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 2015, 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 2015.

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 in the first six months of 2015 was moderately concentrated. Average HHI was 1117 with a minimum of 916 and a maximum of 1468 in the first six months of 2015.
- 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, although high markups during periods of high demand did affect prices.
- Market design was evaluated as effective because the analysis shows that the PJM Energy Market resulted in competitive market outcomes. 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 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 basis for competitive outcomes) and on limiting market power mitigation to

1 Analysis of 2015 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 *2014 State of the Market Report for PJM*, Appendix A, "PJM Geography."

2 PJM. OATT Attachment M (PJM Market Monitoring Plan).

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. If market-based offer caps are raised, or if generators are allowed to modify offers hourly, aggregate market power mitigation rules need to be developed.

Overview

Market Structure

- **Supply.** Supply includes physical generation and imports and virtual transactions. Average offered real-time generation decreased by 11,851 MW, or 7.1 percent, in the first six months of 2015 from an average maximum of 167,891 MW to 156,040 MW. This decrease was a result of unit retirements between July 1, 2014, and June 30, 2015 and unit outages. In the first six months of 2015, 948.2 MW of new capacity were added to PJM. This new generation was offset by the deactivation of 105 units (9,770.5 MW) since January 1, 2015.

  PJM average real-time generation in the first six months of 2015 decreased by 2.6 percent from the first six months of 2014, from 92,458 MW to 90,097 MW.

  PJM average day-ahead supply in the first six months of 2015, including INCs and up-to congestion transactions, decreased by 30.5 percent from the first six months of 2014, from 165,620 MW to 115,148 MW.

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

- **Generation Fuel Mix.** During the first six months of 2015, coal units provided 34.7 percent, nuclear units 28.6 percent and gas units 23.3 percent of total generation. Compared to the first six months of 2014, generation from coal units decreased 17.2 percent, generation from gas units increased 23.9 percent and generation from nuclear units increased 1.5 percent.

- **Marginal Resources.** In the PJM Real-Time Energy Market, in the first six months of 2015, coal units were 56.12 percent of marginal resources and natural gas units were 32.85 percent of marginal resources. In the first six months of 2014, coal units were 48.59 percent and natural gas units were 42.02 percent of the marginal resources.

  In the PJM Day-Ahead Energy Market in the first six months of 2015, up-to congestion transactions were 74.1 percent of marginal resources, INCs were 5.4 percent of marginal resources, DECs were 9.1 percent of marginal resources, and generation resources were 11.1 percent of marginal resources in the first six months of 2015.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM system peak load during the first six months of 2015 was 143,086 MW in the HE 0800 on February 20, 2015, which was 1,441 MW, or 1.0 percent, higher than the PJM peak load for the first six months of 2014, which was 141,673 MW in the HE 1700 on June 17, 2014.

  PJM average real-time load in the first six months of 2015 increased by 0.1 percent from the first six months of 2014, from 90,529 MW to 90,586 MW. PJM average day-ahead demand in the first six months of 2015, including DECs and up-to congestion transactions, decreased by 30.5 percent from the first six months of 2014, from 160,805 MW to 111,749 MW.

- **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 2015, 11.6

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.

percent of real-time load was supplied by bilateral contracts, 30.8 percent by spot market purchases and 57.6 percent by self-supply. Compared with the first six months of 2014, reliance on bilateral contracts increased by 1.0 percent, reliance on spot market purchases increased by 4.1 percentage points and reliance on self-supply decreased by 5.1 percentage points.

- **Supply and Demand: Scarcity.** There were no shortage pricing events in the first six months of 2015.

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 remained at 0.2 percent in the first six months of 2014 and 2015. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 0.7 percent in the first six months of 2014 to 0.5 percent in the first six months of 2015.

  In the first six months of 2015, 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 increased from 0.5 percent in the first six months of 2014 to 0.6 percent in the first six months of 2015. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours increased from 0.4 percent in the first six months of 2014 to 0.5 percent in the first six months of 2015.

- **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 2015, 83.6 percent of marginal units had average dollar markups less than zero and had an average markup index less than or equal to zero. In the first six months of 2015, 7.9 percent of units had average dollar markups greater than or equal to $150. In the first six months of 2014, 11.3 percent of units had average dollar markups greater than or equal to $150.

  In the PJM Day-Ahead Energy Market in the first six months of 2015, 90.0 percent of marginal units had an average markup index less than or equal to zero. In the first six months of 2015, 4.0 percent of units had average dollar markups greater than or equal to $150. In the first six months of 2014, 3.8 percent of units had average dollar markups greater than or equal to $150.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** A new FMU rule became effective November 1, 2014, limiting the availability of FMU adders to units with net revenues less than unit going forward costs. The effects of the new rules were first observed in units eligible for an FMU or AU adder in December 2014, where the number of units that were eligible for an FMU or AU adder declined from an average of 70 units during the first 11 months of 2014, to zero in December 2014, and zero in the first six months of 2015.

- **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. The reduction in up-to congestion transactions (UTC) continued, following a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs.[4]

- **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

4 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

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 2015, 51.2 percent were offered as available for economic dispatch, 23.8 percent were offered as self scheduled, and 21.2 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 2015 were between $250 and $300 for one hour.

  PJM Real-Time Energy Market prices decreased in the first six months of 2015 compared to the first six months of 2014. The load-weighted average real-time LMP was 39.5 percent lower in the first six months of 2015 than in the first six months of 2014, $42.30 per MWh versus $69.92 per MWh.

  PJM Day-Ahead Energy Market prices decreased in the first six months of 2015 compared to the first six months of 2014. The load-weighted average day-ahead LMP was 38.8 percent lower in the first six months of 2015 than in the first six months of 2014, $43.26 per MWh versus $70.67 per MWh.[5]

- **Components of LMP.** In the PJM Real-Time Energy Market, for the first six months of 2015, 40.8 percent of the load-weighted LMP was the result of coal costs, 30.2 percent was the result of gas costs and 0.71 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market for the first six months of 2015, 30.6 percent of the load-weighted LMP was the result of the cost of coal, 15.6 percent was the result of the cost of gas, 5.3 percent was the result of the up-to congestion transactions, 20.4 percent was the result of DECs and 11.4 percent was the result of INCs.

- **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 the first six months of 2015, the adjusted markup component of LMP was $2.42 per MWh or 5.7 percent of the PJM real-time, load-weighted average LMP. The month of February had the highest adjusted markup component, $6.44 per MWh, or 12.65 percent of the real-time load-weighted average LMP. In the first six months of 2014, the adjusted markup was $4.61 per MWh or 6.8 percent of the PJM real-time load-weighted average LMP.

  In the PJM Day-Ahead Energy Market, marginal INCs, DECs and UTCs have zero markups. In the first six months of 2015, the adjusted markup component of LMP resulting from generation resources was $0.64 per MWh or 1.5 percent of the PJM day-ahead load-weighted average LMP.

  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 the Day-Ahead and Real-Time Energy Markets, although the behavior of some participants during the high demand periods in the first quarter 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 -$1.38 per MWh in the first six months of 2014 and -$1.11 per MWh in the first six months of 2015. The difference between average day-ahead and real-time prices, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

5 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."

Scarcity

- There were no shortage pricing events in the first six months of 2015.

Recommendations

- The MMU has recommended the elimination of FMU and AU adders. Since the implementation of FMU adders, PJM has undertaken major redesigns of its market rules that affect 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. (Priority: Medium. First reported 2012. Status: Adopted partially, Q4, 2014.)

  The MMU and PJM proposed, and on October 31, 2014, the Commission approved, a compromise that limited FMU adders to units with net revenues less than unit going forward costs or ACR.[6]

- The MMU recommends that PJM require all generating units to identify the fuel type associated with each of their offered schedules. (Priority: Low. First reported Q2, 2014. Status: Adopted in full, Q4, 2014.)
- The MMU recommends that PJM remove non-specific fuel types such as "other" or "co-fire other" from the list of fuel types available for market participants to identify the fuel type associated with their price and cost schedules. The MMU recommends that PJM require every market participant to make available at least one cost schedule with the same fuel-type and parameters as that of their offered price schedule. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[7] (Priority: Medium. First reported 2012. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2013. Status: Not adopted.)
- 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. (Priority: Low. First reported 2013. Status: Not adopted.)
- 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. (Priority: Low. First reported 2013. Status: Not adopted.)
- 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. (Priority: Low. First reported 2013. Status: Not adopted.)
- There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[8] The MMU recommends that PJM include in the appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[9] (Priority: Low. First reported 2013. Status: Not adopted.)
- 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. (Priority: Low. First reported 2013. Status: Not adopted.)

6 149 FERC ¶ 61,091 (2014).
7 PJM. OATT Section: 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.
8 The general definition of a hub can be found in PJM. "Manual 35: Definitions and Acronyms," Revision 23 (April 11, 2014).
9 According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that generation owners be permitted to submit cost-based and price-based offers above the $1,000/MWh energy offer cap if both offer types are calculated in accordance with PJM's Cost Development Guidelines excluding the ten percent adder, subject to after the fact review by the MMU. Such offers should be allowed to set LMP. (Priority: Medium. First reported 2014. Status: Not adopted. Pending before FERC.)
- 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. (Priority: Medium. First reported Q1, 2010. Status: Not adopted.)

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first six months of 2015, 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 11,851 MW in the first six months of 2015 compared to the first six months of 2014, while peak load increased by 1,441 MW. Market concentration levels remained moderate although there is high concentration in the intermediate and peaking segments which adds to concerns about market power when market conditions are tight. The 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 although the market structure during high demand hours remains a concern.

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 in the first six months of 2015 generally reflected supply-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.[10] 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

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

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.

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 the first quarter. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants during the high demand periods in the first quarter 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 and provide a reason to use cost as the sole basis for hourly changes in offers or offers greater than $1,000 per MWh. The MMU concludes that the PJM energy market results were competitive in the first six months of 2015.

Market Structure

Market Concentration

Analyses of supply curve segments of the PJM energy market in the first six months of 2015 indicates moderate concentration in the base load segment, but high concentration in the intermediate and peaking segments.[11] 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 2015.

11 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.

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.[12]

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM energy market during the first six months of 2015 was moderately concentrated (Table 3-2).

Table 3-2 PJM hourly Energy Market HHI: January through June 2014 and 2015[13]

	Hourly Market HHI (Jan - Jun, 2014)	Hourly Market HHI (Jan - Jun, 2015)
Average	1138	1117
Minimum	891	916
Maximum	1407	1468
Highest market share (One hour)	29%	30%
Average of the highest hourly market share	21%	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 2014 and 2015.

Table 3-3 PJM hourly Energy Market HHI (By supply segment): January through June 2014 and 2015

	Jan - Jun, 2014			Jan - Jun, 2015		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	1029	1174	1454	1021	1148	1489
Intermediate	727	1719	5693	693	2016	8147
Peak	713	6119	10000	802	6080	10000

Figure 3-1 shows the number of units in the baseload, intermediate and peaking segments by fuel source in the first six months of 2015.

12 77 FERC ¶ 61,263, pp. 64-70 (1996), "*Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement.*"

13 This analysis includes all hours in 2014 and 2015, regardless of congestion.

Figure 3-1 Fuel source distribution in unit segments: January through June 2015

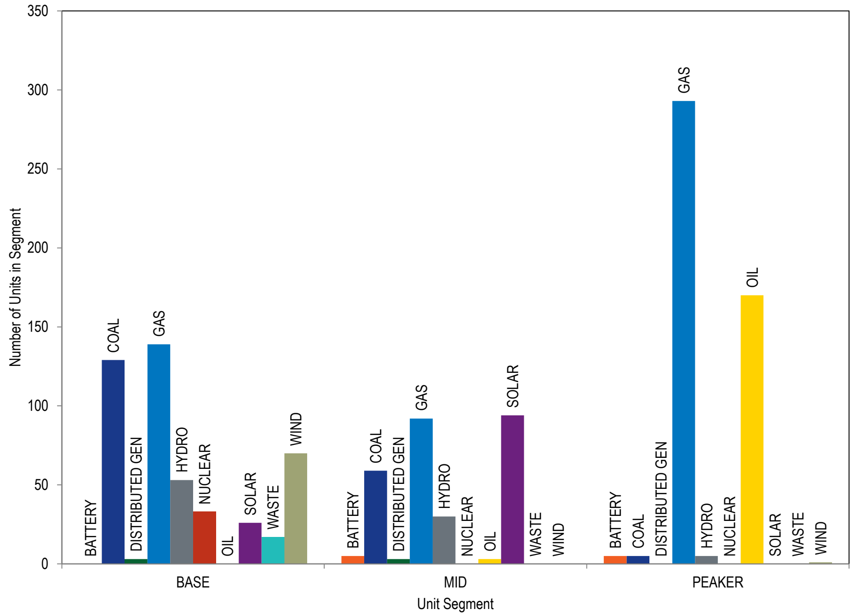
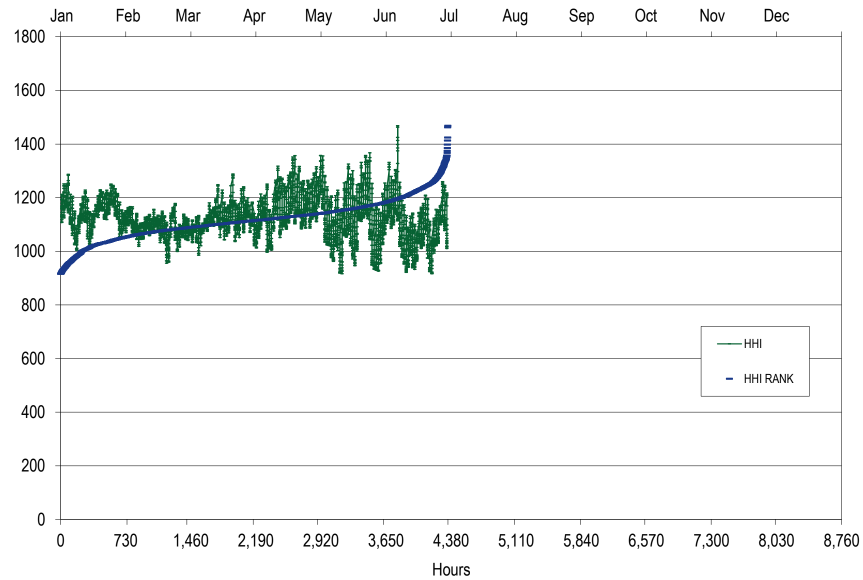


Figure 3-2 presents the hourly HHI values in chronological order and an HHI duration curve for the first six months of 2015.

Figure 3-2 PJM hourly Energy Market HHI: January through June 2015



Ownership of Marginal Resources

Table 3-4 shows the contribution to real-time, load-weighted LMP by individual marginal resource owner.[14] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of 2015, 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 2015, the offers of one company contributed 17.8 percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies contributed 54.7 percent of the real-time, load-weighted, average PJM system LMP. During 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 offers of the top four companies contributed 53.7 percent of the real-time, load-weighted, average PJM system LMP.

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

Table 3-4 Marginal unit contribution to PJM real-time, load-weighted LMP (By parent company): January through June 2014 and 2015

2014 (Jan-Jun)		2015 (Jan-Jun)	
Company	Percent of Price	Company	Percent of Price
1	18.2%	1	17.8%
2	14.6%	2	15.6%
3	12.1%	3	11.4%
4	8.8%	4	9.9%
5	7.6%	5	8.3%
6	6.6%	6	8.2%
7	6.2%	7	5.3%
8	4.8%	8	5.0%
9	3.8%	9	2.8%
Other (58 companies)	17.3%	Other (57 companies)	15.7%

Table 3-5 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.[15] 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 (10.5 percent), in the first six months of 2014 also had the largest impact (16.5 percent) in the first six months of 2015.

Table 3-5 Marginal resource contribution to PJM day-ahead, load-weighted LMP (By parent company): January through June of 2014 and 2015

2014 (Jan - Jun)		2015 (Jan - Jun)	
Company	Percent of Price	Company	Percent of Price
1	10.5%	1	16.5%
2	7.3%	2	10.7%
3	7.0%	3	7.6%
4	6.2%	4	5.8%
5	6.1%	5	5.2%
6	5.7%	6	5.1%
7	4.3%	7	4.7%
8	3.8%	8	4.5%
9	3.3%	9	3.5%
Other (133 companies)	45.9%	Other (136 companies)	36.4%

15 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 56.12 percent and natural gas units were 32.85 percent of marginal resources. In the first six months of 2014, coal units were 48.59 percent and natural gas units were 42.02 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.[16] In the first six months of 2015, 68.81 percent of the wind marginal units had negative offer prices, 24.47 percent had zero offer prices and 3.73 percent had positive offer prices.

16 Prior to April 1, 2015, for the generation units that are capable of using multiple fuel types, PJM did 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 2014 and 2015

Type/Fuel	2014 (Jan - Jun)	2015 (Jan - Jun)
Coal	48.59%	56.12%
Gas	42.02%	32.85%
Oil	3.64%	7.37%
Wind	5.10%	3.11%
Other	0.42%	0.43%
Municipal Waste	0.05%	0.06%
Uranium	0.09%	0.05%
Emergency DR	0.08%	0.00%

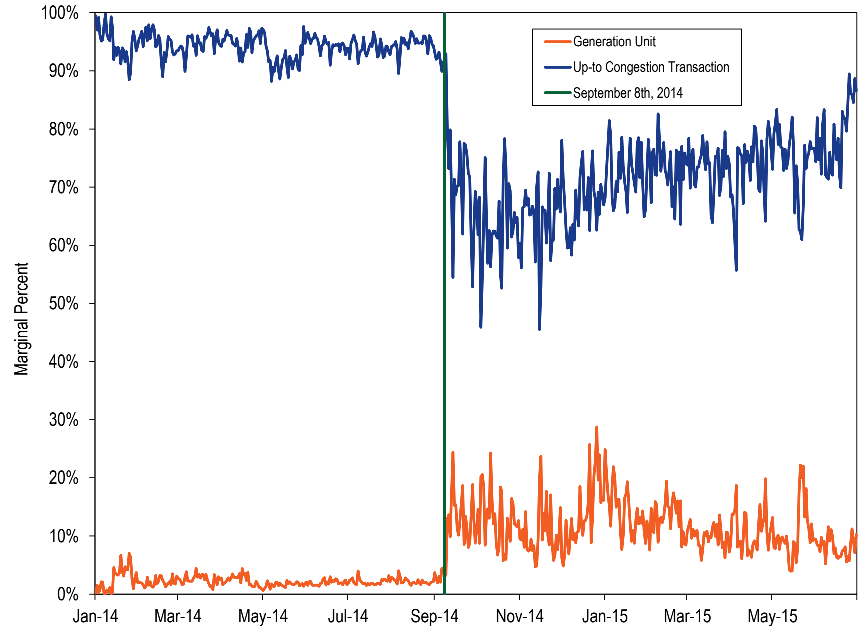
Table 3-7 shows the type and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In the first six months of 2015, up-to congestion transactions were 74.06 percent of the total marginal resources. Up-to congestion transactions were 94.15 percent of the total marginal resources in the first six months of 2014.

Table 3-7 Day-ahead marginal resources by type/fuel: January through June of 2014 and 2015

Type/Fuel	2014 (Jan - Jun)	2015 (Jan - Jun)
Up-to Congestion Transaction	94.15%	74.06%
DEC	2.07%	9.11%
INC	1.38%	5.35%
Coal	1.19%	7.09%
Gas	0.94%	3.29%
Wind	0.11%	0.18%
Dispatchable Transaction	0.10%	0.38%
Oil	0.02%	0.42%
Other	0.02%	0.05%
Price Sensitive Demand	0.01%	0.04%
Import	0.01%	0.00%
Municipal Waste	0.00%	0.01%
Total	100.00%	100.00%

Figure 3-3 shows, for the Day-Ahead Market in 2014 through June of 2015, the daily proportion of marginal resources that were up-to congestion transaction and/or generation units. The percentage of marginal up-to congestion transactions decreased significantly beginning on September 8, 2014, as a result of the FERC's UTC uplift refund notice which became effective on that date.[17] The percentage of marginal up-to congestion transaction decreased and that of generation units increased.

Figure 3-3 Day-ahead marginal up-to congestion transaction and generation units: 2014 through June of 2015



Supply

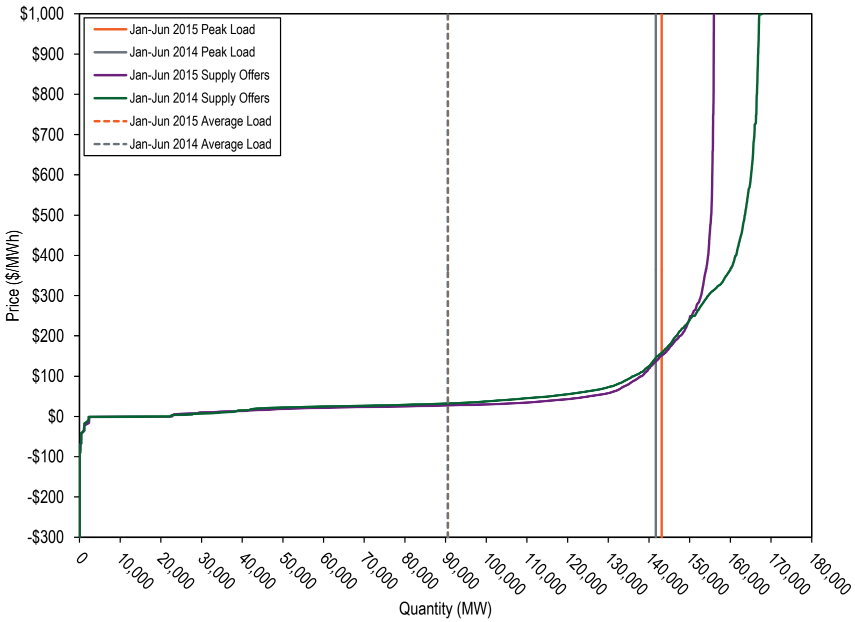
Supply includes physical generation and imports and virtual transactions.

Figure 3-4 shows the average PJM aggregate real-time generation supply curves by offer price, peak load and average load for January through June of 2014 and 2015. Total average PJM aggregate real-time generation supply decreased by 11,851 MW, or 7.1 percent, in the first six months of 2015 from an average maximum of 167,891 MW to 156,040 MW in the first six months

17 See 18 CFR § 385.213 (2014).

of 2015. This decrease was a result of unit retirements between July 1, 2014, and June 30, 2015 and unit outages.

Figure 3-4 Average PJM aggregate real-time generation supply curves by offer price: January through June of 2014 and 2015



Energy Production by Fuel Source

In the first six months of 2015, generation from coal units decreased 16.3 percent and generation from natural gas units increased 29.2 percent compared to the first six months of 2014 (Table 3-8).[18]

Table 3-8 PJM generation (By fuel source (GWh)): January through June of 2014 and 2015[19]

		Jan-Jun 2014		Jan-Jun 2015		Change in
		GWh	Percent	GWh	Percent	Output
Coal		186,497.4	45.8%	156,026.8	39.4%	(16.3%)
	Standard Coal	184,552.9	45.3%	154,324.2	39.0%	(16.4%)
	Waste Coal	1,944.5	0.5%	1,702.6	0.4%	(12.4%)
Nuclear		134,954.5	33.1%	136,978.9	34.6%	1.5%
Gas		65,564.7	16.1%	84,695.5	21.4%	29.2%
	Natural Gas	63,810.4	15.7%	82,781.3	20.9%	29.7%
	Landfill Gas	1,183.3	0.3%	1,237.3	0.3%	4.6%
	Biomass Gas	571.0	0.1%	676.9	0.2%	18.5%
Hydroelectric		8,241.9	2.0%	6,585.4	1.7%	(20.1%)
	Pumped Storage	3,451.6	0.8%	2,696.9	0.7%	(21.9%)
	Run of River	4,790.3	1.2%	3,888.5	1.0%	(18.8%)
Wind		8,678.0	2.1%	8,760.8	2.2%	1.0%
Waste		2,334.9	0.6%	2,252.8	0.6%	(3.5%)
	Solid Waste	2,027.2	0.5%	1,988.8	0.5%	(1.9%)
	Miscellaneous	307.7	0.1%	264.1	0.1%	(14.2%)
Oil		809.0	0.2%	597.5	0.2%	(26.1%)
	Heavy Oil	340.8	0.1%	408.6	0.1%	19.9%
	Light Oil	374.3	0.1%	140.6	0.0%	(62.4%)
	Diesel	70.4	0.0%	46.6	0.0%	(33.8%)
	Kerosene	23.5	0.0%	1.7	0.0%	(92.7%)
	Jet Oil	0.0	0.0%	0.0	0.0%	NA
Solar, Net Energy Metering		201.4	0.0%	262.1	0.0%	30.1%
Battery		5.4	0.0%	2.7	0.0%	(50.1%)
Total		407,287.2	100.0%	396,162.5	100.0%	(2.7%)

18 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.

