JCPL	$0.35	($0.68)	$1.28	$1.43	$1.15	$1.68
Met-Ed	$0.10	($0.75)	$0.89	$2.13	$1.85	$2.39
PECO	$0.01	($0.73)	$0.71	$2.32	$1.71	$2.89
PENELEC	($0.02)	($0.78)	$0.69	$3.59	$2.28	$4.81
PPL	($0.00)	($0.84)	$0.78	$3.00	$2.02	$3.91
PSEG	$0.73	($0.68)	$2.02	$3.56	$2.44	$4.58
Pepco	$0.51	($0.47)	$1.41	$3.90	$3.09	$4.63
RECO	$0.96	($0.57)	$2.27	$3.79	$2.48	$4.92

Markup by Real Time Price Levels

Table 3-52 shows 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 average LMP was in the identified price range.

Table 3-52 Average real-time markup component (By price category, unadjusted): January through June 2013 and 2014

	2013 (Jan - Jun)		2014 (Jan - Jun)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.69)	54.5%	($0.14)	5.7%
$25 to $50	($0.81)	41.3%	($1.44)	62.1%
$50 to $75	$0.15	2.7%	($0.06)	15.9%
$75 to $100	$0.04	0.8%	$0.31	5.8%
$100 to $125	$0.02	0.4%	$0.25	2.6%
$125 to $150	($0.01)	0.1%	$0.39	1.8%
>= $150	$0.02	0.2%	$2.45	6.1%

Table 3-53 Average real-time markup component (By price category, adjusted): January through June, 2013 and 2014

	2013 (Jan - Jun)		2014 (Jan - Jun)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$0.03	54.5%	($0.08)	5.7%
$25 to $50	($0.00)	41.3%	($0.59)	62.1%
$50 to $75	$0.18	2.7%	$0.06	15.9%
$75 to $100	$0.05	0.8%	$0.37	5.8%
$100 to $125	$0.03	0.4%	$0.27	2.6%
$125 to $150	($0.01)	0.1%	$0.40	1.8%
>= $150	$0.02	0.2%	$2.51	6.1%

Day-Ahead Markup

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

The markup component of the PJM day-ahead, load-weighted average LMP by primary fuel and unit type is shown in Table 3-54. INC, DEC and up-to congestion transactions have zero markups. Up-to congestion transactions were marginal for 94.2 percent of marginal resources in the first six months of 2014. INCs were marginal for 1.4 percent of marginal resources and DECs were marginal for 2.1 percent of marginal resources in the first six months of 2014.

The adjusted markup of coal units is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder. Table 3-54 shows the markup component of LMP for marginal generating resources. Generating resources were marginal in only 2.2 percent of marginal resources in the first six months of 2014. The markup component of LMP for marginal generating resources increased in all categories but gas-fired steam units. The markup component of LMP for coal units increased from -$0.75 in the first six months of 2013 to $0.35 in the first six months of 2014,of which $0.37 occurred on days for which PJM declared maximum emergency generation alerts. The markup component of LMP for gas-fired CCs increased from -$0.74 in the first six months of 2013 to -$0.51 in the first six months of 2014.

Table 3-54 Markup component of the annual PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through June of 2013 and 2014

		2013 (Jan - Jun)		2014 (Jan - Jun)	
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	($0.75)	$0.20	$0.35	$0.83
Gas	CC	($0.74)	($0.74)	($0.51)	($0.51)
Gas	CT	$0.00	$0.00	$0.01	$0.01
Gas	Steam	$0.01	$0.01	($1.08)	($1.08)
Municipal Waste	Diesel	$0.00	$0.00	$0.00	$0.00
Municipal Waste	Steam	$0.00	$0.00	$0.00	$0.00
Oil	CC	$0.00	$0.00	$0.02	$0.02
Oil	CT	$0.00	$0.00	$0.10	$0.10
Oil	Steam	$0.00	$0.00	$0.03	$0.03
Wind	Wind	$0.00	$0.00	$0.00	$0.00
Total		($1.47)	($0.52)	($1.08)	($0.59)

Markup Component of Day-Ahead 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 3-55 shows the markup component of average prices and of average monthly on-peak and off-peak prices using unadjusted offers. Table 3-56 shows the markup component of average prices and of average monthly on-peak and off-peak prices using adjusted offers.

Table 3-55 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: January through June of 2013 and 2014

	2013 (Jan - Jun)			2014 (Jan - Jun)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($3.77)	($3.99)	($3.54)	$0.67	$2.17	($0.90)
Feb	($2.53)	($1.43)	($3.67)	$0.34	$2.07	($1.47)
Mar	($1.84)	($0.18)	($3.45)	$0.11	($0.33)	$0.53
Apr	($0.11)	($0.01)	($0.22)	($1.81)	($1.32)	($2.37)
May	($0.10)	($0.04)	($0.17)	($3.38)	($4.12)	($2.60)
Jun	($0.05)	$0.03	($0.14)	($3.06)	($4.43)	($1.45)
Annual	($1.47)	($1.00)	($1.98)	($1.08)	($0.88)	($1.29)

Table 3-56 Monthly markup components of day-ahead (Adjusted), load-weighted LMP: January through June of 2013 and 2014

	2013 (Jan - Jun)			2014 (Jan - Jun)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($2.03)	($2.33)	($1.72)	$0.67	$2.17	($0.90)
Feb	($0.74)	$0.41	($1.93)	$0.34	$2.07	($1.47)
Mar	($0.26)	$1.29	($1.78)	$0.11	($0.33)	$0.53
Apr	$0.07	$0.16	($0.03)	($1.81)	($1.32)	($2.37)
May	$0.02	$0.06	($0.02)	($3.38)	($4.12)	($2.60)
Jun	$0.07	$0.15	($0.02)	($3.06)	($4.43)	($1.45)
Annual	($0.52)	($0.09)	($0.97)	($0.59)	($0.65)	($1.29)

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 3-57. The markup component of annual average day-ahead price using adjusted offers is shown for each zone in Table 3-58. The markup component of the average day-ahead price increased in all zones except the EKPC zone from the first six months of 2013 to the first six months of 2014.

Table 3-57 Day-ahead, average, zonal markup component (Unadjusted): January through June of 2013 and 2014

	2013 (Jan - Jun)			2014 (Jan - Jun)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($1.56)	($1.16)	($1.98)	($1.32)	($1.45)	($1.19)
AEP	($1.44)	($0.92)	($1.98)	($0.95)	($0.63)	($1.28)
AP	($1.55)	($1.04)	($2.08)	($1.06)	($0.66)	($1.48)
ATSI	($1.46)	($0.95)	($2.03)	($1.05)	($0.74)	($1.39)
BGE	($1.50)	($1.10)	($1.92)	($1.20)	($1.13)	($1.27)
ComEd	($1.37)	($0.86)	($1.92)	($0.78)	($0.53)	($1.05)
DAY	($1.49)	($0.94)	($2.08)	($1.00)	($0.72)	($1.30)
DEOK	($1.41)	($0.85)	($2.00)	($0.99)	($0.77)	($1.22)
DLCO	($1.40)	($0.92)	($1.92)	($1.07)	($0.90)	($1.25)
DPL	($1.57)	($1.02)	($2.14)	($1.09)	($1.11)	($1.07)
Dominion	($1.44)	($1.02)	($1.89)	($1.36)	($1.22)	($1.52)
EKPC	($0.05)	$0.04	($0.14)	($0.68)	($0.37)	($1.00)
JCPL	($1.83)	($1.68)	($2.00)	($1.35)	($1.44)	($1.26)
Met-Ed	($1.58)	($1.17)	($2.03)	($1.09)	($0.98)	($1.20)
PECO	($1.50)	($1.02)	($2.02)	($1.12)	($1.06)	($1.19)
PENELEC	($1.46)	($0.94)	($2.03)	($1.28)	($1.13)	($1.45)
Pepco	($1.44)	($1.06)	($1.86)	($1.10)	($0.92)	($1.31)
PPL	($1.65)	($1.24)	($2.09)	($1.20)	($1.13)	($1.28)
PSEG	($1.46)	($1.01)	($1.97)	($1.30)	($1.33)	($1.28)
RECO	($1.41)	($0.93)	($1.97)	($1.34)	($1.34)	($1.34)

Table 3-58 Day-ahead, average, zonal markup component (Adjusted): January through June of 2013 and 2014

	2013 (Jan - Jun)			2014 (Jan - Jun)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($0.61)	($0.25)	($0.99)	($0.87)	($1.25)	($0.46)
AEP	($0.48)	($0.00)	($0.97)	($0.44)	($0.38)	($0.50)
AP	($0.53)	($0.07)	($1.00)	($0.57)	($0.43)	($0.72)
ATSI	($0.50)	($0.02)	($1.02)	($0.54)	($0.50)	($0.59)
BGE	($0.50)	($0.17)	($0.85)	($0.71)	($0.94)	($0.46)
ComEd	($0.47)	$0.01	($0.99)	($0.25)	($0.24)	($0.26)
DAY	($0.51)	($0.01)	($1.06)	($0.47)	($0.45)	($0.49)
DEOK	($0.48)	$0.03	($1.01)	($0.49)	($0.53)	($0.44)
DLCO	($0.48)	($0.04)	($0.96)	($0.56)	($0.67)	($0.45)
DPL	($0.58)	($0.10)	($1.08)	($0.65)	($0.90)	($0.38)
Dominion	($0.49)	($0.12)	($0.87)	($0.88)	($1.00)	($0.76)
EKPC	$0.06	$0.15	($0.03)	($0.21)	($0.13)	($0.29)
JCPL	($0.84)	($0.67)	($1.02)	($0.89)	($1.19)	($0.55)
Met-Ed	($0.64)	($0.29)	($1.02)	($0.64)	($0.78)	($0.48)
PECO	($0.56)	($0.14)	($1.02)	($0.68)	($0.86)	($0.48)
PENELEC	($0.48)	$0.01	($1.01)	($0.78)	($0.89)	($0.66)
Pepco	($0.48)	($0.14)	($0.84)	($0.62)	($0.71)	($0.52)
PPL	($0.68)	($0.32)	($1.07)	($0.75)	($0.91)	($0.58)
PSEG	($0.55)	($0.16)	($1.00)	($0.87)	($1.15)	($0.57)
RECO	($0.55)	($0.13)	($1.03)	($0.92)	($1.17)	($0.63)

Markup by Day-Ahead Price Levels

Table 3-59 and Table 3-60 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 3-59 shows that the average day-ahead markup increased significantly when day-ahead price is greater or equal to $150 from the first six months of 2013 to the first six months of 2014. There were zero hours when generating resources were marginal in this category in the first six months of 2013. However, there were 201 hours when generating resources were marginal in this category in the first six months of 2014. The highest average markup was $437.10 in hour ending 1400 on January 28.

