3. 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, including market size, concentration, pivotal suppliers, offer behavior, markup, and price. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2026.

Table 3-1 The energy market results were competitive

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

- The aggregate market structure was evaluated as partially competitive because the aggregate market power test based on pivotal suppliers indicates that the aggregate day-ahead market structure was not competitive on 261 days, 95.6 percent of the days in the first nine months of 2026. The hourly HHI (Herfindahl-Hirschman Index) results indicate that the PJM aggregate energy market in the first nine months of 2026 was, on average, unconcentrated by FERC HHI standards. The average HHI was 782 with a minimum of 569 and a maximum of 1070. The baseload segment of the supply curve was unconcentrated. The intermediate segment of the supply curve was moderately concentrated. The peaking segment of the supply curve was highly concentrated. The fact that the average HHI is in the unconcentrated range does not mean that the aggregate market was competitive in all hours. As demonstrated for the day-ahead market, it is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. It is possible to have an exercise of market power even when the HHI level is not in the highly concentrated range. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints and local reliability issues. 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. Transmission constraints create the potential for the exercise of local market power. The goal of PJM's application of the three pivotal supplier test is to identify local market power and offer cap to competitive offers, correcting for structural issues created by local transmission constraints. There are, however, identified issues with the definition of cost-based offers and the application of market power mitigation to resources whose owners fail the TPS test that need to be addressed because unit owners can exercise market power even when they fail the TPS test.
- 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 both routinely and during periods of high demand represents noncompetitive economic withholding. The ownership of marginal units is concentrated. The markups of pivotal suppliers in the aggregate market and of many pivotal suppliers in local markets remain unmitigated due to the lack of aggregate market power mitigation and the flawed implementation of offer caps for resources that fail the TPS test. The markups of those participants affected LMP.
- 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

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marginal costs in both day-ahead and real-time energy markets, although high markups for some marginal units did affect prices.

- Market design was evaluated as effective because the analysis shows that the PJM energy market resulted in competitive market outcomes. In general, 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 identifies market power and causes the market to provide competitive market outcomes in most cases although issues with the implementation of market power mitigation and development of cost-based offers remain. The role of UTCs in the day-ahead energy market continues to be an issue. Market design implementation issues, including inaccuracies in modeling of the transmission system and of generator capabilities as well as inefficiencies in price formation, undermine market efficiency in the energy market. The implementation of fast start pricing on September 1, 2021, undermined market efficiency by setting inefficient higher prices that are inconsistent with the dispatch signals. In the first nine months of 2026, the estimated impact of fast start pricing, based on the difference between the real-time PLMP and DLMP times real-time load, was $5.6 billion.[1] The expanding use of transmission constraint penalty factors by PJM is inconsistent with competitive markets and added $9.0 billion to the cost of energy in the first nine months of 2026.
- 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 core functions 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 mitigating market power in instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. FERC relies on effective market power mitigation when it approves market sellers to participate in the PJM market at market based rates.[3] In the PJM energy market, market power mitigation occurs primarily 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.[4] There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power even when market power mitigation rules are applied. These issues need to be addressed, but, so far, PJM and FERC have failed to address them.[5] [6] [7] Some units with market power have positive markups and some have inflexible parameters, which means that the cost-based offer was not used and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are issues related to the level of maintenance expense includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight and there are pivotal suppliers in the aggregate market. Aggregate market power needs to be addressed. Market design must reflect appropriate incentives for competitive behavior, the application of local market power mitigation needs to be fixed, the definition of a competitive offer needs to be fixed, and aggregate market power mitigation rules need to be developed. The importance of these issues is amplified by the rules permitting cost-based offers in excess of $1,000 per MWh.

1 See Monitoring Analytics, LLC, "Market Monitor Report", Members Committee (October 28, 2026) at 35.
2 OATT Attachment M (PJM Market Monitoring Plan).
3 See *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, Order No. 861, 168 FERC ¶ 61,040 (2019); *order on reh'g*, Order No. 861-A; 170 FERC ¶ 61,106 (2020).
4 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.
5 175 FERC ¶ 61,231 (2021).
6 185 FERC ¶ 61,158 (2023).
7 189 FERC ¶ 61,060 (2024).

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Overview

Supply and Demand

Market Structure

- **Supply.** In the first nine months of 2026, 4,616 MW of new resources were added in the energy market, and 698 MW of resources were retired.
- The real-time hourly on peak average offered supply in the first nine months of 2026 increased by 1.1 percent, from the first nine months of 2025, from 142,851 MWh to 144,444 MWh.
- The day-ahead hourly on peak average offered supply in the first nine months of 2026 decreased by 1.5 percent, from the first nine months of 2025, from 151,275 MWh to 149,069 MWh.
- The real-time hourly average cleared generation in the first nine months of 2026 increased by 2.3 percent from the first nine months of 2025, from 100,136 MWh to 102,406 MWh.
- The day-ahead hourly average cleared supply in the first nine months of 2026, including INCs and UTCs, decreased by 0.1 percent from the first nine months of 2025 from 113,755 MWh to 113,649 MWh.
- **Demand.** The summer peak load in the first nine months of 2026 was 158,005 MWh (157,865 MWh with net exports) in the HE 1800 (EPT) on July 02, 2026, higher than the summer peak load in 2025, which was 156,256 MWh (158,789 MWh with net exports) in the HE 1800 (EPT) on June 23, 2025.
- The real-time hourly average load in the first nine months of 2026 increased by 3.4 percent from the first nine months of 2025, from 93,683 MWh to 96,845 MWh.
- The day-ahead hourly average cleared demand in the first nine months of 2026, including DECs and UTCs, increased by 0.6 percent from the first nine months of 2025, from 107,108 MWh to 107,794 MWh.

Market Behavior

- **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 hourly average submitted increment offer MW decreased by 5.1 percent and the cleared increment MW decreased by 14.5 percent in the first nine months of 2026 compared to the first nine months of 2025. The hourly average submitted decrement bid MW increased by 18.6 percent and the cleared decrement MW increased by 5.9 percent in the first nine months of 2026 compared to the first nine months of 2025. The hourly average submitted up to congestion bid MW decreased by 20.8 percent and the cleared up to congestion bid MW decreased by 23.2 percent in the first nine months of 2026 compared to the first nine months of 2025.

Market Performance

- **Generation Fuel Mix.** In the first nine months of 2026, generation from coal units increased 0.4 percent, generation from natural gas units increased 2.5 percent, generation from oil units increased 13.7 percent, generation from wind units increased 5.5 percent, and generation from solar units increased 20.1 percent compared to the first nine months of 2025.
- **Fuel Diversity.** The fuel diversity of energy generation in the first nine months of 2026, measured by the fuel diversity index for energy (FDI_e), increased 0.1 percent compared to the first nine months of 2025.
- **Marginal Resources.** In the PJM Real-Time Energy Market in the first nine months of 2026, coal units were 9.5 percent, natural gas units were 71.3 percent and wind units were 11.9 percent of marginal resources. In the first nine months of 2025, coal units were 7.6 percent, natural gas units were 77.9 and wind units were 10.3 percent of marginal resources.
- **Prices.** The real-time load-weighted average LMP in the first nine months of 2026 increased $24.47 per MWh, or 48.4 percent, from the first nine months of 2025, from $50.51 per MWh to $74.98 per MWh.

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The day-ahead load-weighted average LMP in the first nine months of 2026 increased $22.85 per MWh, or 45.8 percent, from the first nine months of 2025, from $49.88 per MWh to $72.73 per MWh.

- **Fast Start Pricing.** The real-time load-weighted average PLMP was $74.98 per MWh for the first nine months of 2026, which is 13.5 percent, $8.90 per MWh, higher than the real-time load-weighted average DLMP of $66.07 per MWh.
- **Components of Real-Time LMP.** In the PJM Real-Time Energy Market in the first nine months of 2026, 32.0 percent of the real-time load-weighted LMP was the result of gas costs, 18.8 percent was the result of transmission constraint violation penalty factors, 6.1 percent was the result of coal costs, and 5.4 percent was the result of the cost of emission allowances.
- **Components of Day-Ahead LMP.** In the PJM Day-Ahead Energy Market in the first nine months of 2026, 26.7 percent of the day-ahead load-weighted LMP was the result of decrement bids, 12.4 percent was the result of increment offers, 18.0 percent was the result of gas costs, and 6.0 percent was the result of coal costs.
- **Changes in Real-Time LMP.** Of the $24.47 per MWh increase in the real-time load-weighted average LMP, $8.81 per MWh (36.0 percent) was the transmission constraint penalty factor component of LMP, $5.73 per MWh (23.4 percent) was the fuel and consumables cost components of LMP, $1.71 per MWh (7.0 percent) was the sum of the markup, maintenance, and ten percent adder components of LMP, $3.32 per MWh (13.6 percent) was the emissions cost components of LMP, and $2.16 per MWh (8.8 percent) was the PJM's administrative operating reserve demand curve component of LMP. The pre-emergency demand response and price responsive demand component decreased by $0.17 per MWh, -0.7 percent of the increase in LMP. The administrative cap component decreased LMP by $0.23 per MWh, -1.0 percent of the increase in LMP.
- **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 average difference between day-ahead and real-time average prices was $1.80 per MWh in the first nine months of 2026, and $0.38 per MWh in the first nine months of 2025. The average difference between day-ahead and real-time load-weighted average LMP was $2.25 per MWh in the first nine months of 2026, and $0.63 per MWh in the first nine months of 2025. The difference between day-ahead and real-time average prices, by itself, is not a measure of the competitiveness or effectiveness of the day-ahead energy market.

Shortage

- **Shortage Intervals.** There were 345 intervals with five minute shortage pricing on 36 days in the first nine months of 2026. Of the 345 intervals, 40 occurred during cold weather from late January into early February, including Winter Storm Fern, for which PJM issued several emergency warnings and actions. Of the 345 intervals, 153 occurred from June 29 through July 15 during hot weather events for which PJM issued several emergency warnings and actions. Of the 345 intervals of shortage, three overlapped with synchronized reserve events.
- **SCED Shortage Intervals.** In the first nine months of 2026, there were 3,342 five minute intervals, or 4.3 percent of all five minute intervals, for which at least one RT SCED solution showed a shortage of reserves. In the first nine months of 2026, there were 1,213 five minute intervals, or 1.5 percent of all five minute intervals, for which more than one RT SCED solution showed a shortage of reserves. In the first nine months of 2026, PJM triggered shortage pricing for 345 five minute intervals, or 10.3 percent of all five minute intervals that showed a shortage in one of the RT SCED solutions.

Competitive Assessment

Market Structure

- **Aggregate Pivotal Suppliers.** The PJM energy market, at times, requires generation from pivotal suppliers to meet load, resulting in aggregate market power even when the HHI level indicates that the aggregate market is unconcentrated. Three suppliers were jointly pivotal in the day-ahead market on 261 days, 95.6 percent of the days, in the first nine months of

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2026 and 257 days, 94.1 percent of the days, in the first nine months of 2025. The overall frequency of pivotal suppliers rose in 2025 and the first nine months of 2026 due to an increase in the frequency of days with daily peak load above 130 GW.

- **Local Market Power.** In the first nine months of 2026, in the real-time market, the 500 kV system, 13 zones, and the PJM/MISO interface experienced congestion resulting from one or more constraints binding for 75 or more hours. For seven out of the top 10 congested facilities (by real-time binding hours) in the first nine months of 2026, the average number of suppliers providing constraint relief was three or fewer. There was a high level of concentration within the local markets for providing relief to the most congested facilities in the PJM Real-Time Energy Market. The local market structure was not competitive.

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 when the rules are designed and implemented properly. Offer capping levels have historically been low in PJM. In the day-ahead energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 1.9 percent in the first nine months of 2025 to 3.7 percent in the first nine months of 2026. In the real-time energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 1.4 percent in the first nine months of 2025 to 1.7 percent in the first nine months of 2026. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have had a significant impact on prices in the absence of local market power mitigation.
- The analysis of the application of the TPS test to local markets demonstrates that it is working to identify 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. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed promptly.
- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, including for reactive support. In the day-ahead energy market, for units committed for reliability reasons, offer-capped unit hours increased from 0.12 percent in the first nine months of 2025 to 0.26 percent in the first nine months of 2026. In the real-time energy market, for units committed for reliability reasons, offer-capped unit hours increased from 0.10 percent in the first nine months of 2025 to 0.53 percent in the first nine months of 2026. The low offer cap percentages for reliability commitments, relative to offer capping for transmission constraints, do not mean that units committed for reliability reasons do not have market power. All units manually committed for reliability have market power and all are committed on their least cost schedule as defined by PJM in the day-ahead and real-time markets.
- **Parameter Mitigation.** PJM applies operating parameter limits (PLS) to units that fail the TPS test and to all units during hot and cold weather alerts. In the first nine months of 2026, 23.5 percent of unit hours for units that failed the TPS test in the day-ahead market were committed on price-based schedules that were less flexible than their cost-based schedules. On days when cold weather alerts and hot weather alerts were declared, 27.9 percent of unit hours in the day-ahead energy market were committed on price-based schedules that were less flexible than their price PLS schedules. These units should be committed on their parameter limited schedules to resolve the market power issue. If PJM promptly implemented the FERC approved solution to address the failure to correctly apply market power mitigation, this issue would no longer occur.
- **Frequently Mitigated Units (FMU) and Associated Units (AU).** In the first nine months of 2026, no units qualified for an FMU adder. In 2025, 2024, 2023 and 2022, no units qualified for an FMU adder. In 2021, one unit qualified for an FMU adder.
- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. While the average markup

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index in the real-time market was -$0.03 when using unadjusted cost-based offers in the first nine months of 2026, some marginal units did have substantial markups. The highest markup for any marginal unit in the real-time market in the first nine months of 2026 was more than $1,000 per MWh and the highest markup in the first nine months of 2025 was more than $900 per MWh, using unadjusted cost-based offers.

- While the average markup index in the day-ahead market was $0.54 per MWh in the first nine months of 2026, some marginal units did have substantial markups. The highest markup for any marginal unit in the day-ahead market in the first nine months of 2026 was more than $900 per MWh.[8]
- **Markup.** The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion of costs in cost-based offers that are not short run marginal costs.

  The markup frequency distributions also show that a significant proportion of units were offered with high markups, consistent with an attempt to exercise market power.

Market Performance

- **Markup.** The markup conduct of individual owners and units has an identifiable impact on market prices. Markup is a key indicator of the competitiveness of the energy market.
- In the PJM Real-Time Energy Market in the first nine months of 2026, the unadjusted markup component (net of positive and negative markup components) of LMP was $0.65 per MWh or 0.8 percent of the PJM load-weighted average LMP. September had the highest unadjusted peak markup component, $6.25 per MWh, or 5.3 percent of the real-time peak hour load-weighted average LMP for September.
- In the PJM Day-Ahead Energy Market in the first nine months of 2026, the unadjusted markup component (net of positive and negative markup components) of LMP was $2.95 per MWh or 4.1 percent of the PJM load-weighted average LMP. August had the highest unadjusted peak markup component, $16.62 per MWh, or 26.2 percent of the day-ahead peak hour load-weighted average LMP for August.
- 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 represents noncompetitive economic withholding.
- **Markup and Local Market Power.** Comparison of the markup behavior of marginal units with TPS test results shows that for 3.6 percent of all real-time marginal unit intervals in the first nine months of 2026, the marginal unit had both local market power, as determined by the TPS test, and a positive markup. The marginal unit had local market power in 25.4 percent of all real-time marginal unit intervals in the first nine months of 2026. For 14.6 percent of all marginal unit intervals with local market power, the unit had a positive markup. This occurred in 7,185 intervals, or 9.1 percent of all real-time market intervals in the first nine months of 2026. The fact that units with market power had a positive markup means that the cost-based offer was not used, that a higher price-based offer was used, and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power.
- **Markup and Aggregate Market Power.** In the first nine months of 2026, pivotal suppliers in the aggregate market, committed in the day-ahead market and identified as one of three day-ahead aggregate pivotal suppliers, set real-time market prices with markups over $100 per MWh 79 marginal unit hours and 113 day-ahead market hours. Some of the marginal units had local market power, but were not offer capped due to issues with the method that PJM uses to select offer schedules for units that fail the TPS test. Some of the marginal units had aggregate market

8 The MMU identified an error in the PJM marginal resource identification algorithm within the day ahead clearing optimization in April 2024. The calculation of generator sensitivity factors requires accurate identification of marginal resources. The error was fixed by the PJM software vendor in March 2025. The MMU was unable to calculate the component breakdown for 2024 and the first quarter of 2025 due to the inaccurate identification of marginal resources.

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power, for which there is no offer capping, and some had both local and aggregate market power.

Recommendations

Market Power

- The MMU recommends that the market rules explicitly require that offers in the energy market be competitive, where competitive is defined to be the short run marginal cost of the units, including parameter limited schedules. The short run marginal cost should reflect opportunity cost when appropriate. The MMU recommends that the level of incremental costs includable in cost-based offers per the PJM Operating Agreement not exceed the short run marginal cost of the unit. (Priority: Medium. First reported 2009. Status: Not adopted.)

Fuel Cost Policies

- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic, and accurately reflect short run marginal costs. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved fuel cost policy. (Priority: Low. First reported 2020. Status: Not adopted.)
- The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to follow their approved fuel cost policy. (Priority: Medium. First reported 2020. Status: Not adopted.)

Cost-Based Offers

- The MMU recommends removal of all use of FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all maintenance costs from the Cost Development Guidelines. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of the operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced. (Priority: Medium. First reported 2020. Status: Partially adopted 2023.)
- The MMU recommends explicitly accounting for soak costs and changing the definition of the start heat input for combined cycles to include only the amount of fuel used from first fire to the first breaker close in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Partially adopted.)
- The MMU recommends that soak costs, soak time and the MWh produced during soaking be modeled separately. This will ensure that the time required for units to reach a dispatchable level is known and used in the unit commitment process instead of only being communicated verbally between dispatchers and generators. Separating soak costs from start costs and modeling the MWh produced during soaking allows for a better representation of the costs because it eliminates the need to simply assume the price paid for those MWh. (Priority: Medium. First reported 2022. Status: Not adopted.)
- The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)

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- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Low. First reported 2016. Status: Not adopted.)