19 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.

Table 3-9 Monthly PJM generation (By fuel source (GWh)): January through June 2015

		Jan	Feb	Mar	Apr	May	Jun	Total
Coal		32,666.4	33,315.4	25,902.0	18,265.1	21,619.0	24,258.9	156,026.8
	Standard Coal	32,309.5	32,992.8	25,589.6	18,068.7	21,363.2	24,000.4	154,324.2
	Waste Coal	356.8	322.6	312.4	196.4	255.8	258.5	1,702.6
Nuclear		25,881.8	21,994.5	22,290.8	20,346.7	22,641.7	23,823.5	136,978.9
Gas		13,916.1	13,271.0	14,467.2	12,119.3	14,292.4	16,629.6	84,695.5
	Natural Gas	13,567.7	12,957.9	14,155.0	11,840.9	13,978.2	16,281.5	82,781.3
	Landfill Gas	218.1	192.1	212.7	203.7	214.7	196.1	1,237.3
	Biomass Gas	130.4	121.0	99.5	74.7	99.5	151.9	676.9
Hydroelectric		954.0	763.3	1,152.5	1,379.8	1,025.2	1,310.5	6,585.4
	Pumped Storage	398.8	388.7	344.7	331.4	504.2	729.1	2,696.9
	Run of River	555.2	374.6	807.7	1,048.4	521.1	581.5	3,888.5
Wind		1,683.6	1,526.6	1,724.1	1,657.3	1,213.9	955.2	8,760.8
Waste		400.9	324.0	357.1	378.6	384.8	407.5	2,252.8
	Solid Waste	347.8	279.7	308.0	335.4	347.2	370.7	1,988.8
	Miscellaneous	53.1	44.3	49.1	43.2	37.5	36.8	264.1
Oil		81.0	408.6	13.1	5.3	43.8	45.7	597.5
	Heavy Oil	64.3	315.0	0.0	0.0	0.0	29.3	408.6
	Light Oil	13.7	58.8	10.4	5.2	40.0	12.6	140.6
	Diesel	2.9	33.4	2.5	0.2	3.8	3.8	46.6
	Kerosene	0.1	1.4	0.2	0.0	0.0	0.0	1.7
	Jet Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar, Net Energy Metering		23.3	32.1	38.7	53.1	61.9	53.0	262.1
Battery		0.4	0.4	0.5	0.4	0.5	0.6	2.7
Total		75,607.5	71,635.8	65,945.9	54,205.5	61,283.2	67,484.5	396,162.5

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.

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 11,851 MW, or 7.1 percent, in the first six months of 2015 from an average maximum of 167,891 MW to 156,040 MW in the first six months of 2015.[20] This decrease was a result of unit retirements between July 1, 2014, and June 30, 2015 and unit outages. In the first six months of 2015, 948.2 MW of new capacity were added to PJM. This new generation was offset by the deactivation of 105 units (9,770.5 MW) since January 1, 2015.

PJM average real-time generation in the first six months of 2015 decreased by 2.6 percent from the first six months of 2014, from 92,458 MW to 90,097 MW.[21]

PJM average real-time supply including imports decreased by 1.7 percent in the first six months of 2015 from the first six months of 2014, from 106,879 MW to 105,027 MW.

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.

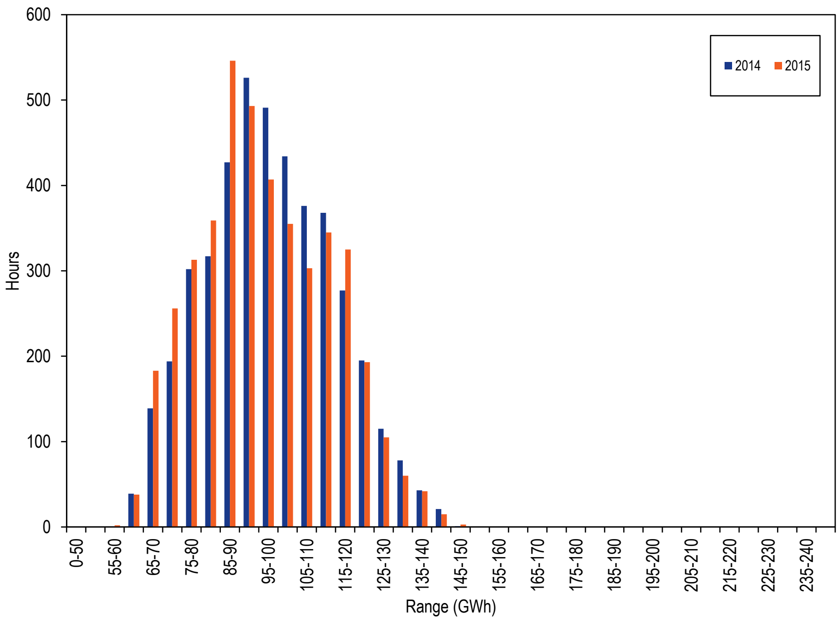
20 Calculated values shown in Section 3, "Energy Market," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.
21 Generation data are the net MWh injections and withdrawals MWh at every generation bus in PJM.

- **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 Tag, and must pass the neighboring balancing authority checkout process.

PJM Real-Time Supply Duration

Figure 3-5 shows the hourly distribution of PJM real-time generation plus imports for the first six months of 2014 and 2015.

Figure 3-5 Distribution of PJM real-time generation plus imports: January through June of 2014 and 2015[22]



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

PJM Real-Time, Average Supply

Table 3-10 presents summary real-time supply statistics for each year for the first six months of the 16-year period from 2000 through 2015.[23]

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 2015

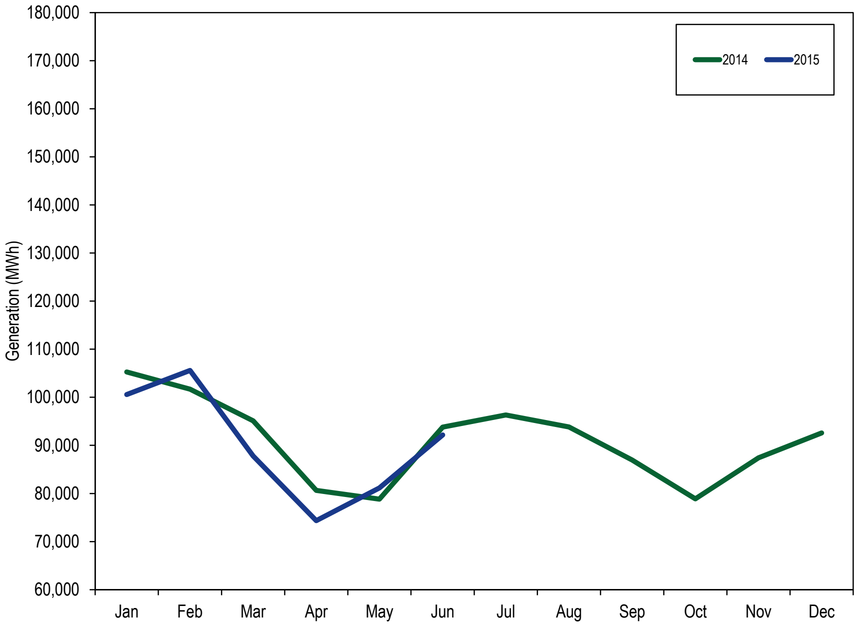
	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2000	31,523	5,560	34,190	6,329	NA	NA	NA	NA
2001	29,428	4,679	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%
2015	90,097	16,028	96,626	17,168	(2.6%)	1.9%	(1.6%)	2.7%

23 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 3-6 compares the real-time, monthly average hourly generation in the first six months of 2014 and 2015.

Figure 3-6 PJM real-time average monthly hourly generation: January 2014 through June 2015



Day-Ahead Supply

PJM average day-ahead supply in the first six months of 2015, including INCs and up-to congestion transactions, decreased by 30.5 percent from the first six months of 2014, from 165,620 MW to 115,148 MW.

PJM average day-ahead supply in the first six months of 2015, including INCs, up-to congestion transactions, and imports, decreased by 30.0 percent from the first six months of 2014, from 167,939 MW to 117,612 MW. The reduction in PJM day-ahead supply was a result of a sharp decrease in in UTCs beginning in September 2014 based on a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs.[24]

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

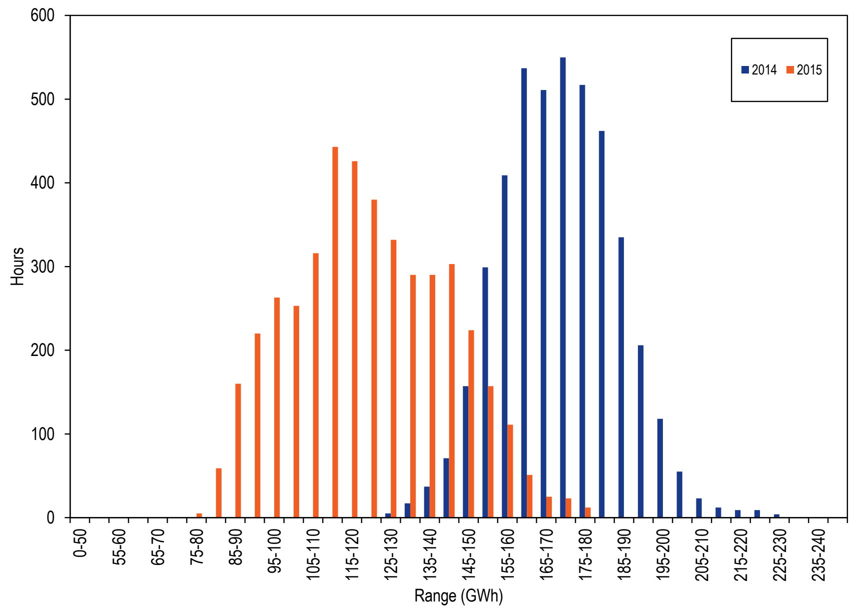
- **Self-Scheduled Generation Offer.** Offer to supply a fixed block of MWh, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MWh and corresponding offer prices from a unit.
- **Increment Offer (INC).** Financial offer to supply MWh and corresponding offer prices. INCs can be submitted by any market participant.
- **Up-to Congestion Transaction (UTC).** 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 3-7 shows the hourly distribution of PJM day-ahead supply, including increment offers, up-to congestion transactions, and imports for the first six months of 2014 and 2015.

24 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

Figure 3-7 Distribution of PJM day-ahead supply plus imports: January through June of 2014 and 2015[25]



PJM Day-Ahead, Average Supply

Table 3-11 presents summary day-ahead supply statistics for the first six months of each year of the 16-year period from 2000 through 2015.[26]

Table 3-11 PJM day-ahead average hourly supply and day-ahead average hourly supply plus average hourly imports: January through June 2000 through 2015

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
	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%)
2015	115,148	18,849	117,612	18,994	(30.5%)	35.3%	(30.0%)	34.5%

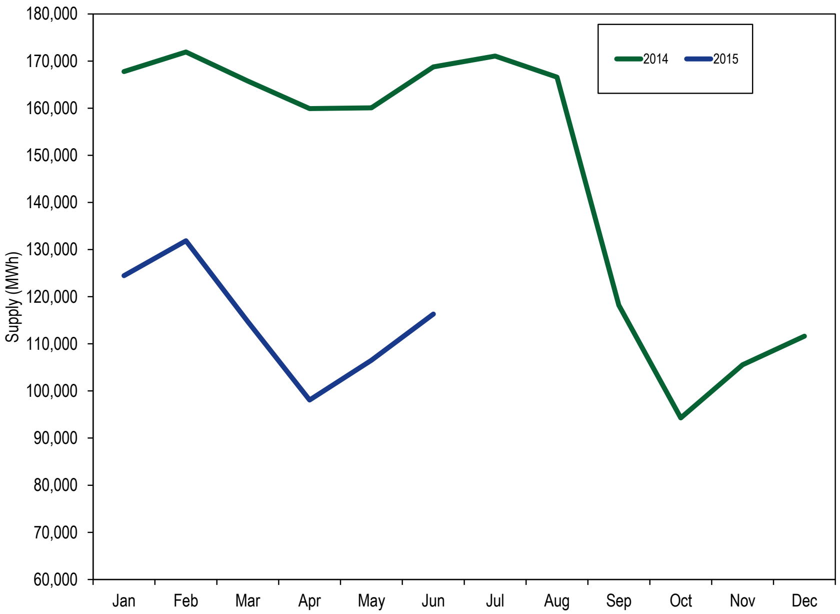
25 Each range on the horizontal axis excludes the start value and includes the end value.

26 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 3-8 compares the day-ahead, monthly average hourly supply, including increment offers and up-to congestion transactions, in the first six months of 2014 and 2015. The reduction in PJM day-ahead supply was a result of a sharp decrease in in UTCs beginning in September 2014 based on a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs.[27]

Figure 3-8 PJM day-ahead monthly average hourly supply: January 2014 through June 2015



Real-Time and Day-Ahead Supply

Table 3-12 presents summary statistics for the first six months of 2014 and 2015, 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 2015 up-to congestion transactions were 14.8 percent of the total day-ahead supply compared to 39.9 percent in the first six months of 2014.

27 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

Table 3-12 Day-ahead and real-time supply (MWh): January through June 2014 and 2015

		Day Ahead					Real Time		Day Ahead Less Real Time	
(Jan-Mar)		Generation	INC Offers	Up-to Congestion	Imports	Total Supply	Generation	Total Supply	Total Supply	Total Generation
Average	2014	95,332	3,240	67,048	2,319	167,939	92,458	98,186	69,753	2,874
	2015	93,011	4,713	17,425	2,464	117,612	90,097	96,626	20,986	2,914
Median	2014	94,879	3,121	67,141	2,286	167,849	91,635	97,154	70,695	3,244
	2015	92,017	4,650	17,190	2,469	116,585	88,510	94,831	21,754	3,507
Standard Deviation	2014	16,262	857	10,018	385	14,119	15,722	16,710	(2,591)	540
	2015	17,290	694	3,592	426	18,994	16,028	17,168	1,826	1,262
Peak Average	2014	104,620	3,633	66,773	2,441	177,466	100,878	107,222	70,243	3,741
	2015	101,910	4,863	18,426	2,602	127,801	97,640	104,825	22,976	4,270
Peak Median	2014	103,967	3,548	67,716	2,375	176,835	100,317	106,500	70,334	3,650
	2015	101,652	4,837	18,037	2,613	126,568	96,767	103,701	22,867	4,885
Peak Standard Deviation	2014	13,288	828	9,565	366	10,818	13,101	13,952	(3,134)	188
	2015	14,167	651	3,604	423	15,794	13,896	14,767	1,027	271
Off-Peak Average	2014	87,165	2,894	67,291	2,213	159,563	85,054	90,240	69,322	2,111
	2015	84,951	4,577	16,518	2,338	108,384	83,265	89,200	19,184	1,685
Off-Peak Median	2014	86,694	2,798	66,558	2,220	159,087	84,042	89,083	70,004	2,652
	2015	83,297	4,490	16,244	2,306	105,973	81,495	86,632	19,340	1,802
Off-Peak Standard Deviation	2014	14,115	723	10,397	370	11,035	14,018	14,789	(3,754)	96
	2015	15,852	704	3,331	388	16,807	14,716	15,755	1,052	1,136

Figure 3-9 shows the average hourly cleared volumes of day-ahead supply and real-time supply for January through June of 2015. 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.

Figure 3-9 Day-ahead and real-time supply (Average hourly volumes): January through June 2015

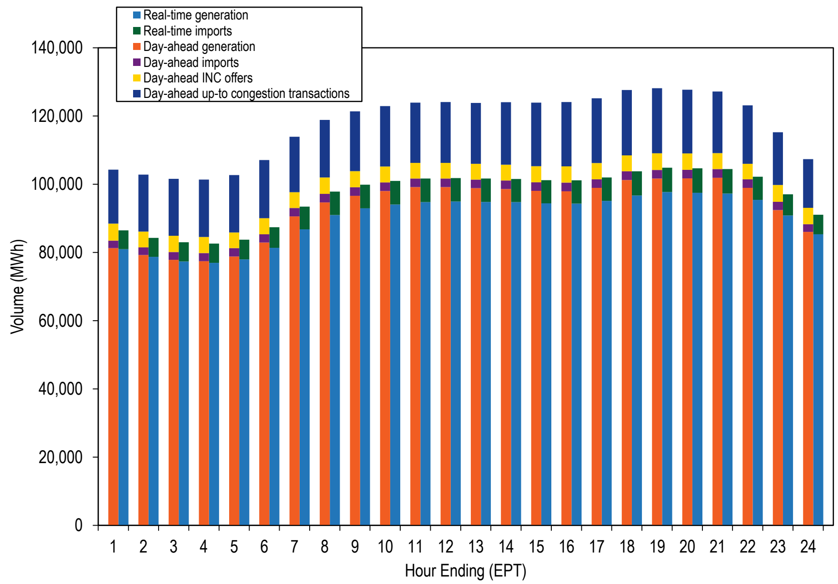


Figure 3-10 shows the difference between the day-ahead and real-time average daily supply in January 2014 through June 2015.

Figure 3-10 Difference between day-ahead and real-time supply (Average daily volumes): January 2014 through June 2015

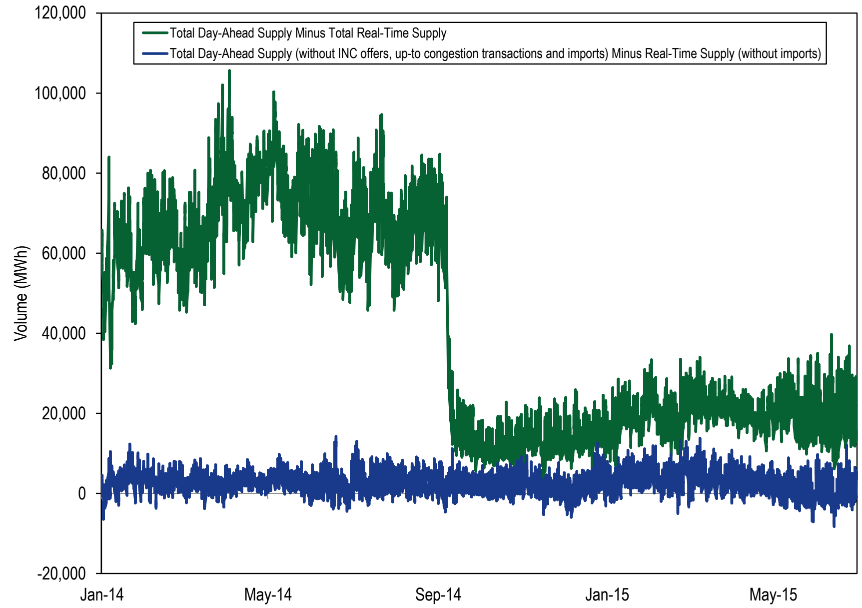
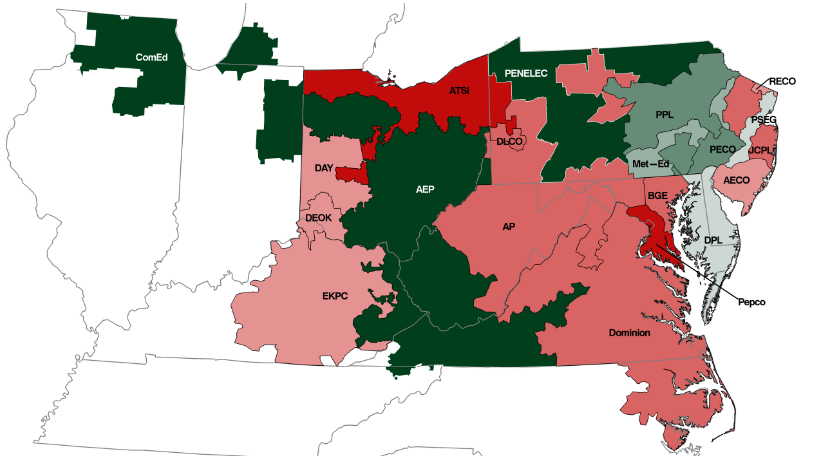


Figure 3-11 shows the difference between the PJM real-time generation and real-time load by zone in the first six months of 2015. Table 3-13 shows the difference between the PJM real-time generation and real-time load by zone in the first six months of 2014 and 2015. Figure 3-11 is color coded on a scale 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 3-11 Map of PJM real-time generation less real-time load by zone: January through June 2015[28]



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	(2,270)	ComEd	15,509	DPL	(5,713)	PENELEC	13,045
AEP	7,843	DAY	(2,177)	EKPC	(1,918)	Pepco	(10,346)
AP	(4,272)	DEOK	(4,054)	JCPL	(5,059)	PPL	4,752
ATSI	(10,611)	DLCO	1,200	Met-Ed	3,470	PSEG	1,671
BGE	(5,370)	Dominion	(5,867)	PECO	8,775	RECO	(731)

28 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.aspx> (Accessed on 7/14/2015)

Table 3-13 PJM real-time generation less real-time load by zone (GWh): January through June 2014 and 2015

	Zonal Generation and Load (GWh)					
	(Jan-Jun) 2014			(Jan-Jun) 2015		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	1,392.9	4,952.0	(3,559.1)	2,836.0	5,105.9	(2,269.9)
AEP	79,566.2	65,576.1	13,990.0	73,030.8	65,187.9	7,842.9
AP	22,057.4	24,691.8	(2,634.4)	20,898.6	25,170.3	(4,271.7)
ATSI	26,162.3	34,171.4	(8,009.2)	23,158.8	33,769.7	(10,610.9)
BGE	11,110.2	16,193.1	(5,082.9)	11,084.5	16,454.9	(5,370.4)
ComEd	62,191.7	48,784.7	13,406.9	62,304.6	46,795.9	15,508.8
DAY	7,109.6	8,599.0	(1,489.4)	6,356.2	8,533.2	(2,177.1)
DEOK	9,079.3	13,578.2	(4,498.9)	9,437.7	13,491.7	(4,054.0)
DLCO	41,837.2	48,093.9	(6,256.8)	43,431.8	49,298.9	(5,867.0)
Dominion	3,453.4	9,243.4	(5,790.0)	3,827.6	9,540.9	(5,713.3)
DPL	8,371.5	7,285.6	1,085.9	8,295.3	7,095.3	1,200.0
EKPC	5,696.2	6,645.9	(949.7)	4,529.2	6,447.5	(1,918.3)
JCPL	5,950.4	11,107.4	(5,157.0)	6,253.7	11,312.5	(5,058.8)
Met-Ed	10,308.8	7,673.6	2,635.2	11,241.4	7,771.3	3,470.1
PECO	29,247.1	19,819.1	9,427.9	29,003.8	20,228.4	8,775.3
PENELEC	24,080.3	8,806.4	15,273.9	21,850.0	8,804.8	13,045.3
Pepco	6,958.7	15,339.9	(8,381.2)	5,128.6	15,475.1	(10,346.5)
PPL	25,990.2	21,007.3	4,982.9	25,840.0	21,087.7	4,752.4
PSEG	20,982.1	20,881.3	100.8	22,781.3	21,110.3	1,671.0
RECO	0.0	717.2	(717.2)	0.0	731.0	(731.0)

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 2015 was 143,115 MW in the HE 0800 on February 20, 2015, which was 1,441 MW, or

1.0 percent, higher than the peak load for the first six months of 2014, which was 141,673 MW in the HE 17 on June 17, 2014.

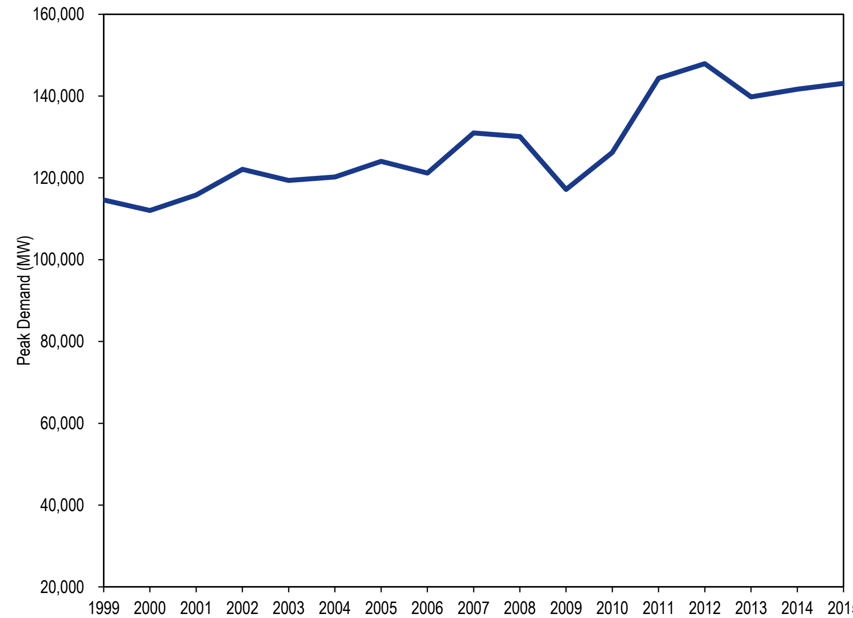
Table 3-14 shows the peak loads for the first six months of 1999 through 2015.