Table 3-59 Average, day-ahead markup (By LMP category, unadjusted): January through June of 2013 and 2014

	2013 (Jan - Jun)		2014 (Jan - Jun)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($1.98)	3.9%	($2.66)	2.7%
$25 to $50	($3.27)	88.3%	($2.02)	64.2%
$50 to $75	$1.16	6.8%	($3.35)	19.7%
$75 to $100	$0.08	0.7%	($2.24)	4.4%
$100 to $125	$0.01	0.3%	($7.01)	1.7%
$125 to $150	$0.00	0.0%	$3.38	1.4%
>= $150	$0.00	0.0%	$10.31	5.9%

Table 3-60 Average, day-ahead markup (By LMP category, adjusted): January through June of 2013 and 2014

	2013 (Jan - Jun)		2014 (Jan - Jun)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.68)	3.9%	($1.27)	2.7%
$25 to $50	($1.36)	88.3%	($1.10)	64.2%
$50 to $75	$1.98	6.8%	($3.12)	19.7%
$75 to $100	$0.26	0.7%	($2.06)	4.4%
$100 to $125	$0.05	0.3%	($6.90)	1.7%
$125 to $150	$0.00	0.0%	$3.61	1.4%
>= $150	$0.00	0.0%	$10.68	5.9%

Prices

The conduct of individual market entities within a market structure is reflected in market prices.[57] PJM locational marginal prices (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 84.2 percent and 84.8 percent higher in the first six months of 2014

57 See the *2013 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*, at "Calculating Locational Marginal Price" for more information on how bus LMPs are aggregated to system LMPs. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

than in the first six months of 2013 as a result of higher fuel costs and higher demand.[58] Natural gas prices were higher, particularly in eastern zones, while coal prices were relatively constant. Natural gas prices in the second quarter of 2014 were lower than the second quarter of 2013, particularly in eastern zones.

PJM real-time energy market prices increased in the first six months of 2014 compared to the first six months of 2013. The average LMP was 69.9 percent higher in the first six months of 2014 than in the first six months of 2013, $62.14 per MWh versus $36.56 per MWh. The load-weighted average LMP was 84.2 percent higher in the first six months of 2014 than in the first six months of 2013, $69.92 per MWh versus $37.96 per MWh.

The fuel-cost adjusted, load-weighted, average LMP for the first six months of 2014 was 17.5 percent lower than the load-weighted, average LMP for the first six months of 2014. If fuel costs in the first six months of 2014 had been the same as in the first six months of 2013, holding everything else constant, the load-weighted LMP would have been lower, $57.71 per MWh instead of the observed $69.92 per MWh in the first six months of 2014.

PJM day-ahead energy market prices increased in the first six months of 2014 compared to the first six months of 2013. The average LMP was 71.2 percent higher in the first six months of 2014 than in the first six months of 2013, $63.52 per MWh versus $37.11 per MWh. The load-weighted average LMP was 84.8 percent higher in the first six months of 2014 than in the first six months of 2013, $70.67 per MWh versus $38.23 per MWh.[59]

Real-Time LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[60]

58 There was an average increase of 2.4 heating degree days and average increase of 0.1 cooling degree days in the first six months of 2014 compared to the first six months of 2013, which meant overall increased demand.

59 Tables reporting zonal and jurisdictional load and prices are in the *2013 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

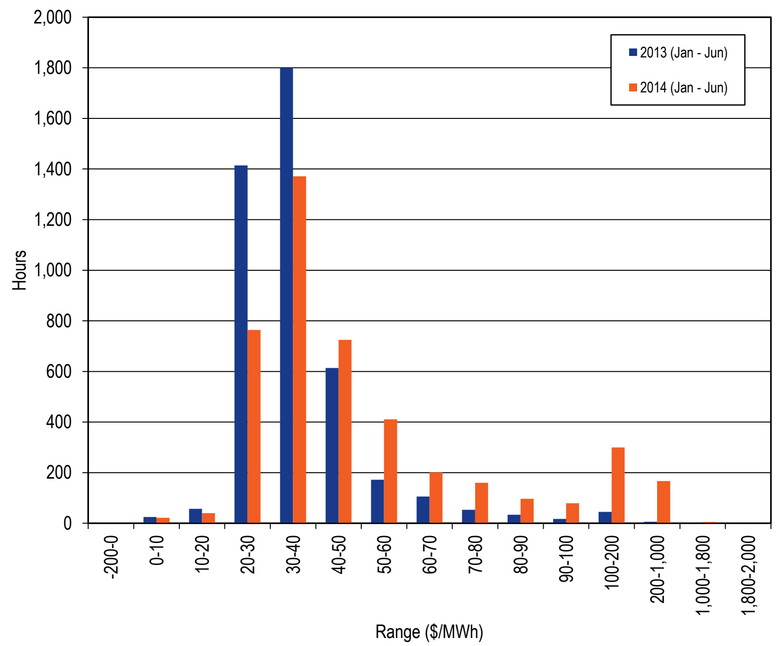
60 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price," for detailed definition of Real-Time LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 3-25 shows the hourly distribution of PJM real-time average LMP for the first six months of 2013 and the first six months of 2014. There were no hours in the first six months of 2013 and 2014 in which the real-time LMP for the entire system was negative. Negative LMPs in the PJM Real-Time Market were primarily the result of marginal wind units with negative offer prices but may also result within a constrained area when inflexible generation exceeds the forecasted load. There were no hours in the first six months of 2013 and six hours in the first six months of 2014 in which the PJM real-time LMP was $0.00. In 2014, there were six hours in January in which PJM real-time average LMP was greater than $1,000 and one hour that was greater $1,800.

Figure 3-25 Average LMP for the PJM Real-Time Energy Market: January through June of 2013 and 2014[61]



61 The data used in the version of this table in the *2014 Quarterly State of the Market Report for PJM: January through March* did not include LMP values greater than $1,000, but this table reflects those LMP values.

PJM Real-Time, Average LMP

Table 3-61 shows the PJM real-time, average LMP for the first six months of each year of the 17-year period 1998 to 2014.[62]

Table 3-61 PJM real-time, average LMP (Dollars per MWh): January through June of 1998 through 2014

	Real-Time LMP			Year-to-Year Change		
Jan - Jun	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$20.13	$15.90	$15.59	NA	NA	NA
1999	$22.94	$17.84	$41.16	14.0%	12.2%	164.0%
2000	$25.38	$18.03	$25.65	10.6%	1.1%	(37.7%)
2001	$33.10	$25.69	$21.11	30.4%	42.5%	(17.7%)
2002	$24.10	$19.64	$13.21	(27.2%)	(23.6%)	(37.4%)
2003	$41.31	$33.74	$27.81	71.4%	71.8%	110.6%
2004	$44.99	$40.75	$22.97	8.9%	20.8%	(17.4%)
2005	$45.71	$39.80	$23.51	1.6%	(2.3%)	2.3%
2006	$49.36	$43.46	$25.26	8.0%	9.2%	7.5%
2007	$55.03	$48.05	$31.42	11.5%	10.6%	24.4%
2008	$70.19	$59.53	$41.77	27.6%	23.9%	33.0%
2009	$40.12	$35.42	$19.30	(42.8%)	(40.5%)	(53.8%)
2010	$43.27	$37.11	$22.20	7.9%	4.8%	15.0%
2011	$45.51	$37.40	$32.52	5.2%	0.8%	46.5%
2012	$29.74	$28.32	$16.10	(34.6%)	(24.3%)	(50.5%)
2013	$36.56	$32.79	$17.18	22.9%	15.8%	6.7%
2014	$62.14	$39.69	$88.87	69.9%	21.0%	417.4%

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 3-62 shows the PJM real-time, load-weighted, average LMP for the first six months of each year of the 17-year period 1998 to 2014.

62 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 3-62 PJM real-time, load-weighted, average LMP (Dollars per MWh): January through June of 1998 through 2014

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
Jan - Jun	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.66	$16.80	$18.39	NA	NA	NA
1999	$25.34	$18.59	$52.06	17.0%	10.7%	183.1%
2000	$27.76	$18.91	$29.69	9.5%	1.7%	(43.0%)
2001	$35.27	$27.88	$22.12	27.0%	47.4%	(25.5%)
2002	$25.93	$20.67	$14.62	(26.5%)	(25.9%)	(33.9%)
2003	$44.43	$37.98	$28.55	71.4%	83.8%	95.2%
2004	$47.62	$43.96	$23.30	7.2%	15.8%	(18.4%)
2005	$48.67	$42.30	$24.81	2.2%	(3.8%)	6.5%
2006	$51.83	$45.79	$26.54	6.5%	8.3%	7.0%
2007	$58.32	$52.52	$32.39	12.5%	14.7%	22.1%
2008	$74.77	$64.26	$44.25	28.2%	22.4%	36.6%
2009	$42.48	$36.95	$20.61	(43.2%)	(42.5%)	(53.4%)
2010	$45.75	$38.78	$23.60	7.7%	5.0%	14.5%
2011	$48.47	$38.63	$37.59	5.9%	(0.4%)	59.3%
2012	$31.21	$28.98	$17.69	(35.6%)	(25.0%)	(52.9%)
2013	$37.96	$33.58	$18.54	21.6%	15.9%	4.8%
2014	$69.92	$42.61	$103.35	84.2%	26.9%	457.6%

Figure 3-26 and Figure 3-27 are contour maps of the real-time, load-weighted, average LMP for the first six months of 2013 and 2014. The maps show that the average real-time LMP across all control zones were higher in the first six months of 2014.