Market Power: TPS Test and Offer Capping

- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. The TPS test application in the day-ahead energy market is not documented. (Priority: High. First reported 2015. Status: Partially adopted.)[9]
- The MMU recommends that PJM modify the process of applying the TPS test in the day-ahead energy market to ensure that all local markets created by binding constraints are tested for market power and to ensure that market sellers with market power are appropriately mitigated to their competitive offers. (Priority: High. First reported 2022. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the real-time market that were not offer capped at the time of commitment in the day-ahead market or at a prior time in the real-time market. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation and to ensure that capacity resources meet their obligations to be flexible, that capacity resources be required to use flexible parameters in all offers at all times. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation, PJM always use cost-based offers for units that fail the TPS test, and always use flexible parameters for all cost-based and all price-based offers during high load conditions such as cold and hot weather alerts and emergency conditions. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM require every market participant to make available at least one cost schedule based on the same hourly fuel type(s) and parameters at least as flexible as their offered price schedule. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be consistently positive or negative across the full MWh range of price and cost-based offers. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation, that PJM commit all resources that fail the TPS test on their cost-based offers, that the Market Seller designate the cost-based offer if there is more than one, and that PJM implement this solution as soon as possible. (Priority: High. First reported 2024. Status: Not adopted.)
- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM energy market except when cost-based offers exceed $1,000 per MWh, and retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999, 2017.)
- The MMU recommends the elimination of FMU and AU adders. 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: Partially adopted, 2014.)[10]

Offer Behavior

- The MMU recommends that resources not be allowed to violate the ICAP must offer requirement. The MMU recommends that PJM enforce the ICAP must offer requirement by assigning a forced outage to any unit that is derated in the energy market below its committed ICAP without an outage that reflects the derate. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that storage resources be subject to an enforceable ICAP must offer rule in the day-ahead and real-time energy markets that

9 The real-time market formula for determining the lowest cost schedule is documented. The day-ahead market formula for determining the lowest cost schedule is not documented.

10 The applicability of the FMU and AU adders is limited by the rule implemented in 2014 requiring that net revenues must fall below avoidable costs, but the possibility of FMU and AU adders is still part of the PJM Market Rules.

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reflects the limitations of these resources. (Priority: Medium. First reported 2020. Status: Not adopted.)

- The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM integrate all the outage reporting tools in order to enforce the ICAP must offer requirement, ensure that outages are reported correctly and eliminate reporting inconsistencies. Generators currently submit availability in three different tools that are not integrated, Markets Gateway, eDART and eGADS. (Priority: Medium. First reported 2022. Status: Not adopted.)
- The MMU recommends that gas generators be required to check with pipelines throughout the operating day to confirm that nominations are accepted beyond the NAESB deadlines, that gas generators be required to inform PJM about whether they have gas, and that gas generators be required to place their units on forced outage until the time that pipelines allow nominations to consume gas at a unit. (Priority: Medium. First reported 2022. Status: Not adopted.)

Capacity Resources

- The MMU recommends that capacity resources be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity market design. The operational parameters used by generation owners to indicate to PJM operators what a unit is capable of during the operating day should not determine capacity resource performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially adopted.)[11]
- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity resources. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that resources not be paid the daily capacity payment when unable to operate to their unit specific parameter limits. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not enforced at the time, or are based on inferior transportation service procured by the generator. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM require generators that violate their approved turn down ratio (by either using the fixed gen option or increasing their economic minimum) to use the temporary parameter exception process that requires market sellers to demonstrate that the request is based on a physical and actual constraint. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends: that gas generators be required to confirm, regularly during the operating day, that they can obtain gas if requested to operate at their economic maximum level; that gas generators provide that information to PJM during the operating day; and that gas generators be required to be on forced outage if they cannot obtain gas during the operating day to meet their must offer requirement as a result of pipeline restrictions, and they do not have backup fuel. As part of this, the MMU recommends that PJM collect data on each individual generator's fuel supply arrangements at least annually or when such arrangements change, and analyze the associated locational and regional risks to reliability. (Priority: Medium. First reported 2022. Status: Not adopted.)

11 Flexible parameter standards are in place for combined cycle and combustion turbine resources when operating on a parameter limited schedule, but not for other schedules or generating technologies.

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Accurate System Modeling

- The MMU recommends that PJM explicitly state its policy on the use of transmission constraint penalty factors including: the level of the penalty factors; the triggers for the use of the penalty factors; the appropriate line ratings, including duration, to trigger the use of penalty factors; the allowed duration of the violation and when the transmission constraint penalty factors will be used to set the shadow price. The MMU recommends that PJM end the practice of manual and automated discretionary reductions in the control limits on transmission constraint line ratings used in the market clearing software (SCED) and included in LMP. (Priority: Medium. First reported 2015. Status: Partially adopted 2020.)[12]
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, duration defined, 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 not use closed loop interface or surrogate constraints to artificially override nodal prices based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to shortage pricing; or for any other reason. (Priority: Medium. 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.[13] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM include in the tariff or 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.[14] [15] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP, even if the MW are settled to the generator. The MMU 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, even if the injection MW are settled to the load serving entity. (Priority: Low. First reported 2013. Status: Not adopted.)
- 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: Partially adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM increase the coordination of outage and operational restrictions data submitted by market participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM model generators' operating transitions, including soak time for units with a steam turbine, configuration transitions for combined cycles, and peak operating modes. (Priority: Medium. First reported 2019. Status: Not adopted.)

12 PJM created a more transparent process for transmission constraint penalty factors and added it to the tariff in 2020. Policies on reductions in control limits and the duration of violations remain discretionary and undocumented in the PJM Market Rules.

13 This recommendation was the result of load shed events in September, 2013. For detailed discussion, please see *2013 Annual State of the Market Report for PJM*, Volume 2: Section 3: Energy Market at 114 – 116.

14 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.

15 There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed. The general definition of a hub can be found in the PJM.com Glossary <http://www.pjm.com/Glossary.aspx>.

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- The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand (not based on operator load bias) including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM stop capping the system marginal price in RT SCED and LPC and instead limit the sum of violated reserve constraint shadow prices that are included in the determination of LMP in LPC to $1,700 per MWh. While PJM no longer caps prices in RT SCED, PJM continues to apply a cap to the system marginal price in the pricing run (LPC) under fast start pricing. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM adjust the ORDCs during spin events to reduce the reserve requirement for synchronized and primary reserves by the amount of the reserves deployed. (Priority: Medium. First reported 2021. Status: Not adopted.)

Transparency

- The MMU recommends that PJM clearly document the calculation of shortage prices and implementation of reserve price caps in the PJM manuals, including defining all the components of reserve prices, and all the constraints whose shadow prices are included in reserve prices. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM allow generators to report fuel type on an hourly basis in their offer schedules and to designate schedule availability on an hourly basis. (Priority: Medium. First reported 2015. Status: Partially adopted.)[16]
- The MMU recommends that PJM define clear criteria for operator approval of RT SCED cases, including shortage cases, that are used to send dispatch signals to resources, and for pricing, to minimize discretion. (Priority: High. First reported 2018. Status: Partially adopted.)[17]

Virtual Bids and Offers

- The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues. (Priority: Medium. First reported 2020. Status: Not adopted.)

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first nine months of 2026, including aggregate supply and demand, concentration ratios, aggregate pivotal supplier results, local three pivotal supplier test results, offer capping, markup, marginal units, the components of LMP, the components of changes in LMP, participation in demand response programs, virtual bids and offers, loads and prices.

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. In a competitive market, prices are directly related to input prices, the marginal cost to serve load. In the first nine months of 2026, LMP increased by $24.47 per MWh compared to the first nine months of 2025, or 48.4 percent. The transmission constraint penalty factor component increased by $8.81 per MWh, 36.0 percent of the increase in LMP, as a result of PJM reducing the line limits applied in SCED (control limits) below the actual line limits. The fuel cost components of LMP (the sum of gas, coal, oil, landfill gas, and consumables) increased by $5.73 per MWh, 23.4 percent of the increase in LMP. The pre-emergency demand response and price responsive demand component decreased by $0.17 per MWh, -0.7 percent of the increase in LMP. The emissions cost components of LMP, including opportunity costs for

16 Fuel type is reported by offer schedule, but it can be inaccurate on an hourly basis.

17 The PJM Market Rules clarify that shortage case approval will be based on RT SCED, but does not address RT SCED case choice or load bias.

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emissions limited resources, increased by $3.32 per MWh, 13.6 percent of the increase in LMP. The administrative cap component decreased LMP by $0.23 per MWh, -1.0 percent of the increase in LMP.

The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and illustrates the potential significance of the impact of the price elasticity of demand on prices. Energy market results in the first nine months of 2026 generally reflected supply-demand fundamentals, although the behavior of some participants both routinely and during high demand periods is noncompetitive economic withholding. Economic withholding occurs when generator offers are greater than competitive levels, the short run marginal cost of generation. In the first nine months of 2026, the sum of the markup, ten percent adder, and maintenance cost (not short run marginal cost) components increased by $1.71 per MWh or 7.0 percent of the increase in LMP. In the first nine months of 2026, PJM actions, in the form of transmission constraint penalty factors, significantly increased prices. In the first nine months of 2026, the transmission constraint penalty factor component increased LMP by $8.81 per MWh, 36.0 percent of the increase in LMP.

Data center load growth affects energy market prices. Increased demand without matching energy supply puts upward pressure on prices, all else equal. It is difficult to shield customers from the costs caused by data center load growth in the energy market. Energy market prices increase when data centers are added without adding corresponding generating capacity and its associated energy output, when any added generating capacity is not located electrically near the load, and when the output of that generating capacity does not match the pattern of data center load.

The potential for prolonged and excessively high administrative pricing in the energy market due to reserve penalty factors and transmission constraint penalty factors remains an issue that needs to be addressed.[18] The transmission constraint penalty factors are currently the second largest determinant of LMP after the marginal cost of gas. PJM has not experienced a prolonged load shedding event, but, if one were to occur, LMP could exceed $3,700 per MWh for the entire event.

With or without a capacity market, energy market design must permit shortage pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised and to ensure no shortage pricing when such pricing is not consistent with market conditions. The point of shortage pricing is to ensure that the price of energy and reserves reflects the actual marginal cost of supply. The point of shortage pricing is not to set prices to arbitrarily high levels based on subjective assertions about the value of lost load. Shortage pricing should not be based on estimates of the value of lost load (VOLL). Electricity is a necessity for customers and it is not the role of wholesale power market operators regulated by FERC to try to set prices so high that customers must do without electricity. That is more like price gouging than shortage pricing. Shortage pricing implemented to increase generators' revenue is not consistent with a competitive market design. Changes in the market, like data center load growth and renewable energy growth, do not imply that PJM's current shortage pricing levels are too low. Artificially increasing energy market prices through market design changes is not a solution for managing either data center load growth or renewable energy growth. Load growth, largely driven by new data centers in the PJM region, increased the frequency of energy market shortages in 2025 and the first nine months of 2026.[19] Arbitrarily increasing shortage pricing during shortage events by raising the administrative prices on the demand curve for reserves (Operating Reserves Demand Curve or ORDC), as PJM proposes in the Reserve Certainty Senior Task Force (RCSTF), will increase the costs imposed on all customers from data center load growth, counter to the Principles of the PJM governors and the White House, as well as the Ratepayer Protection Pledge.[20] [21] Data centers are already raising energy market costs to all customers by increasing load, specifically increasing the frequency of emergency high load alert events, and straining the transmission

18 177 FERC ¶ 61,209 (2021).

19 See PJM. "PJM Load Forecast Accuracy Report," (May 29, 2025) <https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/2026-load-forecast-accuracy-report.pdf>.

20 See Statement of Principles Regarding PJM, National Energy Dominance Council and PJM State Governors (February 15, 2026), <https://www.energy.gov/documents/statement-principles-regarding-pjm>.

21 See Fact Sheet: President Donald J. Trump Advances Energy Affordability with the Ratepayer Protection Pledge, The White House (March 4, 2026); Ratepayer Protection Pledge, The White House (March 4, 2026), <https://www.whitehouse.gov/fact-sheets/2026/03/fact-sheet-president-donald-j-trump-advances-energy-affordability-with-the-ratepayer-protection-pledge/>.

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system. PJM's proposals will undermine the efforts of the Principles and the Pledge by changing the market design in a way that exacerbates the higher energy costs of data centers imposed on other customers.

Shortage pricing for price signals that reflect market conditions and actual short run marginal costs during periods of reserve or energy shortages is consistent with a competitive market design. Shortage pricing is part of an appropriate pricing structure facing both load and generation owners in a working wholesale electric power market design. Shortage pricing must be designed to ensure that market prices reflect actual market conditions, that shortage pricing reflects actual short run marginal costs, that shortage pricing occurs with transparent triggers based on measured reserve levels and transparent prices, that shortage pricing only occurs when shortage exists, that shortage pricing not be excessive or punitive, that shortage pricing recognize that electric power serves a unique and critical role for customers, and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative shortage pricing is a key link between energy and capacity markets.

PJM defined inputs to the dispatch tools, particularly RT SCED, have substantial effects on energy market outcomes. Transmission line ratings in SCED, transmission constraint penalty factors, load forecast bias, hydro resource schedules, fast start pricing, and the treatment of demand resources change the dispatch of the system, affect prices, and can create significant price increases, particularly through transmission constraint penalty factors. PJM operator interventions to reduce the control limits on transmission constraint line ratings in RT SCED unnecessarily trigger transmission constraint penalty factors and significantly increase prices. The transmission constraint penalty factor contribution to the load-weighted average LMP in the first nine months of 2026 was $14.11 per MWh or $9.0 billion of the total $47.6 billion cost of real-time load. In the first nine months of 2026, the transmission constraint penalty factor contribution to the cost of real time load was more than five times higher than the $1.41 billion of energy uplift charges. Most of the LMP costs due to transmission constraint penalty factors occurred during Winter Storm Fern. During peak load conditions, there were significant power flows on several high voltage constraints, including Bedington – Black Oak and BC/PEPCO Doubles. This led to constraint violations in both the day-ahead and real-time energy markets. A majority of the real-time violations were the result of PJM reducing the line rating in SCED. The high constraint shadow prices that result from the application of the transmission constraint penalty factor on high voltage constraints have a larger and broader effect on LMP throughout the market than lower voltage constraints. Differences between day-ahead and real-time unit commitments contributed to these issues, and differences between day-ahead and real-time market pricing also resulted from the different transmission constraint penalty factors used in the day-ahead dispatch run and pricing run.

There were also constraint violations for several hours on May 26, 2026, for multiple 230kV constraints in Data Center Alley during a transmission line outage. Pricing during this event contributed to a record day in UTC profits for the first six months of 2026, which must be paid for by customers through higher prices or balancing congestion charges. In the first nine months of 2026, the control limit used in RT SCED for 88 percent of violated transmission constraint intervals was less than 100 percent of the actual line limit, with an average reduction of 5.1 percent. If the control limits had not been artificially reduced and everything else remained unchanged, the transmission constraint penalty factor's contribution to the load-weighted average LMP in first nine months of 2026 would have decreased by 99.6 percent from $14.11 to $0.06 per MWh.

The MMU recommends that PJM end the practice of manual and automated discretionary reductions in the control limits on transmission constraint line ratings used in the market clearing software (SCED) and included in LMP.

PJM's fast start pricing rules, implemented on September 1, 2021, inappropriately disconnected pricing from dispatch instructions and despite the stated goal of reducing overall uplift, created a greater reliance on uplift rather than price as an incentive to follow PJM's instructions. In the first nine months of 2026, the pricing run LMP (PLMP) exceeded the dispatch run LMP (DLMP) by $8.90 per MWh, 13.5 percent, in the real-time market. The

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large difference resulted in part from the interaction between high fuel costs during Winter Storm Fern and PJM's fast start pricing rules. The fuel costs included in the no load offer for fast start CTs were added to the LMP in the pricing run, creating a significant difference. The difference also resulted during the hot weather events in July and September. The fast start pricing run resulted in constraint violations and reserve requirement shortages that did not occur in the actual, or dispatch run, market dispatch. Fast start pricing creates distortions in efficient market pricing based on an infeasible, inaccurate market solution. The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs using fast start pricing prioritizes minimizing uplift over minimizing production costs.[22] The tradeoff exists because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. Units that start in one hour are not actually fast start units, and their commitment costs are not marginal in a five minute market. The differences between the actual LMP and the fast start LMP distort the incentive for market participants to behave competitively and to follow PJM's dispatch instructions. PJM pays uplift in an attempt to counter the distorted incentives inherent in fast start pricing. PJM also uses the pricing run to implement administrative pricing rules that are not related to fast start pricing. Specifically, PJM uses lower day-ahead transmission constraint penalty factors in the pricing run than in the dispatch run and implements system marginal price capping in the pricing run. Every difference between the dispatch run and the pricing run introduces another inefficiency in the market. In the four years since fast start pricing was introduced, the market has not responded with new entry of fast start units despite consistently higher LMPs when a fast start unit sets price.

The energy market requires more flexible operation of the dispatchable fleet as wind and solar resource penetration grows. Since 2018, PJM has argued that the way to incent investment in flexible units is to increase reserve requirements and to increase the administrative prices defined in the ORDCs. In fact, higher LMPs due to higher ORDCs would benefit inflexible units. Providing windfall gains to all generation through higher LMPs during more frequent reserve shortages is not an effective incentive for flexibility.

The question of how to provide market incentives for investment in flexibility, and for operating to the full capability of that flexibility should be addressed directly. Are units inflexible because they are old and inefficient, because they face gas pipeline constraints, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? Are units inflexible because the PJM software does not model combined cycle transitions?

A direct solution would include improved modelling of generator capabilities, so that PJM can send more targeted dispatch signals that generators are consistently capable of following. A direct solution would include targeted reforms to PJM software, like multi-interval dispatch and combined cycle modelling that would directly address PJM energy market performance. A direct solution would include stronger standards in the PJM Market Rules for performance of resources to their actual physical parameters. These reforms would be more efficient and effective than simply raising prices across the board.