Table 3-14 Actual PJM footprint peak loads: January through June 1999 to 2015[29]

(Jan - Jun)	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (Percent)
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	Tue, June 17	17	141,673	1,895	1.4%
2015	Fri, February 20	8	143,115	1,441	1.0%

Figure 3-12 shows the peak loads for the first six months of 1999 through 2015.

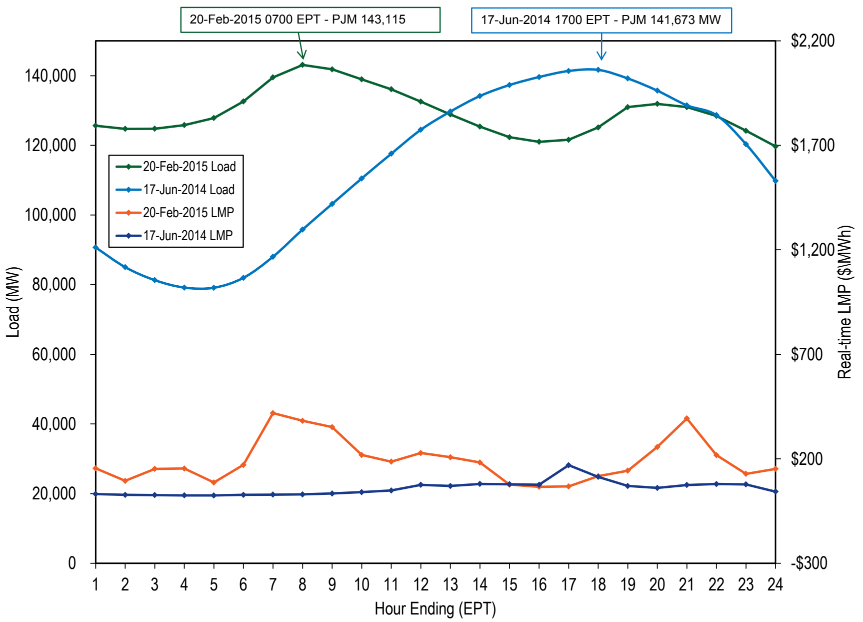
Figure 3-12 PJM footprint calendar year peak loads: January through June 1999 to 2015



29 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 3-13 compares the peak load days during the first six months of 2014 and 2015. The average hourly real-time LMP peaked at $418.74 on February 20, 2015 and peaked at $169.33 on June 17, 2014.

Figure 3-13 PJM peak-load comparison: Friday, February 20, 2015, and Tuesday, June 17, 2014



Real-Time Demand

PJM average real-time load in the first six months of 2015 increased by 0.1 percent from the first six months of 2014, from 90,529 MW to 90,586 MW.[30]

PJM average real-time demand in the first six months of 2015 decreased 1.5 percent from the first six months of 2014, from 96,189 MW to 94,782 MW.

30 Load data are the net MWh injections and withdrawals MWh at every load bus in PJM.

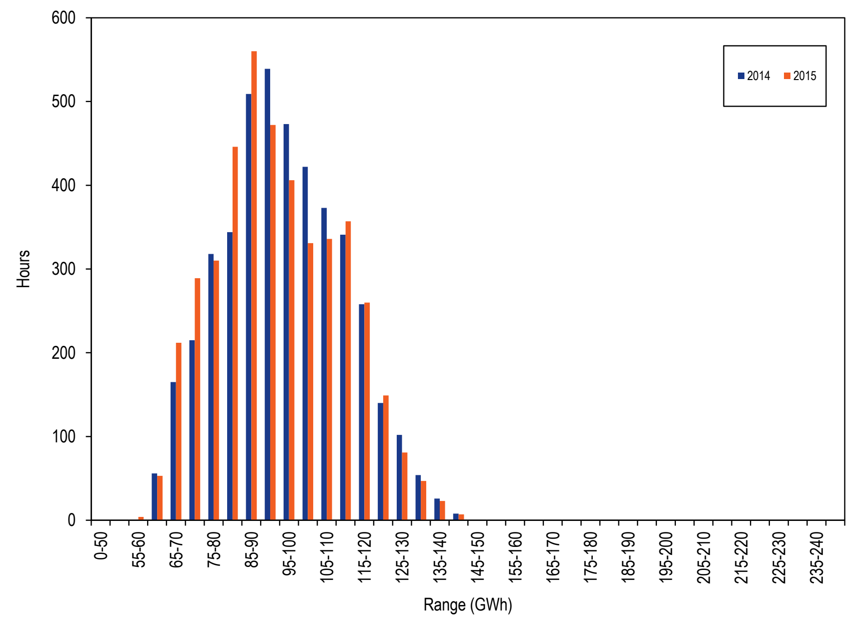
In the PJM Real-Time Energy Market, there are two types of demand:

- **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 Tag, and must pass the neighboring balancing authority checkout process.

PJM Real-Time Demand Duration

Figure 3-14 shows the hourly distribution of PJM real-time load plus exports for the first six months of 2014 and 2015.[31]

Figure 3-14 Distribution of PJM real-time accounting load plus exports: January through June 2014 and 2015[32]



31 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>.
32 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Real-Time, Average Load

Table 3-15 presents summary real-time demand statistics for the first six months during the 18-year period 1998 to 2054. 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.[33]

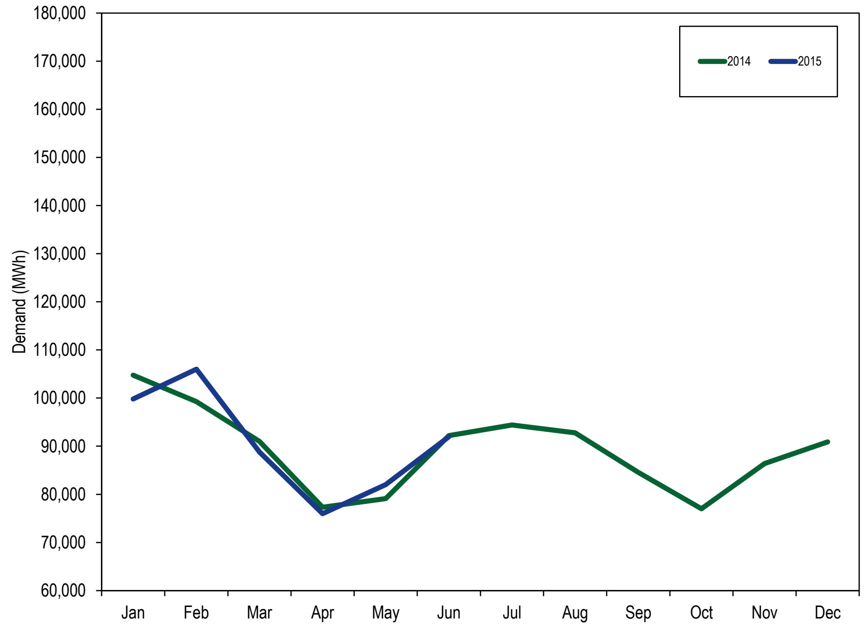
Table 3-15 PJM real-time average hourly load and real-time average hourly load plus average hourly exports: January through June of 1998 through 2015[34]

	PJM Real-Time Demand (MWh)				Year-to-Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
	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%
2015	90,586	16,192	94,782	16,589	0.1%	(0.5%)	(1.5%)	2.7%

PJM Real-Time, Monthly Average Load

Figure 3-15 compares the real-time, monthly average hourly loads in the first six months of 2014 and 2015.

Figure 3-15 PJM real-time monthly average hourly load: January 2014 through June 2015



PJM real-time load is significantly affected by temperature. Figure 3-16 and Table 3-16 compare the PJM monthly heating and cooling degree days in the first six months of 2015 with those in the first six months of 2014.[35] Heating

33 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.

34 Export data are not available before June 1, 2000. The export data for 2000 are for the last six months of 2000.

35 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). PJM uses 60 degrees F for a heating degree day as stated in Manual 19.
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 hourly 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.

degree days decreased 1.8 percent and cooling degree days increased 10.8 percent from the first six months of 2014 to the first six months of 2015.

Figure 3-16 PJM heating and cooling degree days: January 2014 through June 2015

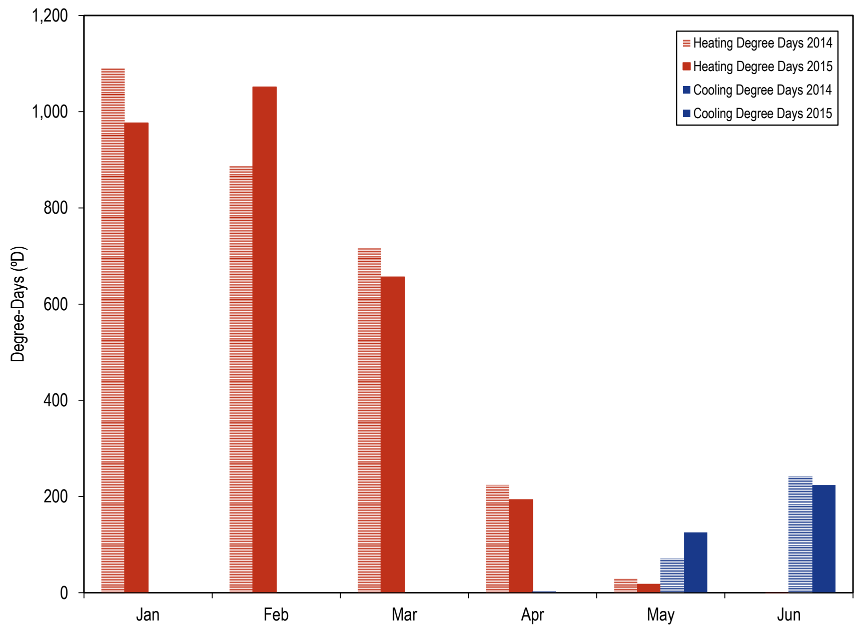


Table 3-16 PJM heating and cooling degree days: January 2014 through June 2015

	2014		2015		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	1,090	0	977	0	(10.4%)	0.0%
Feb	887	0	1,051	0	18.5%	0.0%
Mar	716	0	656	0	(8.4%)	0.0%
Apr	224	2	193	0	(13.8%)	0.0%
May	30	71	18	125	(40.3%)	75.8%
Jun	0	242	1	224	0.0%	(7.3%)
Jul	0	277				
Aug	0	256				
Sep	3	113				
Oct	133	4				
Nov	583	0				
Dec	690	0				
Total	4,358	966	2,896	349	(1.7%)	10.8%

Day-Ahead Demand

PJM average day-ahead demand in the first six months of 2015, including DECs and up-to congestion transactions, decreased by 30.5 percent from the first six months of 2014, from 160,805 MW to 111,749 MW.

PJM average day-ahead demand in the first six months of 2015, including DECs, up-to congestion transactions, and exports, decreased by 30.0 percent from the first six month of 2014, from 164,740 MW to 115,294 MW.

The reduction in PJM day-ahead demand was a result of a substantial decrease in in UTCs beginning in September 2014 based on a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs.[36]

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

36 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

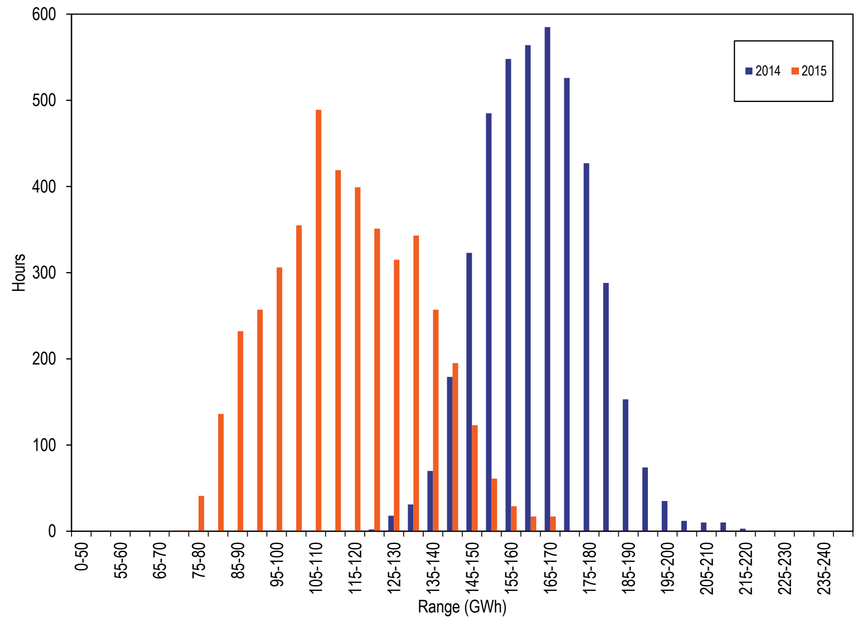
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of 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 (UTC).** 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 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 3-17 shows the hourly distribution of PJM day-ahead demand, including decrement bids, up-to congestion transactions, and exports for the first six months of 2014 and 2015.

Figure 3-17 Distribution of PJM day-ahead demand plus exports: January through June of 2014 and 2015[37]



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

PJM Day-Ahead, Average Demand

Table 3-17 presents summary day-ahead demand statistics for the first six months of each year of the 16-year period 2000 to 2015.[38]

Table 3-17 PJM day-ahead average demand and day-ahead average hourly demand plus average hourly exports: January through June 2000 through 2015

	PJM Day-Ahead Demand (MWh)				Year-to-Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
	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%)
2015	111,749	18,074	115,294	18,468	(30.5%)	30.3%	(30.0%)	33.8%

PJM Day-Ahead, Monthly Average Demand

Figure 3-18 compares the day-ahead, monthly average hourly demand, including decrement bids and up-to congestion transactions, in the first six months of 2014 and 2015. The reduction in PJM day-ahead demand was a result of a sharp decrease in in UTCs beginning in September 2014 based on a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs.[39]

Figure 3-18 PJM day-ahead monthly average hourly demand: January 2014 through June 2015

Real-Time and Day-Ahead Demand

Table 3-18 presents summary statistics for the first six months of 2014 and 2015 day-ahead and real-time demand. The last two columns of Table 3-18 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.

38 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.

39 See PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

Table 3-18 Cleared day-ahead and real-time demand (MWh): January through June 2014 and 2015

		Day Ahead						Real Time		Day Ahead Less Real Time	
	Year	Fixed Demand	Price Sensitive	DEC Bids	Up-to Congestion	Exports	Total Demand	Load	Total Demand	Total Demand	Total Load
Average	2014	86,321	1,270	6,165	67,048	3,935	164,740	90,529	96,189	68,551	21,978
	2015	86,891	3,133	4,300	17,425	3,545	115,294	90,586	94,782	20,512	70,074
Median	2014	84,903	1,257	5,961	67,141	3,823	164,502	89,103	95,269	69,232	19,871
	2015	85,670	3,238	4,079	17,190	3,398	114,177	88,946	93,024	21,153	67,793
Standard Deviation	2014	15,391	173	1,270	10,018	1,081	13,800	16,266	16,147	(2,348)	18,614
	2015	15,378	655	1,279	3,592	1,036	18,468	16,192	16,589	1,878	14,314
Peak Average	2014	95,297	1,351	6,756	66,773	3,886	174,063	99,513	104,987	69,076	30,437
	2015	95,165	3,387	4,613	18,426	3,622	125,213	98,598	102,752	22,461	76,137
Peak Median	2014	94,153	1,354	6,569	67,716	3,811	173,368	98,350	104,292	69,076	29,274
	2015	94,032	3,482	4,386	18,037	3,431	123,990	97,538	101,752	22,238	75,301
Peak Standard Deviation	2014	12,781	162	1,235	9,565	1,082	10,643	13,664	13,478	(2,835)	16,499
	2015	12,762	626	1,216	3,604	1,098	15,420	13,713	14,270	1,150	12,563
Off-Peak Average	2014	78,428	1,200	5,646	67,291	3,978	156,543	82,629	88,453	68,090	14,540
	2015	79,398	2,903	4,016	16,518	3,474	106,310	83,329	87,564	18,746	64,583
Off-Peak Median	2014	77,333	1,191	5,473	66,558	3,837	156,189	81,095	87,373	68,816	12,279
	2015	77,498	2,951	3,771	16,244	3,345	104,000	81,294	85,179	18,821	62,473
Off-Peak Standard Deviation	2014	12,979	149	1,055	10,397	1,078	10,708	14,132	14,228	(3,520)	17,652
	2015	13,604	592	1,269	3,331	970	16,273	14,785	15,181	1,093	13,692

Figure 3-19 shows the average hourly cleared volumes of day-ahead demand and real-time demand for January through June of 2015. 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 3-19 Day-ahead and real-time demand (Average hourly volumes): January through June 2015

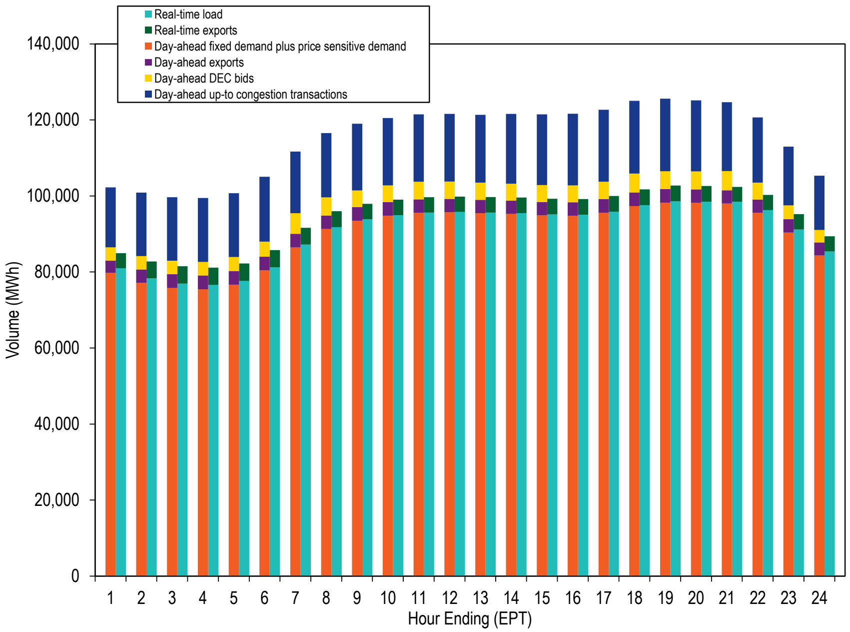
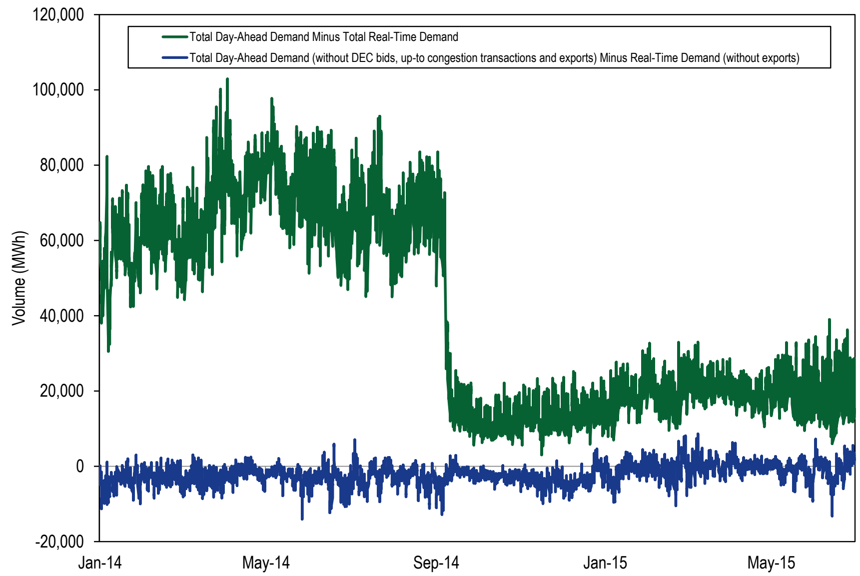


Figure 3-20 shows the difference between the day-ahead and real-time average daily demand in the first six months of 2014 and 2015. The substantial decrease in UTC MW in September, which resulted in a corresponding decrease in day-ahead demand, was a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[40]

40 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

Figure 3-20 Difference between day-ahead and real-time demand (Average daily volumes): January 2014 through June 2015



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 3-19 shows the monthly average share of real-time load served by self-supply, bilateral contracts and spot purchase January 2014 through June 2015 based on parent company. In the first six months of 2015, 11.6 percent of real-time load was supplied by bilateral contracts, 30.8 percent by spot market purchase and 57.6 percent by self-supply. Compared with the first six months of 2014, reliance on bilateral contracts increased by 1.0 percentage points, reliance on spot supply increased by 4.1 percentage points and reliance on self-supply decreased by 5.1 percentage points.

Table 3-19 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: January 2014 through June 2015

	2014			2015			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	9.5%	27.9%	62.6%	13.4%	23.2%	63.5%	3.9%	(4.7%)	0.9%
Feb	9.2%	27.3%	63.5%	12.8%	23.1%	64.1%	3.7%	(4.2%)	0.6%
Mar	9.7%	27.2%	63.0%	12.3%	25.9%	61.8%	2.5%	(1.3%)	(1.2%)
Apr	9.1%	29.7%	61.2%	11.4%	37.8%	50.8%	2.3%	8.1%	(10.4%)
May	9.7%	28.8%	61.5%	10.1%	37.3%	52.6%	0.4%	8.5%	(8.9%)
Jun	10.6%	29.0%	60.4%	9.9%	37.4%	52.6%	(0.7%)	8.5%	(7.8%)
Jul	11.2%	25.7%	63.1%						
Aug	11.2%	25.4%	63.4%						
Sep	11.2%	25.6%	63.2%						
Oct	11.5%	25.1%	63.4%						
Nov	11.8%	24.9%	63.4%						
Dec	12.9%	23.4%	63.7%						
Annual	10.6%	26.7%	62.7%	11.6%	30.8%	57.6%	1.0%	4.1%	(5.1%)

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 3-20 shows the monthly average share of day-ahead demand served by self-supply, bilateral contracts and spot purchases in January 2014 through June 2015, based on parent companies. In the first six months of 2015, 10.3 percent of day-ahead demand was supplied by bilateral contracts, 25.7 percent by spot market purchases, and 63.9 percent by self-supply. Compared with the first six months of 2014, reliance on bilateral contracts increased by 0.8 percentage points, reliance on spot supply decreased by 0.5 percentage points, and reliance on self-supply decreased by 0.3 percentage points.

Table 3-20 Monthly average percentage of day-ahead self-supply demand, bilateral supply demand, and spot-supply demand based on parent companies: January 2014 through June 2015

	2014			2015			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	11.0%	28.9%	60.1%	11.1%	23.1%	65.8%	0.1%	0.1%	0.1%
Feb	8.4%	26.5%	65.1%	10.5%	23.2%	66.2%	0.1%	0.1%	0.1%
Mar	8.6%	27.8%	63.6%	10.1%	26.2%	63.7%	0.1%	0.1%	0.1%
Apr	7.9%	29.8%	62.3%	10.5%	27.9%	61.6%	0.1%	0.1%	0.1%
May	8.1%	29.1%	62.9%	9.7%	26.3%	64.0%	0.1%	0.1%	0.1%
Jun	9.4%	26.2%	64.4%	9.9%	29.0%	61.1%	0.1%	0.1%	0.1%
Jul	9.6%	25.2%	65.2%						
Aug	9.7%	24.6%	65.7%						
Sep	9.4%	25.1%	65.6%						
Oct	9.6%	24.5%	65.9%						
Nov	10.7%	24.3%	65.0%						
Dec	11.3%	23.2%	65.5%						
Annual	9.5%	26.2%	64.2%	10.3%	25.7%	63.9%	0.8%	(0.5%)	(0.3%)

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 3-21. The offer capping percentages shown in Table 3-21 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.

Table 3-21 Offer-capping statistics – energy only: January through June, 2011 to 2015

	Real Time		Day Ahead	
(Jan-Jun)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
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%
2015	0.5%	0.2%	0.2%	0.2%

Table 3-22 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 increased in the first six months from 2011 through 2013. Before 2011, the units that ran to provide black start service and reactive support were generally economic in the energy market. From 2011 through 2013, the percentage of hours when these units were not economic (and were therefore committed on their cost schedule for reliability reasons) increased. This trend reversed in the first six months of 2014 and 2015 because higher LMPs (in the first three months) resulted in the increased economic dispatch of black start and reactive service resources. PJM also created closed loop interfaces to, in some cases, model reactive constraints with a corresponding impact on LMP, which contributed to the reduction in units offer capped for reliability.