Figure 3-26 PJM real-time, load-weighted, average LMP: January through June 2013

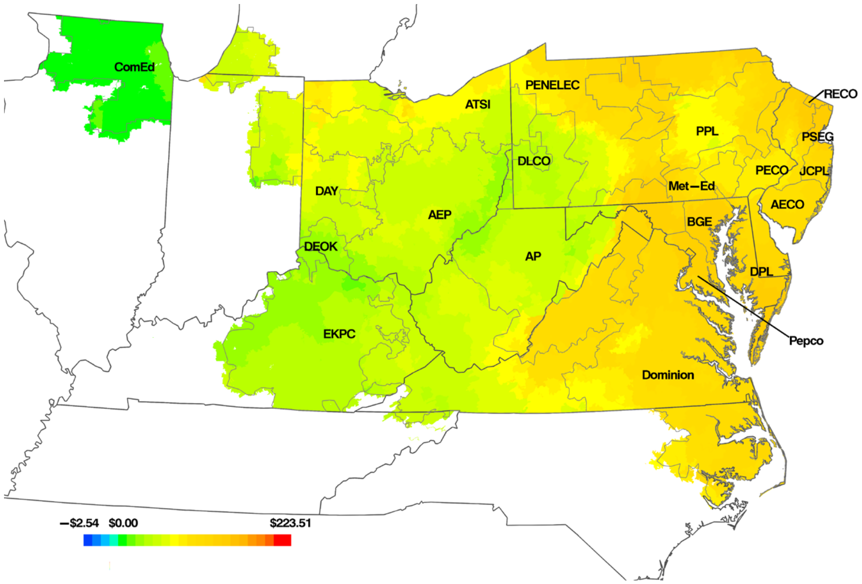


Figure 3-27 PJM real-time, load-weighted, average LMP: January through June 2014

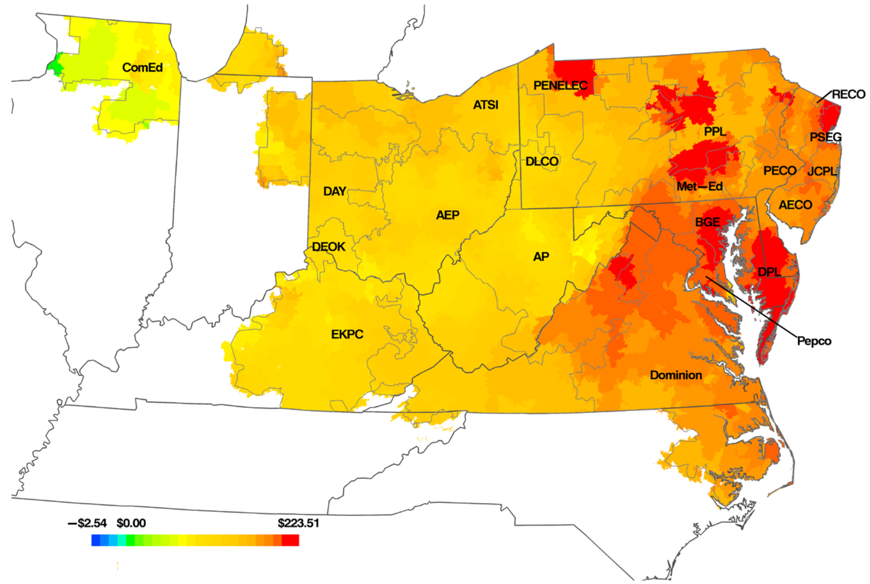


Figure 3-28 and Figure 3-29 are contour maps of the real-time, load-weighted, average LMP for April through June of 2013 and for April through June of 2014. The maps show that the average real-time LMP across all control zones were higher for April through June of 2014 compared to April through June of 2013, except the control zones in New Jersey and eastern Pennsylvania.[63]

The relative decrease in LMP in these control zones was the result of lower natural gas prices. Natural gas prices at the most important natural gas trading hubs within New Jersey and eastern Pennsylvania control zones were, on average, 12.5 percent lower in April through June of 2014 compared to the same period in 2013.[64]

63 Control zones in New Jersey are AECO, JCPL, PSEG and RECO. Control zones in eastern Pennsylvania are Met-Ed, PECO and PPL.
64 The natural gas trading hubs are Transco, zone 6 N.Y., Transco, zone 6 non-N.Y. and Texas Eastern, M-3.

Figure 3-28 PJM real-time, load-weighted, average LMP: April through June 2013

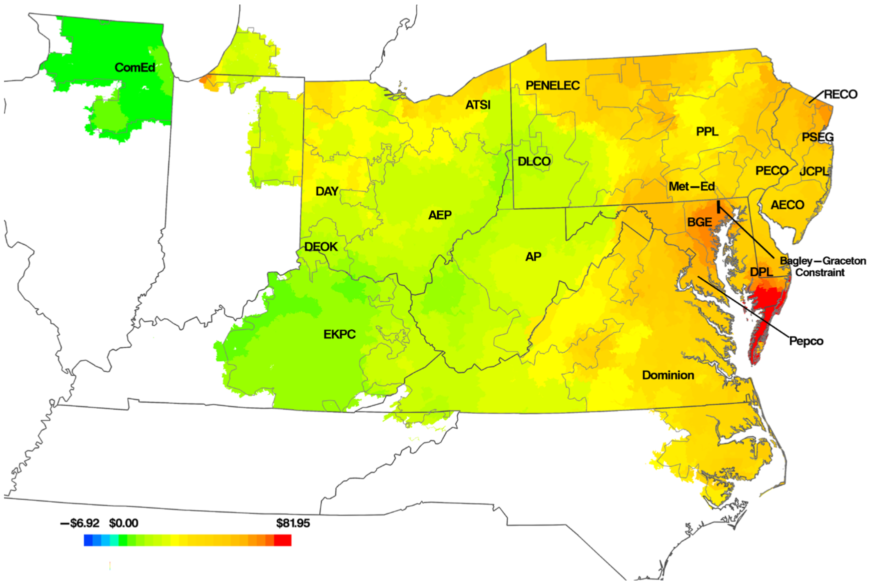
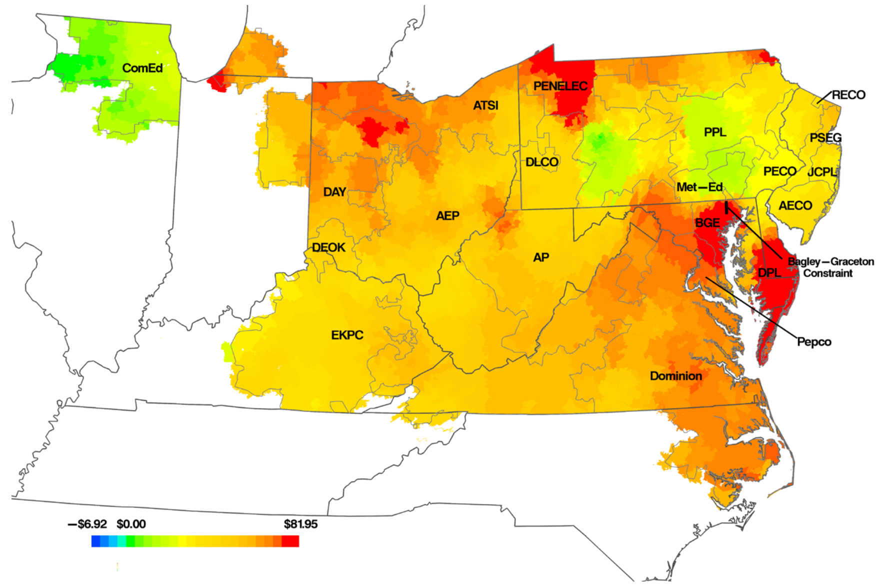


Figure 3-29 PJM real-time, load-weighted, average LMP: April through June 2014

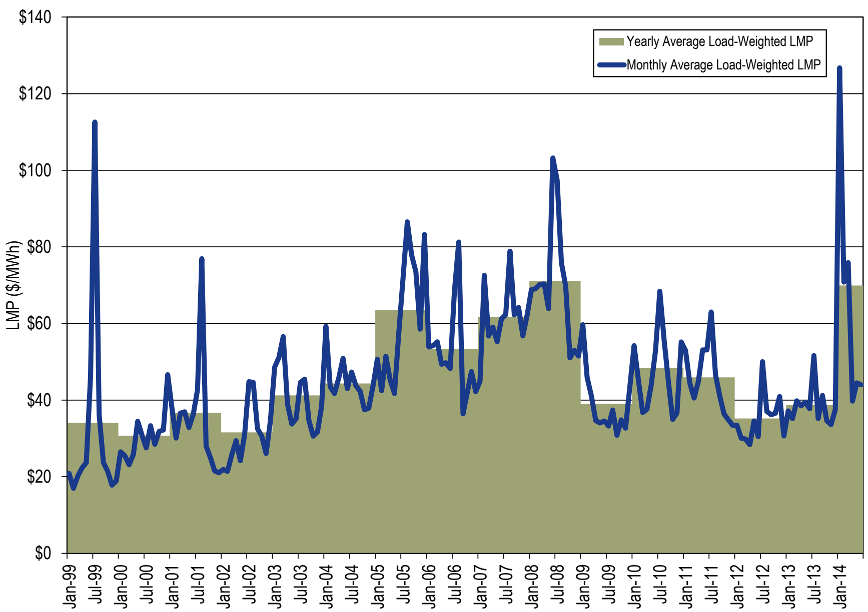


Due to their relatively low cost in April through June 2014, gas fired units in the New Jersey and eastern Pennsylvania control zones were used to supply load in more congested and high priced control zones, such as BGE and Pepco, which had access to relatively high priced gas. In April through June 2014, the resulting flows from low to high priced increased, on a year over year basis, the number of hours that the Bagley – Graceton constraint was binding (increased from 4.7 percent of hours to 19.4 percent of hours) and decreased the number of hours that the AP South constraint was binding (decrease from 6.5 percent of hours binding to 0.5 percent of hours binding). The Bagley – Graceton constraint caused price separation between the New Jersey and eastern Pennsylvania control zones and the BGE and Pepco control zones.