The relationship between supply and demand is referred to as supply-demand fundamentals, or economic fundamentals, or market structure. The market structure of the PJM aggregate energy market is only partially competitive because aggregate market power does exist for a significant number of hours. The HHI is not a definitive measure of structural market power. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. It is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. Even a low HHI may be consistent with the exercise of market power with a low price elasticity of demand. The current market power mitigation rules for the PJM energy market rely on the assumption that the ownership structure of the aggregate market ensures competitive outcomes at all times. This assumption requires that the total demand for energy can be met without

22 See 173 FERC ¶ 61,244 (2020).

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the supply from any individual supplier or from a small group of suppliers. This assumption is not correct. There are pivotal suppliers in the aggregate energy market with increasing frequency as daily peak loads increase. The frequency of days with aggregate pivotal suppliers was 261 days, or 95.6 percent, in the first nine months of 2026, compared to 94.1 percent in the first nine months of 2025. High markups for some units demonstrate the potential to exercise market power both routinely and during high demand conditions. In the first nine months of 2026, pivotal suppliers in the aggregate market, committed in the day-ahead market and identified as one of three day-ahead aggregate pivotal suppliers, set real-time market prices with markups over $100 per MWh for 946, or 0.4 percent of, marginal unit intervals. The existing market power mitigation measures do not address aggregate market power. The MMU is developing an aggregate market power test and will propose market power mitigation rules to address aggregate market power.

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.[23] However, there are issues with the application of market power mitigation in the day-ahead energy market and the real-time energy market when market sellers fail the TPS test. The Commission recognized some of these issues in its order issued on June 17, 2021, but failed to address them in its November 30, 2023 order.[24] [25] Many of these issues can be resolved by simple rule changes. PJM filed and, on October 25, 2024, FERC accepted a proposal that requires that sellers that fail the TPS test be offer capped at their cost-based offers and that operating parameters will be mitigated.[26] That order has no current effect because FERC approved the PJM filing that linked, for no logical reason, implementing the improved rules to PJM's adoption of a software improvement, with no defined date. The flawed rules remain in place. There is no reason to delay implementation of the FERC approved rules until PJM addresses combined cycle modelling which has been discussed since at least 2018 and has been continually delayed for multiple years.[27] [28] The changes would decrease the solution time for the day-ahead market and enhance market efficiency. The approved approach should be implemented as soon as possible to help ensure effective market power mitigation.

The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. A competitive offer is equal to short run marginal costs. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer, under the PJM Market Rules, is not currently correct. The definition, that all costs that are related to electric production are short run marginal costs, is not clear or correct. All costs and investments for power generation are related to electric production. Under this definition, unit owners are allowed to include costs in cost-based energy offers that are not short run marginal costs in offers, especially maintenance costs. This issue can be resolved by simple rule changes to incorporate a clear and accurate definition of short run marginal costs. This rule also had unintended consequences for market seller offer caps in the capacity market. Maintenance costs includable in energy offers cannot be included in capacity market offer caps based on avoidable costs. As a result, capacity market offer caps based on net avoidable costs were lower than they would have been if maintenance costs had been correctly included in avoidable costs rather than incorrectly defined to be part of short marginal costs of producing energy and includable in energy offers.

A competitive power market will result in higher prices when fuel costs increase and in lower prices when fuel costs decrease. A competitive market will not result in higher prices when markups increase based on market power, or when PJM selects a price-based offer including a markup rather than a cost-based offer when there is local market power, or when PJM artificially triggers transmission constraint penalty factors. 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

23 The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.
24 See 175 FERC ¶ 61,231 (2021).
25 185 FERC ¶ 61,158 (2023).
26 189 FERC ¶ 61,060 (2024).
27 See PJM, "GE Feedback on MGSTF Design Components," Modeling Generation Senior Task Force (May 21, 2018).
28 See PJM, "nGEM Enhanced Combined Cycle (ECC) model Implementation Timeline," Combined Cycle Modelling Education Workshop (October 20, 2022).

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not always the case in the first nine months of 2026 or prior years. Given the design of the energy market which can permit the exercise of aggregate and local market power, some participants' offer behavior results in the exercise of market power in the energy market. This is a reason to use correctly defined short run marginal cost as the sole basis for cost-based offers, to correct the offer capping process for resources with local market power, to implement an aggregate market power test, to end PJM's use of reduced line ratings in SCED to trigger the use of transmission constraint penalty factors, and to end fast start pricing. The energy market prices are greater than competitive market prices as a result both of the exercise of market power and PJM's extensive administrative interventions in the energy market. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2026.

Supply and Demand

Market Structure

Supply

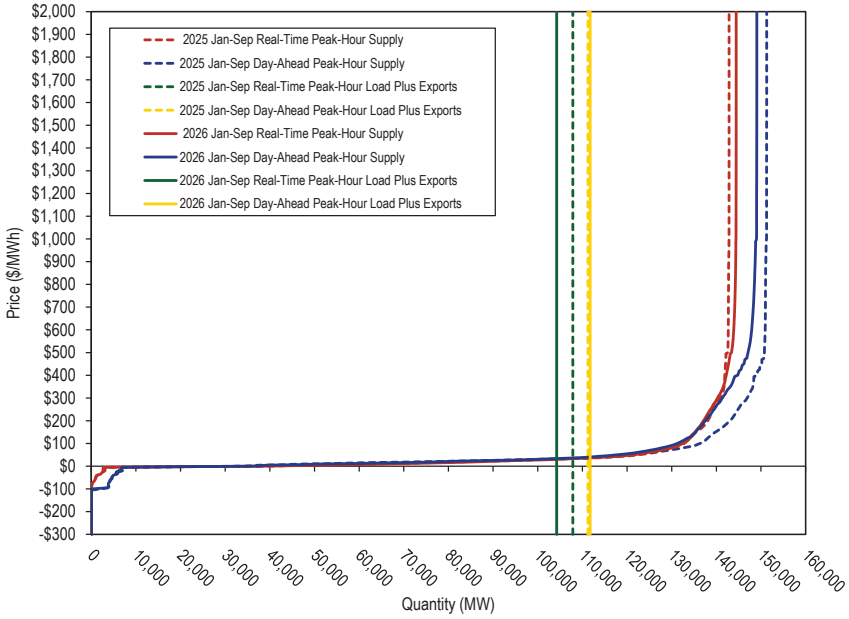
Supply includes physical generation, imports and virtual transactions.

In the first nine months of 2026, 4,616 MW of new resources were added in the energy market, and 698 MW of resources were retired.

Figure 3-1 shows real-time and day-ahead hourly supply curves for the first nine months of 2025 and 2026.[29] The real-time supply curve includes hourly on peak average offers. [30] The real-time supply curve only includes available MW from units that are online or have a notification plus start time that is no more than one hour. The day-ahead supply curve shows all available hourly on peak average offers.

The real-time hourly on peak average offered supply in the first nine months of 2026 increased by 1.1 percent, from the first nine months of 2025, from 142,851 MWh to 144,444 MWh. The day-ahead hourly on peak average offered supply in the first nine months of 2026 decreased by 1.5 percent, from the first nine months of 2025, from 151,275 MWh to 149,069 MWh.

Figure 3-1 Real-time and day-ahead hourly supply curves: January through September, 2025 and 2026



29 Real-time supply includes real-time generation offers and import MWh.
30 PJM typically considers weekdays from 0700 to 1100 to be on peak, excluding holidays.

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Figure 3-2 shows the typical dispatch range.

Figure 3-2 Typical dispatch range of supply curves

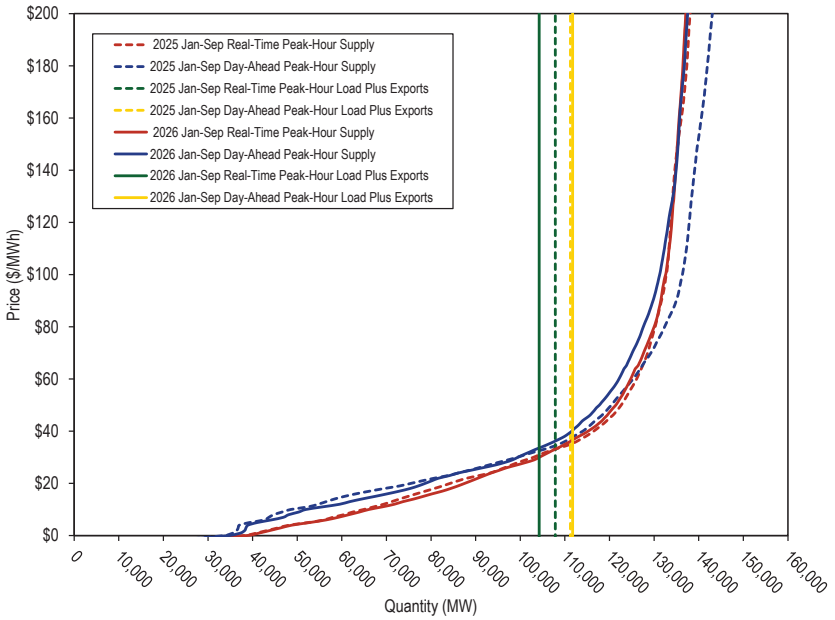


Table 3-2 shows the price elasticity of the real-time supply curve for the peak hours for the first nine months of 2020 through 2026 by load level.[31]

The real-time supply curve in the first nine months of 2026 was most elastic in the 95 to 115 GW range at 0.341, which was less elastic than the supply curve in the 95 to 115 GW range in the first nine months of 2025, with an elasticity of 0.387.

The price elasticity of the supply curve measures the responsiveness of the quantity supplied to a change in price:

The supply curve is defined to be elastic when elasticity is greater than 1.0. The quantity supplied is more sensitive to changes in price the higher the elasticity. Although the aggregate supply curve may appear flat as a result of the wide range in prices and quantities, the supply curve is inelastic throughout.

Table 3-2 Price elasticity of the real-time on peak average supply curve

	GW				
Jan-Sep	Min - 75	75 - 95	95 - 115	115 - 135	135 - Max
2020	0.138	0.643	0.686	0.039	0.004
2021	0.089	0.657	0.502	0.050	0.007
2022	0.046	0.556	0.384	0.102	0.012
2023	0.096	0.361	0.428	0.020	0.005
2024	0.108	0.316	0.378	0.032	0.008
2025	0.061	0.428	0.387	0.053	0.009
2026	0.066	0.335	0.341	0.048	0.013

Real-Time Supply

In the PJM Real-Time Energy Market, there are three types of supply offers:[32]

- **Self Scheduled Generation Offer.** Offer to supply a fixed block of MW, as a price taker, from a unit that may also have a dispatchable component above the fixed MW.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MW and corresponding offer prices from a 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

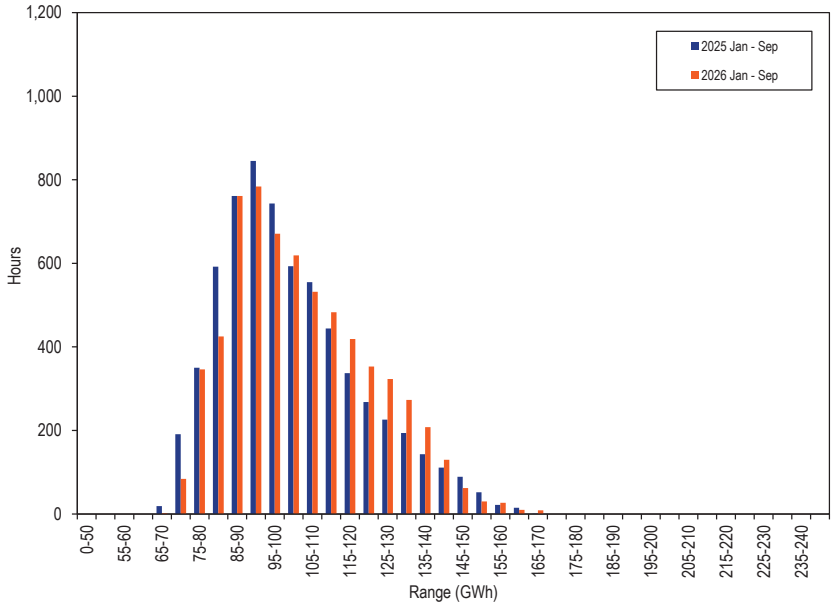
Figure 3-3 shows the hourly distribution of the real-time generation plus imports in the first nine months of 2025 and 2026.

31 The price elasticity results have been corrected from previous reports.

32 Generation data are the net MWh injections and withdrawals MWh at every generation bus in PJM.

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Figure 3-3 Distribution of real-time generation plus imports: January through September, 2025 and 2026[33]



PJM Real-Time Average Cleared Supply

Table 3-3 shows the real-time hourly average cleared supply and its standard deviation in the first nine months of 2026.

The real-time hourly average cleared generation in the first nine months of 2026 increased by 2.3 percent from the first nine months of 2025, from 100,136 MWh to 102,406 MWh. This was the highest cleared generation for the first nine months of any year since the start of the PJM markets.

The real-time hourly average cleared supply including gross imports in the first nine months of 2026 increased by 2.6 percent from the first nine months of 2025, from 102,018 MWh to 104,672 MWh. This was the highest cleared generation plus imports for the first nine months of any year since the start of the PJM markets.

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

Table 3-3 Real-time hourly average generation and generation plus imports: January through September, 2001 through 2026

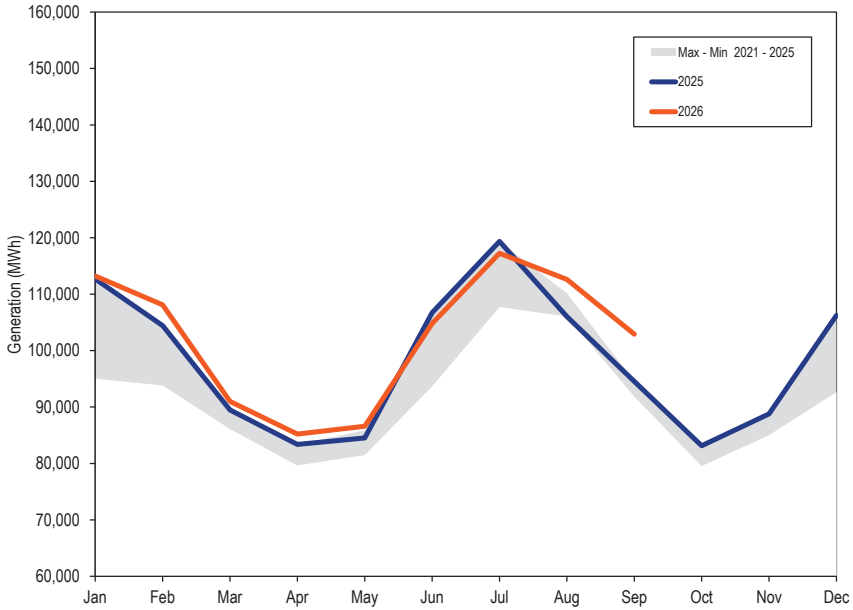
	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
Jan-Sep	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2001	30,304	5,216	33,299	5,571	NA	NA	NA	NA
2002	34,467	8,217	38,207	8,540	13.7%	57.5%	14.7%	53.3%
2003	37,211	6,556	40,815	6,526	8.0%	(20.2%)	6.8%	(23.6%)
2004	45,888	11,035	49,990	11,185	23.3%	68.3%	22.5%	71.4%
2005	81,095	16,710	86,330	17,216	76.7%	51.4%	72.7%	53.9%
2006	84,260	14,696	88,621	15,399	3.9%	(12.1%)	2.7%	(10.5%)
2007	87,297	14,853	91,647	15,668	3.6%	1.1%	3.4%	1.7%
2008	85,241	14,203	90,621	14,646	(2.4%)	(4.4%)	(1.1%)	(6.5%)
2009	78,850	14,242	83,986	14,728	(7.5%)	0.3%	(7.3%)	0.6%
2010	84,086	16,346	88,876	17,001	6.6%	14.8%	5.8%	15.4%
2011	86,966	17,369	91,746	18,276	3.4%	6.3%	3.2%	7.5%
2012	90,367	16,893	95,726	17,810	3.9%	(2.7%)	4.3%	(2.5%)
2013	90,432	15,792	95,639	16,729	0.1%	(6.5%)	(0.1%)	(6.1%)
2014	92,449	16,002	97,922	17,064	2.2%	1.3%	2.4%	2.0%
2015	91,901	16,711	97,896	17,863	(0.6%)	4.4%	(0.0%)	4.7%
2016	92,799	19,003	96,907	19,067	1.0%	13.7%	(1.0%)	6.7%
2017	91,658	15,964	93,639	16,216	(1.2%)	(16.0%)	(3.4%)	(15.0%)
2018	95,561	17,506	97,588	17,747	4.3%	9.7%	4.2%	9.4%
2019	95,531	17,206	96,659	17,378	(0.0%)	(1.7%)	(1.0%)	(2.1%)
2020	92,226	17,790	92,983	17,883	(3.5%)	3.4%	(3.8%)	2.9%
2021	95,792	18,039	96,519	18,173	3.9%	1.4%	3.8%	1.6%
2022	96,397	16,816	98,064	17,031	0.6%	(6.8%)	1.6%	(6.3%)
2023	93,886	15,544	95,437	15,561	(2.6%)	(7.6%)	(2.7%)	(8.6%)
2024	96,954	16,635	98,593	16,917	3.3%	7.0%	3.3%	8.7%
2025	100,136	18,290	102,018	18,551	3.3%	10.0%	3.5%	9.7%
2026	102,406	18,351	104,672	18,547	2.3%	0.3%	2.6%	(0.0%)

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PJM Real-Time Monthly Average Cleared Supply

Figure 3-4 compares the real-time monthly average generation in 2025 and the first nine months of 2026 with the historic five year range. The real-time monthly average generation was higher than the five year historical maximum for each month except June and July.