Table 3-22 Offer-capping statistics for energy and reliability: January through June, 2011 to 2015

	Real Time		Day Ahead	
(Jan-Jun)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
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%
2015	1.0%	1.0%	0.8%	0.9%

Table 3-23 shows the offer capping percentages for units committed to provide black start service and reactive support. The data in Table 3-23 is the difference between the offer cap percentages shown in Table 3-22 and Table 3-21.

Table 3-23 Offer-capping statistics for reliability: January through June, 2011 to 2015

	Real Time		Day Ahead	
(Jan-Jun)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2011	0.0%	0.0%	0.0%	0.0%
2012	0.4%	0.3%	0.0%	0.0%
2013	2.3%	2.0%	2.9%	2.0%
2014	0.4%	0.4%	0.5%	0.4%
2015	0.5%	0.7%	0.6%	0.7%

Table 3-24 presents data on the frequency with which units were offer capped in the first six months of 2014 and 2015, for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market.

Table 3-24 Real-time offer-capped unit statistics: January through June, 2014 and 2015

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	(Jan - Jun)	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2015	0	1	0	0	0	9
	2014	0	0	0	0	0	1
80% and < 90%	2015	0	0	0	1	0	10
	2014	0	0	1	0	1	2
75% and < 80%	2015	0	0	0	0	1	3
	2014	0	0	1	1	1	2
70% and < 75%	2015	0	0	0	0	1	3
	2014	0	0	0	0	1	1
60% and < 70%	2015	0	0	0	0	0	9
	2014	1	0	0	0	10	6
50% and < 60%	2015	0	0	0	0	0	8
	2014	0	0	0	0	2	15
25% and < 50%	2015	0	0	2	1	0	30
	2014	0	0	4	7	10	51
10% and < 25%	2015	0	0	1	3	3	38
	2014	0	0	0	0	1	36

Table 3-24 shows that nine units were offer capped for 90 percent or more of their run hours in the first six months of 2015 compared to one unit in the first six months of 2014.

Offer Capping for Local Market Power

In the first six months of 2015, the AEP, AP, ATSI, BGE, ComEd, DEOK, DLCO, Dominion, DPL, JCPL, MetEd, PECO, PENELEC, and PSEG control zones experienced congestion resulting from one or more constraints binding for 50 or more hours or resulting from an interface constraint. The AECO, DAY, EKPC, Pepco, PPL, and RECO control zones did not have constraints binding for 50 or more hours in the first six months of 2015. Table 3-25 shows that AEP, AP, BGE, ComEd, and PSEG were the control zones experienced congestion resulting from one or more constraints binding for 50 or more hours or resulting from an interface constraint that was binding for one or more hours in every year in January through June of 2009 through 2015.

Table 3-25 Numbers of hours when control zones experienced congestion resulting from one or more constraints binding for 50 or more hours or from an interface constraint: January through June, 2009 through 2015

	2009 (Jan - Jun)	2010 (Jan - Jun)	2011 (Jan - Jun)	2012 (Jan - Jun)	2013 (Jan - Jun)	2014 (Jan - Jun)	2015 (Jan - Jun)
AECO	149	69	88	NA	NA	NA	NA
AEP	932	355	1,228	322	811	1,773	1,902
AP	598	1,292	1,117	173	51	170	451
ATSI	101	NA	NA	1	70	403	464
BGE	90	154	184	1,556	316	1,142	3,079
ComEd	576	1,406	153	845	1,678	1,729	1,727
DEOK	NA	NA	NA	58	NA	NA	69
DLCO	156	342	NA	209	NA	281	747
Dominion	310	589	824	200	NA	52	1,422
DPL	NA	NA	NA	126	142	560	1,199
EKPC	NA	NA	NA	NA	NA	65	NA
JCPL	NA	NA	NA	NA	NA	NA	79
Met-Ed	NA	NA	NA	123	NA	NA	182
PECO	59	NA	130	53	256	944	485
PENELEC	55	NA	NA	NA	NA	1,441	1,385
Pepco	NA	NA	59	203	85	39	NA
PPL	176	NA	52	146	261	147	NA
PSEG	438	479	605	316	1,462	2,023	2,591

The local market structure in the Real-Time Energy Market associated with each of the frequently binding constraints was analyzed using the three pivotal supplier results in the first six months of 2015.[41] 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.

41 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 3-26 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.

Table 3-26 Three pivotal supplier test details for interface constraints: January through June, 2015

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	385	477	15	2	13
	Off Peak	424	574	15	2	13
AEP - DOM	Peak	436	297	8	0	8
	Off Peak	254	278	7	0	7
AP South	Peak	341	423	11	2	10
	Off Peak	276	438	11	1	10
Bedington - Black Oak	Peak	177	234	14	2	12
	Off Peak	175	220	13	2	10
Central	Peak	945	918	14	2	12
	Off Peak	667	754	13	3	10
Eastern	Peak	837	740	13	0	13
	Off Peak	897	763	12	4	9
Western	Peak	617	633	13	1	12
	Off Peak	476	508	12	1	11

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 3-27 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 3-27 Summary of three pivotal supplier tests applied for interface constraints: January through June, 2015

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
5004/5005 Interface	Peak	1,817	58	3%	38	2%	66%
	Off Peak	1,801	107	6%	59	3%	55%
AEP - DOM	Peak	148	21	14%	18	12%	86%
	Off Peak	106	11	10%	4	4%	36%
AP South	Peak	118	6	5%	3	3%	50%
	Off Peak	65	10	15%	2	3%	20%
Bedington - Black Oak	Peak	1,535	55	4%	27	2%	49%
	Off Peak	960	32	3%	12	1%	38%
Central	Peak	198	3	2%	3	2%	100%
	Off Peak	102	1	1%	0	0%	0%
Eastern	Peak	86	3	3%	3	3%	100%
	Off Peak	14	0	0%	0	0%	0%
Western	Peak	429	9	2%	5	1%	56%
	Off Peak	116	0	0%	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.[42] 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 3-28 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 2015, 83.6 percent of marginal units had average dollar markups less than zero. The data show that some marginal units did have substantial markups. Using the unadjusted cost offers, the highest markup in the first six months of 2015 was $792.21 while the highest markup in the first six months of 2014 was $922.26. The unit with the highest markup in the first six months of 2015 was marginal for at least one interval on March 6, 2015. The unit with highest markup in the first three months of 2014 was marginal for at least one interval on January 6, 2014.

42 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 3-28 Average, real-time marginal unit markup index (By offer price category): January through June 2014 and 2015

	2014 (Jan - Jun)			2015 (Jan - Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.16)	($2.20)	11.7%	(0.05)	($2.60)	35.2%
$25 to $50	(0.01)	($1.08)	58.1%	(0.03)	($1.30)	48.4%
$50 to $75	0.04	$1.12	10.4%	0.06	$3.27	4.0%
$75 to $100	0.08	$5.93	3.3%	0.10	$7.35	1.6%
$100 to $125	0.06	$6.12	3.6%	0.09	$9.02	1.5%
$125 to $150	0.10	$12.94	1.6%	0.06	$6.97	1.4%
>= $150	0.09	$23.49	11.3%	0.05	$12.11	7.9%

Day-Ahead Markup

Table 3-29 shows the average markup index of marginal units in the Day-Ahead Energy Market, by offer price category. In the first six months of 2015, 90.0 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.00. The data show that some marginal units in the first six months of 2014 did have substantial markups. The average markup index decreased significantly, for example, from 0.14 in the first six months of 2014, to -0.01 in the first six months of 2015 in the offer price category from $100 to $125.

Table 3-29 Average day-ahead marginal unit markup index (By offer price category): January through June of 2014 and 2015

	2014 (Jan - Jun)			2015 (Jan - Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.09)	($2.42)	8.2%	(0.00)	($1.44)	34.4%
$25 to $50	(0.02)	($1.27)	68.2%	(0.01)	($0.52)	53.2%
$50 to $75	0.03	$1.48	13.9%	0.10	$5.81	3.3%
$75 to $100	0.06	$4.09	2.3%	0.04	$2.58	1.6%
$100 to $125	0.14	$15.42	1.7%	(0.01)	($3.25)	1.2%
$125 to $150	0.02	($2.02)	1.7%	0.00	($2.90)	1.2%
>= $150	0.07	$14.43	3.8%	0.02	$3.45	4.0%

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 FMU adder was filed with FERC in 2005, and approved effective February 2006.[43] 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 has recommended 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 on the elimination of FMU adders that maintains the ability of certain generating units to qualify for FMU adders but limits FMU adders to units with net revenues less than unit going forward costs or ACR. PJM submitted the joint MMU/PJM proposal to the Commission pursuant to section 206 of the Federal Power Act. On October 31, 2014, the Commission conditionally approved the filing and the new rule became effective November 1, 2014.

43 110 FERC ¶ 61,053 (2005).

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 10 percent of their cost-based offer or $30 per MWh. Units capped for 80 percent or more of their run hours are entitled to an adder of either 10 percent of their cost-based offer or $40 per MWh. These categories are designated Tier 1, Tier 2 and Tier 3.

In addition to being offer capped for the designated percent of run hours, in order to qualify for the FMU adder, a generating unit's Projected PJM Market Revenues plus the unit's PJM capacity market revenues on a rolling 12-month basis, divided by the unit's MW of installed capacity (in $/MW-year) must be less than its accepted unit specific Avoidable Cost Rate (in $/MW-year) (excluding APIR and ARPIR), or its default Avoidable Cost Rate (in $/MW-year) if no unit-specific Avoidable Cost Rate is accepted for the BRAs for the Delivery Years included in the rolling 12-month period, determined pursuant to Sections 6.7 and 6.8 of Attachment DD of the Tariff. (The relevant Avoidable Cost Rate is the weighted average of the Avoidable Cost Rates for each Delivery Year included in the rolling 12-month period, weighted by month.) No portion of the unit may be included in a FRR Capacity Plan or be receiving compensation under Part V of the PJM Tariff and the unit must be internal to the PJM Region and subject only to PJM dispatch.[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.[45] 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.

44 PJM. OA, Schedule 1 § 6.4.2.

45 An associated unit (AU) must belong to the same design class (where a design class includes generation that is the same size and utilizes the same technology, without regard to manufacturer) and uses the identical primary fuel as the FMU.

The new rules for determining the qualification of a unit as a FMU or AU became effective November 1, 2014. 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.[46] The effects of the new rules were first observed in units eligible for an FMU or AU adder in December, 2014, where the number of units that were eligible for an FMU or AU adder declined from an average of 70 units during the first 11 months of 2014, to zero in December 2014 (See Table 3-31).

Table 3-30 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 2014 and January through June, 2015.[47] In the first six months of 2015, no units qualified as an FMU or AU.

Table 3-30 Frequently mitigated units and associated units by total months eligible: 2014 and January through June, 2015

Months Adder-Eligible	2014	2015
1	21	8
2	9	13
3	0	2
4	3	2
5	5	0
6	15	0
7	1	
8	6	
9	8	
10	5	
11	35	
12	4	
Total	112	25

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

47 The data on FMUs and AUs reported in the *2015 Quarterly State of the Market Report for PJM: January through March*, reflected an incorrect calculation by the MMU. In fact, there should have been zero FMUs and AUs since the implementation of the new FMU rules effective for December 2014.

Figure 3-21 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 Jun 30, 2015, there were 351 unique units that have qualified for an FMU adder in at least one month. Of these 351 units, no unit qualified for an adder in all months. Two units qualified in 106 of the 114 possible months, and 74 of the 351 units (21.1 percent) qualified for an adder in more than half of the possible months.

Figure 3-21 Frequently mitigated units and associated units total months eligible: February, 2006 through June, 2015

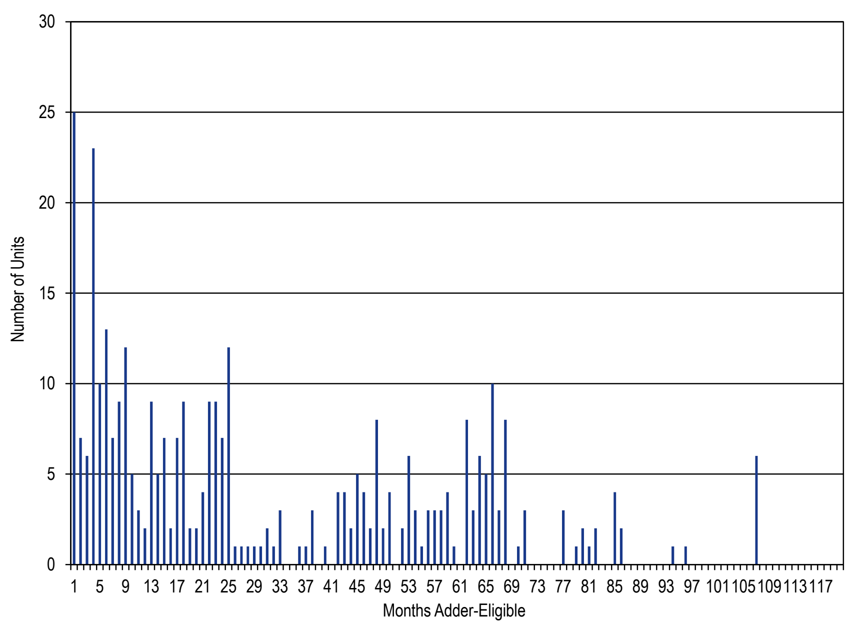


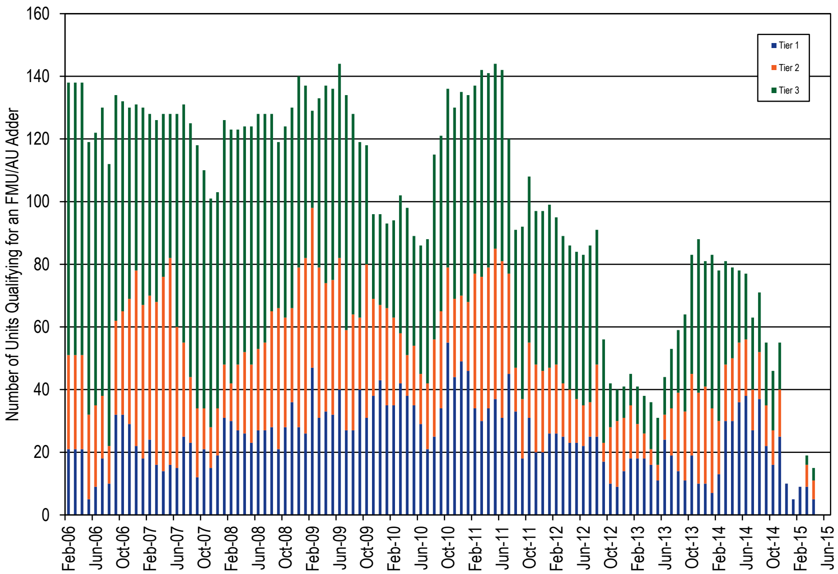
Table 3-31 shows, by month, the number of FMUs and AUs in 2014 and January through June, 2015. For example, in November 2014, there were 25 FMUs and AUs in Tier 1, 15 FMUs and AUs in Tier 2, and 15 FMUs and AUs in Tier 3. In the first six months of 2015, no units qualified as an FMU or AU.

Table 3-31 Number of frequently mitigated units and associated units (By month): January 2014 through June 2015

	2014				2015			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	7	27	49	83	5	0	0	5
February	13	17	48	78	9	0	0	9
March	30	18	33	81	9	7	3	19
April	30	20	29	79	5	6	4	15
May	36	19	23	78	0	0	0	0
June	38	18	21	77	0	0	0	0
July	27	13	23	63				
August	37	15	19	71				
September	22	13	20	55				
October	16	11	19	46				
November	25	15	15	55				
December	10	0	0	10				

Figure 3-22 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 and continued to affect the number of FMU eligible units through November of 2014. The reduction in the total number of units qualifying for an FMU or AU adder starting in December 2014 was the result of the revised rules for FMUs.

Figure 3-22 Frequently mitigated units and associated units (By month): February 2006 through June 2015



An error in the Market Monitoring Unit's (MMU) monthly calculation used to determine unit eligibility for the Frequently Mitigated Unit (FMU) adder under the new FMU rules resulted in a number of generators permitted to use an adder when no units should have been permitted to use an adder. This occurred for the period from December 1, 2014, the first day that the new FMU rules had an effect, to April 22, 2015. The affected generators were immediately directed to cease using FMU adders when the issue was discovered. The MMU has evaluated the impact of the incorrect FMU status on the markets and found that there was no impact on the day-ahead market outcomes. In the four months where the units were incorrectly allowed to use FMU adders, a total of four five-minute intervals in the real-time market were affected. The impact on hourly PJM system-wide load-weighted real-time LMP ranged between $0.19 and $0.58 per MWh for the three hours affected. There was no impact on the monthly PJM system-wide load-weighted real-time LMP.

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 437 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 3-23 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 2015.

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 3-23 PJM day-ahead aggregate supply curves: 2015 example day

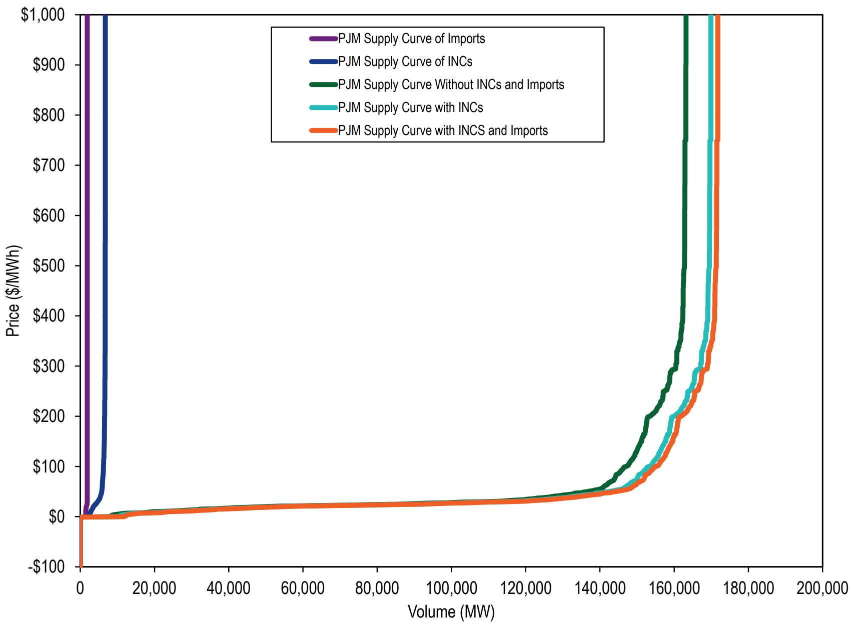


Table 3-32 shows the average hourly number of increment offers and decrement bids and the average hourly MW January 2014 through June 2015. In the first six months of 2015, the average hourly submitted and cleared increment offer MW increased 51.2 and 42.1 percent, and the average hourly submitted and cleared decrement bid MW decreased 17.1 and 28.4 percent, compared to the first six months of 2014.

Table 3-32 Hourly average number of cleared and submitted INCs, DECs by month: January 2014 through June 2015

		Increment Offers				Decrement Bids			
		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
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	2,961	3,889	66	179	6,744	9,452	97	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	Jul	3,892	6,350	66	305	7,331	9,514	146	402
2014	Aug	3,465	4,981	66	293	6,540	7,967	155	331
2014	Sep	3,416	5,020	69	356	6,996	8,839	198	417
2014	Oct	3,477	5,826	91	470	6,806	9,991	136	510
2014	Nov	4,210	7,151	134	553	7,193	11,028	166	637
2014	Dec	3,992	7,021	102	525	7,210	10,260	139	490
2014	Annual	3,494	5,279	78	310	6,596	9,278	125	393
2015	Jan	4,350	6,447	78	398	5,153	7,320	76	295
2015	Feb	4,754	7,109	116	578	4,511	7,445	72	409
2015	Mar	4,973	8,689	142	760	4,305	8,894	101	648
2015	Apr	4,511	6,351	187	558	3,453	6,990	84	451
2015	May	5,089	7,459	181	656	4,171	6,823	94	404
2015	June	4,592	7,043	143	697	4,196	6,696	89	410
2015	Annual	4,713	7,190	141	608	4,300	7,366	86	436

The reduction in up-to congestion transactions (UTC) continued, following a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs.[49] Table 3-33 shows the average hourly number of up-to congestion transactions and the average hourly MW for January 2014 through June 2015. In the first six months of 2015, the average hourly up-to congestion submitted MW decreased 70.1 percent and cleared MW decreased 74.0 percent, compared to the first six months of 2014, as a result of the decreases after September 8.

49 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

Table 3-33 Hourly average of cleared and submitted up-to congestion bids by month: January 2014 through June 2015

		Up-to Congestion			
		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2014	Jan	55,969	199,708	2,436	7,056
2014	Feb	64,123	229,256	3,262	9,020
2014	Mar	66,003	243,469	3,527	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	Jul	66,800	212,485	2,855	7,856
2014	Aug	66,272	214,713	3,003	7,933
2014	Sep	25,370	86,237	1,210	2,979
2014	Oct	9,298	30,502	512	1,289
2014	Nov	11,890	36,600	661	1,633
2014	Dec	12,952	37,177	770	1,770
2014	Annual	49,511	166,537	2,269	6,315
2015	Jan	15,903	46,626	806	2,132
2015	Feb	17,255	57,318	892	2,695
2015	Mar	18,406	72,995	979	2,912
2015	Apr	16,300	73,446	811	2,734
2015	May	18,929	81,358	941	3,219
2015	Jun	17,714	81,452	896	3,220
2015	Annual	17,421	68,947	888	2,818

Table 3-34 shows the average hourly number of import and export transactions and the average hourly MW for January 2014 through June 2015. In the first six months of 2015, the average hourly submitted and cleared import transaction MW increased 8.4 and 6.2 percent, and the average hourly submitted and cleared export transaction MW decreased 15.6 and 13.0 percent, compared to the first six months of 2014.

Table 3-34 Hourly average number of cleared and submitted import and export transactions by month: January 2014 through June 2015

		Imports				Exports			
		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
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	Jul	2,236	2,279	12	12	3,786	3,787	21	21
2014	Aug	2,224	2,236	11	12	3,138	3,140	18	18
2014	Sep	2,114	2,123	11	11	3,744	3,755	23	23
2014	Oct	1,714	1,721	11	11	3,506	3,525	20	21
2014	Nov	2,087	2,097	13	13	3,491	3,528	21	21
2014	Dec	2,373	2,498	12	13	3,939	3,959	21	22
2014	Annual	2,221	2,276	12	13	3,740	3,823	22	22
2015	Jan	2,579	2,716	15	17	4,473	4,559	26	26
2015	Feb	2,588	2,726	17	19	4,383	4,469	23	25
2015	Mar	2,484	2,668	16	18	3,268	3,302	16	17
2015	Apr	2,531	2,638	18	21	2,624	2,626	13	13
2015	May	2,339	2,482	18	20	2,612	2,623	17	17
2015	Jun	2,269	2,349	14	16	2,895	2,906	14	14
2015	Annual	2,464	2,595	16	18	3,366	3,404	18	19

Table 3-35 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 3-35 Type of day-ahead marginal units: January through June of 2015

	Generation	Dispatchable Transaction	Up-to Congestion Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	14.3%	0.5%	71.9%	6.9%	6.3%	0.1%
Feb	13.1%	0.4%	73.1%	7.6%	5.6%	0.1%
Mar	10.1%	0.7%	73.2%	10.6%	5.3%	0.0%
Apr	10.4%	0.3%	73.2%	10.8%	5.3%	0.0%
May	10.2%	0.1%	75.2%	9.2%	5.3%	0.0%
Jun	8.0%	0.1%	78.2%	9.5%	4.1%	0.0%
Annual	11.1%	0.4%	74.1%	9.1%	5.4%	0.0%

Figure 3-24 shows the monthly volume of bid and cleared INC, DEC and up-to congestion bids by month for the period from January 2005 through June 2015. Figure 3-25 shows the daily volume of bid and cleared INC, DEC and up-to congestion bids for the period for January 2014 through June 2015 in order to show the drop off in UTC volumes compared to volumes in the last 15 months.