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

Figure 3-30 shows the PJM real-time monthly and annual load-weighted LMP from 1999 through the first six months of 2014.

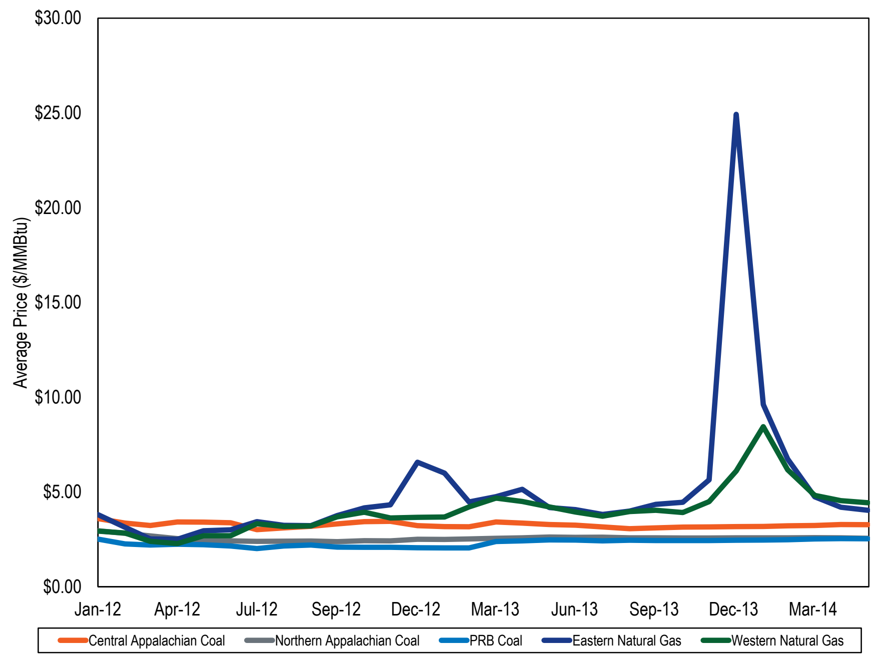
Figure 3-30 PJM real-time, monthly and annual, load-weighted, average LMP: 1999 through June of 2014



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 six months of 2014. Comparing fuel prices in the first six months of 2014 to the first six months of 2013, the price of Northern Appalachian coal was 1.8 percent higher; the price of Central Appalachian coal was 3.5 percent lower; the price of Powder River Basin coal was 12.4 percent higher; the price of eastern natural gas was 85.6 percent higher; and the price of western natural gas was 40.6 percent higher. Figure 3-31 shows monthly average spot fuel prices for the first six months of 2013 and the first six months of 2014.[65] Natural gas prices were above coal prices in the first six months of 2014.

Figure 3-31 Spot average fuel price comparison with fuel delivery charges: 2012 through 2014 ($/MMBtu)



65 Eastern natural gas consists of the average of Texas M3, Transco Zone 6 non-NY, Transco Zone 6 NY and Transco Zone 5 daily fuel price indices. Western natural gas prices are the average of Dominion North Point, Columbia Appalachia and Chicago Citygate daily fuel price indices. 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.

Table 3-63 compares the first six months of 2014 PJM real time fuel-cost adjusted, load-weighted, average LMP to the first six months of 2013 load-weighted, average LMP. The real time fuel-cost adjusted, load-weighted, average LMP for the first six months of 2014 was 17.5 percent lower than the real time load-weighted, average LMP for the first six months of 2014. The real-time, fuel-cost adjusted, load-weighted, average LMP for the first six months of 2014 was 52.0 percent higher than the real time load-weighted LMP for the first six months of 2013. If fuel costs in the first six months of 2014 had been the same as in the first six months of 2013, holding everything else constant, the real time load-weighted LMP in the first six months of 2014 would have been lower, $57.71 per MWh instead of the observed $69.92 per MWh.

Table 3-63 PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): Six Months over Six Months

	2014 Load-Weighted LMP	2014 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$69.92	$57.71	(17.5%)
	2013 Load-Weighted LMP	**2014 Fuel-Cost-Adjusted, Load-Weighted LMP**	**Change**
Average	$37.96	$57.71	52.0%
	2013 Load-Weighted LMP	2014 Load-Weighted LMP	Change
Average	$37.96	$69.92	84.2%

Table 3-64 shows the impact of each fuel type on the difference between the fuel-cost adjusted, load-weighted average LMP and the load-weighted LMP in the first six months of 2014. Table 3-64 shows that higher natural gas prices explain almost all of the fuel-cost related increase in the real time annual load-weighted average LMP in the first six months of 2014.

Table 3-64 Change in PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh) by Fuel-type: Six Months over Six Months

Fuel Type	Share of Change in Fuel Cost Adjusted, Load Weighted LMP	Percent
Coal	$0.18	1.5%
Gas	$12.07	98.8%
Oil	($0.04)	(0.3%)
Other	$0.00	0.0%
Uranium	$0.00	0.0%
Wind	($0.00)	(0.0%)
Total	$12.21	100.0%

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 forecasts of system conditions. Those offers can be decomposed into components including 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 LMP by the components of unit offers.

Cost offers of marginal units are separated 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, emission rates for NO_x, emission rates for SO_2 and emission rates for CO_2. The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware and Maryland.[66] 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.

Since the implementation of scarcity pricing on October 1, 2012, PJM jointly optimizes the commitment and dispatch of 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 opportunity cost of the reduced generation and the associated incremental cost to maintain reserves. If a unit incurring such opportunity costs is a marginal resource in the energy market, this opportunity cost contributes to LMP. In addition, in periods when generators providing energy cannot meet the reserve requirements, PJM can invoke shortage pricing. PJM invoked shortage pricing on January 6 and January 7 of 2014.[67] During the shortage conditions, the LMPs of marginal generators reflect the cost of not meeting the reserve requirements, the scarcity adder, which is defined by the operating reserve demand curve.

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

67 PJM triggered shortage pricing on January 6 following a RTO-wide voltage reduction action. PJM triggered shortage pricing on January 7, due to RTO-wide shortage of synchronized reserve.

The components of LMP are shown in Table 3-65, including markup using unadjusted cost offers.[68] Table 3-65 shows that for the first six months of 2014, 23.4 percent of the load-weighted LMP was the result of coal costs, 39.1 percent was the result of gas costs and 0.47 percent was the result of the cost of emission allowances. Markup was $1.73 per MWh. The fuel-related components of LMP reflect the degree to which the cost of the identified fuel affects LMP and does not reflect the other components of the offers of units burning that fuel. The component NA is the unexplainable portion of load-weighted LMP. Occasionally, PJM fails to provide all the data needed to accurately calculate generator sensitivity factors. As a result, the LMP for those intervals cannot be decomposed into component costs. The cumulative effect of excluding those five-minute intervals is the component NA. In the first six months of 2014, nearly eight percent of all five-minute intervals had insufficient data. The percent column is the difference in the proportion of LMP represented by each component between the first six months of 2014 and the first six months of 2013.

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

Table 3-65 Components of PJM real-time (Unadjusted), annual, load-weighted, average LMP: January through June, 2013 and 2014

	2013 (Jan - Jun)		2014 (Jan - Jun)		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Gas	$12.08	31.8%	$27.31	39.1%	7.2%
Coal	$19.52	51.4%	$16.38	23.4%	(28.0%)
Oil	$0.68	1.8%	$7.45	10.7%	8.9%
Ten Percent Adder	$3.38	8.9%	$4.69	6.7%	(2.2%)
Emergency DR Adder	$0.00	0.0%	$3.63	5.2%	5.2%
NA	$0.34	0.9%	$2.84	4.1%	3.2%
VOM	$2.35	6.2%	$2.74	3.9%	(2.3%)
Markup	($1.26)	(3.3%)	$1.73	2.5%	5.8%
Increase Generation Adder	$0.27	0.7%	$1.23	1.8%	1.1%
FMU Adder	$0.23	0.6%	$1.01	1.4%	0.8%
Ancillary Service Redispatch cost	$0.25	0.6%	$0.81	1.2%	0.5%
Scarcity Adder	$0.00	0.0%	$0.20	0.3%	0.3%
CO2 Cost	$0.09	0.2%	$0.20	0.3%	0.0%
NOx Cost	$0.10	0.3%	$0.12	0.2%	(0.1%)
Municipal Waste	$0.00	0.0%	$0.02	0.0%	0.0%
SO2 Cost	$0.01	0.0%	$0.01	0.0%	(0.0%)
Other	($0.00)	(0.0%)	($0.00)	(0.0%)	0.0%
LPA-SCED Differential	($0.03)	(0.1%)	($0.01)	(0.0%)	0.1%
Market-to-Market Adder	$0.01	0.0%	($0.01)	(0.0%)	(0.0%)
Uranium	$0.00	0.0%	($0.02)	(0.0%)	(0.0%)
Wind	($0.00)	(0.0%)	($0.02)	(0.0%)	(0.0%)
LPA Rounding Difference	$0.10	0.3%	($0.12)	(0.2%)	(0.4%)
Decrease Generation Adder	($0.14)	(0.4%)	($0.26)	(0.4%)	(0.0%)
Total	$37.96	100.0%	$69.92	100.0%	0.0%

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 3-65 and Table 3-69) markup is simply the difference between the price offer and the cost offer. In the second approach, (Table 3-66 and Table 3-70) the 10 percent markup is removed from the cost offers of coal units.