Figure 3-4 Real-time monthly average generation: 2025 through September 2026



Day-Ahead Supply

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

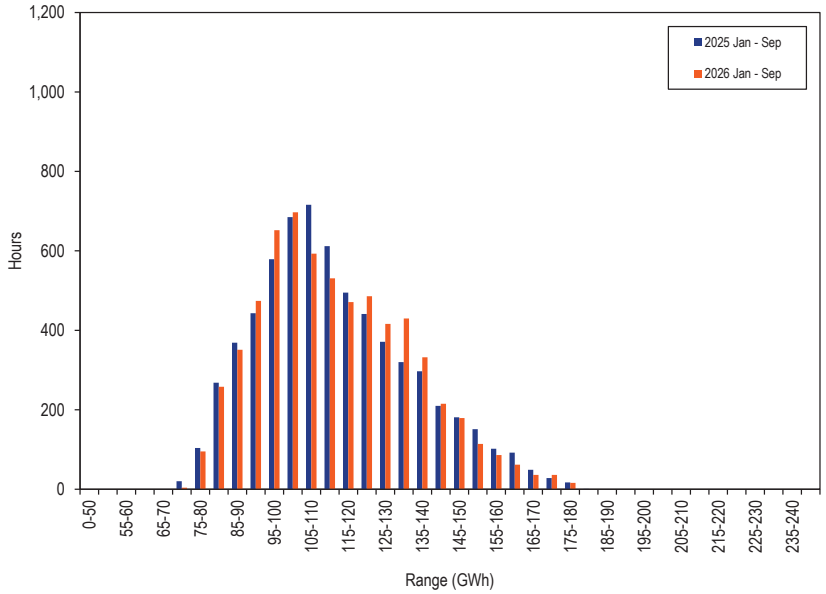
- **Self Scheduled Generation Offer.** Offer to supply a fixed block of MW, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MW and corresponding offer prices from a unit.
- **Increment Offer (INC).** Financial offer to supply MW 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 for a specific amount of MW between the transaction source and sink. An up to congestion transaction is a matched pair of an injection and a withdrawal.
- **Import.** An import is an external energy transaction for a specific MW amount 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.

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PJM Day-Ahead Supply Duration

Figure 3-5 shows the distribution of the day-ahead hourly cleared supply, including increment offers, up to congestion transactions, and gross imports in the first nine months of 2025 and 2026.

Figure 3-5 Distribution of day-ahead cleared supply plus imports: January through September, 2025 and 2026 [34]



PJM Day-Ahead Average Cleared Supply

Table 3-4 presents day-ahead hourly cleared supply summary statistics for each year for the first nine months of 2001 through 2026.

The day-ahead hourly average cleared supply in the first nine months of 2026, including INCs and UTCs, decreased by 0.1 percent from the first nine months of 2025 from 113,755 MWh to 113,649 MWh.

The day-ahead hourly average cleared supply in the first nine months of 2026, including INCs, UTCs and imports, increased by 0.1 percent from the first nine months of 2025, from 114,012 MWh to 114,124 MWh.

Table 3-4 Day-ahead hourly average cleared supply and cleared supply plus imports: January through September, 2001 through 2026

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
Jan-Sep	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2001	27,519	4,839	28,279	4,911	NA	NA	NA	NA
2002	30,080	10,982	30,629	10,992	9.3%	126.9%	8.3%	123.8%
2003	40,024	9,079	40,556	9,066	33.1%	(17.3%)	32.4%	(17.5%)
2004	56,103	13,380	56,799	13,349	40.2%	47.4%	40.0%	47.2%
2005	94,437	18,671	96,315	18,963	68.3%	39.5%	69.6%	42.1%
2006	100,888	18,061	103,029	18,071	6.8%	(3.3%)	7.0%	(4.7%)
2007	110,300	17,561	112,575	17,752	9.3%	(2.8%)	9.3%	(1.8%)
2008	107,367	16,601	109,811	16,717	(2.7%)	(5.5%)	(2.5%)	(5.8%)
2009	98,527	17,462	101,123	17,526	(8.2%)	5.2%	(7.9%)	4.8%
2010	108,309	23,295	111,059	23,464	9.9%	33.4%	9.8%	33.9%
2011	116,988	22,722	119,488	23,015	8.0%	(2.5%)	7.6%	(1.9%)
2012	135,213	18,553	137,670	18,788	15.6%	(18.3%)	15.2%	(18.4%)
2013	148,489	18,858	150,785	19,073	9.8%	1.6%	9.5%	1.5%
2014	161,137	23,922	163,431	24,080	8.5%	26.9%	8.4%	26.2%
2015	116,975	20,289	119,349	20,502	(27.4%)	(15.2%)	(27.0%)	(14.9%)
2016	133,089	23,414	134,881	23,403	13.8%	15.4%	13.0%	14.1%
2017	133,377	20,602	134,000	20,710	0.2%	(12.0%)	(0.7%)	(11.5%)
2018	116,068	21,950	116,471	21,939	(13.0%)	6.5%	(13.1%)	5.9%
2019	118,913	20,009	119,249	19,989	2.5%	(8.8%)	2.4%	(8.9%)
2020	115,205	20,611	115,386	20,577	(3.1%)	3.0%	(3.2%)	2.9%
2021	104,785	20,136	104,970	20,154	(9.0%)	(2.3%)	(9.0%)	(2.1%)
2022	110,598	19,369	110,875	19,455	5.5%	(3.8%)	5.6%	(3.5%)
2023	119,823	18,378	120,158	18,427	8.3%	(5.1%)	8.4%	(5.3%)
2024	112,192	19,975	112,477	20,061	(6.4%)	8.7%	(6.4%)	8.9%
2025	113,755	20,834	114,012	20,887	1.4%	4.3%	1.4%	4.1%
2026	113,649	20,408	114,124	20,431	(0.1%)	(2.0%)	0.1%	(2.2%)

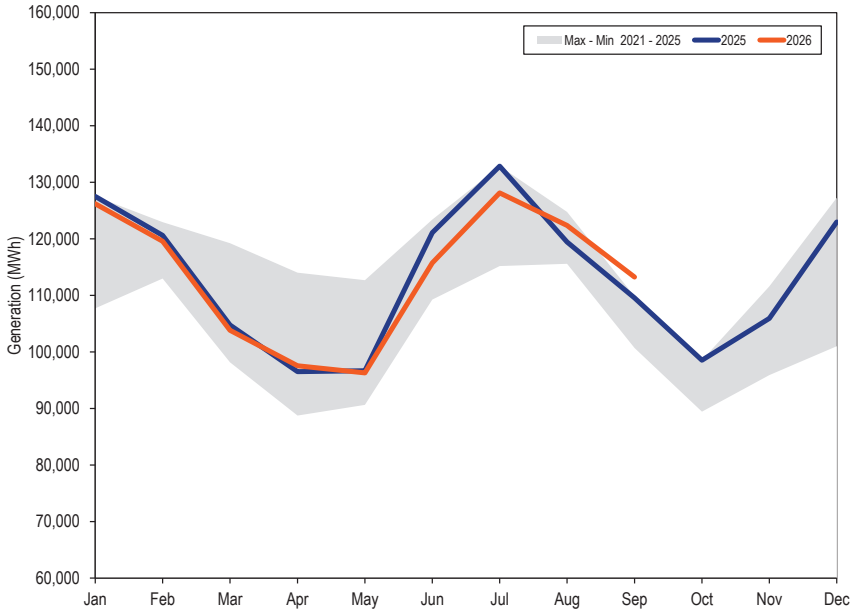
34 Each range on the horizontal axis excludes the start value and includes the end value.

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PJM Day-Ahead Monthly Average Cleared Supply

Figure 3-6 compares the day-ahead monthly average cleared supply including increment offers and up to congestion transactions in 2025 and the first nine months of 2026 with the historic five year range. The day-ahead monthly average generation for September was higher than the five year historical maximum for September.

Figure 3-6 Day-ahead monthly average cleared supply: 2025 through September 2026



Real-Time and Day-Ahead Supply

Table 3-5 presents summary statistics for day-ahead and real-time cleared supply in the first nine months of 2025 and 2026. The last two columns of Table 3-5 are the day-ahead cleared supply minus the real-time cleared supply. The first column is the total physical day-ahead generation less the total physical real-time generation and the second column is the total day-ahead cleared supply less the total real-time cleared supply. The total real-time cleared supply includes real-time generation and real-time imports. The total day-ahead cleared supply includes physical day-ahead generation, INCs, UTCs, and day-ahead imports.

The difference between total physical day-ahead average generation and total real-time average generation in the first nine months of 2026 decreased 624 MWh from the first nine months of 2025, from -999 MWh to -375 MWh. The difference between total day-ahead average supply and total real-time average supply in the first nine months of 2026 decreased 2,543 MWh from the first nine months of 2025, from 11,994 MWh to 9,452 MWh.

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Table 3-5 Day-ahead and real-time hourly cleared supply (MWh): January through September, 2025 and 2026

		Day Ahead					Real Time		Day Ahead Less Real Time	
	Jan-Sep	Generation	INC Offers	Up to Congestion	Imports	Total Supply	Generation	Total Supply	Generation	Supply
Average	2025	99,137	5,297	9,321	257	114,012	100,136	102,018	(999)	11,994
	2026	102,031	4,536	7,093	474	114,124	102,406	104,672	(375)	9,452
Median	2025	95,452	5,234	9,050	198	110,672	96,704	98,361	(1,252)	12,311
	2026	99,049	4,405	6,793	397	111,385	99,491	101,444	(442)	9,940
Standard Deviation	2025	18,693	1,734	3,360	228	20,887	18,290	18,551	403	2,336
	2026	19,132	1,659	2,752	334	20,431	18,351	18,547	781	1,884
Peak Average	2025	107,319	6,106	10,742	310	124,477	107,890	109,926	(572)	14,551
	2026	110,110	5,118	8,344	532	124,084	109,849	112,265	261	11,818
Peak Median	2025	104,073	5,960	10,457	259	120,987	104,759	106,529	(686)	14,458
	2026	107,906	5,000	8,151	474	121,989	107,678	110,015	228	11,974
Peak Standard Deviation	2025	18,208	1,592	3,091	250	18,968	17,948	18,166	260	802
	2026	18,616	1,606	2,567	369	18,801	17,980	18,045	636	755
Off-Peak Average	2025	91,983	4,590	8,078	211	104,862	93,356	95,104	(1,373)	9,759
	2026	94,897	4,022	5,990	423	105,340	95,833	97,967	(936)	7,373
Off-Peak Median	2025	88,979	4,500	7,742	155	101,454	90,331	91,908	(1,353)	9,547
	2026	91,821	3,931	5,504	348	101,536	93,026	94,816	(1,205)	6,720
Off-Peak Standard Deviation	2025	15,982	1,532	3,082	195	17,992	15,712	15,940	270	2,053
	2026	16,576	1,530	2,419	290	17,587	16,018	16,261	558	1,326

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Figure 3-7 shows the average cleared volumes of day-ahead and real-time supply by hour of the day in the first nine months of 2026. The day-ahead cleared supply consists of cleared MW of physical generation, imports, increment offers and up to congestion transactions. The real-time cleared supply consists of cleared MW of physical generation and imports.

Figure 3-7 Day-ahead and real-time cleared supply (Average volumes by hour of the day): January through September, 2026

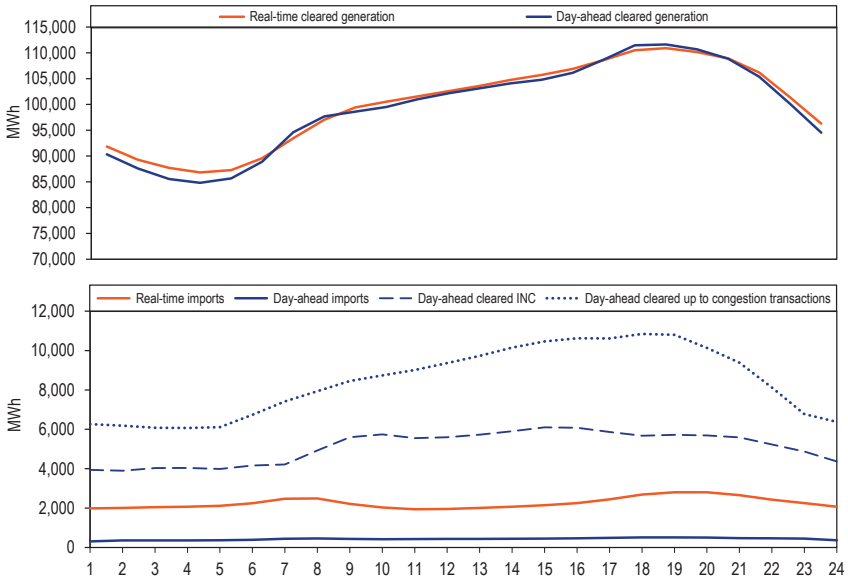
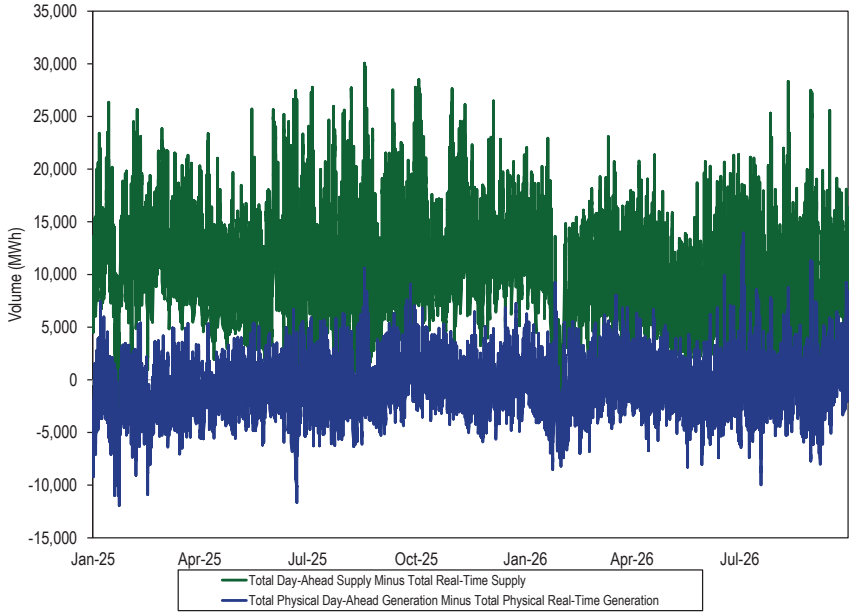


Figure 3-8 shows the difference between day-ahead and real-time daily average cleared supply in 2025 and the first nine months of 2026. The blue line is the total physical day-ahead generation less the total physical real-time generation, and the green line is the total day-ahead cleared supply less the total real-time cleared supply. The total real-time cleared supply includes real-time generation and real-time imports. The total day-ahead cleared supply includes physical day-ahead generation, INCs, UTCs, and day-ahead imports.

Figure 3-8 Difference between day-ahead and real-time daily average cleared supply: 2025 through September 2026



Demand

In the real-time energy market, demand includes physical load and exports. In the day-ahead energy market, demand includes physical load, exports, and virtual transactions.

Peak Demand

In the real-time energy market, demand refers to physical accounting load and exports, and in the day-ahead energy market, demand also includes virtual demand transactions.[35]

35 PJM reports peak load including accounting load plus an addback equal to PJM's estimated load drop from demand side resources. This will generally result in PJM reporting peak load values greater than accounting load values. PJM's load drop estimate is based on PJM Manual 19: Load Forecasting and Analysis," Attachment A: Load Drop Estimate Guidelines.

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Table 3-6 shows the seasonal peak load, net exports, real-time generation and the LMP for the peak load hour from 2004 through the first nine months of 2026.

The summer peak load in the first nine months of 2026 of 158,005 MWh (157,865 MWh with net exports) in the HE 1800 (EPT) on July 02, 2026, was higher than the summer peak load in 2025, of 156,256 MWh (158,789 MWh with net exports) in the HE 1800 (EPT) on June 23, 2025. The 2026 summer peak hour was the highest PJM peak load since the start of the PJM markets.