Figure 3-24 Monthly bid and cleared INCs, DECs, and UTCs (MW): January 2005 through June 2015

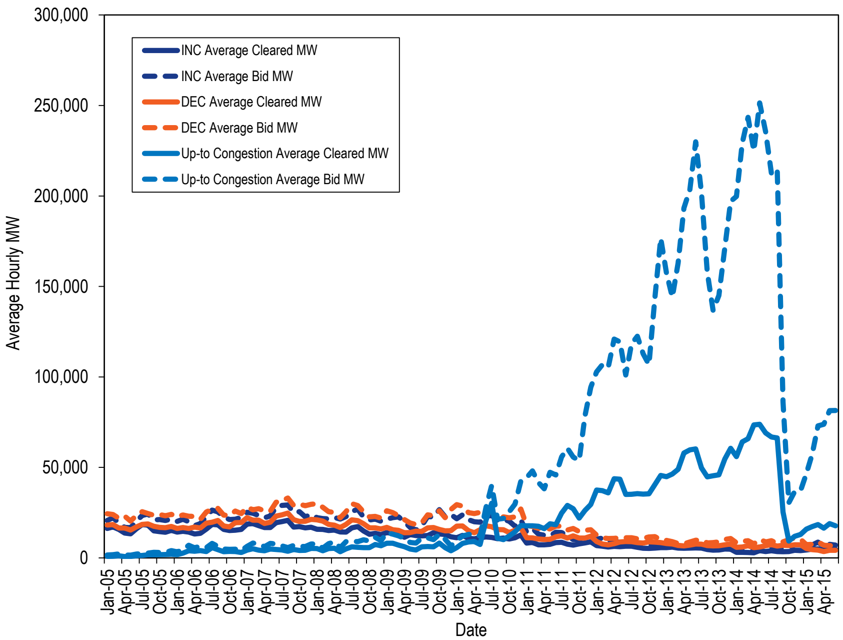
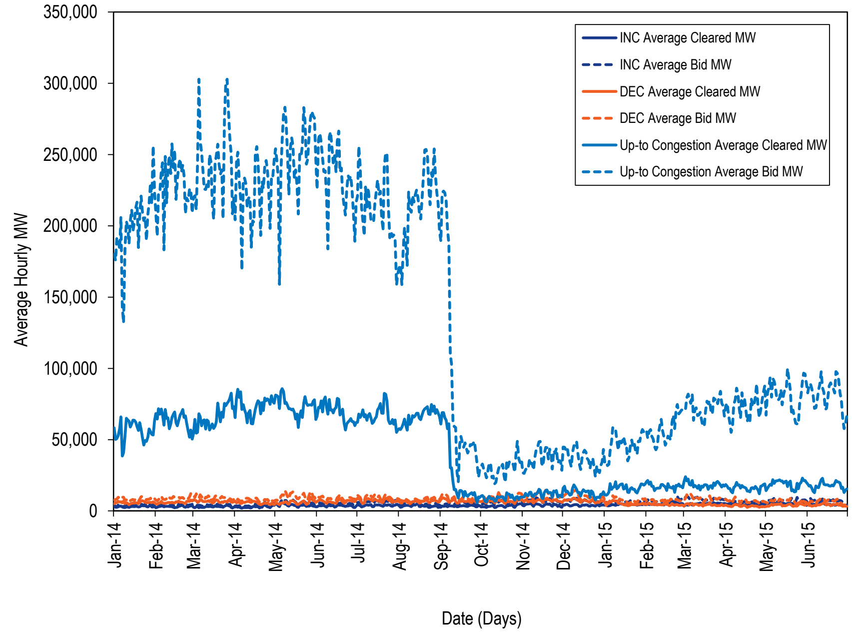


Figure 3-25 Daily bid and cleared INCs, DECs, and UTCs (MW): January 2014 through June 2015



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 3-36 shows, for the first six months of 2014 and 2015, the total increment offers and decrement bids by whether the parent organization is financial or physical.

Table 3-36 PJM INC and DEC bids by type of parent organization (MW): January through June 2014 and 2015

	2014 (Jan-Jun)		2015 (Jan-Jun)	
Category	Total Virtual Bids MW	Percent	Total Virtual Bids MW	Percent
Financial	20,768,062	35.6%	26,591,256	42.1%
Physical	37,611,273	64.4%	36,518,285	57.9%
Total	58,379,334	100.0%	63,109,541	100.0%

Table 3-37 shows, for the first six months of 2014 and 2015, the total up-to congestion transactions by the type of parent organization.

Table 3-37 PJM up-to congestion transactions by type of parent organization (MW): January through June 2014 and 2015

	2014 (Jan-Jun)		2015 (Jan-Jun)	
Category	Total Up-to Congestion MW	Percent	Total Up-to Congestion MW	Percent
Financial	276,055,889	94.8%	62,960,182	83.6%
Physical	15,264,864	5.2%	12,381,797	16.4%
Total	291,320,753	100.0%	75,341,978	100.0%

Table 3-38 shows for the first six months of 2014 and 2015, the total import and export transactions by whether the parent organization is financial or physical.

Table 3-38 PJM import and export transactions by type of parent organization (MW): January through June 2014 and 2015

	2014 (Jan-Jun)		2015 (Jan-Jun)	
Category	Total Import and Export MW	Percent	Total Import and Export MW	Percent
Financial	9,353,076	34.4%	10,531,899	40.4%
Physical	17,809,239	65.6%	15,561,730	59.6%
Total	27,162,315	100.0%	26,093,629	100.0%

Table 3-39 shows increment offers and decrement bids bid by top ten locations for the first six months of 2014 and 2015.

Table 3-39 PJM virtual offers and bids by top ten locations (MW): January through June 2014 and 2015

2014 (Jan-Jun)					2015 (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	5,392,588	6,060,329	11,452,917	WESTERN HUB	HUB	9,644,293	11,368,368	21,012,662
MISO	INTERFACE	293,286	4,007,374	4,300,660	SOUTHIMP	INTERFACE	4,116,718	0	4,116,718
PPL	ZONE	95,332	3,305,357	3,400,689	IMO	INTERFACE	2,553,011	36,819	2,589,830
SOUTHIMP	INTERFACE	3,336,133	0	3,336,133	N ILLINOIS HUB	HUB	446,003	1,625,506	2,071,509
PECO	ZONE	94,450	2,718,399	2,812,848	NYIS	INTERFACE	1,036,204	201,609	1,237,813
IMO	INTERFACE	2,226,609	137,034	2,363,643	LINDENVFT	INTERFACE	200,100	560,299	760,399
AEP-DAYTON HUB	HUB	990,986	1,206,700	2,197,686	MISO	INTERFACE	225,653	484,675	710,328
N ILLINOIS HUB	HUB	490,521	1,438,357	1,928,878	BGE	ZONE	81,842	578,517	660,359
BGE	ZONE	6,905	1,492,146	1,499,051	BOCGASE2138 KV T1	LOAD	113,791	526,349	640,140
NYIS	INTERFACE	458,402	357,044	815,446	AEP-DAYTON HUB	HUB	260,402	360,024	620,427
Top ten total		13,385,210	20,722,740	34,107,950			18,678,019	15,742,166	34,420,185
PJM total		19,489,604	38,889,730	58,379,334			31,223,368	31,988,489	63,211,856
Top ten total as percent of PJM total		68.7%	53.3%	58.4%			59.8%	49.2%	54.5%

Table 3-40 shows up-to congestion transactions by import bids for the top ten locations for the first six months of 2014 and 2015.[50]

Table 3-40 PJM cleared up-to congestion import bids by top ten source and sink pairs (MW): January through June 2014 and 2015

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	559,234
MISO	INTERFACE	COOK	EHVAGG	464,744
OVEC	INTERFACE	BIG SANDY CT1	AGGREGATE	424,626
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	370,916
NEPTUNE	INTERFACE	SOUTHRIV 230	AGGREGATE	323,460
MISO	INTERFACE	AEP-DAYTON HUB	HUB	311,956
OVEC	INTERFACE	DEOK	ZONE	285,971
HUDSONTP	INTERFACE	LEONIA 230 T-1	AGGREGATE	283,077
SOUTHEAST	INTERFACE	CLOVER	EHVAGG	271,791
Top ten total				3,964,249
PJM total				18,515,599
Top ten total as percent of PJM total				21.4%
2015 (Jan-Jun)				
Imports				
Source	Source Type	Sink	Sink Type	MW
SOUTHIMP	INTERFACE	NAGELAEP	EHVAGG	1,374,846
OVEC	INTERFACE	AEP-DAYTON HUB	HUB	325,363
SOUTHIMP	INTERFACE	WOLF HILLS 1-5	AGGREGATE	299,757
SOUTHEAST	INTERFACE	HALIFXDP TX1	AGGREGATE	241,852
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	232,246
NORTHWEST	INTERFACE	COMED	ZONE	213,288
SOUTHEAST	INTERFACE	NAGELAEP	EHVAGG	206,945
MISO	INTERFACE	21 KINCA ATR24304	AGGREGATE	188,052
SOUTHWEST	INTERFACE	NAGELAEP	EHVAGG	187,521
SOUTHEAST	INTERFACE	DOM	ZONE	153,981
Top ten total				3,423,851
PJM total				10,714,345
Top ten total as percent of PJM total				32.0%

Table 3-41 shows up-to congestion transactions by export bids for the top ten locations for the first six months of 2014 and 2015.

Table 3-41 PJM cleared up-to congestion export bids by top ten source and sink pairs (MW): January through June 2014 and 2015

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	508,887
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	493,537
ROCKPORT	EHVAGG	OVEC	INTERFACE	406,763
LINDEN A	AGGREGATE	LINDENVFT	INTERFACE	383,555
STUART 1	AGGREGATE	OVEC	INTERFACE	322,069
JEFFERSON	EHVAGG	SOUTHWEST	INTERFACE	321,205
BECKJORD 6	AGGREGATE	OVEC	INTERFACE	320,470
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	311,767
Top ten total				5,490,874
PJM total				20,675,487
Top ten total as percent of PJM total				26.6%
2015 (Jan-Jun)				
Exports				
Source	Source Type	Sink	Sink Type	MW
FOWLER RIDGE II WF	AGGREGATE	SOUTHWEST	INTERFACE	222,312
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	139,271
21 KINCA ATR24304	AGGREGATE	NIPSCO	INTERFACE	102,611
COMED	ZONE	NIPSCO	INTERFACE	94,998
MARION	AGGREGATE	HUDSONTP	INTERFACE	85,614
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	83,097
FOWLER RIDGE II WF	AGGREGATE	OVEC	INTERFACE	78,238
KAMMER 2	AGGREGATE	NIPSCO	INTERFACE	75,128
ROCKPORT	EHVAGG	OVEC	INTERFACE	70,132
RECO	ZONE	HUDSONTP	INTERFACE	67,428
Top ten total				1,018,829
PJM total				3,957,549
Top ten total as percent of PJM total				25.7%

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 3-42 shows up-to congestion transactions by wheel bids for the top ten locations for the first six months of 2014 and 2015.

Table 3-42 PJM cleared up-to congestion wheel bids by top ten source and sink pairs (MW): January through June 2014 and 2015

		2014 (Jan-Jun)		
		Wheels		
Source	Source Type	Sink	Sink Type	MW
NORTHWEST	INTERFACE	MISO	INTERFACE	677,437
OVEC	INTERFACE	SOUTHEXP	INTERFACE	293,822
MISO	INTERFACE	NORTHWEST	INTERFACE	204,572
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	176,441
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	80,739
IMO	INTERFACE	NYIS	INTERFACE	71,240
MISO	INTERFACE	SOUTHEXP	INTERFACE	60,208
OVEC	INTERFACE	SOUTHWEST	INTERFACE	59,451
SOUTHEAST	INTERFACE	SOUTHEXP	INTERFACE	57,579
MISO	INTERFACE	NIPSCO	INTERFACE	54,605
Top ten total				1,736,095
PJM total				2,181,474
Top ten total as percent of PJM total				79.6%
		2015 (Jan-Jun)		
		Wheels		
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	164,983
MISO	INTERFACE	NIPSCO	INTERFACE	102,566
NORTHWEST	INTERFACE	MISO	INTERFACE	97,019
IMO	INTERFACE	NYIS	INTERFACE	66,275
NYIS	INTERFACE	IMO	INTERFACE	48,713
SOUTHWEST	INTERFACE	IMO	INTERFACE	32,383
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	28,262
NIPSCO	INTERFACE	IMO	INTERFACE	25,694
SOUTHEAST	INTERFACE	SOUTHEXP	INTERFACE	17,129
NYIS	INTERFACE	HUDSONTP	INTERFACE	13,525
Top ten total				596,548
PJM total				707,302
Top ten total as percent of PJM total				84.3%

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. The top ten internal up-to congestion transaction locations were 10.7 percent of the PJM total internal up-to congestion transactions in the first six months of 2015.

Table 3-43 shows up-to congestion transactions by internal bids for the top ten locations for the first six months of 2014 and 2015.

Table 3-43 PJM cleared up-to congestion internal bids by top ten source and sink pairs (MW): January through June 2014 and 2015

		2014 (Jan-Jun)		
		Internal		
Source	Source Type	Sink	Sink Type	MW
MOUNTAINEER	EHVAGG	GAVIN	EHVAGG	4,015,383
VERNON BK 4	AGGREGATE	AEC - JC	AGGREGATE	2,941,605
MOUNTAINEER	EHVAGG	FLATLICK	EHVAGG	2,876,108
DAY	ZONE	BUCKEYE - DPL	AGGREGATE	2,851,509
ATSI GEN HUB	HUB	ATSI	ZONE	2,505,841
FE GEN	AGGREGATE	ATSI	ZONE	2,293,233
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	1,444,519
Top ten total				23,878,343
PJM total				249,948,193
Top ten total as percent of PJM total				9.6%
		2015 (Jan-Jun)		
		Internal		
Source	Source Type	Sink	Sink Type	MW
BERGEN 2CC	AGGREGATE	LEONIA 230 T-1	AGGREGATE	1,288,307
BYRON 1	AGGREGATE	ROCKFORD	AGGREGATE	848,984
JEFFERSON	EHVAGG	COOK	EHVAGG	773,981
ROCKPORT	EHVAGG	JEFFERSON	EHVAGG	673,877
ATSI GEN HUB	HUB	ATSI	ZONE	595,816
VALLEY	EHVAGG	DOOMS	EHVAGG	474,637
RONCO	EHVAGG	HATFIELD	EHVAGG	465,256
BERGEN 2CC	AGGREGATE	LEONIA 230 T-2	AGGREGATE	448,254
167 PLANO	EHVAGG	112 WILTON	EHVAGG	425,084
ALBURTIS	EHVAGG	PPL	ZONE	413,348
Top ten total				6,407,544
PJM total				59,962,987
Top ten total as percent of PJM total				10.7%

Table 3-44 shows the number of source-sink pairs that were offered and cleared monthly in January of 2013 through June 2015. The annual row in Table 3-44 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 January 2013 and continuing through the first eight 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. There was a sharp decrease in UTCs in September as a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[51]

51 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

Table 3-44 Number of PJM offered and cleared source and sink pairs: January 2013 through June 2015

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
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	Jul	10,057	12,304	7,202	8,486
2014	Aug	10,877	12,863	7,609	9,254
2014	Sep	5,618	11,269	4,281	8,743
2014	Oct	2,871	4,092	1,972	2,506
2014	Nov	2,463	3,988	1,812	3,163
2014	Dec	2,803	3,672	2,197	2,786
2014	Annual	5,996	14,065	3,620	8,069
2015	Jan	3,337	5,422	2,263	3,270
2015	Feb	4,600	7,041	2,775	4,147
2015	Mar	4,061	5,799	2,625	3,244
2015	Apr	3,777	6,967	2,343	3,378
2015	May	4,025	5,513	2,587	3,587
2015	Jun	3,852	5,967	2,781	3,748
2015	Annual	3,933	7,041	3,933	4,147

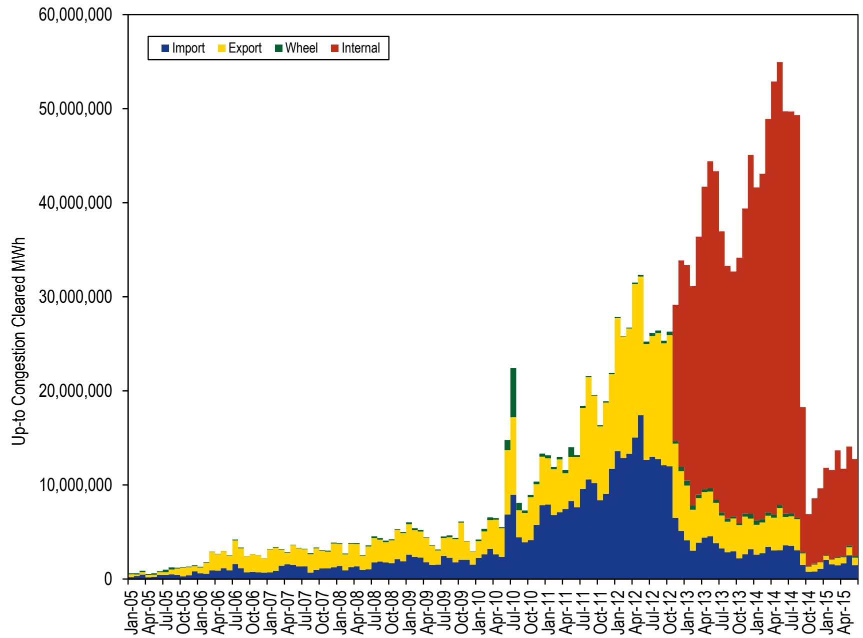
Table 3-45 and Figure 3-26 show total cleared up-to congestion transactions by type for the first six months of 2014 and 2015. Internal up-to congestion transactions in the first six months of 2015 were 79.6 percent of all up-to congestion transactions compared to 85.8 percent in the first six months of 2014.

Table 3-45 PJM cleared up-to congestion transactions by type (MW): January through June 2014 and 2015

	2014 (Jan-Jun)				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	3,964,249	5,490,874	1,736,095	23,878,343	35,069,561
PJM total (MW)	18,515,599	20,675,487	2,181,474	249,948,193	291,320,753
Top ten total as percent of PJM total	21.4%	26.6%	79.6%	9.6%	12.0%
PJM total as percent of all up-to congestion transactions	6.4%	7.1%	0.7%	85.8%	100.0%
	2015 (Jan-Jun)				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	3,423,851	1,018,829	596,548	6,407,544	11,446,772
PJM total (MW)	10,714,345	3,957,549	707,302	59,962,987	75,342,184
Top ten total as percent of PJM total	32.0%	25.7%	84.3%	10.7%	15.2%
PJM total as percent of all up-to congestion transactions	14.2%	5.3%	0.9%	79.6%	100.0%

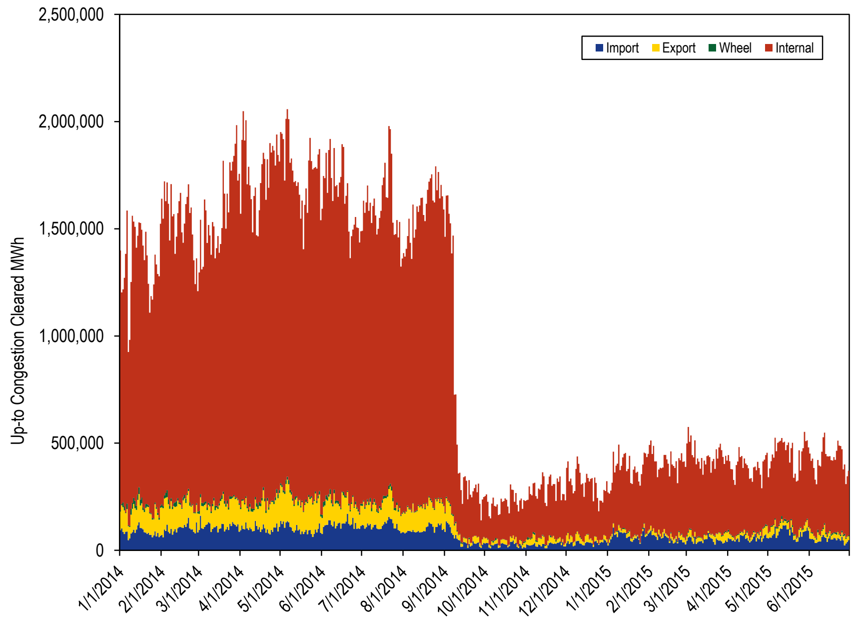
Figure 3-26 shows the initial increase and continued increase in internal up-to congestion transactions by month following the November 1, 2012 rule change permitting such transactions, until September 8, 2014. There was a sharp decrease in UTCs in September as a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[52] Figure 3-27 shows the daily cleared up-to congestion MW by transaction type for the period from January 2014 through June 2015 in order to show the drop off in UTC volumes compared to volumes in the last 18 months.

Figure 3-26 PJM monthly cleared up-to congestion transactions by type (MW): January 2005 through June 2015



52 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

Figure 3-27 PJM daily cleared up-to congestion transaction by type (MW): January 2014 through June 2015



Generator Offers

Generator offers are categorized as dispatchable (Table 3-46) or self scheduled (Table 3-47).[53] 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 3-46 and Table 3-47 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 emergency maximum, are categorized as emergency MW. The emergency MW are included in both tables.

Table 3-46 shows the proportion of MW offers by dispatchable units, by unit type and by offer price range, for the first six months of 2015. For example, 72.4 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, 81.0 percent of all CC MW offers were dispatchable, including the 5.1 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, 45.2 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 2015, 51.2 percent were offered as available for economic dispatch.

Table 3-46 Distribution of MW for dispatchable unit offer prices: January through June 2015

	Dispatchable (Range)							
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	0.3%	72.4%	1.9%	0.5%	0.8%	0.0%	5.1%	81.0%
CT	0.2%	70.7%	15.7%	1.7%	1.3%	0.1%	9.2%	98.9%
Diesel	6.2%	24.0%	21.5%	7.1%	1.8%	0.7%	12.4%	73.7%
Fuel Cell	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	7.5%	0.0%	0.0%	0.0%	0.0%	0.0%	7.5%
Pumped Storage	13.4%	38.2%	0.0%	0.0%	0.0%	0.0%	15.7%	67.3%
Run of River	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
Solar	7.3%	7.0%	0.0%	0.0%	0.0%	0.0%	2.1%	16.4%
Steam	0.0%	45.1%	1.7%	0.1%	0.0%	0.0%	2.2%	49.2%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	50.7%	12.1%	0.0%	0.0%	0.0%	0.0%	0.6%	63.3%
All Dispatchable Offers	1.2%	45.2%	3.9%	0.5%	0.4%	0.0%	3.8%	55.0%

Table 3-47 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

53 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.

self-scheduled and dispatchable units, for the first six months of 2015. For example, 15.9 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, 19.0 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 0.7 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 22.6 percent of all offers and self-scheduled and dispatchable units accounted for 20.2 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 2015, 23.8 percent were offered as self scheduled and 21.2 percent were offered as self scheduled and dispatchable.

Table 3-47 Distribution of MW for self scheduled offer prices: January through June 2015

	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	1.3%	0.4%	0.2%	15.9%	0.2%	0.1%	0.2%	0.0%	0.7%	19.0%
CT	0.5%	0.1%	0.0%	0.4%	0.0%	0.0%	0.0%	0.1%	0.0%	1.1%
Diesel	24.8%	1.1%	0.0%	0.2%	0.1%	0.0%	0.0%	0.0%	0.1%	26.3%
Fuel Cell	65.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	34.8%	100.0%
Nuclear	91.0%	1.0%	0.0%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	92.5%
Pumped Storage	16.7%	8.2%	3.5%	0.0%	0.0%	0.0%	0.0%	0.0%	4.2%	32.7%
Run of River	62.6%	9.1%	5.1%	15.2%	0.0%	0.0%	0.0%	5.1%	2.7%	99.8%
Solar	61.9%	21.2%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	83.6%
Steam	5.6%	1.4%	0.2%	41.6%	0.2%	0.0%	0.0%	0.0%	1.7%	50.8%
Transaction	5.6%	1.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	92.5%	100.0%
Wind	3.5%	2.2%	27.8%	3.3%	0.0%	0.0%	0.0%	0.0%	0.0%	36.7%
All Self-Scheduled Offers	22.6%	1.2%	0.7%	19.2%	0.1%	0.0%	0.0%	0.1%	1.0%	45.0%

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.[54]

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

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

price and a higher cost than the actual marginal unit. If the actual marginal unit has marginal costs that would cause it to be inframarginal, a new unit would be marginal. If the offer of that new unit were greater than the cost of the original marginal unit, the markup impact would be lower than the MMU measure. If the newly marginal unit is on a price-based schedule, the analysis would have to capture the markup impact of that unit as well.

The MMU calculated an explicit measure of the impact of marginal unit markups on LMP. The markup impact includes the impact of the identified markup conduct on a unit by unit basis, but the inclusion of negative markup impacts has an offsetting effect. The markup analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval. The markup analysis is a more general measure of the competitiveness of the energy market.

Real-Time Markup

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

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

Table 3-48 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 3-48 on the system-wide load-weighted LMP. The negative markup components of LMP reflect the negative markups shown in the Table 3-28.