The components of LMP are shown in Table 3-66, including markup using adjusted cost offers.

Table 3-66 Components of PJM real-time (Adjusted), annual, load-weighted, average LMP: January through June, 2013 and 2014

	2013 (Jan - Jun)		2014 (Jan - Jun)		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Gas	$12.08	31.8%	$27.31	39.1%	7.2%
Coal	$19.52	51.4%	$16.38	23.4%	(28.0%)
Oil	$0.68	1.8%	$7.45	10.7%	8.9%
Emergency DR Adder	$0.00	0.0%	$3.63	5.2%	5.2%
Ten Percent Adder	$1.82	4.8%	$3.53	5.1%	0.3%
Markup	$0.30	0.8%	$2.88	4.1%	3.3%
NA	$0.34	0.9%	$2.84	4.1%	3.2%
VOM	$2.35	6.2%	$2.74	3.9%	(2.3%)
Increase Generation Adder	$0.27	0.7%	$1.23	1.8%	1.1%
FMU Adder	$0.23	0.6%	$1.01	1.4%	0.8%
Ancillary Service Redispatch cost	$0.25	0.6%	$0.81	1.2%	0.5%
Scarcity Adder	$0.00	0.0%	$0.20	0.3%	0.3%
CO2 Cost	$0.09	0.2%	$0.20	0.3%	0.0%
NOx Cost	$0.10	0.3%	$0.12	0.2%	(0.1%)
Municipal Waste	$0.00	0.0%	$0.02	0.0%	0.0%
SO2 Cost	$0.01	0.0%	$0.01	0.0%	(0.0%)
Other	($0.00)	(0.0%)	($0.00)	(0.0%)	0.0%
LPA-SCED Differential	($0.03)	(0.1%)	($0.01)	(0.0%)	0.1%
Market-to-Market Adder	$0.01	0.0%	($0.01)	(0.0%)	(0.0%)
Uranium	$0.00	0.0%	($0.02)	(0.0%)	(0.0%)
Wind	($0.00)	(0.0%)	($0.02)	(0.0%)	(0.0%)
LPA Rounding Difference	$0.10	0.3%	($0.12)	(0.2%)	(0.4%)
Decrease Generation Adder	($0.14)	(0.4%)	($0.26)	(0.4%)	(0.0%)
Total	$37.96	100.0%	$69.92	100.0%	0.0%

Day-Ahead LMP

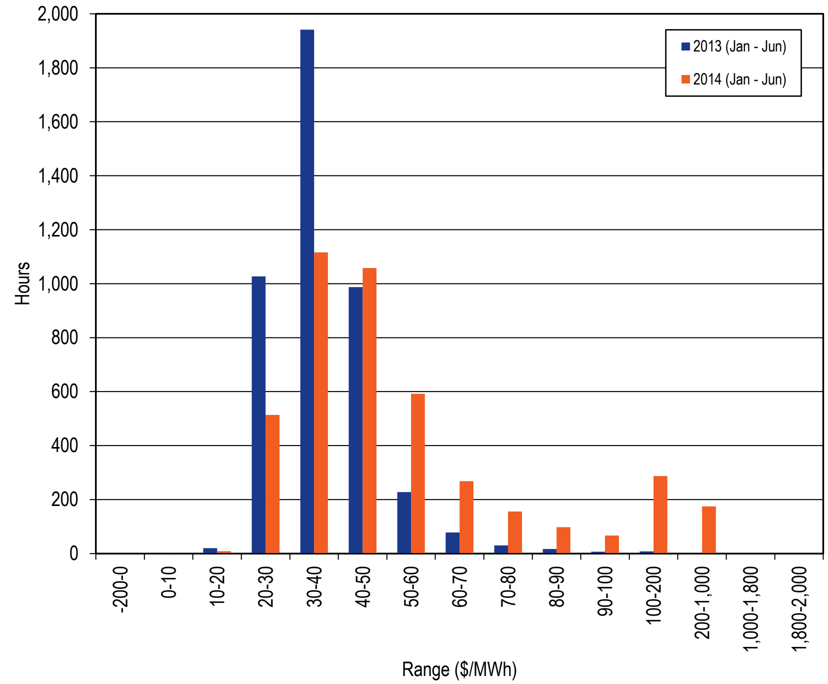
Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[69]

Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 3-32 shows the hourly distribution of PJM day-ahead average LMP for the first six months of 2013 and the first six months of 2014.

Figure 3-32 Average LMP for the PJM Day-Ahead Energy Market: January through June of 2013 and 2014



69 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price" for a detailed definition of Day-Ahead LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

PJM Day-Ahead, Average LMP

Table 3-67 shows the PJM day-ahead, average LMP for the first six months of each year of the 14-year period 2001 to 2014.

Table 3-67 PJM day-ahead, average LMP (Dollars per MWh): January through June of 2001 through 2014

	Day-Ahead LMP			Year-to-Year Change		
Jan - Jun	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$35.02	$31.34	$17.43	NA	NA	NA
2002	$24.76	$21.28	$12.49	(29.3%)	(32.1%)	(28.4%)
2003	$42.83	$39.18	$23.52	73.0%	84.1%	88.3%
2004	$44.02	$43.14	$18.33	2.8%	10.1%	(22.0%)
2005	$45.63	$42.51	$18.35	3.7%	(1.5%)	0.1%
2006	$48.33	$47.07	$16.02	5.9%	10.7%	(12.7%)
2007	$53.03	$51.08	$22.91	9.7%	8.5%	43.0%
2008	$70.12	$66.09	$31.98	32.2%	29.4%	39.6%
2009	$40.01	$37.46	$15.38	(42.9%)	(43.3%)	(51.9%)
2010	$43.81	$40.64	$15.66	9.5%	8.5%	1.8%
2011	$44.75	$40.85	$19.53	2.1%	0.5%	24.8%
2012	$30.44	$29.64	$11.77	(32.0%)	(27.4%)	(39.8%)
2013	$37.11	$35.19	$10.42	21.9%	18.7%	(11.4%)
2014	$63.52	$44.42	$69.93	71.2%	26.2%	571.1%

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 3-68 shows the PJM day-ahead, load-weighted, average LMP for the first six months of each year of the 14-year period 2001 to 2014.

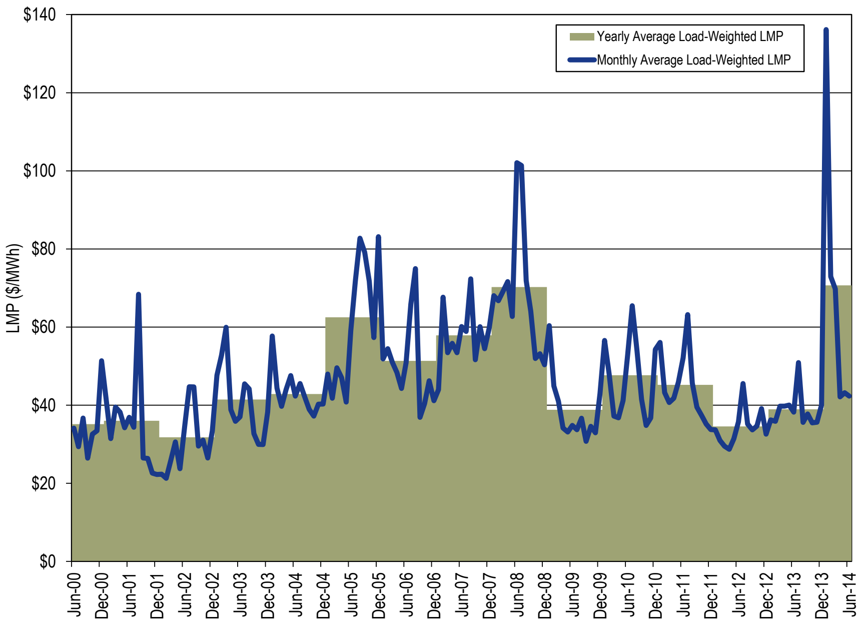
Table 3-68 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January through June of 2001 through 2014

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
Jan - Jun	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$37.08	$33.91	$18.11	NA	NA	NA
2002	$26.88	$23.00	$14.36	(27.5%)	(32.2%)	(20.7%)
2003	$45.62	$42.01	$23.96	69.8%	82.6%	66.8%
2004	$46.12	$45.45	$18.62	1.1%	8.2%	(22.3%)
2005	$48.12	$44.88	$19.24	4.3%	(1.3%)	3.3%
2006	$50.21	$48.67	$16.23	4.3%	8.5%	(15.7%)
2007	$55.70	$54.26	$23.47	10.9%	11.5%	44.7%
2008	$73.71	$69.33	$33.95	32.3%	27.8%	44.7%
2009	$42.21	$38.83	$16.16	(42.7%)	(44.0%)	(52.4%)
2010	$46.12	$42.50	$16.54	9.3%	9.5%	2.3%
2011	$47.12	$42.58	$22.34	2.2%	0.2%	35.1%
2012	$31.84	$30.35	$13.94	(32.4%)	(28.7%)	(37.6%)
2013	$38.23	$36.19	$11.03	20.1%	19.3%	(20.8%)
2014	$70.67	$47.04	$79.85	84.8%	30.0%	623.8%

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

Figure 3-33 shows the PJM day-ahead, monthly and annual, load-weighted LMP from 2000 through the first six months of 2014.[70]

Figure 3-33 Day-ahead, monthly and annual, load-weighted, average LMP: 2000 through June of 2014



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 their components including 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 with an offer price that 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.