Table 3-6 Actual PJM peak load by season: 2004 through September 2026[36] [37]

Summer Peak Load Hour						Winter Peak Load Hour					
Date	Hour Ending	RT Load (MWh)	Net Export (MWh)	RT Generation (MWh)	LMP ($/MWh)	Date	Hour Ending	RT Load (MWh)	Net Export (MWh)	RT Generation (MWh)	LMP ($/MWh)
Tuesday, August 03, 2004	17	77,950	435	78,666	$90.55	Monday, December 20, 2004	19	96,838	1,796	98,797	$129.90
Tuesday, July 26, 2005	16	134,017	(2,206)	131,975	$156.02	Wednesday, December 14, 2005	19	110,632	(376)	110,406	$163.45
Wednesday, August 02, 2006	17	144,904	(782)	143,957	$404.80	Friday, December 08, 2006	19	106,866	873	108,002	$83.17
Wednesday, August 08, 2007	16	136,368	404	140,170	$471.98	Monday, February 05, 2007	20	119,072	(3,964)	115,252	$178.18
Monday, June 09, 2008	17	127,216	2,862	125,804	$155.67	Thursday, January 03, 2008	19	109,239	(641)	112,339	$130.11
Monday, August 10, 2009	17	123,900	163	127,229	$85.64	Friday, January 16, 2009	19	114,765	(2,316)	115,093	$80.73
Tuesday, July 06, 2010	17	133,297	(247)	136,442	$194.02	Tuesday, December 14, 2010	19	113,121	(1,688)	115,284	$137.02
Thursday, July 21, 2011	17	154,095	(5,906)	151,790	$162.28	Monday, January 24, 2011	8	108,156	(1,218)	109,394	$176.49
Tuesday, July 17, 2012	17	150,879	(4,825)	149,582	$203.72	Tuesday, January 03, 2012	19	119,450	109	122,802	$67.07
Thursday, July 18, 2013	17	153,790	(7,607)	149,806	$244.92	Tuesday, January 22, 2013	19	123,473	(3,412)	123,283	$119.20
Tuesday, June 17, 2014	18	138,448	(7,382)	134,914	$113.51	Tuesday, January 07, 2014	19	136,932	(9,127)	131,731	$386.36
Tuesday, July 28, 2015	17	140,266	(3,942)	139,450	$101.40	Friday, February 20, 2015	8	139,647	(6,994)	137,504	$381.93
Thursday, August 11, 2016	16	148,577	1,235	153,820	$128.83	Thursday, December 15, 2016	19	127,759	(2,946)	128,979	$107.06
Wednesday, July 19, 2017	18	142,387	3,166	148,409	$59.49	Monday, January 09, 2017	8	124,210	(1,054)	126,761	$67.72
Tuesday, August 28, 2018	17	147,042	3,238	154,067	$131.36	Friday, January 05, 2018	19	133,851	(403)	137,173	$164.15
Friday, July 19, 2019	18	148,228	3,253	154,542	$37.47	Thursday, January 31, 2019	8	134,060	1,077	138,744	$85.21
Monday, July 20, 2020	17	141,449	6,013	150,667	$74.91	Wednesday, January 22, 2020	8	116,761	4,230	123,609	$31.76
Tuesday, August 24, 2021	17	145,563	2,984	151,708	$243.98	Friday, January 29, 2021	9	114,457	3,200	120,648	$27.87
Wednesday, July 20, 2022	18	144,356	3,190	151,620	$204.29	Friday, December 23, 2022	19	131,474	3,340	136,132	$2,011.80
Thursday, July 27, 2023	18	144,215	7,211	151,896	$110.52	Friday, February 03, 2023	20	117,705	746	121,952	$56.22
Tuesday, July 16, 2024	18	148,890	508	152,864	$384.56	Wednesday, January 17, 2024	9	130,293	9,291	143,324	$103.66
Monday, June 23, 2025	18	156,256	2,533	162,599	$273.39	Wednesday, January 22, 2025	9	140,043	7,660	151,437	$355.76
Thursday, July 02, 2026	18	158,005	(140)	162,143	$1,621.76	Thursday, January 29, 2026	8	135,722	1,316	140,610	$295.93

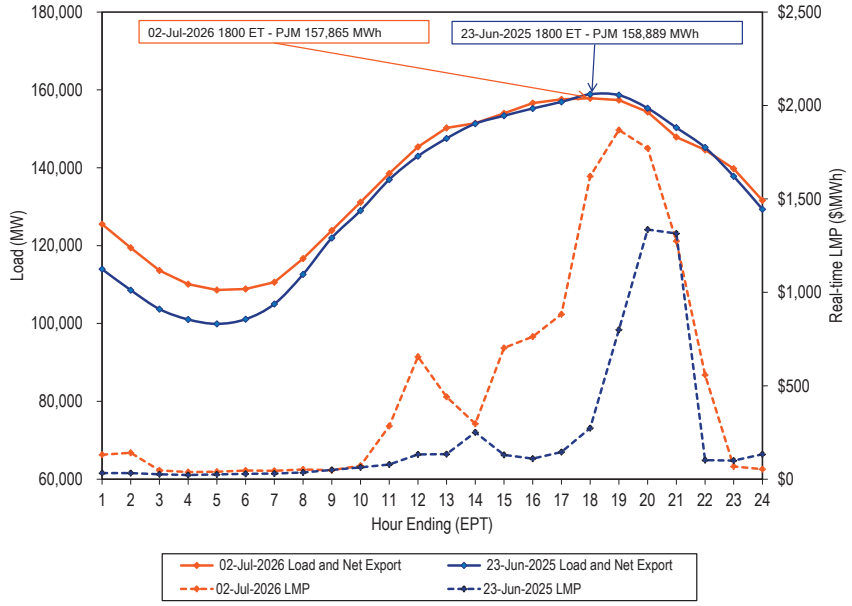
36 Peak loads shown are accounting load, without losses. See the *MMU Technical Reference for the PJM Markets*, at "Load Definitions," for detailed definitions of load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

37 Peak loads shown have been corrected to reflect the accounting load value excluding PJM loss adjustment. The values presented in this table do not include settlement adjustments made prior to January 1, 2017.

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Figure 3-9 compares prices and load plus net exports on the peak load days for the first nine months of 2025 and 2026. The real-time average LMP for June 23, 2025, peak load hour was $273.39 per MWh, and for July 2, 2026, peak load hour was $1,621.76 per MWh.

Figure 3-9 Peak load with net export day comparison



Real-Time Demand

In the PJM Real-Time Energy Market, there are two types of demand:[38]

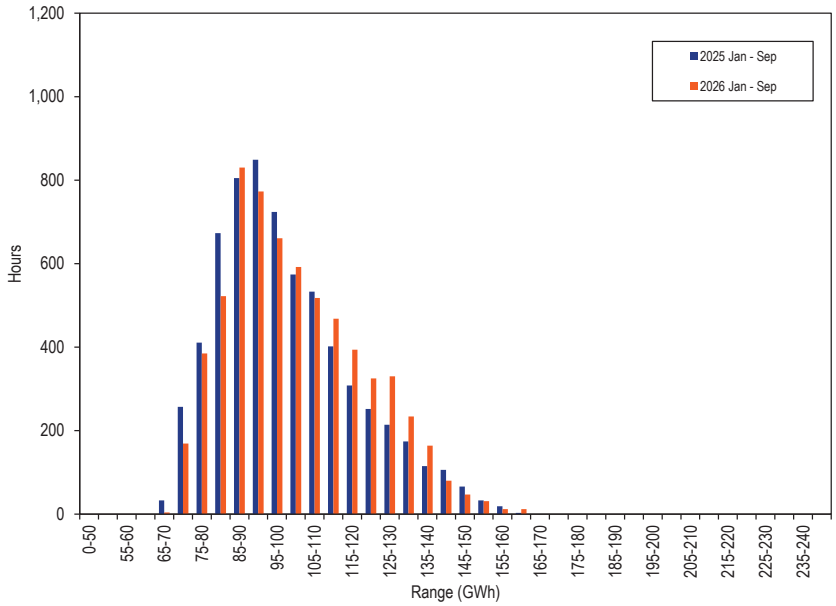
- **Load.** The actual MWh level of energy used by load within PJM.
- **Export.** An export is an external energy transaction scheduled from PJM to another balancing authority. A real-time export must have a valid OASIS reservation when offered, must have available ramp room to support the export, must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

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

PJM Real-Time Demand Duration

Figure 3-10 shows the distribution of the real-time hourly load plus gross exports in the first nine months of 2025 and 2026.[39]

Figure 3-10 Distribution of real-time load plus exports: January through September, 2025 and 2026[40]



39 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>.

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

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PJM Real-Time Average Demand

Table 3-7 presents real-time hourly demand summary statistics for the first nine months of 2001 through 2026.[41]

The real-time hourly average load in the first nine months of 2026 increased by 3.4 percent from the first nine months of 2025, from 93,683 MWh to 96,845 MWh. This was the highest real-time hourly average load for the first nine months of any year since the start of the PJM markets.

The real-time hourly average demand including exports in the first nine months of 2026 increased by 2.4 percent from the first nine months of 2025, from 100,114 MWh to 102,514 MWh. This was the highest real-time hourly average demand for the first nine months of any year since the start of the PJM markets.

Table 3-7 Real-time hourly average load and load plus exports: January through September, 2001 through 2026

	PJM Real-Time Demand (MWh)				Year to Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
Jan-Sep	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
2001	31,060	6,156	32,900	5,861	NA	NA	NA	NA
2002	35,715	8,688	37,367	8,878	15.0%	41.1%	13.6%	51.5%
2003	37,996	7,187	39,965	7,120	6.4%	(17.3%)	7.0%	(19.8%)
2004	45,294	10,512	49,176	11,556	19.2%	46.3%	23.0%	62.3%
2005	78,235	17,541	85,295	17,794	72.7%	66.9%	73.4%	54.0%
2006	80,717	15,568	87,326	16,147	3.2%	(11.2%)	2.4%	(9.3%)
2007	83,114	15,386	89,390	16,008	3.0%	(1.2%)	2.4%	(0.9%)
2008	80,611	14,389	87,788	14,893	(3.0%)	(6.5%)	(1.8%)	(7.0%)
2009	76,954	13,879	82,118	14,360	(4.5%)	(3.5%)	(6.5%)	(3.6%)
2010	81,068	16,209	86,994	16,687	5.3%	16.8%	5.9%	16.2%
2011	83,762	17,604	89,628	17,799	3.3%	8.6%	3.0%	6.7%
2012	88,687	17,431	93,763	17,329	5.9%	(1.0%)	4.6%	(2.6%)
2013	89,123	16,384	93,647	16,254	0.5%	(6.0%)	(0.1%)	(6.2%)
2014	90,567	16,662	96,015	16,518	1.6%	1.7%	2.5%	1.6%
2015	91,857	17,211	96,102	17,300	1.4%	3.3%	0.1%	4.7%
2016	90,599	18,183	95,340	18,571	(1.4%)	5.6%	(0.8%)	7.3%
2017	87,243	16,008	91,954	15,794	(3.7%)	(12.0%)	(3.6%)	(15.0%)
2018	91,905	17,064	95,795	17,245	5.3%	6.6%	4.2%	9.2%
2019	89,834	16,794	94,918	16,924	(2.3%)	(1.6%)	(0.9%)	(1.9%)
2020	85,886	17,201	91,356	17,464	(4.4%)	2.4%	(3.8%)	3.2%
2021	89,515	16,875	94,746	17,748	4.2%	(1.9%)	3.7%	1.6%
2022	90,514	16,367	96,196	16,581	1.1%	(3.0%)	1.5%	(6.6%)
2023	87,269	14,833	93,709	15,199	(3.6%)	(9.4%)	(2.6%)	(8.3%)
2024	90,917	16,529	96,746	16,478	4.2%	11.4%	3.2%	8.4%
2025	93,683	17,631	100,114	18,080	3.0%	6.7%	3.5%	9.7%
2026	96,845	17,469	102,514	18,080	3.4%	(0.9%)	2.4%	(0.0%)

41 Accounting load is used because accounting load is the load customers pay for in PJM settlements. 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. 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 the incorporation of marginal loss pricing in LMP.

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PJM Real-Time Monthly Average Demand

Figure 3-11 compares the real-time monthly average load plus exports in 2025 and the first nine months of 2026 with the historic five year range. The real-time monthly average load plus exports was higher than the five year historical maximum for each month except June and July.

Figure 3-11 Real-time monthly average hourly load plus exports: 2025 through September 2026

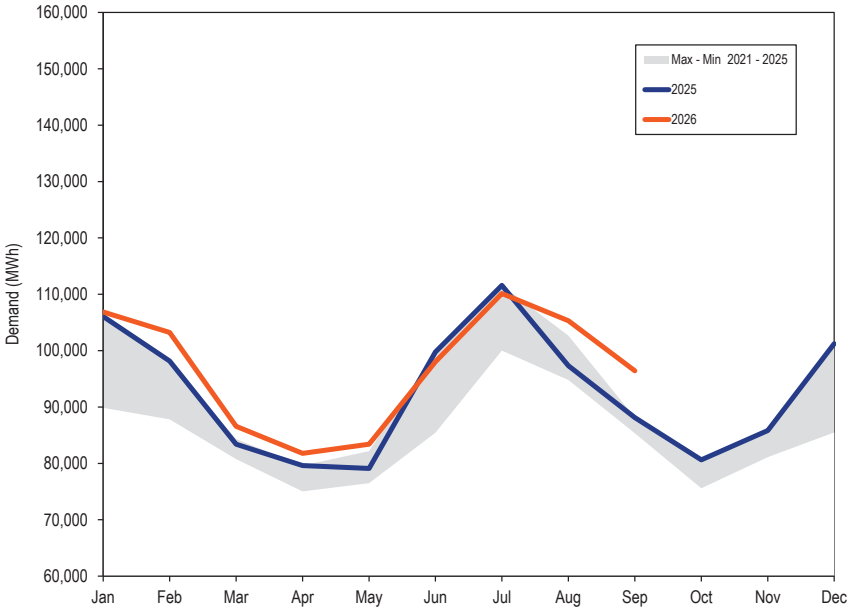
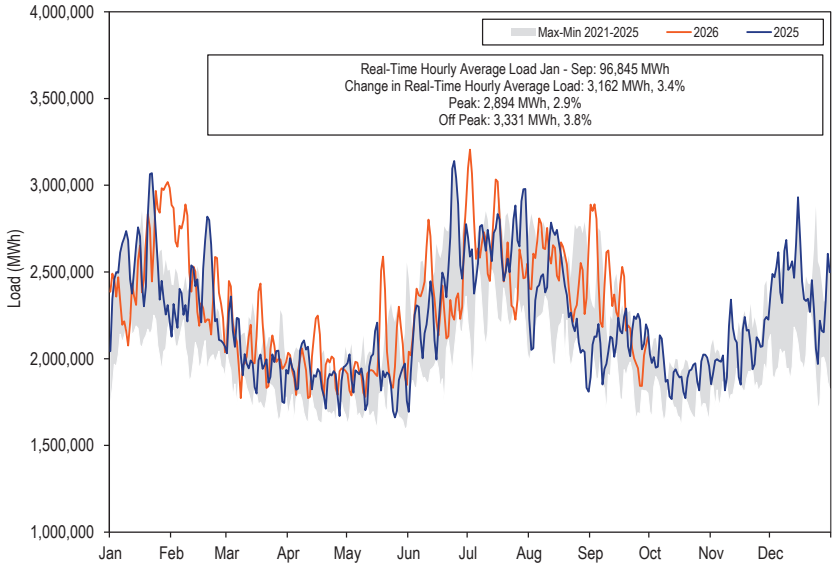


Figure 3-12 compares the real-time daily average load in 2025 and the first nine months of 2026, with the historic five year range.

Figure 3-12 Real-time daily load: 2025 through September 2026



The real-time load is significantly affected by weather conditions. Table 3-8 compares the monthly heating and cooling degree days in 2025 and the first nine months of 2026.[42] Heating degree days increased 0.8 percent compared to the first nine months of 2025. Cooling degree days increased 11.0 percent compared to the first nine months of 2025.

42 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). Reference: <https://www.eia.gov/energyexplained/units-and-calculators/degree-days.php>. This calculation was modified starting in 2024 Q3 from the method used in prior State of the Market Reports which was the PJM calculation method based on 60 degrees for heating degree days and 65 degrees for cooling degree days. 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.

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Table 3-8 Heating and cooling degree days: 2025 through September 2026

	2025		2026		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	985	0	986	0	0.1%	0.0%
Feb	720	0	750	0	4.2%	0.0%
Mar	370	2	365	4	(1.3%)	89.1%
Apr	173	10	130	39	(25.2%)	280.8%
May	21	31	58	70	180.2%	129.4%
Jun	1	302	0	254	(100.0%)	(16.1%)
Jul	0	433	0	393	0.0%	(9.2%)
Aug	0	242	0	327	0.0%	35.2%
Sep	0	139	0	199	0.0%	43.5%
Oct	128	15				
Nov	432	0				
Dec	837	0				
Jan-Sep	2,270	1,158	2,289	1,285	0.8%	11.0%

Day-Ahead Demand

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

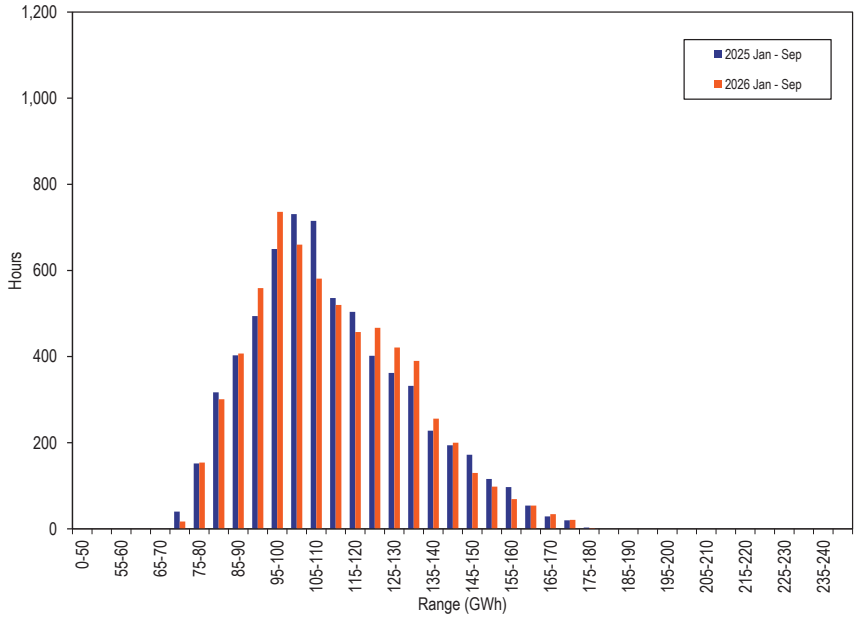
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP. Fixed-Demand Bids are included in Day-Ahead physical load.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero. Price-Sensitive Bids are included in Day-Ahead physical load.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero.
- **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.
- **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. 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 sum of the five types of cleared demand bids.

PJM Day-Ahead Demand Duration

Figure 3-13 shows the hourly distribution of the day-ahead cleared demand including DECs, UTCs and exports in the first nine months of 2025 and 2026.

Figure 3-13 Distribution of day-ahead cleared demand plus exports: January through September, 2025 and 2026[43]



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

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PJM Day-Ahead Average Demand

Table 3-9 shows day-ahead hourly average cleared demand including DECs, UTCs and exports in 2001 through the first nine months of 2026.

The day-ahead hourly average cleared demand in the first nine months of 2026, including DECs and UTCs, increased by 0.6 percent from the first nine months of 2025, from 107,108 MWh to 107,794 MWh.

The day-ahead hourly average cleared demand in the first nine months of 2026, including DECs, UTCs and exports, increased by 0.1 percent from the first nine months of 2025, from 111,552 MWh to 111,620 MWh.