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.[55]

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 3-48 shows the markup component of the load-weighted LMP by fuel type and unit type using unadjusted and adjusted offers. The adjusted markup component of LMP decreased from $4.61 in the first six months of 2014 to $2.42 in the first six months of 2015. The adjusted markup contribution of coal units in the first six months of 2015 was $0.79. Although the price of natural gas was substantially lower in the first six months of 2015 compared to that in 2014, the adjusted markup component of all gas-fired units in the first six months of 2015 was $1.22, a decrease of $0.23 from the first six months of 2014. Coal units accounted for 72.4 percent of the decreased markup component of LMP in the first six months of 2015. The markup

55 See PJM. "Manual 15: Cost Development Guidelines," Revision: 25 (July 28, 2014).

component of wind units was $0.02. If a price-based offer is negative, but less negative than a cost-based offer, the markup is positive. In the first six months of 2015, among the wind units that were marginal, 3.73 percent had positive offer prices.

Table 3-48 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January through June 2014 and 2015[56]

		2014 (Jan - Jun)		2015 (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	$1.19	$2.38	($0.95)	$0.79
Gas	CC	$0.89	$0.89	$1.25	$1.25
Gas	CT	$0.40	$0.40	($0.03)	($0.03)
Gas	Diesel	$0.17	$0.17	$0.01	$0.01
Gas	Steam	($0.01)	($0.01)	($0.01)	($0.01)
Municipal Waste	Steam	$0.30	$0.30	$0.17	$0.17
Oil	CC	$0.18	$0.18	$0.09	$0.09
Oil	CT	$0.18	$0.18	$0.06	$0.06
Oil	Diesel	$0.00	$0.00	$0.01	$0.01
Oil	Steam	$0.09	$0.09	$0.04	$0.04
Other	Steam	$0.00	$0.00	$0.03	$0.03
Uranium	Steam	$0.01	$0.01	$0.00	$0.00
Wind	Wind	$0.02	$0.02	$0.02	$0.02
Total		$3.43	$4.61	$0.67	$2.42

Markup Component of Real-Time Price

Table 3-49 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on-peak and off-peak prices. Table 3-50 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 2015, when using unadjusted cost offers, $0.67 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost-offers, $2.42 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In the first six months of 2015, the peak markup component was highest in February, $4.79 per MWh using unadjusted cost offers and $6.64 per MWh using adjusted cost offers. This corresponds to 8.85 percent and 12.27 percent of the real time load-weighted average LMP in February.

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 3-49 Monthly markup components of real-time load-weighted LMP (Unadjusted): January through June 2014 and 2015

	2014			2015		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	$5.44	$3.91	$6.92	($1.42)	($2.55)	($0.31)
Feb	$3.02	$0.88	$5.08	$4.62	$4.46	$4.79
Mar	$7.11	$3.24	$11.17	$2.34	$2.82	$1.86
Apr	($0.43)	($2.16)	$1.07	$0.95	($0.69)	$2.39
May	$1.74	($1.27)	$4.62	($2.13)	($4.17)	$0.03
Jun	$2.43	($0.08)	$4.60	($0.53)	($1.43)	$0.21
Total	$3.42	$1.02	$5.69	$0.67	($0.14)	$1.45

Table 3-50 Monthly markup components of real-time load-weighted LMP (Adjusted): January through June 2014 and 2015

	2014			2015		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	$6.83	$5.48	$8.12	$0.61	($0.53)	$1.72
Feb	$3.94	$1.97	$5.84	$6.44	$6.26	$6.64
Mar	$8.21	$4.59	$12.02	$4.21	$4.69	$3.74
Apr	$0.86	($0.45)	$2.00	$2.59	$0.72	$4.23
May	$2.87	$0.09	$5.54	($0.71)	($3.00)	$1.72
Jun	$3.69	$1.46	$5.62	$1.09	($0.16)	$2.10
Total	$4.61	$2.45	$6.65	$2.42	$1.48	$3.32

Hourly Markup Component of Real-Time Prices

Figure 3-28 shows markup contribution to the hourly load-weighted LMP using unadjusted cost offers for the first six months of 2015 and the first six months of 2014. Figure 3-29 shows markup contribution to the hourly load-weighted LMP using adjusted cost offers for the first six months of 2015 and the first six months of 2014. In 2014, high markups were seen during the polar vortex events in January and early March. In contrast, January 2015 had very low markups. Most high markup hours in 2015 were observed in February and March.

Figure 3-28 Markup Contribution to real-time hourly load-weighted LMP (Unadjusted): January through June 2014 and 2015

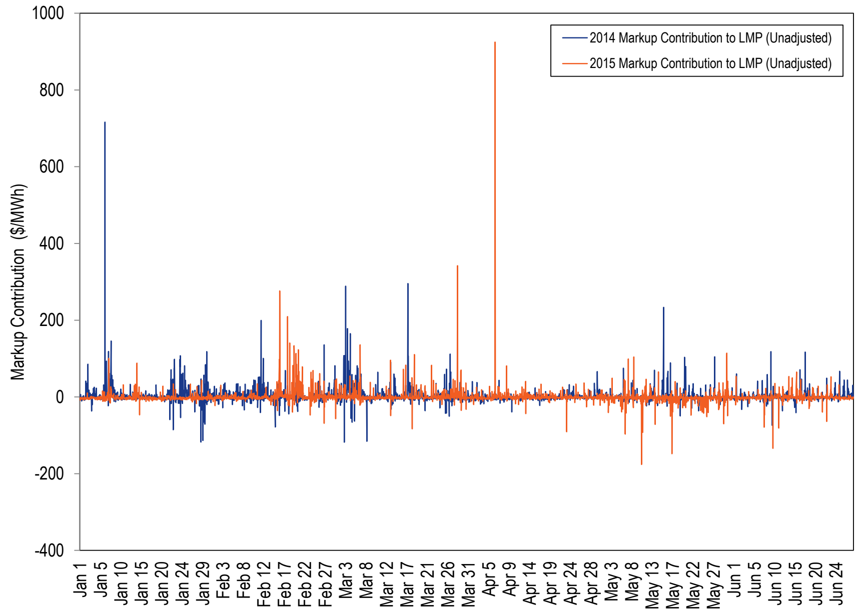
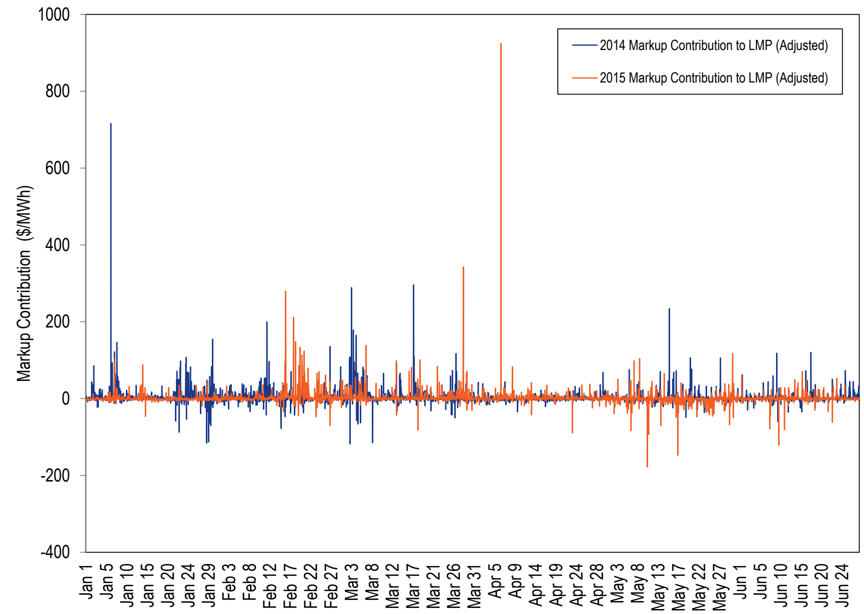


Figure 3-29 Markup Contribution to real-time hourly load-weighted LMP (Adjusted): January through June 2014 and 2015



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 2015 in Table 3-51 and for adjusted offers in Table 3-52. The smallest zonal all hours average markup component using unadjusted offers for the first six months of 2015 was in the DPL Zone, -$1.82 per MWh, while the highest was in the BGE Control Zone, $2.60 per MWh. The smallest zonal on peak average markup was in the PPL Control Zone, -$0.64 per MWh, while the highest was in the Pepco Control Zone, $3.31 per MWh.

Table 3-51 Average real-time zonal markup component (Unadjusted): January through June 2014 and 2015

	2014 (Jan - Jun)			2015 (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	$3.37	$0.83	$5.81	($0.41)	($1.56)	$0.67
AEP	$2.94	$0.60	$5.22	($0.21)	($0.77)	$0.29
APS	$2.82	$0.86	$4.70	$0.41	($0.40)	$1.12
ATSI	$2.41	$0.28	$4.43	$0.16	($0.90)	$1.13
BGE	$5.10	$2.15	$7.89	$2.60	$2.21	$2.96
ComEd	$2.49	$0.50	$4.35	($0.60)	($1.67)	$0.33
DAY	$2.60	$0.28	$4.75	$0.60	($0.68)	$1.78
DEOK	$2.55	$0.15	$4.83	$0.45	($1.05)	$1.85
DLCO	$2.34	$0.73	$3.85	$0.04	($1.29)	$1.25
DPL	$3.88	$1.35	$6.30	($1.82)	($3.52)	($0.31)
Dominion	$5.35	$2.34	$8.19	$1.48	$0.88	$2.04
EKPC	$3.08	$0.69	$5.47	$0.10	($0.83)	$1.01
JCPL	$2.81	$0.65	$4.76	($0.57)	($1.19)	($0.02)
Met-Ed	$3.03	$1.10	$4.81	($0.54)	($1.14)	$0.01
PECO	$3.33	$0.86	$5.65	($0.76)	($1.15)	($0.39)
PENELEC	$3.28	$0.84	$5.56	$0.12	($0.79)	$0.95
PPL	$3.84	$1.22	$6.30	($0.85)	($1.09)	($0.64)
PSEG	$4.04	$1.46	$6.40	($0.57)	($1.27)	$0.05
Pepco	$4.93	$2.14	$7.48	$2.24	$1.04	$3.31
RECO	$4.26	$1.77	$6.41	$0.21	($1.15)	$1.33

Table 3-52 Average real-time zonal markup component (Adjusted): January through June 2014 and 2015

	2014 (Jan - Jun)			2015 (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	$4.52	$2.19	$6.77	$0.71	($0.47)	$1.82
AEP	$4.18	$2.13	$6.16	$1.59	$0.75	$2.34
APS	$3.99	$2.28	$5.65	$2.24	$1.17	$3.19
ATSI	$3.63	$1.78	$5.38	$1.97	$0.73	$3.10
BGE	$6.32	$3.63	$8.87	$5.15	$4.40	$5.85
ComEd	$3.68	$1.94	$5.31	$0.86	($0.46)	$2.00
DAY	$3.86	$1.83	$5.74	$2.43	$0.90	$3.82
DEOK	$3.77	$1.64	$5.78	$2.20	$0.49	$3.79
DLCO	$3.67	$2.32	$4.93	$1.82	$0.35	$3.16
DPL	$5.03	$2.69	$7.26	($0.87)	($2.72)	$0.75
Dominion	$6.45	$3.65	$9.11	$3.57	$2.70	$4.38
EKPC	$4.31	$2.18	$6.43	$1.91	$0.83	$2.99
JCPL	$3.96	$2.01	$5.73	$0.61	($0.05)	$1.19
Met-Ed	$4.17	$2.46	$5.75	$0.66	($0.02)	$1.28
PECO	$4.48	$2.21	$6.61	$0.41	($0.01)	$0.80
PENELEC	$4.49	$2.25	$6.57	$1.71	$0.66	$2.67
PPL	$5.00	$2.58	$7.27	$0.24	($0.06)	$0.51
PSEG	$5.16	$2.77	$7.35	$0.65	($0.13)	$1.34
Pepco	$6.12	$3.58	$8.44	$4.58	$2.94	$6.02
RECO	$5.45	$3.10	$7.47	$1.67	$0.25	$2.85

Markup by Real Time Price Levels

Table 3-53 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 3-53 Average real-time markup component (By price category, unadjusted): January through June 2014 and 2015

	2014 (Jan - Jun)		2015 (Jan - Jun)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$0.60	51.4%	$0.46	69.3%
$25 to $50	($0.29)	25.2%	($0.45)	26.7%
$50 to $75	$0.33	10.2%	$0.35	2.6%
$75 to $100	$0.34	3.7%	$0.19	0.8%
$100 to $125	$0.18	2.0%	$0.01	0.3%
$125 to $150	$0.30	1.6%	$0.04	0.1%
>= $150	$2.01	5.8%	$0.07	0.2%

Table 3-54 Average real-time markup component (By price category, adjusted): January through June 2014 and 2015

	2014 (Jan - Jun)		2015 (Jan - Jun)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$1.18	51.4%	$1.68	69.3%
$25 to $50	$0.11	25.2%	$0.04	26.7%
$50 to $75	$0.41	10.2%	$0.38	2.6%
$75 to $100	$0.39	3.7%	$0.19	0.8%
$100 to $125	$0.19	2.0%	$0.02	0.3%
$125 to $150	$0.31	1.6%	$0.05	0.1%
>= $150	$2.08	5.8%	$0.07	0.2%

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 3-55. INC, DEC and up-to congestion transactions have zero markups. Up-to congestion transactions were marginal for 74.1 percent of marginal resources in the first six months of 2015. INCs were marginal for 5.4 percent of marginal resources and DECs were marginal for 9.1 percent of marginal resources in the first six months of 2015. The percentage of marginal up-to congestion transactions decreased significantly beginning on September 8, 2014, as a result of the FERC's UTC uplift refund notice which became effective on September 8, 2014.[57] 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 3-55 shows the markup component of LMP for marginal generating resources. Generating resources were marginal in only 11.1 percent of marginal resources in the first six months of 2015. The markup component of LMP for marginal generating resources decreased in coal-fired steam units and oil-fired CT units. The markup component of LMP for coal units decreased from $1.49 in the first six months of 2014 to $0.39 in the first six months of 2015. The markup component of LMP for gas-fired CCs increased from -$0.46 in the first six months of 2014 to -$0.13 in the first six months of 2015.

Table 3-55 Markup component of the annual PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through June of 2014 and 2015

		2014 (Jan - Jun)		2015 (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	$0.36	$1.49	($1.03)	$0.39
Gas	CC	($0.46)	($0.46)	($0.13)	($0.13)
Gas	CT	$0.05	$0.05	$0.07	$0.07
Gas	Diesel	$0.00	$0.00	$0.01	$0.01
Gas	Steam	($0.05)	($0.05)	$0.06	$0.06
Import	Steam	$0.00	$0.01	$0.00	$0.00
Municipal Waste	Steam	($0.00)	($0.00)	($0.00)	($0.00)
Oil	CC	$0.04	$0.04	$0.06	$0.06
Oil	CT	$0.06	$0.08	$0.03	$0.03
Oil	Steam	$0.03	$0.03	$0.13	$0.13
Other	Steam	($0.01)	($0.01)	$0.00	$0.00
Wind	Wind	$0.00	$0.00	$0.03	$0.03
Total		$0.01	$1.17	($0.78)	$0.64

57 See 18 CFR § 385.213 (2014).

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 3-56 shows the markup component of average prices and of average monthly on-peak and off-peak prices using unadjusted offers. Table 3-57 shows the markup component of average prices and of average monthly on-peak and off-peak prices using adjusted offers. In the first six months of 2015, when using adjusted cost-offers, $0.64 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In the first six months of 2015, the peak markup component was highest in February, $4.26 per MWh using adjusted cost offers. Using adjusted cost-offers, the markup component in the first six months of 2015 decreased in every month except February from the first six months of 2014. The markup component decreased from $1.80 to -$0.26 in January.

Table 3-56 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: January through June of 2014 and 2015

	2014 (Jan - Jun)			2015 (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	$1.03	$2.85	($0.88)	($1.96)	($1.25)	($2.64)
Feb	$0.34	$2.07	($1.47)	$1.39	$3.18	($0.26)
Mar	$0.14	($0.27)	$0.53	($0.43)	$0.49	($1.37)
Apr	($0.88)	$0.42	($2.37)	($0.76)	($0.02)	($1.63)
May	($0.99)	$0.07	($2.10)	($2.14)	($3.29)	($1.04)
Jun	$0.03	$1.30	($1.45)	($0.87)	($0.83)	($0.92)
Annual	$0.01	$1.16	($1.21)	($0.78)	($0.25)	($1.32)

Table 3-57 Monthly markup components of day-ahead (Adjusted), load-weighted LMP: January through June of 2014 and 2015

	2014 (Jan - Jun)			2015 (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	$1.80	$3.42	$0.09	($0.26)	$0.23	($0.74)
Feb	$1.44	$2.86	($0.05)	$2.72	$4.26	$1.30
Mar	$1.34	$0.64	$2.01	$1.02	$1.79	$0.22
Apr	$0.51	$1.34	($0.45)	$0.50	$1.02	($0.11)
May	$0.24	$0.85	($0.39)	($0.66)	($1.62)	$0.26
Jun	$1.38	$2.31	$0.29	$0.37	$0.40	$0.34
Annual	$1.17	$1.98	$0.30	$0.64	$1.06	$0.22

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 3-58. The markup component of annual average day-ahead price using adjusted offers is shown for each zone in Table 3-59. The markup component of the average day-ahead price decreased in all zones from the first six months of 2014 to the first six months of 2015. The smallest zonal all hours average markup component using adjusted offers for the first six months of 2015 was in the DEOK Zone, $0.28 per MWh, while the highest was in the RECO Control Zone, $0.92 per MWh. The smallest zonal on peak average markup was in the Dominion Control Zone, $0.53 per MWh, while the highest was in the PPL Control Zone, $1.46 per MWh.

Table 3-58 Day-ahead, average, zonal markup component (Unadjusted): January through June of 2014 and 2015

	2014 (Jan - Jun)			2015 (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	$0.14	$1.33	($1.12)	($0.73)	($0.62)	($0.84)
AEP	($0.03)	$1.09	($1.20)	($1.19)	($0.80)	($1.59)
AP	($0.09)	$1.16	($1.39)	($0.71)	($0.22)	($1.21)
ATSI	($0.09)	$1.05	($1.31)	($0.88)	($0.00)	($1.81)
BGE	$0.11	$1.35	($1.22)	($0.76)	($0.19)	($1.35)
ComEd	$0.02	$0.94	($0.98)	($0.74)	$0.14	($1.67)
DAY	($0.03)	$1.06	($1.22)	($1.16)	($0.27)	($2.11)
DEOK	($0.04)	$1.01	($1.14)	($1.23)	($0.59)	($1.88)
DLCO	($0.10)	$0.90	($1.18)	($0.76)	$0.38	($1.97)
Dominion	($0.11)	$1.10	($1.39)	($0.96)	($1.04)	($0.89)
DPL	$0.24	$1.45	($1.04)	($0.39)	$0.04	($0.83)
EKPC	$0.16	$1.25	($0.92)	($0.95)	($0.22)	($1.65)
JCPL	$0.12	$1.28	($1.19)	($0.47)	($0.07)	($0.91)
Met-Ed	$0.21	$1.45	($1.12)	($0.40)	$0.07	($0.90)
PECO	$0.26	$1.53	($1.11)	($0.38)	$0.06	($0.84)
PENELEC	($0.04)	$1.17	($1.38)	($0.41)	$0.39	($1.21)
Pepco	$0.12	$1.35	($1.25)	($0.61)	($0.06)	($1.17)
PPL	$0.10	$1.35	($1.23)	($0.32)	$0.32	($0.97)
PSEG	$0.18	$1.41	($1.20)	($0.41)	$0.01	($0.87)
RECO	$0.18	$1.41	($1.26)	($0.24)	$0.36	($0.93)

Table 3-59 Day-ahead, average, zonal markup component (Adjusted): January through June of 2014 and 2015

	2014 (Jan - Jun)			2015 (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	$1.28	$2.15	$0.36	$0.66	$0.84	$0.47
AEP	$1.15	$1.92	$0.34	$0.46	$0.86	$0.06
AP	$1.06	$1.96	$0.12	$0.65	$0.96	$0.34
ATSI	$1.09	$1.87	$0.25	$0.61	$1.29	($0.11)
BGE	$1.30	$2.17	$0.36	$0.61	$0.90	$0.31
ComEd	$1.20	$1.79	$0.56	$0.71	$1.41	($0.04)
DAY	$1.17	$1.92	$0.36	$0.37	$1.09	($0.38)
DEOK	$1.13	$1.84	$0.40	$0.28	$0.80	($0.24)
DLCO	$1.04	$1.67	$0.36	$0.60	$1.44	($0.28)
Dominion	$1.03	$1.91	$0.10	$0.59	$0.53	$0.65
DPL	$1.37	$2.26	$0.42	$0.79	$1.11	$0.47
EKPC	$1.28	$2.03	$0.54	$0.54	$1.11	($0.01)
JCPL	$1.28	$2.17	$0.28	$0.74	$1.03	$0.41
Met-Ed	$1.35	$2.28	$0.33	$0.79	$1.14	$0.41
PECO	$1.38	$2.34	$0.35	$0.78	$1.10	$0.44
PENELEC	$1.10	$2.02	$0.10	$0.84	$1.41	$0.27
Pepco	$1.29	$2.18	$0.29	$0.79	$1.16	$0.40
PPL	$1.22	$2.17	$0.19	$0.91	$1.46	$0.33
PSEG	$1.25	$2.21	$0.18	$0.79	$1.13	$0.42
RECO	$1.21	$2.20	$0.06	$0.92	$1.39	$0.37

Markup by Day-Ahead Price Levels

Table 3-60 and Table 3-61 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 3-60 Average, day-ahead markup (By LMP category, unadjusted): January through June of 2014 and 2015

	2014 (Jan - Jun)		2015 (Jan - Jun)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($2.75)	2.6%	($1.75)	17.9%
$25 to $50	($1.65)	64.1%	($1.11)	66.0%
$50 to $75	$1.07	19.6%	($1.77)	7.7%
$75 to $100	($1.08)	4.5%	($1.56)	4.1%
$100 to $125	($7.11)	1.7%	$1.14	2.1%
$125 to $150	$5.66	1.4%	$9.11	0.9%
>= $150	$10.47	6.0%	$13.21	1.3%

Table 3-61 Average, day-ahead markup (By LMP category, adjusted): January through June 2014 and 2015

	2014 (Jan - Jun)		2015 (Jan - Jun)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.85)	2.6%	($0.36)	17.9%
$25 to $50	$0.21	64.1%	$0.58	66.0%
$50 to $75	$2.26	19.6%	($0.28)	7.7%
$75 to $100	($0.54)	4.5%	($0.95)	4.1%
$100 to $125	($6.43)	1.7%	$1.77	2.1%
$125 to $150	$6.32	1.4%	$9.28	0.9%
>= $150	$11.45	6.0%	$13.45	1.3%

Prices

The conduct of individual market entities within a market structure is reflected in market prices. 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 39.5 percent and 38.8 percent lower in the first six months of 2015 than in the first six months of 2014 as a result of lower fuel costs and lower demand in the first six months of 2015. Coal and natural gas prices decreased in 2015. Comparing fuel prices in 2015 to 2014, the price of Northern Appalachian coal was 16.6 percent lower; the price of Central Appalachian coal was 23.1 percent lower; the price of Powder River Basin coal was 11.9 percent lower; the price of eastern natural gas was 45.2 percent lower; and the price of western natural gas was 55.1 percent lower.

PJM real-time energy market prices decreased in the first six months of 2015 compared to the first six months of 2014. The average LMP was 61.7 percent lower in the first six months of 2015 than in the first six months of 2014, $38.87 per MWh versus $62.14 per MWh. The load-weighted average LMP was 63.4 percent lower in the first six months of 2015 than in the first six months of 2014, $42.30 per MWh versus $69.92 per MWh.

The fuel-cost adjusted, load-weighted, average LMP in the first six months of 2015 was 24.9 percent higher than the load-weighted, average LMP for the first six months of 2015. If fuel costs in the first six months of 2015 had been the same as in the first six months of 2014, holding everything else constant, the load-weighted LMP would have been higher, $52.85 per MWh instead of the observed $42.30 per MWh.

PJM day-ahead energy market prices decreased in the first six months of 2015 compared to the first six months of 2014. The average LMP was 58.9 percent lower in the first six months of 2015 than in the first six months of 2014, $39.98 per MWh versus $63.52 per MWh. The day-ahead load-weighted average LMP was 59.6 percent lower in the first six months of 2015 than in the first six months of 2014, $43.26 per MWh versus $70.67 per MWh.[58]

58 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."