Cost offers of marginal units are separated 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, emission rates for $NO_{X,}$ emission rates for SO_2 and emission rates for CO_2. CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware and Maryland.[71] 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. 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.

The components of day-ahead LMP are shown in Table 3-69, including markup using unadjusted cost offers. Table 3-69 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In the first six months of 2014, 24.7 percent of the load-weighted LMP was the result of gas, 16.0 percent was the result of the up-to congestion transactions and 15.2 percent was the result of DEC bids.

70 Since the Day-Ahead Energy Market did not start until June 1, 2000, the day-ahead data for 2000 only includes data for the last six months of that year.

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

Table 3-69 Components of PJM day-ahead, (unadjusted) annual, load-weighted, average LMP (Dollars per MWh): January through June of 2013 and 2014[72]

	2013 (Jan - Jun)		2014 (Jan - Jun)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Gas	$4.25	11.1%	$17.45	24.7%	13.6%
Up-to Congestion Transaction	$18.62	48.7%	$11.31	16.0%	(32.7%)
DEC	$3.20	8.4%	$10.77	15.2%	6.9%
INC	$1.94	5.1%	$9.96	14.1%	9.0%
Coal	$8.70	22.8%	$8.13	11.5%	(11.2%)
Dispatchable Transaction	$0.25	0.6%	$4.06	5.7%	5.1%
Ten Percent Cost Adder	$1.39	3.6%	$2.88	4.1%	0.4%
FMU Adder	$0.03	0.1%	$2.43	3.4%	3.4%
Oil	$0.00	0.0%	$1.61	2.3%	2.3%
Price Sensitive Demand	$0.10	0.2%	$1.57	2.2%	2.0%
VOM	$0.93	2.4%	$1.21	1.7%	(0.7%)
CO2	$0.03	0.1%	$0.13	0.2%	0.1%
IMPORT	$0.00	0.0%	$0.12	0.2%	0.2%
DASR Offer Adder	$0.00	0.0%	$0.10	0.1%	0.1%
NOx	$0.03	0.1%	$0.06	0.1%	(0.0%)
Municipal Waste	$0.00	0.0%	$0.05	0.1%	0.1%
SO2	$0.01	0.0%	$0.01	0.0%	(0.0%)
Constrained Off	$0.00	0.0%	$0.01	0.0%	0.0%
Wind	($0.00)	(0.0%)	$0.00	0.0%	0.0%
DASR LOC Adder	$0.00	0.0%	($0.06)	(0.1%)	(0.1%)
Markup	($1.47)	(3.8%)	($1.08)	(1.5%)	2.3%
NA	$0.23	0.6%	($0.02)	(0.0%)	(0.6%)
Total	$38.23	100.0%	$70.67	100.0%	(0.0%)

72 PJM acknowledged an error in identifying marginal up-to congestion transactions following April 2013 changes to the day-ahead solution software. The software incorrectly increased the volume of marginal up-to congestion transactions. The fix to the problem is expected to be in place in 2014.

Table 3-70 shows the components of the PJM day ahead, annual, load-weighted average LMP including the adjusted markup calculated by excluding the 10 percent adder from the coal units.

Table 3-70 Components of PJM day-ahead, (adjusted) annual, load-weighted, average LMP (Dollars per MWh): January through June of 2013 and 2014

	2013 (Jan - Jun)		2014 (Jan - Jun)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Gas	$4.25	11.1%	$17.45	24.7%	13.6%
Up-to Congestion Transaction	$18.62	48.7%	$11.31	16.0%	(32.7%)
DEC	$3.20	8.4%	$10.77	15.2%	6.9%
INC	$1.94	5.1%	$9.96	14.1%	9.0%
Coal	$8.70	22.7%	$8.08	11.4%	(11.3%)
Dispatchable Transaction	$0.25	0.6%	$4.06	5.7%	5.1%
Ten Percent Cost Adder	$0.44	1.2%	$2.44	3.5%	2.3%
FMU Adder	$0.03	0.1%	$2.43	3.4%	3.4%
Oil	$0.00	0.0%	$1.61	2.3%	2.3%
Price Sensitive Demand	$0.10	0.2%	$1.57	2.2%	2.0%
VOM	$0.93	2.4%	$1.21	1.7%	(0.7%)
CO2	$0.03	0.1%	$0.13	0.2%	0.1%
IMPORT	$0.00	0.0%	$0.12	0.2%	0.2%
DASR Offer Adder	$0.00	0.0%	$0.10	0.1%	0.1%
NOx	$0.03	0.1%	$0.06	0.1%	(0.0%)
Municipal Waste	$0.00	0.0%	$0.05	0.1%	0.1%
SO2	$0.01	0.0%	$0.01	0.0%	(0.0%)
Constrained Off	$0.00	0.0%	$0.01	0.0%	0.0%
Wind	($0.00)	(0.0%)	$0.00	0.0%	0.0%
DASR LOC Adder	$0.00	0.0%	($0.06)	(0.1%)	(0.1%)
Markup	($0.52)	(1.4%)	($0.59)	(0.8%)	0.5%
NA	$0.23	0.6%	($0.02)	(0.0%)	(0.6%)
Total	$38.23	100.0%	$70.67	100.0%	(0.0%)

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 Energy 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 on a day to day basis is not a realistic expectation as a result of uncertainty, lags in response time and modeling differences, such as differences in modeled contingencies and marginal loss calculations, between the Day-Ahead and Real-Time Energy Market.

Where arbitrage opportunities are created by differences between Day-Ahead and Real-Time Energy Market expectations, the resulting behavior can lead to more efficient market outcomes by improving day-ahead commitments relative to real-time system requirements.

But there is no guarantee that the results of virtual bids and offers will result in more efficient market outcomes.

Where arbitrage incentives are created by systematic modeling differences, such as differences between the day-ahead and real-time modeled transmission contingencies and marginal loss calculations, virtual bids and offers cannot result in more efficient market outcomes. Such offers may be profitable but cannot change the underlying reason for the price difference. The virtual transactions will continue to profit from the activity for that reason. This is termed false arbitrage.

INCs, DECs and UTCs allow participants to arbitrage price differences between the Day-Ahead and Real-Time Energy Market. Absent a physical position in real time, the seller of an INC must buy energy in the Real-Time Energy Market to fulfill the financial obligation to provide energy. If the day-ahead price for energy is higher than the real-time price for energy, the INC makes a profit. Absent a physical position in real time, the buyer of a DEC must sell energy in the Real-Time Energy Market to fulfill the financial obligation to buy energy. If the day-ahead price for energy is lower than the real-time price for energy, the DEC makes a profit.

While the profitability of an INC or DEC position is an indicator that the INC or DEC, all else held equal, contributed to price convergence at the specific bus, unprofitable INCs and DECs may also contribute to price convergence.

Profitability is a less reliable indicator of whether a UTC contributes to price convergence than for INCs and DECs. The profitability of a UTC transaction is the net of the separate profitability of the component INC and DEC. A UTC can be net profitable if the profit on one side of the UTC transaction exceeds the losses on the other side. A profitable UTC can contribute to both price divergence on one side and to price convergence on the other side.

Table 3-71 shows the number of cleared UTC transactions, the number of profitable cleared UTCs, the number of cleared UTCs that were profitable at their source point and the number of cleared UTCs that were profitable at their sink point in the first six months of 2013 and the first six months of 2014. In the first six months of 2014, 55.4 percent of all cleared UTC transactions were net profitable, with 68.8 percent of the source side profitable and 32.3 percent of the sink side profitable (Table 3-71).

Table 3-71 Cleared UTC profitability by source and sink point: January through June of 2013 and 2014[73]

Jan-Jun	Cleared UTCs	Profitable UTCs	UTC Profitable at Source Bus	UTC Profitable at Sink Bus	Profitable UTC	Profitable Source	Profitable Sink
2013	6,963,165	3,817,472	4,626,806	2,398,423	54.8%	66.4%	34.4%
2014	13,212,749	7,317,892	9,088,006	4,262,210	55.4%	68.8%	32.3%

There are incentives to use virtual transactions to arbitrage price differences between the Day-Ahead and Real-Time Energy Markets, but there is no guarantee that such activity will result in price convergence and no data to support that claim. As a general matter, virtual offers and bids are based on expectations about both Day-Ahead and Real-Time Energy Market conditions and reflect the uncertainty about conditions in both markets and the fact that these conditions change hourly and daily. PJM markets do not provide a mechanism that could result in immediate convergence after a change in system conditions as there is at least a one day lag after any change in system conditions before offers could reflect such changes.

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 3-35).

Table 3-72 shows that the difference between the average real-time price and the average day-ahead price was -$0.55 per MWh in the first six months of 2013 and -$1.38 per MWh in the first six months of 2014. The difference between average peak real-time price and the average peak day-ahead price was -$0.01 per MWh in the first six months of 2013 and -$1.92 per MWh in the first six months of 2014.