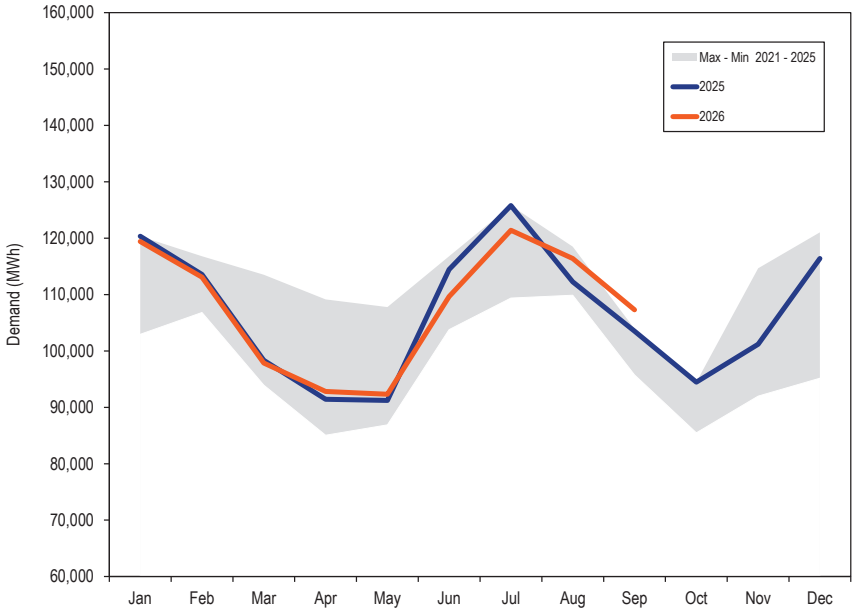
Table 3-9 Day-ahead hourly average cleared demand and demand plus exports: January through September, 2001 through 2026

	PJM Day-Ahead Demand (MWh)				Year to Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
Jan-Sep	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2001	33,944	7,016	34,444	6,817	NA	NA	NA	NA
2002	41,634	11,073	41,726	11,120	22.7%	57.8%	21.1%	63.1%
2003	45,371	8,377	45,477	8,354	9.0%	(24.3%)	9.0%	(24.9%)
2004	55,830	13,319	56,558	13,753	23.1%	59.0%	24.4%	64.6%
2005	93,525	19,126	96,302	19,455	67.5%	43.6%	70.3%	41.5%
2006	99,403	18,165	102,520	18,687	6.3%	(5.0%)	6.5%	(3.9%)
2007	107,295	17,580	110,711	17,949	7.9%	(3.2%)	8.0%	(3.9%)
2008	103,586	16,618	107,169	16,810	(3.5%)	(5.5%)	(3.2%)	(6.3%)
2009	96,020	16,995	99,084	17,117	(7.3%)	2.3%	(7.5%)	1.8%
2010	105,018	22,972	109,113	23,286	9.4%	35.2%	10.1%	36.0%
2011	113,724	22,444	117,533	22,651	8.3%	(2.3%)	7.7%	(2.7%)
2012	132,494	18,115	135,840	18,235	16.5%	(19.3%)	15.6%	(19.5%)
2013	145,139	18,667	148,444	18,696	9.5%	3.0%	9.3%	2.5%
2014	156,542	23,584	160,425	23,533	7.9%	26.3%	8.1%	25.9%
2015	113,555	19,789	116,912	19,957	(27.5%)	(16.1%)	(27.1%)	(15.2%)
2016	129,048	22,492	132,405	22,801	13.6%	13.7%	13.3%	14.2%
2017	128,453	20,002	131,572	20,158	(0.5%)	(11.1%)	(0.6%)	(11.6%)
2018	111,589	21,194	114,373	21,392	(13.1%)	6.0%	(13.1%)	6.1%
2019	114,133	19,233	117,048	19,465	2.3%	(9.3%)	2.3%	(9.0%)
2020	109,850	19,762	113,188	20,089	(3.8%)	2.7%	(3.3%)	3.2%
2021	99,788	19,097	102,947	19,632	(9.2%)	(3.4%)	(9.0%)	(2.3%)
2022	105,195	18,664	108,685	18,945	5.4%	(2.3%)	5.6%	(3.5%)
2023	113,807	17,840	117,715	17,977	8.2%	(4.4%)	8.3%	(5.1%)
2024	106,355	19,453	110,189	19,559	(6.5%)	9.0%	(6.4%)	8.8%
2025	107,108	19,979	111,552	20,243	0.7%	2.7%	1.2%	3.5%
2026	107,794	19,650	111,620	20,021	0.6%	(1.6%)	0.1%	(1.1%)

PJM Day-Ahead Monthly Average Demand

Figure 3-14 compares the day-ahead monthly average cleared demand including DECs and UTCs for 2025 and the first nine months of 2026, with the historic five year range. The day-ahead monthly average demand was lower than the five-year historical maximum for each month except September.

Figure 3-14 Day-ahead monthly average cleared demand: 2025 through September 2026



Real-Time and Day-Ahead Demand

Table 3-10 presents summary statistics for day-ahead and real-time cleared demand in the first nine months of 2025 and 2026. The last two columns of Table 3-10 are day-ahead cleared load and demand minus real-time cleared load and demand. The first of these two columns is the total physical day-ahead load (fixed demand plus cleared price-sensitive demand) less the

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physical real-time load. The second of these two columns is the total cleared day-ahead demand less the total cleared real-time demand (real-time load plus gross exports).

The difference between total physical day-ahead load and total real-time load in the first nine months of 2026 increased 689 MWh from the first nine months of 2025, from -1,302 MWh to -1,991 MWh. The difference between total day-ahead demand and total real-time demand in the first nine months of 2026 decreased 2,332 MWh from the first nine months of 2025, from 11,438 MWh to 9,107 MWh.

Table 3-10 Day-ahead and real-time demand (MWh): January through September, 2025 and 2026

		Day Ahead						Real Time		Day Ahead Less Real Time	
Jan-Sep	Year	Fixed Demand	Price Sensitive	DEC Bids	Up to Congestion	Exports	Total Demand	Load	Total Demand	Load	Demand
Average	2025	91,975	407	5,589	9,138	4,445	111,552	93,683	100,114	(1,302)	11,438
	2026	94,396	458	5,940	7,013	3,824	111,620	96,845	102,514	(1,991)	9,107
Median	2025	88,767	400	5,320	8,837	4,358	108,280	90,530	96,618	(1,363)	11,661
	2026	91,096	467	5,536	6,688	3,863	108,732	93,639	99,384	(2,076)	9,348
Standard Deviation	2025	17,083	86	2,004	3,246	1,137	20,243	17,631	18,080	(462)	2,163
	2026	17,176	90	2,203	2,689	1,060	20,021	17,469	18,080	(203)	1,941
Peak Average	2025	99,971	426	6,359	10,442	4,489	121,687	101,452	107,857	(1,055)	13,830
	2026	102,068	463	6,794	8,200	3,814	121,317	104,346	109,935	(1,816)	11,382
Peak Median	2025	96,890	422	6,209	10,219	4,344	118,323	98,093	104,605	(781)	13,718
	2026	99,461	476	6,505	7,918	3,809	119,097	102,134	107,822	(2,198)	11,275
Peak Standard Deviation	2025	16,219	86	1,955	2,991	1,214	18,359	16,963	17,691	(657)	668
	2026	16,226	94	2,325	2,555	1,110	18,546	16,785	17,607	(465)	939
Off-Peak Average	2025	84,982	390	4,915	7,998	4,406	102,690	86,890	93,344	(1,518)	9,347
	2026	87,621	454	5,186	5,966	3,834	103,069	90,221	95,961	(2,146)	7,108
Off-Peak Median	2025	82,065	379	4,603	7,673	4,367	99,587	83,805	90,319	(1,362)	9,267
	2026	84,326	462	4,858	5,455	3,920	99,379	86,940	92,893	(2,152)	6,486
Off-Peak Standard Deviation	2025	14,568	83	1,791	3,024	1,064	17,467	15,239	15,519	(588)	1,948
	2026	15,008	87	1,776	2,348	1,014	17,176	15,243	15,820	(148)	1,356

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Figure 3-15 shows the average cleared volumes of day-ahead and real-time demand in the first nine months of 2026. The day-ahead demand includes day-ahead load, decrement bids, up to congestion transactions, and day-ahead exports. The real-time demand includes real-time load and real-time exports.

Figure 3-15 Day-ahead and real-time demand (Average hourly volumes): January through September, 2026

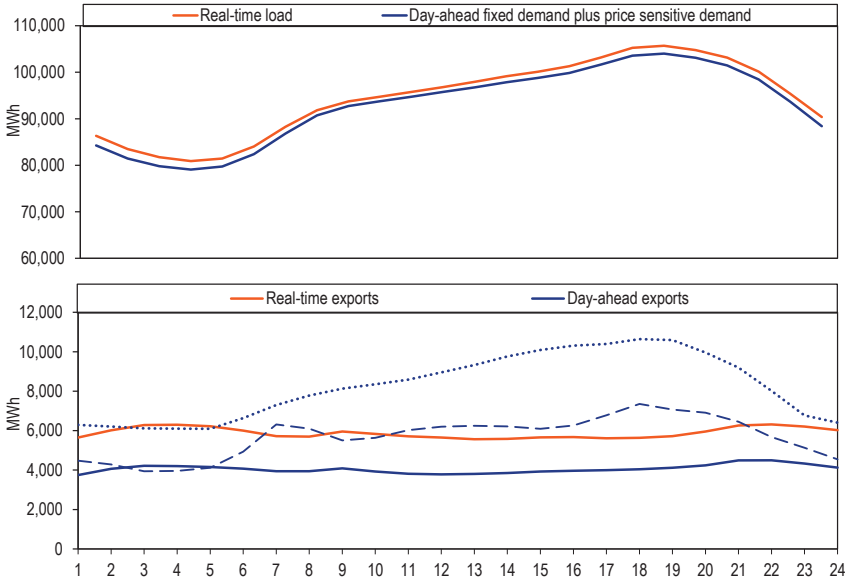
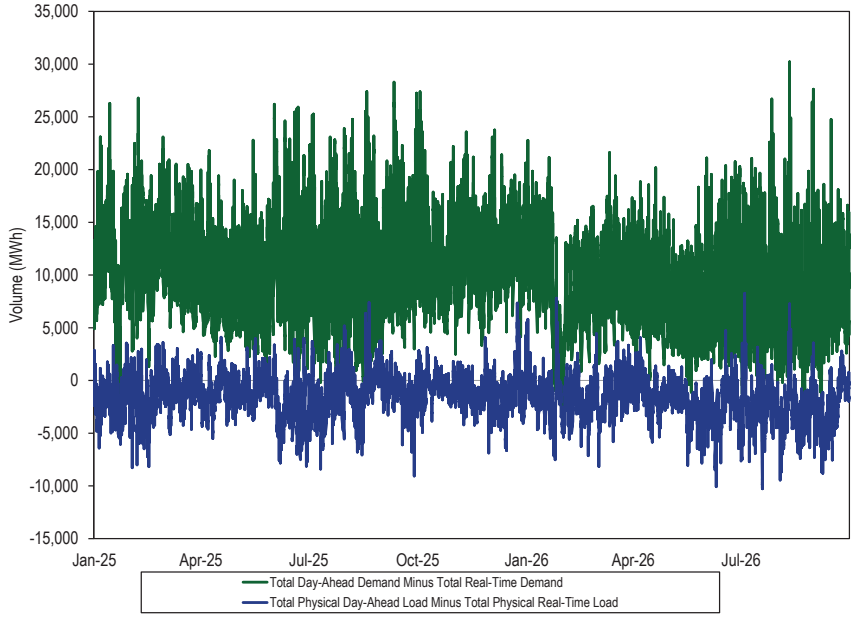


Figure 3-16 shows the difference between the physical day-ahead load and the physical real-time load, and the difference between the day-ahead demand including DECs, UTCs, and exports, and the real-time demand including exports, in 2025 through September 2026.

Figure 3-16 Day-ahead minus real-time daily demand: 2025 through September 2026



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Figure 3-17 shows the difference between the day-ahead and real-time hourly average load by hour of the day. DECs, UTCs and exports are not included. The largest difference generally occurs during off peak hours, especially at hours beginning 1 and 2. The smallest difference generally occurs during peak hours, especially at hours beginning 9 and 10.

Compared to the first nine months of 2025, the average difference between the day-ahead and real-time hourly average load has increased for every hour of the day in the first nine months of 2026.

Figure 3-17 Difference between day-ahead and real-time hourly average physical load by hour of the day (Average hourly volumes): January through September, 2022 through 2026

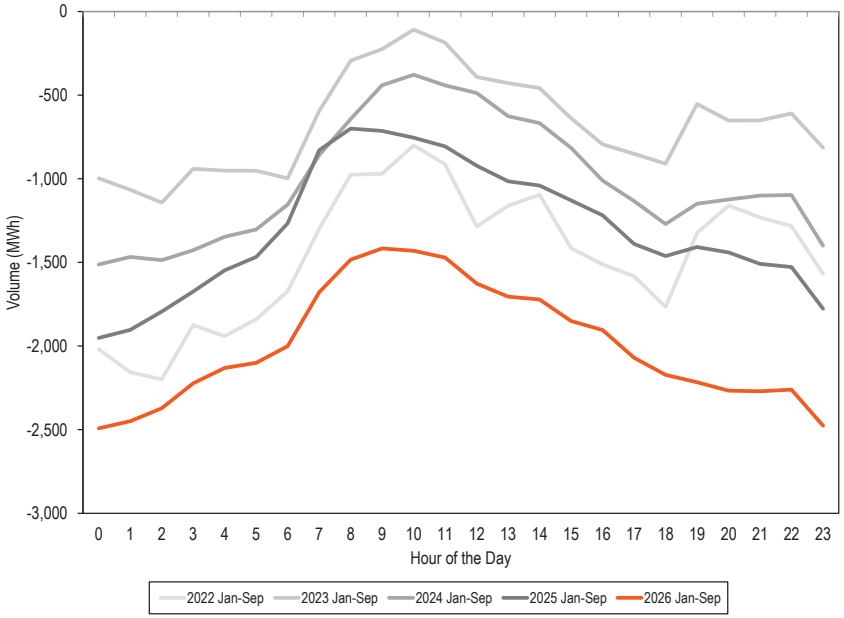
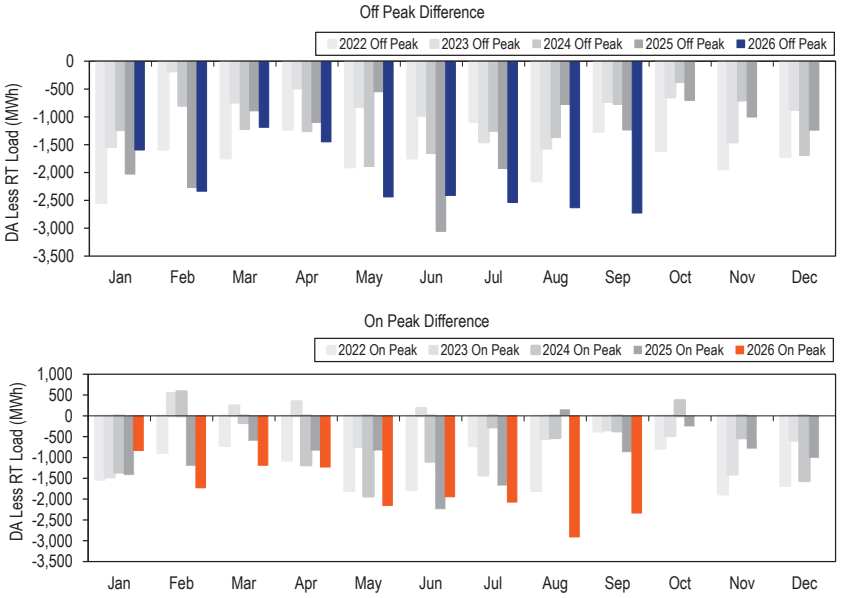


Figure 3-18 shows the difference between the day-ahead and real-time on peak and off peak hourly average physical load by month. DECs, UTCs and exports are not included.

Figure 3-18 Difference between day-ahead and real-time on peak and off peak hourly average physical load by month: 2022 through September 2026



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Table 3-11 shows the MW and percent difference between the day-ahead and real-time on peak and off peak physical load by zone. DECs, UTCs and exports are not included. There are significant differences among zones.

Table 3-11 Difference between day-ahead and real-time on peak and off peak load by zone: January through September, 2025 and 2026

	2025 Jan-Sep				2026 Jan-Sep			
	Off Peak		On Peak		Off Peak		On Peak	
Zone	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load
AECO	(8.22)	(0.1%)	10.16	2.3%	(18.46)	(1.1%)	1.67	1.9%
AEP	(48.63)	(0.2%)	(11.11)	0.0%	162.24	1.1%	163.51	1.0%
APS	(70.30)	(1.1%)	1.52	0.2%	(22.13)	(0.5%)	27.73	0.5%
ATSI	(41.47)	(0.3%)	50.52	0.8%	(145.01)	(1.9%)	(60.25)	(0.5%)
BGE	(135.72)	(3.8%)	(141.70)	(3.3%)	(156.39)	(4.5%)	(145.12)	(3.5%)
COMED	(29.43)	(0.1%)	(56.16)	(0.2%)	(237.74)	(2.2%)	(201.76)	(1.5%)
DAY	(19.40)	(0.8%)	(14.16)	(0.4%)	(6.10)	(0.1%)	4.99	0.5%
DOM	(745.43)	(5.2%)	(793.17)	(5.0%)	(1,391.45)	(9.1%)	(1,466.71)	(8.6%)
DPL	(41.63)	(2.0%)	(36.49)	(1.3%)	(32.78)	(1.6%)	(12.01)	(0.3%)
DUQ	6.71	0.8%	38.24	2.8%	(0.63)	0.1%	6.06	0.5%
EKPC/DEOK	(32.76)	(0.6%)	13.91	0.3%	(7.39)	(0.0%)	13.78	0.5%
JCPL	(44.18)	(1.5%)	17.25	1.7%	(5.87)	0.1%	35.90	2.5%
METED	15.14	1.3%	26.30	1.7%	(19.63)	(1.2%)	(8.98)	(0.3%)
PECO	(27.61)	(0.4%)	(6.59)	0.1%	(67.44)	(1.3%)	(71.30)	(1.3%)
PENELEC	(3.60)	0.1%	12.51	0.9%	(5.22)	(0.1%)	(2.45)	0.1%
PEPCO	(107.71)	(3.4%)	(94.98)	(2.4%)	(86.92)	(2.7%)	(57.93)	(1.4%)
PPL	(29.14)	(0.5%)	4.38	0.4%	(0.44)	0.2%	2.76	0.2%
PSEG	(142.36)	(2.9%)	(63.51)	(0.6%)	(89.88)	(1.5%)	(32.03)	0.2%
RECO	0.53	0.5%	1.41	1.2%	(1.68)	(0.7%)	(0.66)	0.4%

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Table 3-12 shows the MW and percent difference between the day-ahead and real-time physical load by zone for the last five years. DECs, UTCs and exports are not included.