Real-Time LMP

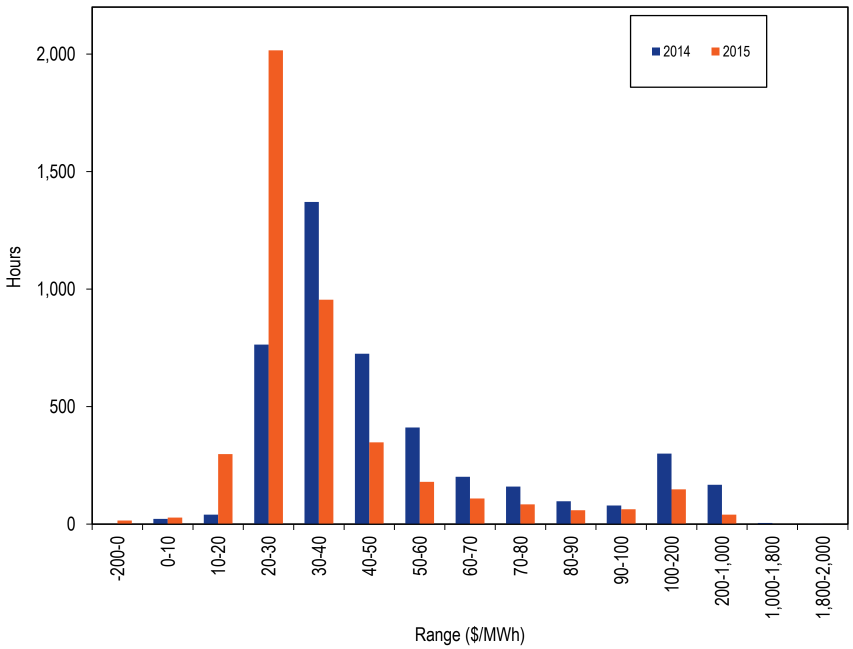
Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[59]

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 3-30 shows the hourly distribution of PJM real-time average LMP for the first six months of 2014 and 2015. In the first six months of 2014, there were six hour in January in which PJM real-time average LMP was greater than $1,000 and one hour in which the real-time LMP was greater than $1,800.

Figure 3-30 Average LMP for the PJM Real-Time Energy Market: January through June 2014 and 2015[60]



59 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>.

60 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 3-62 shows the PJM real-time, average LMP for the first six months of each year of the 18 year period 1998 to 2015.[61]

Table 3-62 PJM real-time, average LMP (Dollars per MWh): January through June of 1998 through 2015

	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%
2015	$38.87	$29.04	$34.04	(37.4%)	(26.8%)	(61.7%)

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. The real-time, load-weighted, average LMP decreased by 39.5 percent compared to the first six months of 2014.

61 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.

PJM Real-Time, Load-Weighted, Average LMP

Table 3-63 shows the PJM real-time, load-weighted, average LMP for the first six months of each year of the 18 year period 1998 to 2015.

Table 3-63 PJM real-time, load-weighted, average LMP (Dollars per MWh): January through June of 1998 through 2015

	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%
2015	$42.30	$30.34	$37.85	(39.5%)	(28.8%)	(63.4%)

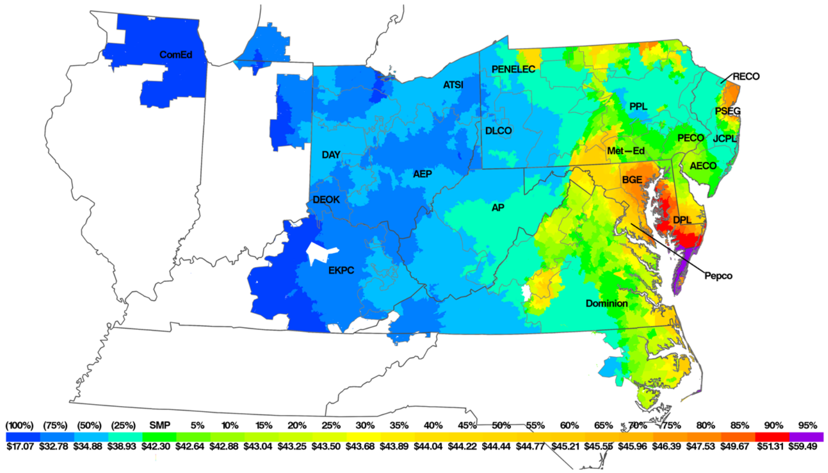
Table 3-64 shows zonal real-time, and real-time, load-weighted, average LMP for the first six months of 2014 and 2015.

Table 3-64 Zone real-time and real-time, load-weighted, average LMP (Dollars per MWh): January through June of 2014 and 2015

	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
Zone	2014 (Jan-Jun) Average	2015 (Jan-Jun) Average	Percent Change	2014 (Jan-Jun) Average	2015 (Jan-Jun) Average	Percent Change
AECO	$68.78	$41.58	(39.5%)	$76.31	$45.10	(40.9%)
AEP	$54.16	$35.25	(34.9%)	$59.99	$37.76	(37.1%)
AP	$60.95	$40.67	(33.3%)	$69.31	$44.73	(35.5%)
ATSI	$56.42	$35.82	(36.5%)	$60.96	$37.75	(38.1%)
BGE	$77.75	$48.89	(37.1%)	$92.61	$54.57	(41.1%)
ComEd	$47.30	$29.91	(36.8%)	$50.82	$31.54	(37.9%)
Day	$53.38	$35.45	(33.6%)	$58.75	$37.79	(35.7%)
DEOK	$50.79	$34.15	(32.8%)	$55.90	$36.50	(34.7%)
DLCO	$50.21	$33.23	(33.8%)	$53.86	$34.87	(35.3%)
Dominion	$72.42	$43.48	(40.0%)	$86.92	$49.19	(43.4%)
DPL	$50.21	$33.23	(33.8%)	$88.47	$52.35	(40.8%)
EKPC	$50.98	$32.82	(35.6%)	$60.73	$36.36	(40.1%)
JCPL	$68.98	$41.20	(40.3%)	$77.00	$45.14	(41.4%)
Met-Ed	$67.18	$41.09	(38.8%)	$77.14	$45.80	(40.6%)
PECO	$67.93	$40.41	(40.5%)	$77.01	$44.65	(42.0%)
PENELEC	$61.27	$40.07	(34.6%)	$67.58	$43.29	(35.9%)
Pepco	$77.00	$45.42	(41.0%)	$90.86	$50.34	(44.6%)
PPL	$67.23	$40.68	(39.5%)	$78.54	$46.08	(41.3%)
PSEG	$73.40	$44.83	(38.9%)	$80.35	$48.14	(40.1%)
RECO	$71.85	$45.63	(36.5%)	$77.97	$48.24	(38.1%)
PJM	$62.14	$38.87	(37.4%)	$69.92	$42.30	(39.5%)

Figure 3-31 is a contour map of the real-time, load-weighted, average LMP in the first six months of 2015. Green represents the system marginal price (SMP) for each year with each color to the right of green including five percent of the pricing nodes above SMP and each color to the left of green including 25 percent of pricing nodes below SMP. Prices in Eastern MAAC were all higher, on average, than the SMP for the first six months of 2015.

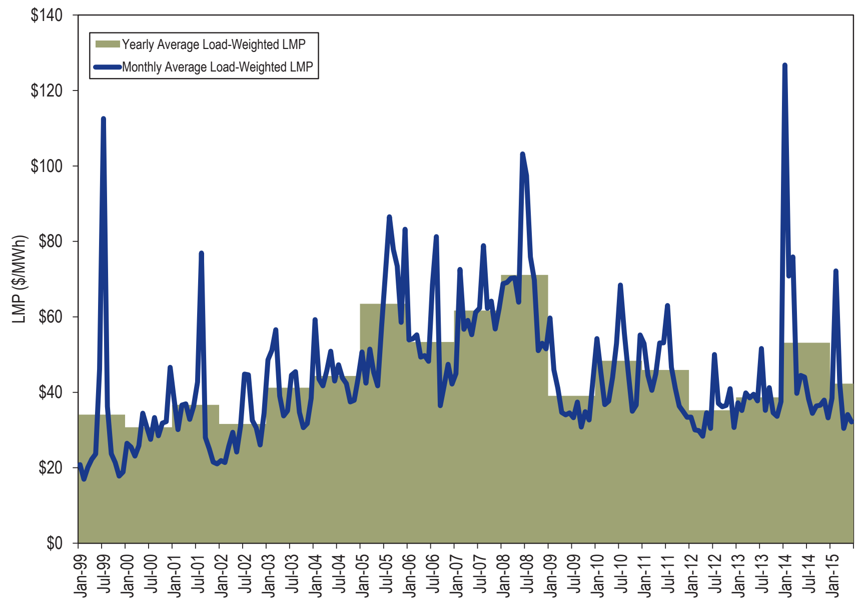
Figure 3-31 PJM real-time, load-weighted, average LMP: January through June 2015



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

Figure 3-32 shows the PJM real-time monthly and annual load-weighted LMP for the first six months from 1999 through 2015.

Figure 3-32 PJM real-time, monthly and annual, load-weighted, average LMP: January 1999 through June 2015



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. Coal and natural gas prices decreased in 2015. Comparing fuel prices in 2015 to 2014, the price of Northern Appalachian coal was 16.6 percent lower; the price of Central Appalachian coal was 23.1 percent lower; the price of Powder River Basin coal was 11.9 percent lower; the price of eastern natural gas was 45.2 percent lower; and the price of western natural gas was 55.1 percent lower. Figure 3-33 shows monthly average spot fuel prices.[62]

Figure 3-33 Spot average fuel price comparison with fuel delivery charges: 2012 through June, 2015 ($/MMBtu)

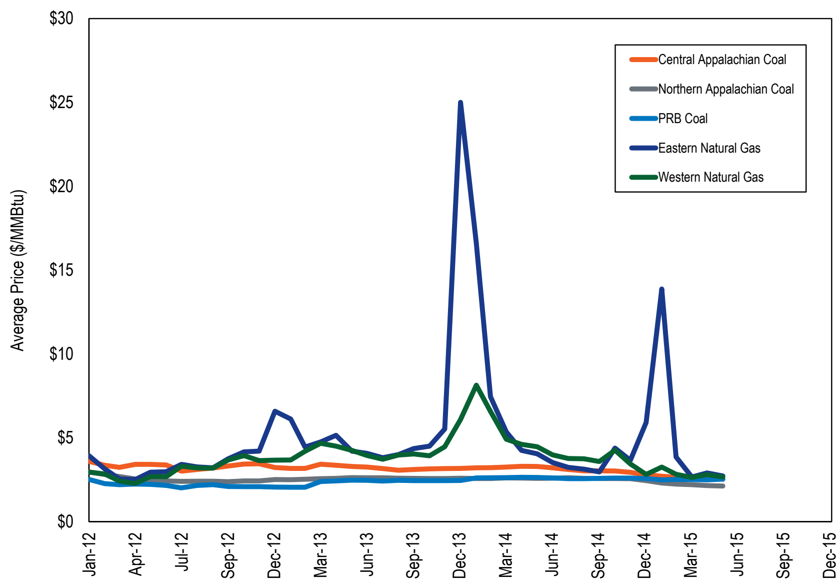


Table 3-65 compares the first six months of 2015 PJM real time fuel-cost adjusted, load-weighted, average LMP to the first six months of 2015 load-weighted, average LMP. The real time fuel-cost adjusted, load-weighted, average LMP for the first six months of 2015 was 24.9 percent higher than the real time load-weighted, average LMP for the first six months of 2015. The real-time, fuel-cost adjusted, load-weighted, average LMP for the first six months of 2015 was 24.4 percent lower than the real time load-weighted LMP for the first six months of 2014. If fuel costs in the first six months of 2015 had been the same as in the first six months of 2014, holding everything else constant, the real time load-weighted LMP in 2015 would have been higher, $52.85 per MWh instead of the observed $42.30 per MWh.

Table 3-65 PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): six months over six months

	2015 Load-Weighted LMP	2015 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$42.30	$52.85	24.9%
	2014 Load-Weighted LMP	2015 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$69.92	$52.85	(24.4%)
	2014 Load-Weighted LMP	2015 Load-Weighted LMP	Change
Average	$69.92	$42.30	(39.5%)

Table 3-66 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 2015. Table 3-66 shows that lower coal, natural gas and oil prices explain almost all of the fuel-cost related decrease in the real time annual load-weighted average LMP in the first six months of 2015. Unlike oil and natural gas, there was no substantial change in the price of coal from the first six months of 2014 to the first six months of 2015. However, coal units' offer prices were generally lower in the first six months of 2015 compared to their offers in the first six months of 2014, particularly the high offer prices during the cold weather days in January and March of 2014.

62 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 3-66 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	($2.44)	23.1%
Gas	($6.94)	65.8%
Municipal Waste	($0.00)	0.0%
Oil	($1.12)	10.6%
Other	($0.04)	0.4%
Uranium	$0.00	(0.0%)
Wind	($0.00)	0.0%
Total	($10.55)	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.[63] 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.[64] 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.

The components of LMP are shown in Table 3-67, including markup using unadjusted cost offers.[65] Table 3-67 shows that for the first six months of 2015, 40.8 percent of the load-weighted LMP was the result of coal costs, 30.2 percent was the result of gas costs and 0.71 percent was the result of the cost of emission allowances. Markup was $0.67 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 2015, nearly nine 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 2015 and 2014.

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

64 PJM triggered shortage pricing on January 6, 2014 following a RTO-wide voltage reduction action. PJM triggered shortage pricing on January 7, 2014, due to RTO-wide shortage of synchronized reserve.

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

Table 3-67 Components of PJM real-time (Unadjusted), six month, load-weighted, average LMP: January through June 2014 and 2015

	2014 (Jan - Jun)		2015 (Jan - Jun)		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Coal	$17.39	24.9%	$17.27	40.8%	16.0%
Gas	$26.93	38.5%	$12.78	30.2%	(8.3%)
Ten Percent Adder	$4.54	6.5%	$3.53	8.3%	1.9%
VOM	$2.79	4.0%	$2.66	6.3%	2.3%
Oil	$5.32	7.6%	$2.30	5.4%	(2.2%)
Ancillary Service Redispatch Cost	$0.76	1.1%	$1.27	3.0%	1.9%
LPA Rounding Difference	($0.11)	(0.2%)	$0.80	1.9%	2.1%
Markup	$3.42	4.9%	$0.67	1.6%	(3.3%)
NA	$2.73	3.9%	$0.67	1.6%	(2.3%)
Increase Generation Adder	$1.23	1.8%	$0.36	0.9%	(0.9%)
CO_2 Cost	$0.20	0.3%	$0.26	0.6%	0.3%
Other	$0.03	0.0%	$0.06	0.1%	0.1%
NO_x Cost	$0.13	0.2%	$0.03	0.1%	(0.1%)
SO_2 Cost	$0.01	0.0%	$0.01	0.0%	0.0%
Market-to-Market Adder	($0.01)	(0.0%)	$0.01	0.0%	0.0%
FMU Adder	$1.01	1.5%	$0.00	0.0%	(1.4%)
Emergency DR Adder	$3.63	5.2%	$0.00	0.0%	(5.2%)
Scarcity Adder	$0.20	0.3%	$0.00	0.0%	(0.3%)
Constraint Violation Adder	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Uranium	($0.02)	(0.0%)	($0.00)	(0.0%)	0.0%
Wind	($0.02)	(0.0%)	($0.06)	(0.1%)	(0.1%)
Decrease Generation Adder	($0.26)	(0.4%)	($0.08)	(0.2%)	0.2%
LPA-SCED Differential	($0.01)	(0.0%)	($0.10)	(0.2%)	(0.2%)
Municipal Waste	$0.03	0.0%	($0.15)	(0.4%)	(0.4%)
Total	$69.92	100.0%	$42.30	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 3-67 and Table 3-71) markup is simply the difference between the price offer and the cost offer. In the second approach, (Table 3-68 and Table 3-72) the 10 percent markup is removed from the cost offers of coal units.

The components of LMP are shown in Table 3-68, including markup using adjusted cost offers.

Table 3-68 Components of PJM real-time (Adjusted), six month, load-weighted, average LMP: January through June 2014 and 2015

	2014 (Jan - Jun)		2015 (Jan - Jun)		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Coal	$17.39	24.9%	$17.27	40.8%	16.0%
Gas	$26.93	38.5%	$12.78	30.2%	(8.3%)
VOM	$2.79	4.0%	$2.66	6.3%	2.3%
Markup	$4.61	6.6%	$2.42	5.7%	(0.9%)
Oil	$5.32	7.6%	$2.30	5.4%	(2.2%)
Ten Percent Adder	$3.35	4.8%	$1.78	4.2%	(0.6%)
Ancillary Service Redispatch Cost	$0.76	1.1%	$1.27	3.0%	1.9%
LPA Rounding Difference	($0.11)	(0.2%)	$0.80	1.9%	2.1%
NA	$2.73	3.9%	$0.67	1.6%	(2.3%)
Increase Generation Adder	$1.23	1.8%	$0.36	0.9%	(0.9%)
CO_2 Cost	$0.20	0.3%	$0.26	0.6%	0.3%
Other	$0.03	0.0%	$0.06	0.1%	0.1%
NO_x Cost	$0.13	0.2%	$0.03	0.1%	(0.1%)
SO_2 Cost	$0.01	0.0%	$0.01	0.0%	0.0%
Market-to-Market Adder	($0.01)	(0.0%)	$0.01	0.0%	0.0%
FMU Adder	$1.01	1.5%	$0.00	0.0%	(1.4%)
Emergency DR Adder	$3.63	5.2%	$0.00	0.0%	(5.2%)
Scarcity Adder	$0.20	0.3%	$0.00	0.0%	(0.3%)
Constraint Violation Adder	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Uranium	($0.02)	(0.0%)	($0.00)	(0.0%)	0.0%
Wind	($0.02)	(0.0%)	($0.06)	(0.1%)	(0.1%)
Decrease Generation Adder	($0.26)	(0.4%)	($0.08)	(0.2%)	0.2%
LPA-SCED Differential	($0.01)	(0.0%)	($0.10)	(0.2%)	(0.2%)
Municipal Waste	$0.03	0.0%	($0.15)	(0.4%)	(0.4%)
Total	$69.92	100.0%	$42.30	100.0%	0.0%

Day-Ahead LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[66]

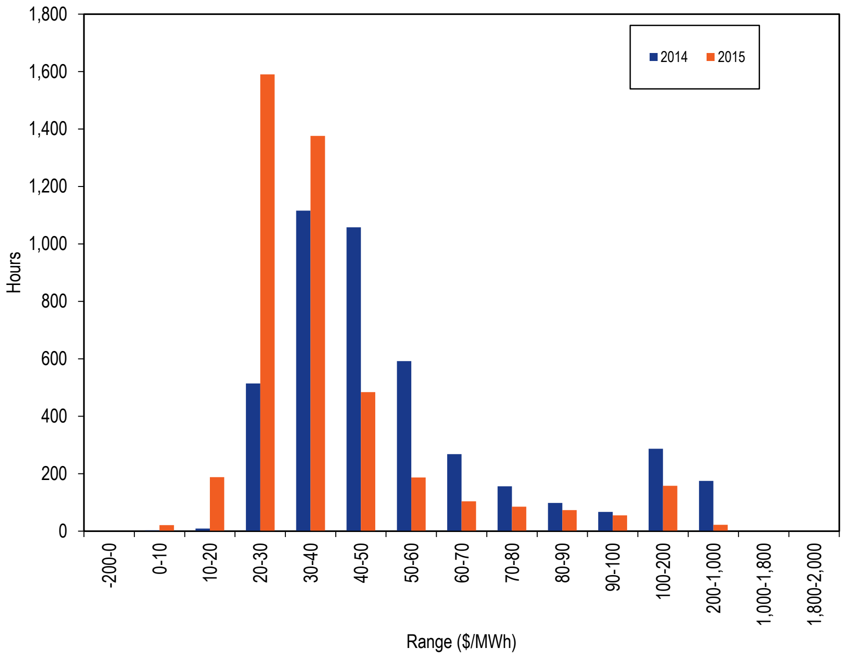
Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 3-34 shows the hourly distribution of PJM day-ahead average LMP for the first six months of 2014 and 2015.

66 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>.

Figure 3-34 Average LMP for the PJM Day-Ahead Energy Market: January through June 2014 and 2015



PJM Day-Ahead, Average LMP

Table 3-69 shows the PJM day-ahead, average LMP for the first six months of each year of the 15-year period 2001 to 2015.

Table 3-69 PJM day-ahead, average LMP (Dollars per MWh): January through June of 2001 through 2015

	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%
2015	$39.98	$31.93	$28.76	(37.1%)	(28.1%)	(58.9%)

Day-Ahead, Load-Weighted, Average LMP

Day-ahead, load-weighted LMP reflects the average LMP paid for day-ahead MWh. Day-ahead, load-weighted LMP is the average of PJM day-ahead hourly LMP, each weighted by the PJM total cleared day-ahead hourly load, including day-ahead fixed load, price-sensitive load, decrement bids and up-to congestion.

PJM Day-Ahead, Load-Weighted, Average LMP

Table 3-70 shows the PJM day-ahead, load-weighted, average LMP for the first six months of each year of the 15-year period 2001 to 2015.

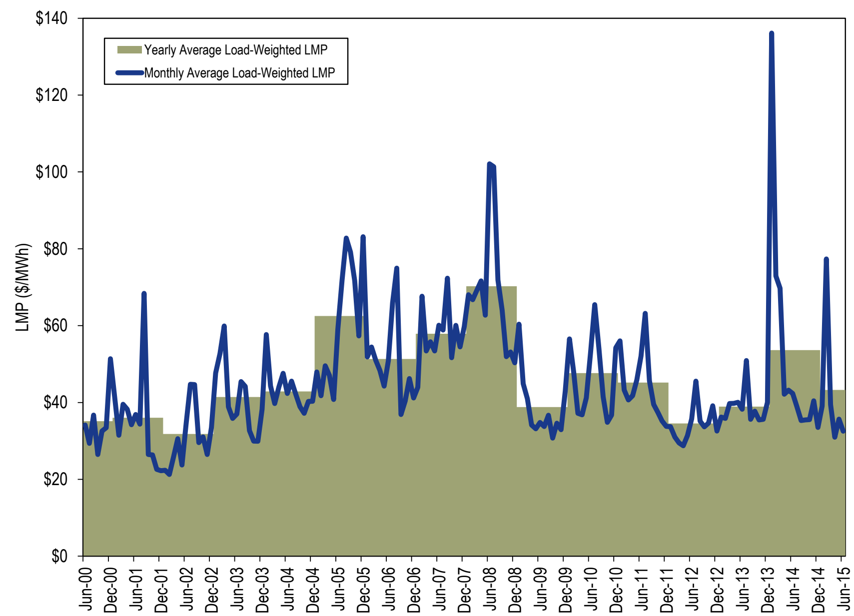
Table 3-70 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January through June 2001 through 2015

	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%
2015	$43.26	$33.45	$32.23	(38.8%)	(28.9%)	(59.6%)

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

Figure 3-35 shows the PJM day-ahead, monthly and annual, load-weighted LMP from June 2000 through June 2015.[67]

Figure 3-35 Day-ahead, monthly and annual, load-weighted, average LMP: June 2000 through June 2015



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

67 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.

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.[68] 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 3-71, including markup using unadjusted cost offers.