Table 3-72 Day-ahead and real-time average LMP (Dollars per MWh): January through June of 2013 and 2014[74]

	2013 (Jan - Jun)				2014 (Jan - Jun)			
	Day Ahead	Real Time	Difference	Percent of Real Time	Day Ahead	Real Time	Difference	Percent of Real Time
Average	$37.11	$36.56	($0.55)	(1.5%)	$63.52	$62.14	($1.38)	(2.2%)
Median	$35.19	$32.79	($2.40)	(7.3%)	$44.42	$39.69	($4.72)	(11.9%)
Standard deviation	$10.42	$17.18	$6.76	39.3%	$69.93	$88.87	$18.94	21.3%
Peak average	$42.68	$42.67	($0.01)	(0.0%)	$79.77	$77.85	($1.92)	(2.5%)
Peak median	$40.62	$37.38	($3.25)	(8.7%)	$52.96	$48.52	($4.43)	(9.1%)
Peak standard deviation	$10.86	$20.39	$9.53	46.7%	$86.69	$111.61	$24.91	22.3%
Off peak average	$32.21	$31.19	($1.02)	(3.3%)	$49.22	$48.32	($0.90)	(1.9%)
Off peak median	$31.01	$29.29	($1.72)	(5.9%)	$36.52	$33.05	($3.47)	(10.5%)
Off peak standard deviation	$7.01	$11.29	$4.29	38.0%	$46.33	$59.03	$12.70	21.5%

73 Calculations exclude PJM administrative charges.
74 The averages used are the annual average of the hourly average PJM prices for day-ahead and real-time.

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 3-73 shows the difference between the Real-Time and the Day-Ahead Energy Market prices for the first six months of each year of the 14-year period 2001 to 2014.

Table 3-73 Day-ahead and real-time average LMP (Dollars per MWh): January through June of 2001 through 2014

Jan - Jun	Day Ahead	Real Time	Difference	Percent of Real Time
2001	$35.02	$33.10	($1.92)	(5.5%)
2002	$24.76	$24.10	($0.66)	(2.7%)
2003	$42.83	$41.31	($1.53)	(3.6%)
2004	$44.02	$44.99	$0.97	2.2%
2005	$45.63	$45.71	$0.07	0.2%
2006	$48.33	$49.36	$1.03	2.1%
2007	$53.03	$55.03	$2.00	3.8%
2008	$70.12	$70.19	$0.08	0.1%
2009	$40.01	$40.12	$0.11	0.3%
2010	$43.81	$43.27	($0.54)	(1.2%)
2011	$44.75	$45.51	$0.76	1.7%
2012	$30.44	$29.74	($0.69)	(2.3%)
2013	$37.11	$36.56	($0.55)	(1.5%)
2014	$63.52	$62.14	($1.38)	(2.2%)

Table 3-74 provides frequency distributions of the differences between PJM real-time hourly LMP and PJM day-ahead hourly LMP for the first six months of 2007 through 2014.

Table 3-74 Frequency distribution by hours of PJM real-time LMP minus day-ahead LMP (Dollars per MWh): January through June of 2007 through 2014

	2007		2008		2009		2010		2011		2012		2013		2014	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($1,000)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($1,000) to ($750)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	2	0.05%
($750) to ($500)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	3	0.12%
($500) to ($450)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.14%
($450) to ($400)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	6	0.28%
($400) to ($350)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	5	0.39%
($350) to ($300)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	5	0.51%
($300) to ($250)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	6	0.64%
($250) to ($200)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.02%	0	0.00%	14	0.97%
($200) to ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	3	0.09%	0	0.00%	14	1.29%
($150) to ($100)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.02%	4	0.18%	0	0.00%	45	2.33%
($100) to ($50)	17	0.39%	62	1.42%	3	0.07%	6	0.14%	27	0.64%	8	0.37%	0	0.00%	89	4.37%
($50) to $0	2,365	54.85%	2,578	60.45%	2,541	58.58%	2,890	66.68%	2,773	64.49%	2,940	67.69%	3,018	69.49%	2,837	69.70%
$0 to $50	1,832	97.03%	1,505	94.92%	1,772	99.38%	1,366	98.13%	1,414	97.05%	1,377	99.22%	1,281	98.99%	1,144	96.04%
$50 to $100	118	99.75%	195	99.38%	25	99.95%	69	99.72%	105	99.47%	25	99.79%	34	99.77%	82	97.93%
$100 to $150	7	99.91%	23	99.91%	2	100.00%	5	99.84%	16	99.84%	5	99.91%	4	99.86%	36	98.76%
$150 to $200	0	99.91%	2	99.95%	0	100.00%	7	100.00%	2	99.88%	2	99.95%	5	99.98%	17	99.15%
$200 to $250	1	99.93%	1	99.98%	0	100.00%	0	100.00%	2	99.93%	0	99.95%	0	99.98%	9	99.36%
$250 to $300	1	99.95%	0	99.98%	0	100.00%	0	100.00%	0	99.93%	1	99.98%	1	100.00%	8	99.54%
$300 to $350	2	100.00%	1	100.00%	0	100.00%	0	100.00%	0	99.93%	1	100.00%	0	100.00%	3	99.61%
$350 to $400	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.93%	0	100.00%	0	100.00%	3	99.68%
$400 to $450	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.93%	0	100.00%	0	100.00%	2	99.72%
$450 to $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.93%	0	100.00%	0	100.00%	0	99.72%
$500 to $750	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%	0	100.00%	0	100.00%	7	99.88%
$750 to $1,000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.88%
$1,000 to $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	1	99.91%
>= $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	4	100.00%

Figure 3-34 shows the hourly differences between day-ahead and real-time hourly LMP in the first six months of 2014.

Figure 3-34 Real-time hourly LMP minus day-ahead hourly LMP: January through June of 2014

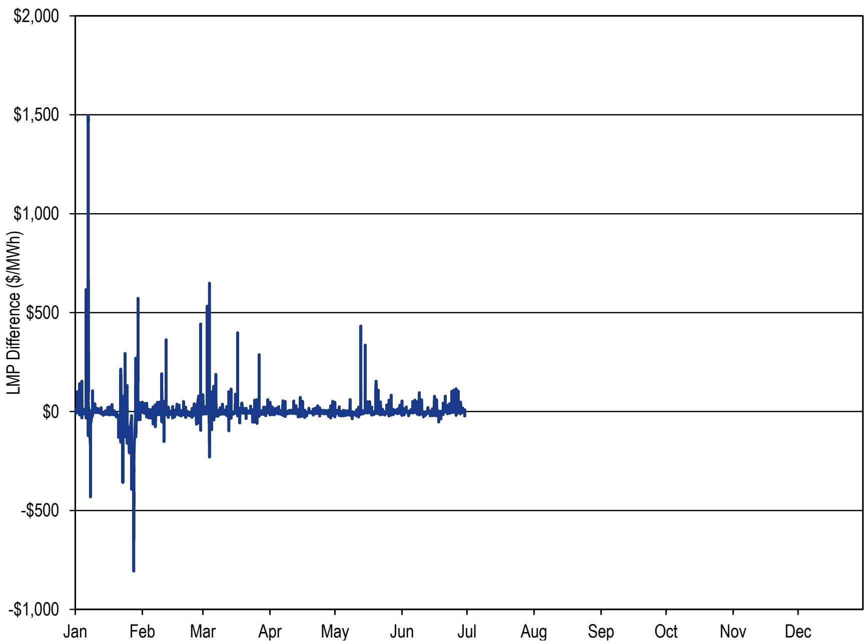
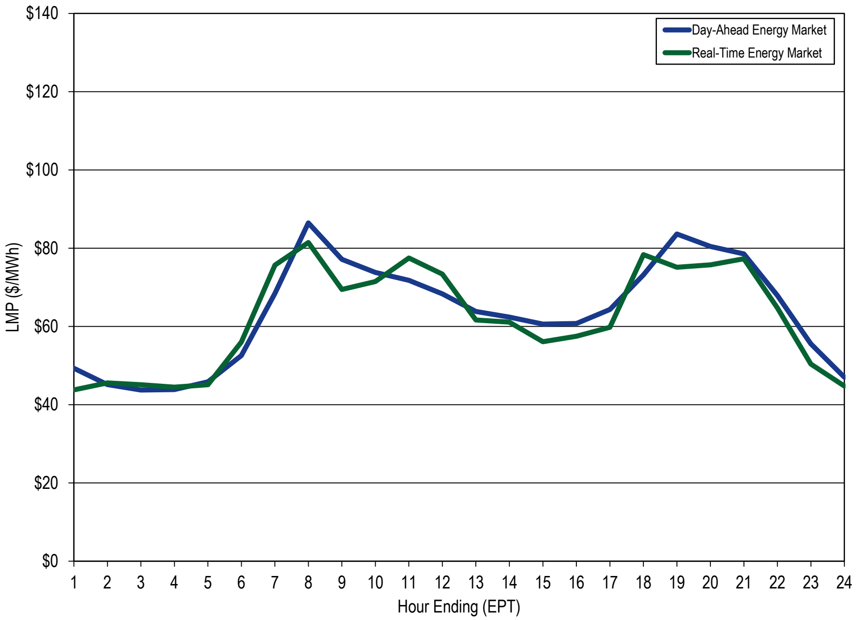


Figure 3-35 shows the monthly average differences between the day-ahead and real-time LMP in the first six months of 2014.

Figure 3-35 Monthly average of real-time minus day-ahead LMP: January through June of 2014

Figure 3-36 shows day-ahead and real-time LMP on an average hourly basis for the first six months of 2014.

Figure 3-36 PJM system hourly average LMP: January through June of 2014



Scarcity

PJM's Energy Market experienced shortage pricing events on two days in January 2014. Extreme cold weather conditions in January resulted in record winter peak loads. The high demand combined with high forced outage rates, and supply interruptions for natural gas fueled generation resulted in low reserve margins and associated shortage pricing events, and high uplift payments in January. Table 3-75 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in the first six months of 2013 and 2014. The only emergency alerts declared in the first six months of 2013 were cold weather and hot weather alerts.