Table 3-12 Difference between day-ahead and real-time load by zone: January through September, 2022 through 2026

	2022 Jan-Sep		2023 Jan-Sep		2024 Jan-Sep		2025 Jan-Sep		2026 Jan-Sep	
Zone	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load
AECO	(41.73)	(2.2%)	9.39	1.3%	29.75	2.9%	0.36	1.0%	(9.02)	0.3%
AEP	(134.42)	(1.0%)	(73.93)	(0.4%)	(96.23)	(0.7%)	(31.13)	(0.1%)	162.84	1.0%
APS	(97.87)	(1.7%)	(109.05)	(1.9%)	(53.83)	(0.9%)	(36.80)	(0.5%)	1.25	(0.0%)
ATSI	(101.32)	(1.2%)	16.05	0.4%	(38.98)	(0.4%)	1.44	0.2%	(105.27)	(1.3%)
BGE	(93.35)	(2.6%)	(80.01)	(2.3%)	(144.66)	(4.0%)	(138.51)	(3.6%)	(151.10)	(4.0%)
COMED	(53.20)	(0.3%)	144.35	1.5%	12.41	0.3%	(41.90)	(0.2%)	(220.87)	(1.8%)
DAY	(37.57)	(1.7%)	20.59	1.3%	(10.71)	(0.3%)	(16.96)	(0.6%)	(0.90)	0.2%
DOM	(601.12)	(4.8%)	(626.85)	(4.9%)	(438.82)	(3.2%)	(767.70)	(5.1%)	(1,426.74)	(8.9%)
DPL	(65.47)	(3.0%)	(29.24)	(1.3%)	(31.07)	(1.4%)	(39.23)	(1.6%)	(23.04)	(1.0%)
DUQ	(90.70)	(5.7%)	24.98	1.8%	18.20	1.1%	21.42	1.7%	2.51	0.3%
EKPC/DEOK	(76.47)	(1.6%)	(42.19)	(0.8%)	(36.78)	(0.7%)	(10.99)	(0.2%)	2.54	0.2%
JCPL	(39.26)	(0.7%)	16.34	1.2%	2.22	0.7%	(15.52)	(0.0%)	13.72	1.2%
METED	(62.02)	(3.1%)	17.85	1.2%	17.51	1.2%	20.34	1.5%	(14.63)	(0.8%)
PECO	83.77	2.1%	50.05	1.5%	(28.98)	(0.4%)	(17.80)	(0.2%)	(69.25)	(1.3%)
PENELEC	10.90	0.6%	33.71	1.9%	0.59	0.1%	3.92	0.5%	(3.92)	(0.0%)
PEPCO	(20.31)	(0.6%)	(38.30)	(1.0%)	(115.80)	(3.6%)	(101.77)	(2.9%)	(73.33)	(2.1%)
PPL	32.06	0.9%	64.64	1.6%	55.88	1.4%	(13.50)	(0.1%)	1.06	0.2%
PSEG	(57.58)	(0.8%)	(59.41)	(1.1%)	(135.86)	(2.5%)	(105.58)	(1.8%)	(62.75)	(0.7%)
RECO	(1.53)	(0.9%)	(0.60)	0.3%	(5.69)	(3.4%)	0.94	0.8%	(1.20)	(0.2%)

Market Behavior

Generator Offers

Generators indicate their availability in the day-ahead market by submitting offers that specify a status: must-run, economic, emergency, or unavailable.

- **Must-Run:** If a unit selects must-run status, the day-ahead market will commit the unit at no less than its economic minimum MW.
- **Economic:** If a unit selects economic status, the day-ahead market will commit the unit based on the unit offers.
- **Emergency:** If a unit selects emergency status, the day-ahead market will commit the unit only as needed to preserve system reliability.
- **Unavailable:** If a unit selects unavailable status, the day-ahead market will not consider the unit for commitment.

Table 3-13 shows the share of total MW offered in the day-ahead market by availability status in the first nine months of 2026.

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For each availability status, a unit may set its economic minimum MW equal to its economic maximum MW, termed block loading. This share of MW is reported in the Block Loaded columns. If a unit sets its economic minimum MW below its economic maximum MW, the economic minimum MW are reported in the Eco Min column. The capacity between the economic minimum MW and the emergency maximum MW are reported in the Dispatchable column.

In the first nine months of 2026, 26.6 percent of available MW were offered as must run, 55.5 percent of MW were offered as economic, 0.1 percent of MW were offered as emergency, and 17.8 percent of MW were unavailable in the day-ahead market.[44]

Table 3-13 Unit Status of day-ahead energy offers: January through September, 2026

Unit Type	Must Run				Economic				Emergency	Unavailable
	Block Loaded	Eco Min	Dispatchable	Total	Block Loaded	Eco Min	Dispatchable	Total		
CC	0.3%	6.1%	5.4%	11.8%	0.7%	38.5%	34.1%	73.2%	0.0%	15.0%
CT	0.3%	0.5%	0.2%	1.0%	8.6%	47.7%	25.6%	82.0%	0.5%	16.5%
Diesel	0.0%	0.0%	0.0%	0.0%	97.9%	0.0%	0.0%	97.9%	0.2%	1.8%
Hydro	49.9%	29.3%	15.1%	94.4%	0.0%	0.1%	5.5%	5.6%	0.0%	0.0%
Nuclear	74.0%	2.3%	0.5%	76.8%	17.9%	0.0%	0.0%	17.9%	0.0%	5.3%
Other	12.2%	0.0%	9.1%	21.3%	16.9%	20.8%	27.8%	65.5%	2.7%	10.5%
Solar	10.3%	0.0%	6.2%	16.6%	0.2%	0.2%	83.1%	83.4%	0.0%	0.0%
Steam - Coal	1.2%	15.9%	9.7%	26.8%	0.7%	19.4%	19.1%	39.3%	0.0%	33.9%
Steam - Other	3.5%	5.4%	6.3%	15.1%	7.1%	13.0%	27.6%	47.8%	0.0%	37.1%
Wind	0.1%	0.5%	21.9%	22.4%	0.0%	0.1%	77.4%	77.6%	0.0%	0.0%
All Units	15.3%	6.3%	4.9%	26.6%	5.7%	25.4%	24.4%	55.5%	0.1%	17.8%

44 Unavailable MW are calculated based on the total default emergency maximum MW of all the unavailable units in day-ahead market. Wind, Solar and Hydro emergency MW were set to zero MW based on the units' technology.

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Table 3-14 shows the share of total MW offered in the day-ahead market by dispatchable status in the first nine months of 2026.

The Block Loaded column shows the percentage of total MW for all units that set their economic minimum MW equal to their economic maximum MW, regardless of commitment availability status. The Eco Min column shows the percentage of total MW represented by the economic minimum MW for all units that set their economic minimum MW below their economic maximum MW, regardless of commitment availability status. The Dispatchable column shows the percentage of total MW between the economic minimum MW and the economic maximum MW. The Dispatchable Range section shows the percentage of total MW offered within each price range. The Emergency column shows the percentage of total MW between the economic maximum MW and the emergency maximum MW. The numerator includes only available MW. The denominator is total available and unavailable MW. The columns for each row equal the total available percent by technology.

In the first nine months of 2026, 21.0 percent of MW were offered as block loaded MW, 31.8 percent of MW were offered as economic minimum MW, 29.3 percent of MW were offered as dispatchable MW, and 0.1 percent of MW were offered as emergency MW in the day-ahead market.

Table 3-14 Dispatchable status of day-ahead energy offers: January through September, 2026 6

		Dispatchable Percent												
				Dispatchable Range										
Unit Type	Block Loaded Percent	Eco Min	Dispatchable Percent	($300) - $0	$0 - $25	$25 - $50	$50 - $75	$75 - $100	$100 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1000	Emergency Percent
CC	0.9%	44.5%	39.4%	0.0%	23.6%	10.5%	1.7%	0.6%	1.4%	1.1%	0.3%	0.1%	0.1%	0.1%
CT	9.1%	48.4%	25.9%	0.0%	1.1%	3.7%	4.1%	3.5%	4.9%	5.8%	2.4%	0.3%	0.1%	0.1%
Diesel	98.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Hydro	49.9%	29.4%	20.3%	19.6%	0.8%	-0.0%	0.0%	-0.0%	0.0%	-0.0%	0.0%	-0.0%	0.0%	0.0%
Nuclear	91.9%	2.3%	0.5%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Other	31.8%	20.8%	36.8%	4.1%	3.4%	8.8%	0.2%	0.1%	0.6%	14.2%	0.2%	0.3%	4.9%	0.1%
Solar	10.5%	0.2%	89.3%	72.3%	12.2%	0.8%	0.9%	0.6%	0.9%	1.0%	0.2%	0.0%	0.5%	0.0%
Steam - Coal	2.0%	35.3%	28.8%	0.0%	4.7%	18.3%	2.1%	0.8%	0.5%	1.1%	1.3%	0.0%	0.0%	0.1%
Steam - Other	10.6%	18.4%	33.6%	2.8%	10.5%	8.9%	4.5%	1.6%	2.0%	3.2%	0.1%	0.0%	0.0%	0.4%
Wind	0.1%	0.6%	99.0%	71.4%	17.3%	3.7%	1.7%	0.8%	0.9%	1.4%	0.4%	0.0%	1.4%	0.0%
All Units	21.0%	31.8%	29.3%	3.3%	10.2%	8.4%	2.0%	1.1%	1.5%	1.8%	0.8%	0.1%	0.1%	0.1%

Hourly Offers and Intraday Offer Updates

All participants may make specific hourly offers. Hourly offers mean that participants can specify different MW and price pairs for each hour of the day. Hourly offers can be submitted in the day-ahead market and offers may be updated in the real-time market. Participants must opt in on a monthly basis to make intraday offer updates in real time. Participants that have opted in can make updates only based on the process defined in their fuel cost policies. Units typically use hourly offers to reflect the two gas days in a power day. A gas day is from 10:00 AM EPT to 10:00 AM EPT the next day. Therefore, gas fired units may face two different gas prices. Typically, gas units have one offer from 00:00 EPT until 10:00 EPT and a different offer from 10:00 EPT until 24:00 EPT. Units typically use intraday updates to reflect changes in gas costs that occur in real time.

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Table 3-15 shows the daily average number of units that made hourly offers in the day-ahead market, that opted in to intraday offer updates and that made intraday offer updates. In the first nine months of 2026, an average of 368 units per day made hourly offers, a decrease of five units from the first nine months of 2025. In the first nine months of 2026, 653 units opted in for intraday offer updates, an increase of 41 units from the first nine months of 2025. In the first nine months of 2026, an average of 164 units made intraday offer updates each day, an increase of one unit from the first nine months of 2025.

Table 3-15 Daily average number of units making hourly offers, opted in for intraday offers and making intraday offer updates: January through September, 2025 and 2026

	Fuel Type	2025	2026	Difference
Hourly Offers	Natural Gas	322	309	(13)
	Other Fuels	51	59	8
	Total	373	368	(5)
Opt In	Natural Gas	435	441	6
	Other Fuels	177	212	35
	Total	612	653	41
Intraday Offer Updates	Natural Gas	160	162	2
	Other Fuels	3	2	(1)
	Total	163	164	1
Total Units with nonzero offers		851	893	43

ICAP Must Offer Requirement

Committed generation capacity resources are required to offer their available capacity into the day-ahead and real-time energy market, and report an outage for the capacity not available.[45] Thermal resources are required to offer the ICAP equivalent of their committed UCAP and intermittent resources are required to offer their median forecast on an hourly basis. The full installed capacity (ICAP) is the ICAP of the resources that cleared in the capacity market. This is known as the ICAP must offer requirement. The categorical exemption for intermittent resources, capacity storage resources, and hybrid resources from the capacity market must offer requirement was eliminated in February 2025.[46] Only demand resources are exempt from the capacity market must offer requirement.

The MMU recommends that all capacity resources have a must offer obligation. The MMU also recommends that performance penalties not be applied to solar and wind resources when they are not capable of performing based on ambient conditions. For example, solar resources should be subject to performance penalties if they fail to perform when the sun is shining but should not be subject to performance penalties in the middle of the night. This would be a rational application of the PAI penalties that recognizes the physical capabilities of resources and is therefore not discriminatory, in contrast to PJM's current treatment of such resources which applies penalties to solar resources for not performing at night.

The current enforcement of the ICAP must offer requirement is inadequate.[47] The problem is a complex combination of generator behavior, and inadequate and inconsistent reporting tools that are not synchronized. Compliance is subject to mistakes and susceptible to manipulation.

Resources are required to submit their available capacity in three different systems. Resources are required to make offers in the energy market via Markets Gateway. Resources are required to report outages in the Dispatch Application Reporting Tool (eDART) in advance or in real time. Resources are required to report outages in the Generator Availability Data System (eGADS) after the fact. The three applications are not linked and there is no formal process to ensure consistency.

For example, ambient ratings are an issue. When the weather is hotter than test conditions, the capacity of some units is reduced below the ICAP levels. While this fact may be reported by unit owners in eDART and reflected in lower offered MW in the energy market, the derates are not reported as

45 OA Schedule 1 § 1.10.1A(d).

46 FERC approved extending the RPM must offer requirement to intermittent resources, capacity storage resources, and hybrid resources but not to demand resources on February 20, 2025. 190 FERC ¶ 61,117.

47 PJM compares the data submitted in eDART to the data submitted in Markets Gateway using the eDART Gen Checkout. Generators are supposed to acknowledge their Gen Checkout reports. Manual 10 and the eDART User Guide do not specify what acknowledging the Gen Checkout report means, any requirements to acknowledge the Gen Checkout report or any consequences for not doing so. Gen Checkout is also only triggered if generators fail by more than defined thresholds.

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outages in eGADS and are therefore not included as outages for purposes of defining capacity using EFORd.

The MMU recommends that PJM enforce the ICAP must offer requirement by assigning a forced outage to any unit that is derated in the energy market below its committed ICAP without an outage that reflects the derate.

The MMU recommends that storage resources also be subject to an enforceable ICAP must offer requirement that reflects the limitations of these resources.

Table 3-16 shows average hourly MW, for each month, that violated the ICAP must offer requirement in the first nine months of 2026. On average for all hours, 1,367 MW did not meet the ICAP must offer requirement, but for 10 percent of the hours, 2,439 MW did not meet the must offer requirement. To put this level of withholding in perspective, these MW levels are larger than the reserve shortages that trigger shortage pricing and larger than most supply contingencies that lead to synchronized reserve events.

Table 3-16 Average hourly estimated capacity (MW) failing the ICAP must offer requirement: January through September, 2026

Month	90th Percentile	Average	10th Percentile
Jan-26	750	412	196
Feb-26	2,006	1,542	1,190
Mar-26	2,964	2,552	2,270
Apr-26	1,569	1,058	571
May-26	2,230	1,695	1,286
Jun-26	1,522	1,028	525
Jul-26	2,221	1,009	408
Aug-26	2,285	1,590	984
Sep-26	2,219	1,411	765
2026	2,439	1,367	404

The outage data reported in eGADS do not exactly match the energy market data submitted in Markets Gateway. For example, economic maximum MW levels submitted in Markets Gateway that reflect expected ambient conditions (including ambient derates) can be inconsistent with the maximum capability submitted in eGADS. Another example is the start and end times of planned outages in the shoulder months. In many situations units are derated in Markets Gateway to reflect an upcoming planned outage for which the unit must ramp down over an extended period but in eGADS the outage start time is not reported until the unit is completely unavailable. These differences can result in units not meeting their ICAP must offer requirement.

The MMU recommends that PJM integrate all the outage reporting tools in order to enforce the ICAP must offer requirement, ensure that outages are reported correctly and eliminate reporting inconsistencies. Generators currently submit availability in three different tools that are not integrated, Markets Gateway, eDART and eGADS.

Emergency Maximum MW

Generation resources are offered with economic maximum MW and emergency maximum MW. The economic maximum MW is the output level the resource can achieve following economic dispatch. The emergency maximum MW is the output level the resource can achieve when emergency conditions are declared by PJM. The MW difference between the two ratings equals emergency maximum MW. The PJM market rules allow generators to include emergency maximum MW as part of ICAP offered in the capacity market.[48]

Generation resources have to meet one of four conditions to offer any MW as emergency in the energy market: environmental limits imposed by a federal, state or other governmental agency that significantly limit availability; fuel limits beyond the control of the generation owner; temporary emergency conditions that significantly limit availability; or temporary MW additions not ordinarily available.[49]

The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy.[50] Capacity resources should offer their full output in the energy market and be subject to economic dispatch. The result would be incentives for correct

48 See 151 FERC ¶ 61,208 at P 476 (2015).

49 OA Schedule 1 § 1.10.1A(d).

50 This recommendation was accepted by PJM and filed with FERC in 2014 as part of the capacity performance updates to the RPM. See PJM Filing, Attachment A (Redlines of OA Schedule 1 § 1.10.1A(d), EL15-29-000 (December 12, 2014). FERC rejected the proposed change. See 151 FERC ¶ 61,208 at P 476 (2015).

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reporting of ICAP, more efficient energy market pricing, and a reduction in the need for manual overrides by PJM dispatchers during emergency conditions. Resources that do have capacity that can only be achieved with extraordinary measures could offer such capacity in the energy market but should not take on a capacity market obligation.