Table 3-71 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In the first six months of 2015, 30.6 percent of the load-weighted LMP was the result of coal cost, 15.6 percent of the load-weighted LMP was the result of gas cost, 5.3 percent was the result of the up-to congestion transaction cost, 20.4 percent was the result of DEC bid cost and 11.4 percent was the result of INC bid cost. The contribution of up-to congestion transactions decreased on September 8, 2014, as a result of the FERC's UTC uplift refund notice which became effective on that date.[69]

Table 3-71 Components of PJM day-ahead, (unadjusted) six month, load-weighted, average LMP (Dollars per MWh): January through June of 2014 and 2015

	2014 (Jan - Jun)		2015 (Jan - Jun)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$9.84	13.9%	$13.22	30.6%	16.6%
DEC	$10.77	15.2%	$8.83	20.4%	5.2%
Gas	$16.45	23.3%	$6.76	15.6%	(7.7%)
INC	$9.96	14.1%	$4.91	11.4%	(2.7%)
Ten Percent Cost Adder	$2.96	4.2%	$2.34	5.4%	1.2%
Up-to Congestion Transaction	$11.31	16.0%	$2.30	5.3%	(10.7%)
VOM	$1.43	2.0%	$1.72	4.0%	2.0%
Dispatchable Transaction	$4.06	5.7%	$1.55	3.6%	(2.1%)
Oil	$1.54	2.2%	$1.50	3.5%	1.3%
DASR LOC Adder	($0.06)	(0.1%)	$0.29	0.7%	0.8%
DASR Offer Adder	$0.10	0.1%	$0.23	0.5%	0.4%
CO_2	$0.14	0.2%	$0.14	0.3%	0.1%
Price Sensitive Demand	$1.57	2.2%	$0.06	0.1%	(2.1%)
NO_x	$0.08	0.1%	$0.01	0.0%	(0.1%)
Municipal Waste	$0.02	0.0%	$0.01	0.0%	(0.0%)
SO_2	$0.01	0.0%	$0.01	0.0%	0.0%
Constrained Off	$0.01	0.0%	($0.00)	(0.0%)	(0.0%)
Other	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Wind	$0.00	0.0%	($0.02)	(0.0%)	(0.1%)
Markup	$0.01	0.0%	($0.78)	(1.8%)	(1.8%)
Import	$0.12	0.2%	$0.00	0.0%	(0.2%)
FMU Adder	$0.52	0.7%	$0.00	0.0%	(0.7%)
NA	($0.15)	(0.2%)	$0.16	0.4%	0.6%
Total	$70.67	100.0%	$43.26	100.0%	(0.0%)

68 New Jersey withdrew from RGGI, effective January 1, 2012.
69 See 18 CFR § 385.213 (2014).

Table 3-72 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 3-72 Components of PJM day-ahead, (adjusted) six month, load-weighted, average LMP (Dollars per MWh): January through June of 2014 and 2015

	2014 (Jan - Jun)		2015 (Jan - Jun)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$9.80	13.9%	$13.22	30.6%	16.7%
DEC	$10.77	15.2%	$8.83	20.4%	5.2%
Gas	$16.45	23.3%	$6.76	15.6%	(7.7%)
INC	$9.96	14.1%	$4.91	11.4%	(2.7%)
Up-to Congestion Transaction	$11.31	16.0%	$2.30	5.3%	(10.7%)
VOM	$1.42	2.0%	$1.72	4.0%	2.0%
Dispatchable Transaction	$4.06	5.7%	$1.55	3.6%	(2.1%)
Oil	$1.54	2.2%	$1.50	3.5%	1.3%
Ten Percent Cost Adder	$1.85	2.6%	$0.91	2.1%	(0.5%)
Markup	$1.17	1.7%	$0.64	1.5%	(0.2%)
DASR LOC Adder	($0.06)	(0.1%)	$0.29	0.7%	0.8%
DASR Offer Adder	$0.10	0.1%	$0.23	0.5%	0.4%
CO_2	$0.14	0.2%	$0.14	0.3%	0.1%
Price Sensitive Demand	$1.57	2.2%	$0.06	0.1%	(2.1%)
NO_x	$0.08	0.1%	$0.01	0.0%	(0.1%)
Municipal Waste	$0.02	0.0%	$0.01	0.0%	(0.0%)
SO_2	$0.01	0.0%	$0.01	0.0%	0.0%
Constrained Off	$0.01	0.0%	($0.00)	(0.0%)	(0.0%)
Other	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Wind	$0.00	0.0%	($0.02)	(0.0%)	(0.1%)
Import	$0.12	0.2%	$0.00	0.0%	(0.2%)
FMU Adder	$0.52	0.7%	$0.00	0.0%	(0.7%)
NA	($0.15)	(0.2%)	$0.17	0.4%	0.6%
Total	$70.67	100.0%	$43.26	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 3-73 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 2014 and 2015. In the first six months of 2015, 51.7 percent of all cleared UTC transactions were net profitable, with 66.8 percent of the source side profitable and 34.6 percent of the sink side profitable.

Table 3-73 Cleared UTC profitability by source and sink point: January through June 2014 and 2015[70]

(Jan-Jun)	Cleared UTCs	Profitable UTCs	UTC Profitable at Source Bus	UTC Profitable at Sink Bus	Profitable UTC	Profitable Source	Profitable Sink
2014	13,216,571	7,322,948	9,090,125	4,265,202	55.4%	68.8%	32.3%
2015	3,837,460	1,985,380	2,564,982	1,326,587	51.7%	66.8%	34.6%

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 3-37).

Table 3-74 shows that the difference between the average real-time price and the average day-ahead price was -$1.38 per MWh in the first six months of 2014, and -$1.11 per MWh in the first six months of 2015. The difference between average peak real-time price and the average peak day-ahead price was -$1.92 per MWh in the first six months of 2014 and -$3.29 per MWh in the first six months of 2015.

70 Calculations exclude PJM administrative charges.

Table 3-74 Day-ahead and real-time average LMP (Dollars per MWh): January through June, 2014 and 2015[71]

	2014 (Jan-Jun)				2015 (Jan-Jun)			
	Day Ahead	Real Time	Difference	Percent of Real Time	Day Ahead	Real Time	Difference	Percent of Real Time
Average	$63.52	$62.14	($1.38)	(2.2%)	$39.98	$38.87	($1.11)	(2.8%)
Median	$44.42	$39.69	($4.72)	(11.9%)	$31.93	$29.04	($2.90)	(10.0%)
Standard deviation	$69.93	$88.87	$18.94	21.3%	$28.76	$34.04	$5.29	15.5%
Peak average	$79.77	$77.85	($1.92)	(2.5%)	$47.35	$44.07	($3.29)	(7.5%)
Peak median	$52.96	$48.52	($4.43)	(9.1%)	$36.58	$32.83	($3.75)	(11.4%)
Peak standard deviation	$86.69	$111.61	$24.91	22.3%	$33.49	$34.20	$0.71	2.1%
Off peak average	$49.22	$48.32	($0.90)	(1.9%)	$33.58	$34.37	$0.78	2.3%
Off peak median	$36.52	$33.05	($3.47)	(10.5%)	$27.14	$25.87	($1.27)	(4.9%)
Off peak standard deviation	$46.33	$59.03	$12.70	21.5%	$22.01	$33.27	$11.26	33.8%

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 3-75 shows the difference between the Real-Time and the Day-Ahead Energy Market prices for January through June in each year of the 15-year period 2001 to 2015.

Table 3-75 Day-ahead and real-time average LMP (Dollars per MWh): January through June 2001 through 2015

(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%)
2015	$39.98	$38.87	($1.11)	(2.8%)

Table 3-76 provides frequency distributions of the differences between PJM real-time hourly LMP and PJM day-ahead hourly LMP for January through June of 2007 through 2015.

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

Table 3-76 Frequency distribution by hours of PJM real-time LMP minus day-ahead LMP (Dollars per MWh): January through June of 2007 through 2015

(Jan-Jun)	2007		2008		2009		2010		2011		2012		2013		2014		2015	
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	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%	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%	0	0.00%
($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%	0	0.00%
($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%	0	0.00%
($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%	0	0.00%
($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%	0	0.00%
($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%	0	0.00%
($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%	0	0.00%
($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%	1	0.02%
($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%	4	0.12%
($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%	12	0.39%
($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	1.54%
($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%	3,020	71.08%
$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%	1,146	97.47%
$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%	74	99.17%
$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%	28	99.82%
$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%	6	99.95%
$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%	1	99.98%
$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%	1	100.00%
$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%	0	100.00%
$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%	0	100.00%
$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%	0	100.00%
$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%	0	100.00%
$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%	0	100.00%
$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%	0	100.00%
$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%	0	100.00%
>= $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%	0	100.00%

Figure 3-36 shows the hourly differences between day-ahead and real-time hourly LMP in the first six months of 2015.

Figure 3-36 Real-time hourly LMP minus day-ahead hourly LMP: January through June 2015

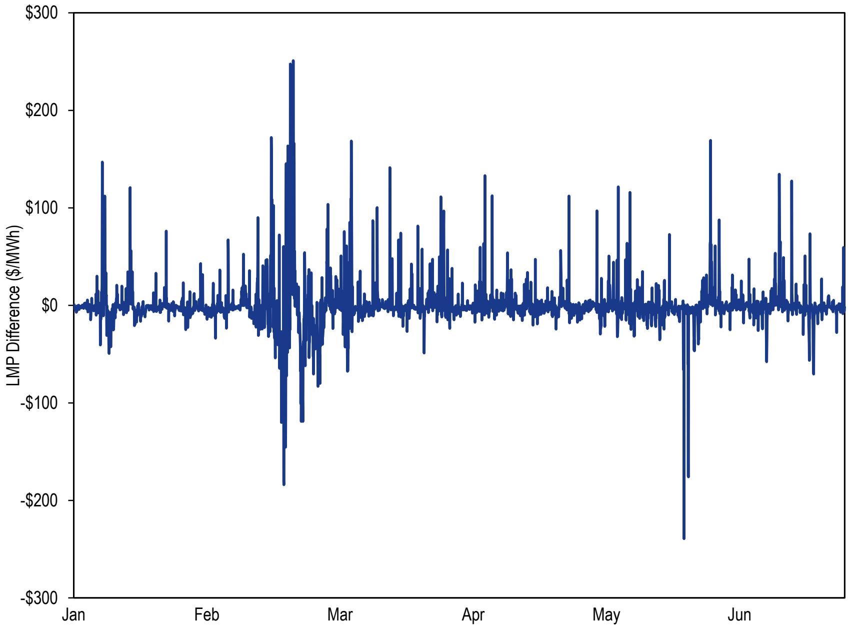


Figure 3-37 shows the monthly average differences between the day-ahead and real-time LMP in the first six months of 2015.

Figure 3-37 Monthly average of real-time minus day-ahead LMP: January through June 2015

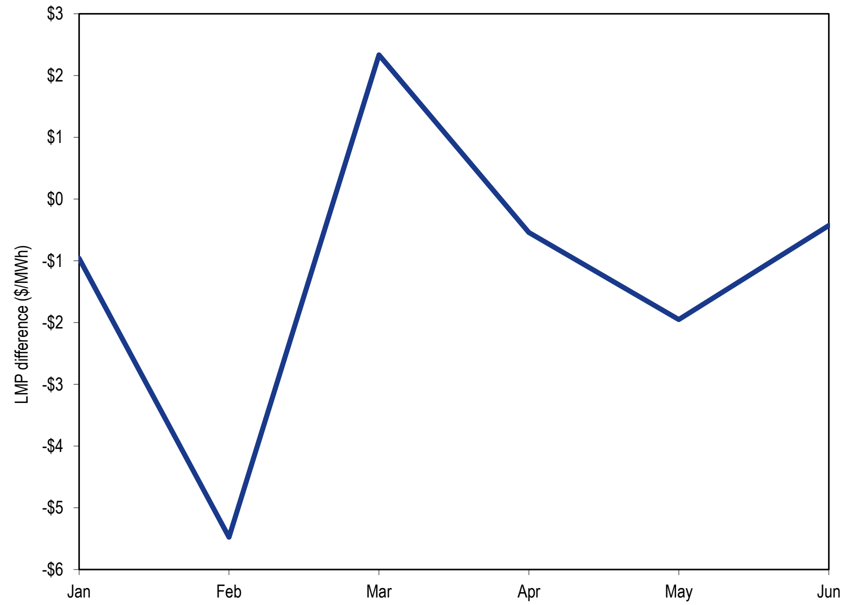
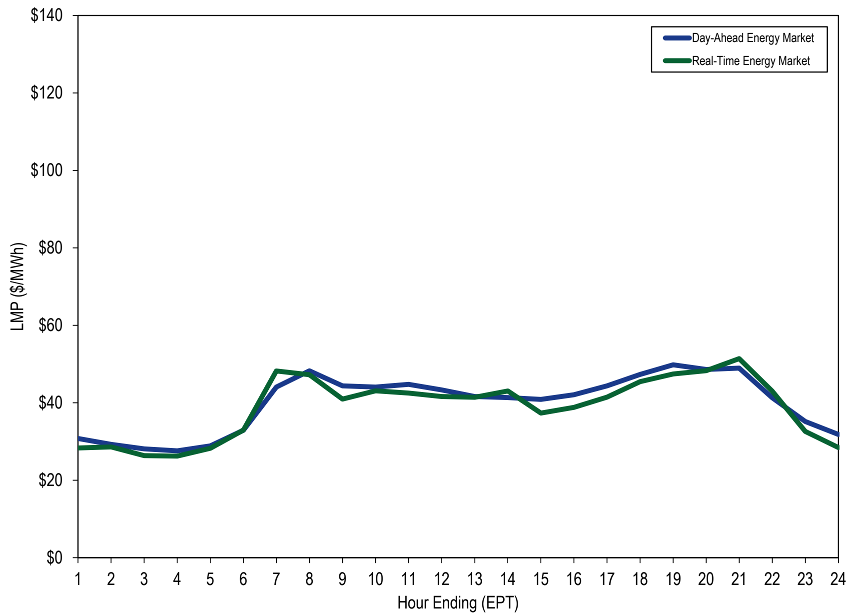


Figure 3-38 shows day-ahead and real-time LMP on an average hourly basis for the first six months of 2015.

Figure 3-38 PJM system hourly average LMP: January through June 2015



Scarcity

PJM's Energy Market experienced no shortage pricing events in the first six months of 2015 compared to two days in the first six months of 2014. Table 3-77 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in the first six months of 2014 and 2015.

Table 3-77 Summary of emergency events declared: January through June, 2014 and 2015

	Number of days events declared	
Event Type	Jan - Jun, 2014	Jan - Jun, 2015
Cold Weather Alert	25	26
Hot Weather Alert	3	9
Maximum Emergency Generation Alert	6	0
Primary Reserve Alert	2	0
Voltage Reduction Alert	2	0
Primary Reserve Warning	1	0
Voltage Reduction Warning	4	0
Pre Emergency Mandatory Load Management Reduction Action	0	2
Emergency Load Management Long Lead Time	6	2
Emergency Load Management Short Lead Time	6	2
Maximum Emergency Action	8	1
Emergency Energy Bids Requested	3	0
Voltage Reduction Action	1	0
Shortage Pricing	2	0
Energy export recalls from PJM capacity resources	0	0

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 26 days in the first six months of 2015 compared to 25 days in the first six months of 2014.[72] 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 nine days in the first six months of 2015 compared to three days in the first six months of 2014.[73] The purpose of a hot weather alert is to prepare personnel and facilities for expected extreme hot

72 See PJM. "Manual 13: Emergency Operations," Revision 57 (January 1, 2015), Section 3.3 Cold Weather Alert, p. 46.
73 See PJM. "Manual 13: Emergency Operations," Revision 57 (January 1, 2015), Section 3.4 Hot Weather Alert, p. 50.

and humid weather conditions, generally when temperatures are forecast to exceed 90 degrees Fahrenheit with high humidity.

PJM did not declare any maximum emergency generation alerts in the first six months of 2015 compared to 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.[74] 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 did not declare any primary reserve alert in the first six months of 2015 compared to 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 did not declare any voltage reduction alert in the first six months of 2015, compared to two days 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 did not declare any primary reserve warning in the first six months of 2015, compared to 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.

74 See PJM. "Manual 13: Emergency Operations," Revision 57 (January 1, 2015), Section 2.3.1 Advance Notice Emergency Procedures: Alerts, p. 16.

PJM did not declare any voltage reduction warning and reduction of non-critical plant load in the first six months of 2015 compared to 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.

PJM declared emergency mandatory load management reductions on two days in the first six months of 2015 compared to six days in all or parts of the PJM service territory 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). Starting in June 2014, PJM combined the long lead and short lead emergency load management action procedures into Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time). PJM dispatch declares NERC Energy Emergency Alert level 2 (EEA2) concurrent with Emergency Mandatory load Management Reductions. PJM also added a Pre-Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time) step to request load reductions before declaring emergency load management reductions. PJM declared Pre-Emergency Mandatory Load Management Reduction Action on two days in the first six months of 2015.

PJM declared maximum emergency generation action on one day in the first six months of 2015 compared to 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.

PJM did not request any bids for emergency energy purchases in the first six months of 2015 compared to three days in the first six months of 2014.

PJM did not declare any voltage reduction action in the first three months of 2015 compared to 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 eleven synchronized reserve events in the first six months of 2015 compared to 24 in the first six months of 2014.[75] Synchronized reserve events may occur at any time of the year due to sudden loss of generation or transmission facilities and do not necessarily coincide with capacity emergency conditions such as maximum generation emergency events or emergency load management events.

Table 3-78 provides a description of PJM declared emergency procedures.

Table 3-78 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 that 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 requirement and that voltage reduction may be required.
Pre-Emergency Mandatory Load Management Reduction Action (30, 60 or 120-minute)	To request any site registered in the PJM demand response program as a demand resource (DR) that needs 30, 60 or 120 minute lead time to provide load relief. This is declared prior to or with out PJM dispatch issuing a NERC Energy Emergency Alert Level 2 (EEA2).
Emergency Mandatory Load Management Reduction Action (30, 60 or 120-minute)	To request any site registered in the PJM demand response program as a demand resource (DR) that needs 30, 60 or 120 minute lead time to provide load relief. A NERC EEA2 is declared concurrent with the issuance of Emergency Mandatory Load Management Reductions.
Maximum Emergency 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 Action	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.

Table 3-79 shows when emergency alerts and warnings were declared and when emergency actions were implemented in the first six months of 2015.

75 See *2015 Quarterly State of the Market Report for PJM: January through June*, Section 10: Ancillary Service Markets for details on the spinning events.

Table 3-79 PJM declared emergency alerts, warnings and actions: January through June, 2015

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	Pre-Emergency Mandatory Load Management Reduction	Maximum Emergency Generation Action	Emergency Mandatory Load Management Reduction	Voltage Reduction	Manual Load Dump Warning	Load Shed Directive
1/5/2015	ComEd												
1/6/2015	ComEd												
1/7/2015	PJM Western Region												
1/8/2015	PJM												
1/9/2015	PJM Western Region												
1/10/2015	PJM Western Region												
1/14/2015	PJM Western Region												
1/15/2015	PJM Western Region												
2/2/2015	PJM												
2/3/2015	PJM												
2/5/2015	ComEd,DLCO,ATSI												
2/6/2015	Mid-Atlantic												
2/13/2015	DLCO,AP,ATSI												
2/14/2015	PJM Western Region												
2/15/2015	Mid-Atlantic,PJM Western Region												
2/16/2015	PJM												
2/17/2015	Mid-Atlantic												
2/18/2015	PJM Western Region												
2/19/2015	PJM												
2/20/2015	PJM												
2/21/2015												AEP	
2/23/2015	PJM Western Region												
2/24/2015	PJM												
2/26/2015	DLCO,ATSI												
2/27/2015	PJM Western Region												
3/5/2015	ComEd												
3/6/2015	PJM Western Region												
4/21/2015								Penelec	Penelec	Penelec			
4/22/2015								Penelec		Penelec			
5/26/2015		Mid-Atlantic,PJM Southern Region											
5/27/2015		Mid-Atlantic,PJM Southern Region											AEP (Milton, WV)
6/11/2015		Mid-Atlantic,PJM Southern Region											
6/12/2015		Mid-Atlantic,PJM Southern Region											
6/13/2015		Mid-Atlantic,PJM Southern Region											
6/16/2015		PJM Southern Region											
6/21/2015		PJM Southern Region											
6/22/2015		Mid-Atlantic,PJM Southern Region											
6/23/2015		Mid-Atlantic,PJM Southern Region											AECO

Scarcity and Scarcity Pricing

In electricity markets, scarcity means that demand, including reserve requirements, is nearing the limits of the available capacity of the system. Under the PJM rules that were in place through September 30, 2012, high prices, or scarcity pricing, resulted from high offers by individual generation owners for specific units when the system was close to its available capacity. But this was not an efficient way to manage scarcity pricing and made it difficult to distinguish between market power and scarcity pricing.

On October 1, 2012, PJM introduced a new administrative scarcity pricing regime. Under the current PJM market rules, shortage pricing conditions are triggered when there is a shortage of synchronized or primary reserves in the RTO or in the Mid-Atlantic and Dominion (MAD) subzone. In times of reserve shortage, the value of reserves is included as a penalty factor in the optimization and in the price of energy.[76] Shortage pricing is also triggered when PJM issues a voltage reduction action or a manual load dump action for a reserve zone or a reserve sub-zone. When shortage pricing is triggered, the primary reserve penalty factor and the synchronized reserve penalty factor are incorporated in the calculation of the synchronized and non-synchronized reserve market clearing prices and the locational marginal price.

In the first six months of 2015, there were no shortage pricing events triggered in PJM compared to two days in the first six months of 2014

PJM Cold Weather Operations 2015

Natural gas supply and prices

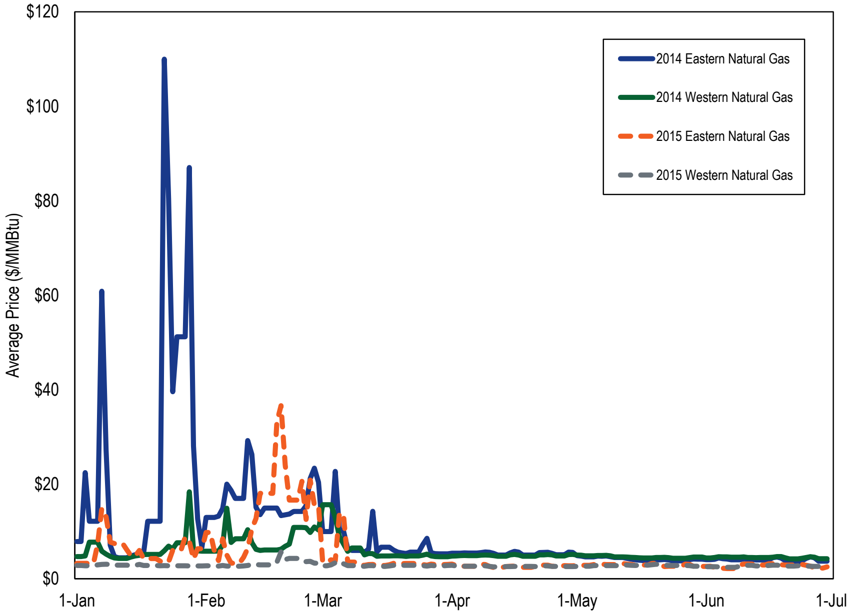
As of January 1, 2015, gas fired generation was 30.7 percent (56,364.5 MW) of the total installed PJM capacity (183,724.1MW).[77] The extreme cold weather conditions and the associated high demand for natural gas led to supply constraints on the gas transmission system which resulted in natural gas price volatility and interruptions to customers without firm transportation. Figure 3-39 shows the average daily price of delivered natural gas for eastern and western parts of PJM service territory in the first six months of 2014 and 2015.

During the first three months of 2014 and 2015, a number of interstate gas pipelines that supply fuel for generators in the PJM service territory issued notices for lack of non-firm gas availability. These notices include warnings of operational flow orders (OFO) and actual OFOs. OFOs may restrict the provision of gas to 24 hour ratable takes which means that hourly nominations must be the same for each of the 24 hours in the day, with penalties for deviating from the nominated quantities. Pipelines may also enforce strict balancing constraints which limit the ability of gas users (without no-notice service) to deviate from the 24 hour ratable take and which limit the ability of users to have access to unused gas.

The extreme conditions illustrate the shortcomings of a gas pipeline system that relies on individual pipelines to manage the balancing of supply and demand. Pipeline operators use restrictive and inflexible rules to manage the balance of supply and demand. The experience of pipelines and electric generators in these extreme conditions also suggests the potential benefits of creating an ISO/RTO structure to coordinate the supply of gas across pipelines and with the electric RTOs, or the inclusion of gas coordination under existing electric ISO/RTOs.

76 See PJM OATT, 2.2 (d) General, (February 25, 2014), pp. 1815, 1819.
77 *2015 Quarterly State of the Market Report for PJM: January through June*, Section 5: Capacity Market, at Installed Capacity.

Figure 3-39 Average daily delivered price for natural gas: January through June, 2014 and 2015 ($/MMBtu)



Parameter Limited Schedules

All capacity resources in PJM are required to submit at least one cost based offer. All cost based offers are parameter limited in accordance with the Parameter Limited Schedule (PLS) matrix or to the level of a prior approved exception.[78] All capacity resources that choose to offer price based schedules are required to make available at least one price based parameter limited schedule. This schedule is to be used by PJM for committing generation resources when a maximum emergency generation alert is declared.

During the extreme cold weather conditions in the first three months of 2015, a number of gas fired generators requested temporary exceptions to parameter limits for their parameter limited schedules due to restrictions imposed by natural gas pipelines. The parameters that were affected because of gas pipeline restrictions include minimum run time (MRT) and turn down ratio (TDR, ratio of economic maximum MW to economic minimum MW). When pipelines issue critical notices and enforce ratable take requirements, generators may be forced to nominate an equal amount of gas for each hour in a 24 hour period, with penalties for deviating from the nominated quantity. This led to requests for 24 hour minimum run times and turn down ratios close to 1, to avoid deviations from the hourly nominated quantity.

Key parameters like startup and notification time were not limited by the PLS matrix through the first six months of 2015. Some resource owners notified PJM that they needed extended notification times based on the claimed necessity for generation owners to nominate gas prior to gas nomination cycle deadlines.

78 See PJM, OATT, § 6.6 Minimum Generator Operating Parameters - Parameter-Limited Schedules, (September 10, 2014), pp. 1937- 1940.