Table 3-75 Summary of emergency events declared January through June, 2013 and 2014

	Number of days events declared	
Event Type	Jan - Jun, 2013	Jan - Jun, 2014
Cold Weather Alert	4	25
Hot Weather Alert	6	3
Maximum Emergency Generation Alert	0	6
Primary Reserve Alert	0	2
Voltage Reduction Alert	0	2
Primary Reserve Warning	0	1
Voltage Reduction Warning	0	4
Emergency Load management Long Lead Time	0	6
Emergency Load management Short Lead tTime	0	6
Maximum Emergency Action	0	8
Emergency Energy Bids Requested	0	3
Voltage Reduction Action	0	1
Shortage Pricing	0	2

Emergency procedures

PJM declares alerts at least a day prior to the operating day to warn members of possible emergency actions that could be taken during the operating day. In real time on the operating day, PJM issues warnings notifying members of system conditions that could result in emergency actions during the operating day.

PJM declared cold weather alerts on 25 days in the first six months of 2014 compared to only four days in the first six months of 2013.[75] The purpose of a cold weather alert is to prepare personnel and facilities for expected extreme cold weather conditions, generally when temperatures are forecast to approach minimums or fall below ten degrees Fahrenheit.

PJM declared hot weather alerts on three days in the first six months of 2014 compared to six days in the first six months of 2013.[76] The purpose of a hot weather alert is to prepare personnel and facilities for expected extreme hot and humid weather conditions, generally when temperatures are forecast to exceed 90 degrees Fahrenheit with high humidity.

75 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), Section 3.3 Cold Weather Alert, p. 41.
76 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), Section 3.3 Cold Weather Alert, p. 41.

PJM declared maximum emergency generation alerts on six days in the first six months of 2014. The purpose of a maximum emergency generation alert is to provide an alert at least one day prior to the operating day that system conditions may require use of PJM emergency actions. It is called to alert PJM members that maximum emergency generation may be requested in the operating capacity.[77] This means that if PJM directs members to load maximum emergency generation during the operating day, the resources must be able to increase generation above the maximum economic level of their offer.

PJM declared a primary reserve alert on two days in the first six months of 2014. The purpose of a primary reserve alert is to alert members at least one day prior to the operating day that available primary reserves are anticipated to be short of the primary reserve requirement on the operating day. It is issued when the estimated primary reserves are less than the forecast primary reserve requirement.

PJM declared a voltage reduction alert on two days in the first six months of 2014. The purpose of a voltage reduction alert is to alert members at least one day prior to the operating day that a voltage reduction may be required on the operating day. It is issued when the estimated operating reserve is less than the forecast synchronized reserve requirement.

PJM declared a primary reserve warning on one day in the first six months of 2014. The purpose of a primary reserve warning is to warn members that available primary reserves are less than the primary reserve requirement but greater than the synchronized reserve requirement.

PJM declared a voltage reduction warning and reduction of non-critical plant load on four days in the first six months of 2014. The purpose of a voltage reduction warning and reduction of non-critical plant load is to warn members that available synchronized reserves are less than the synchronized reserve requirement and that a voltage reduction may be required. It can be issued for the RTO or for specific control zones.

77 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), Section 2.3.1 Day-Ahead Emergency Procedures: Alerts, p. 16.

PJM declared emergency mandatory load management reductions (long lead time and short lead time) in all or parts of the PJM service territory on six days in the first six months of 2014. The purpose of emergency mandatory load management is to request curtailment service providers (CSP) to implement load reductions from demand resources registered in PJM demand response programs that have a lead time of between one and two hours (long lead time) and a lead time of up to one hour (short lead time). Despite that the formal name of PJM's action, load reductions (both long lead time and short lead time) during the first six months of 2014 are voluntary and not mandatory, because they occurred outside of the mandatory summer compliance period of June 1 through September 30. Load reductions during these events are not counted for performance assessment.

PJM declared maximum emergency generation actions on eight days in the first six months of 2014. The purpose of a maximum emergency generation action is to request generators to increase output to the maximum emergency level which unit owners may define at a level above the maximum economic level. A maximum emergency generation action can be issued for the RTO, for specific control zones or for parts of control zones. Maximum emergency generation action was declared for the RTO on four days in the first six months of 2013 (January 6, 7, 8 and March 4); for the BGE and Pepco control zones on January 22; for the Mid-Atlantic and Dominion regions on January 23, 24 and 30; and for the AP zone on January 23 and 24.

PJM requested bids for emergency energy purchases on three days in the first six months of 2014. On January 7, PJM requested bids for emergency energy between 0600 and 1100 and again between hours 1700 to 2100. PJM also requested bids for emergency energy on January 8 and January 23, but did not purchase any emergency energy.

PJM did not recall energy from PJM capacity resources that were exporting energy during emergency conditions in the first six months of 2014.

PJM issued a voltage reduction action on one day (January 6) in the first six months of 2014. The purpose of a voltage reduction is to reduce load to provide sufficient reserves, to maintain tie flow schedules, and to preserve limited energy sources. When a voltage reduction action is issued for a reserve zone or sub-zone, the primary reserve penalty factor and synchronized reserve penalty factor are incorporated into the synchronized and non-synchronized reserve market clearing prices and locational marginal prices until the voltage reduction action has been terminated.

There were nineteen spinning events in the first six months of 2014 compared to four in the first six months of 2013.[78] Of the nineteen, ten were classified as system disturbances caused by unit trips. Of those ten system disturbances, seven occurred in January.

Table 3-76 provides a description of PJM declared emergency procedures.

Table 3-76 Description of Emergency Procedures

Emergency Procedure	Purpose
Cold Weather Alert	To prepare personnel and facilities for extreme cold weather conditions, generally when forecast weather conditions approach minimum or temperatures fall below ten degrees Fahrenheit.
Hot Weather Alert	To prepare personnel and facilities for extreme hot and/or humid weather conditions, generally when forecast temperatures exceed 90 degrees with high humidity.
Maximum Emergency Generation Alert	To provide an early alert at least one day prior to the operating day that system conditions may require the use of the PJM emergency procedures and resources must be able to increase generation above the maximum economic level of their offers.
Primary Reserve Alert	To alert members of a projected shortage of primary reserve for a future period. It is implemented when estimated primary reserve is less than the forecast requirement.
Voltage Reduction Alert	To alert members thjat a voltage reduction may be required during a future critical period. It is implemented when estimated reserve capacity is less than forecasted synchronized reserve requirement.
Primary Reserve Warning	To warn members that available primary reserve is less than required and present operations are becoming critical. It is implemented when available primary reserve is less than the primary reserve requirement but greater than the synchronized reserve requirement.
Voltage Reduction Warning & Reduction of Non-Critical Plant Load	To warn members that actual synchronized reserves are less than the synchronized reserve requiremtn and that voltage reduction may be required.
Emergency Mandatory Load Management Reductions (Long Lead Time)	To request end-use customers registered in the PJM demand response program as a demand resource (DR) that need between one to two hours lead time to make reductions.
Emergency Mandatory Load Management Reductions (Short Lead Time)	To request end-use customers registered in the PJM demand response program as a demand resource (DR) that need up to one hour lead time to make reductions.
Maximum Emergency Generation Action	To provide real time notice to increase generation above the maximum economic level. It is implemented whenever generation is needed that is greater than the maximum economic level.
Voltage Reduction	To reduce load to provide sufficient reserve capacity to maintain tie flow schedules and preserve limited energy sources. It is implemented when load relief is needed to maintain tie schedules.

78 See *2014 Quarterly State of the Market Report for PJM: January through March*, Section 10: Ancillary Service Markets for details on the spinning events.

Table 3-77 shows the dates on which emergency alerts and warnings were declared as well as emergency actions were implemented in the first six months of 2014.

Table 3-77 PJM declared emergency alerts, warnings and actions: January through June, 2014

Dates	Cold Weather Alert	Hot Weather Alert	Maximum Emergency Generation Alert	Primary Reserve Alert	Voltage Reduction Alert	Primary Reserve Warning	Voltage Reduction Warning and Reduction of Non-Critical Plant Load	Maximum Emergency Generation Action	Emergency Load Management Long Lead Time	Emergency Load Management Short Lead Time	Voltage Reduction
1/1/2014	ComEd										
1/2/2014	ComEd										
1/3/2014	PJM except Southern region										
1/6/2014	PJM except Mid-Atlantic and Dominion						PJM	PJM			PJM
1/7/2014	PJM		PJM			PJM	PJM	PJM	PJM	PJM	
1/8/2014	PJM		PJM					PJM	PJM	PJM	
1/21/2014	PJM except Mid-Atlantic and Dominion										
1/22/2014	PJM							BGE, Pepco	BGE, Pepco	BGE, Pepco	
1/23/2014	PJM		Mid-Atlantic region, AP and Dominion control zones		BGE, Pepco			Mid-Atlantic region, AP and Dominion control zones	Mid-Atlantic region, AP and Dominion control zones	Mid-Atlantic region, AP and Dominion control zones	
1/24/2014	PJM		Mid-Atlantic				PJM	Mid-Atlantic region, AP and Dominion control zones	Mid-Atlantic region, AP and Dominion control zones	Mid-Atlantic region, AP and Dominion control zones	
1/27/2014	PJM										
1/28/2014	PJM		PJM	PJM	PJM						
1/29/2014	PJM										
1/30/2014							PJM	Mid-Atlantic and Dominion			
2/6/2014	ComEd										
2/7/2014	PJM Western Region										
2/10/2014	PJM Western Region										
2/11/2014	PJM Western Region										
2/12/2014	PJM Western Region										
2/24/2014	ComEd										
2/25/2014	ComEd										
2/26/2014	ComEd										
2/27/2014	ComEd										
2/28/2014	PJM Mid-Atlantic and Western regions										
3/4/2014	PJM		Mid-Atlantic and Dominion	PJM				PJM	PJM	PJM	
3/13/2014	PJM Western Region										
6/17/2014		PJM									
6/18/2014		PJM									
6/19/2014		Dominion									