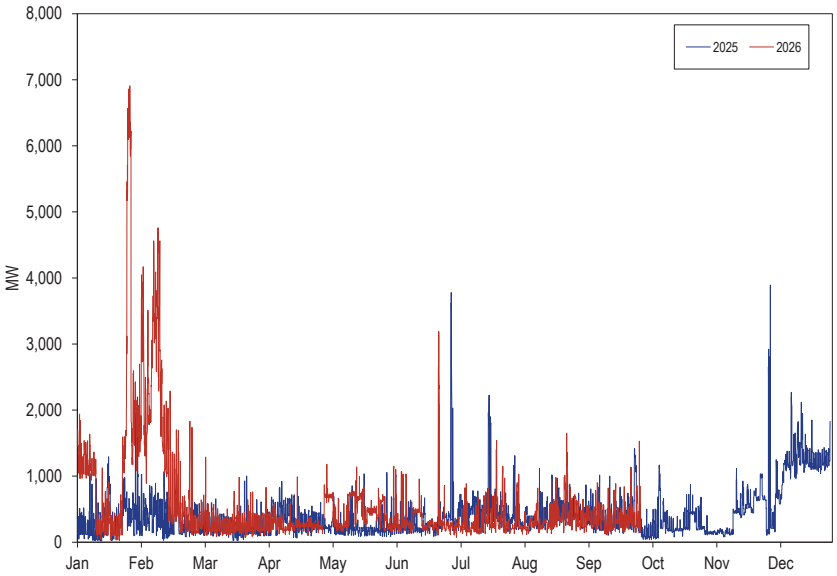
Table 3-17 shows average hourly maximum emergency MW, for each month. The levels of maximum emergency MW change hourly, daily and seasonally. For example, in February 2026, 10 percent of hours had maximum emergency MW greater than or equal to 3,380 MW while 10 percent of hours had maximum emergency MW less than 194 MW. The hourly average, in the first nine months of 2026, was 568 MW offered as maximum emergency, 86.9 percent higher than in the first nine months of 2025.

Table 3-17 Maximum emergency MW by month: January through September, 2026

Month	90th Percentile	Average	10th Percentile
Jan-26	2,141	1,261	116
Feb-26	3,380	1,431	194
Mar-26	470	284	129
Apr-26	404	272	188
May-26	735	504	236
Jun-26	502	361	190
Jul-26	601	312	166
Aug-26	653	379	200
Sep-26	564	371	199
2026	1,238	568	176

Figure 3-19 shows maximum emergency MW by hour in 2025 and the first nine months of 2026. The sharp increases in maximum emergency MW typically result from short term situations at generators, such as testing of equipment which can be suspended in the event of a system emergency. The increase in December 2025 was caused by operational restrictions such as limited run hours due to environmental permits. The increases in January and February 2026 were caused mainly by oil fired units that had limited inventory remaining due to their operation during Winter Storm Fern. During Winter Storm Fern, PJM increased the criterion for maximum emergency from 16 hours to 32 hours (meaning that units could be placed in maximum emergency if their inventory fell below 32 hours of full output operation).

Figure 3-19 Maximum Emergency MW by hour: 2025 and January through September, 2026



Parameter Limited Schedules

Cost-Based Offers

All resources in PJM are required to submit at least one cost-based offer. Cost-based offers, submitted by capacity resources for a defined set of technologies, are parameter limited based on unit specific parameter limits. Nuclear, wind, solar and hydro units are not subject to parameter limits.

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Price-Based Offers

All capacity resources that choose to make price-based offers are required to make available at least one price-based parameter limited offer (referred to as price-based PLS). The prices in a price-based PLS offer are at the discretion of the seller but the parameters are the same parameters used in the cost-based offers. For capacity resources, the price-based parameter limited schedule is used by PJM for committing generation resources when hot weather alerts and cold weather alerts are declared.

Offer Schedule Selection

PJM's current process for selecting unit offers (schedules) does not prevent the exercise of market power through the use of markups or through the use of inflexible parameters. The goal of having parameter limited offers is to prevent the use of inflexible operating parameters to exercise market power. Instead of ensuring that parameter limits apply, PJM chooses the lower of the price-based schedule and the price-based parameter limited schedule during hot and cold weather alerts. The goal of having cost-based offers is to prevent the use of markups to exercise market power. Instead of ensuring the least cost solution, PJM frequently chooses the higher price-based schedule that includes no parameter limits rather than the cost-based schedule that includes parameter limits when a resource fails the TPS test. The result is that PJM does not select the lowest cost schedule and allows market power to be exercised. The Commission recognized this flaw in the implementation of market power mitigation in its order to show cause, issued June 17, 2021, but did not take corrective action in its November 30, 2023, order.[51] [52]

PJM raised the schedule selection issues in the stakeholder process to address computational time in the day-ahead market. PJM's original proposal would have weakened market power mitigation. FERC rejected PJM's proposal because PJM's proposal would create the ability for market sellers to exercise market power.[53] PJM filed and, on October 25, 2024, FERC accepted a revised proposal that would require that sellers that fail the TPS test be offer capped at their cost-based offers and that operating parameters be mitigated.[54] FERC accepted PJM's proposal that has no specific plans to implement the improved rules and instead links implementation to PJM's long delayed improvements to its combined cycle modelling. PJM's revised proposal also continues to use the flawed formula, which was the basis for the first proposal rejected by FERC, to select among cost-based offers. This will result in the illogical selection of cost-based offers in some circumstances, for example if a dual fuel unit submits offers for both oil and gas on a day when the economics change between the two fuels midday. PJM should modify its implementation to address that issue. The result would allow market sellers to select the correct cost-based fuel schedule. There is no reason to delay implementation until PJM addresses combined cycle modelling. The changes would decrease the solution time for the day-ahead market and enhance market efficiency. The new approach should be implemented as soon as possible.

The MMU analyzed the extent of parameter mitigation in the day-ahead energy market when units are committed after failing the TPS test for transmission constraints in the first nine months of 2026. The analysis includes units with technologies that are subject to parameter limits and offer both price-based and cost-based schedules.[55] Table 3-18 shows the number and percentage of day-ahead unit run hours that failed the TPS test but were committed on price schedules. Table 3-18 shows that 23.5 percent of unit hours for units that failed the day-ahead TPS test were committed on price-based schedules that were less flexible than their cost-based schedules. If there were effective market power mitigation there would be zero units that fail the TPS test and are committed with parameters less flexible than their cost-based schedules.

51 See 175 FERC ¶ 61,231 (2021).
52 See 185 FERC ¶ 61,158 (2023).
53 See 187 FERC ¶ 61,051 at P 25 (2024).
54 See 189 FERC ¶ 61,060 (2024).
55 Nuclear, wind, solar and hydro units are not subject to parameter limits.

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Table 3-18 Parameter mitigation for units failing the day-ahead TPS test: January through September, 2026

Day-ahead Commitment For Units That Failed TPS Test	Day-ahead Unit Hours	Percent Day-ahead Unit Hours
Committed on price schedule less flexible than cost	31,570	23.5%
Committed on price schedule as flexible as cost	9,183	6.8%
Committed on cost (cost capped)	88,288	65.6%
Committed on price PLS	5,496	4.1%
Total committed on schedule as flexible as cost	102,967	76.5%
Total failed TPS test commitments	134,537	100.0%

The MMU analyzed the extent of parameter mitigation in the day-ahead energy market for units in zones with a cold weather alert, a hot weather alert, or a maximum generation emergency declaration in the first nine months of 2026. PJM declared cold weather alerts on 16 days and hot weather alerts on 30 days in the first nine months of 2026. The analysis includes units with technologies that are subject to parameter limits, with a capacity commitment, in the zones where the cold or hot weather alerts were declared. Table 3-19 shows that 27.9 percent of unit hours during weather alerts in the day-ahead energy market were committed on price-based schedules that were less flexible than their price PLS schedules. Effective market power mitigation would result in zero units committed during cold and hot weather alerts with parameters less flexible than their price PLS schedules.

Table 3-19 Parameter mitigation during weather alerts: January through September, 2026

Day-ahead Commitment During Hot And Cold Weather Alerts	Day-ahead Unit Hours	Percent Day-ahead Unit Hours
Committed on price schedule less flexible than PLS	77,436	27.9%
Committed on price schedule as flexible as PLS	34,924	12.6%
Committed on cost (cost capped)	17,154	6.2%
Committed on price PLS	147,774	53.3%
Total committed on schedule as flexible as PLS	199,852	72.1%
Total weather alert commitments	277,288	100.0%

Currently, there are no rules in the PJM tariff or manuals that limit the markup attributes of price-based PLS offers. The intent of the price-based PLS offer is to prevent the exercise of market power during high demand conditions by preventing units from offering inflexible operating parameters in order to extract higher market revenues or higher uplift payments. However, a generator can include a higher markup in the price-based PLS offer than in the price-based non-PLS schedule. The result is that the offer is higher and market prices are higher as a result of the exercise of market power using the PLS offer. This defeats the purpose of requiring price-based PLS offers.

The best solution to the use of inflexible parameters is to require the use of flexible parameters in all offers at all times for capacity resources. Capacity resources are paid to be flexible but that payment will not result in flexible offers in the energy market, the only place it matters, unless there are explicit requirements that energy offers from capacity resources incorporate that flexibility.

The MMU recommends, in order to ensure effective market power mitigation and to ensure that capacity resources meet their obligations to be flexible, that capacity resources be required to use flexible parameters in all offers at all times.

If flexible parameters are not required at all times, the use of flexible parameters should be required whenever a unit fails the TPS test and whenever the system is facing weather alerts or emergency conditions. PJM should always use cost-based offers for units that fail the TPS test, and always use flexible parameters in all price-based offers during weather alerts and emergencies. This approach would allow PJM to effectively mitigate inflexible operating parameters consistent with PJM's asserted processing time constraints. PJM's revised schedule selection proposal adopts this approach, but PJM has failed to propose an implementation date and the flawed rules remain in place as a result.

The MMU recommends that in order to ensure effective market power mitigation, PJM always use cost-based offers for units that fail the TPS test, and always use flexible parameters for all cost-based and all price-based offers during cold and hot weather alerts and emergency conditions.[56] [57]

56 *See* "Comments of the Independent Market Monitor for PJM," Docket No. EL21-78 (October 15, 2021) at 18 - 19.

57 *See* Monitoring Analytics, LLC "Schedule Selection: IMM Package," Markets Implementation Committee (September 6, 2023), <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Schedule_Selection_IMM_Package_20230906.pdf>.

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Parameter Limits

The unit specific parameter limits for capacity resources are based on default minimum operating parameter limits posted by PJM by technology type, and any adjustments based on a unit specific review process. These default parameters were based on analysis by the MMU.

The PJM tariff specifies that all generation capacity resources, regardless of the current commitment status, are subject to parameter limits on their cost-based offers. The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity resources.

Unit Specific Adjustment Process

Market participants can request an adjustment to the default values of parameter limits for capacity resources by submitting supporting documentation which is reviewed by PJM and the MMU. The default minimum operating parameter limits or approved adjusted values are used by capacity resources for their parameter limited schedules.

PJM has the authority to approve adjusted parameters with input from the MMU. PJM has inappropriately applied different review standards to coal units than to CTs and CCs despite the objections of the MMU. PJM has approved parameter limits for boiler based steam units based on historical performance and existing equipment while holding CTs and CCs to higher standards based on OEM documentation and a best practices equipment configuration.

The PJM process for the review of unit specific parameter limit adjustments is generally described in Manual 11: Energy and Ancillary Services Market Operations. The standards used by PJM to review the requests are currently not described in the tariff or PJM manuals. The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources.

Only certain technology types are subject to limits on operating parameters in their parameter limited schedules.[58] Solar units, wind units, run of river hydro units, and nuclear units are currently not subject to parameter limits. The MMU analyzed, for the units that are subject to parameter limits, the proportion of units that use the default limits published by PJM and the proportion of units that have unit specific adjustments for some of the parameters. Table 3-20 shows, for the delivery year beginning June 1, 2026, the number of units with approved unit specific parameter limits, and the number of units that used the default parameter limits published by PJM.

Table 3-20 Adjusted unit specific parameter limit statistics: 2026/2027 Delivery Year

Technology Classification	Units Using Default Parameter Limits	Units with One or More Adjusted Parameter Limits	Percent of Units with One or More Adjusted Parameter Limits
Aero CT	115	36	23.8%
Frame CT	147	106	41.9%
Combined Cycle	95	28	22.8%
Reciprocating Internal Combustion Engines	55	3	5.2%
Solid Fuel NUG	32	6	15.8%
Oil and Gas Steam	10	22	68.8%
Subcritical and Supercritical Coal Steam	5	65	92.9%
Total	459	266	36.7%

Parameter Limited Schedule Exceptions

There are three different types of exceptions to the parameter limited schedule default values: temporary exceptions, period exceptions, and persistent exceptions, each differentiated by the length of time it applies. Market sellers must submit requests for exceptions to PJM and the MMU for approval, along with data and documentation. Valid exceptions must be based on physical operational or contractual limits.[59]

There are no defined consequences for real-time exceptions for units that change their parameters but do not meet the requirements in the tariff. Units

58 For the default parameter limits by technology type, see PJM. "Unit-Specific Minimum Operating Parameters for Capacity Performance and Base Capacity Resources," which can be accessed at <*https://www.pjm.com/~/media/committees-groups/committees/elc/postings/20150612-june-2015-capacity-performance-parameter-limitations-informational-posting.ashx*>.

59 *See* OA Schedule 1 § 6.6(i) and PJM Manual 11, Section 2.3.4.3.

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that override their turn down ratio (economic maximum divided by economic minimum) either use PJM's fixed gen flag or simply increase their hourly economic minimum.[60] The turn down ratio has a defined parameter limit, but the limit can be evaded by the use of the fixed gen flag. These resources override their output limit parameters with no consequence.

The MMU has proposed that such a unit should not be paid a portion of its capacity market revenues, the daily value for each day, if it fails to include its defined parameter values in its offer (by either using the fixed gen option or increasing their economic minimum). The MMU recommends that PJM require generators to request temporary parameter exceptions for the use of the fixed gen flag. The request process requires generators to demonstrate that the request is based on a physical and actual constraint.

Consistent with the no excuses approach of the capacity performance paradigm and consistent with long term incentives for flexibility, resources that operate with a denied temporary parameter limit exception should not be paid the corresponding portion of the daily capacity value of the resource for days when it is not fully available consistent with its parameter limited schedule. If flexibility is valued as a generator attribute, the market design should not provide incentives to be inflexible. An effective market design should reward flexible operation, and ensure that capacity resources are paid for their capacity only when they meet their required level of flexibility. Without clearly defined consequences, market sellers will continue to submit inflexible parameters. The MMU recommends that resources not be paid the daily capacity payment when unable to operate to their unit specific parameter limits.[61]

Generator Flexibility Incentives in the Capacity Market

In its June 9, 2015, order on capacity performance, the Commission determined that capacity performance resources should be able to submit operating parameters to the market based not just on the resource physical constraints, but also based on other constraints, such as contractual limits.[62] The order primarily addressed limits imposed by natural gas pipelines. The Commission directed PJM to revise its tariff to establish a process through which capacity performance resources that operate outside the defined unit specific parameter limits can justify such operation and therefore remain eligible for make whole payments.[63]

A primary goal of the capacity performance market design is to assign performance risk to generation owners and to ensure that capacity prices reflect underlying supply and demand conditions, including the cost of mitigating the performance risk. The June 9th Order's determination on parameters is not consistent with that goal. By permitting generation owners to establish unit parameters based on nonphysical limits, the June 9th Order weakened the incentives for units to be flexible and weakened the assignment of performance risk to generation owners. Contractual limits and the option to choose from a range of gas pipeline tariff provisions, unlike generating unit operational limits, are a function of the interests and incentives of the generators making the choices. If a generation owner expects to be compensated through uplift payments for running for 24 hours regardless of whether the energy is economic or needed, that generation owner has no incentive to pay more to purchase the flexible gas service that would permit the unit to be flexible in response to dispatch.

The approach to parameters defined in the June 9th Order has increased energy market uplift payments substantially. While some uplift is necessary and efficient in an LMP market, this uplift is not. Electric customers are not in a position to determine the terms of the contracts that resources enter into. Customers rely on the market rules to create incentives that protect them by assigning operational risk to generators, who are in the best position to efficiently manage those risks.

The MMU recommends that capacity performance resources be held to the OEM operating parameters of the capacity market reference resource used for the Cost of New Entry (CONE) calculation for performance assessment and

60 PJM Markets Gateway User Guide, Section 5.8: Self-schedule a Generating Unit and Ignore PJM Dispatch Instruction at 54, Section 14.3 Submit Revised MW Operating Limits at 138 and Section 14.4 Revise the Status of a Generating Unit at 139 <https://www.pjm.com/~/media/etools/markets-gateway/markets-gateway-user-guide.ashx>.

61 *See* Monitoring Analytics LLC, "Real-Time Values," PJM Markets Implementation Committee Special Session (October 7, 2020) at 12, *which can be accessed at* <https://www.pjm.com/-/media/committees-groups/committees/mic/2020/20201007/20201007-item-06b-real-time-values-imm.ashx>.

62 See 151 FERC ¶ 61,208 at P 437 (2015).

63 *Id.* at P 440.

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energy uplift payments and that this standard be applied to all technologies on a uniform basis. This solution creates the incentives for flexibility and preserves the incentive to follow PJM's dispatch instructions during high demand conditions.

Parameter Impacts of Gas Pipeline Conditions

During extreme cold weather conditions, and more recently, also during hot weather conditions, a number of gas fired generators request temporary exceptions to parameter limits for their parameter limited schedules due to restrictions imposed by natural gas pipelines. The parameters affected include notification time, minimum run time (MRT) and turn down ratio (TDR, the ratio of economic maximum MW to economic minimum MW). When pipelines issue critical notices and enforce ratable take requirements, generators may, depending on the nature of the transportation service purchased, 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 leads to requests for 24 hour minimum run times and turn down ratios close to 1.0, to avoid deviations from the hourly nominated quantity. The frequency of 24 hour minimum run time requests increased after Winter Storm Elliott in December 2022. Table 3-21 shows the number of units, and the installed capacity MW that submitted parameter exception requests for a 24 hour minimum run time due to gas pipeline restrictions. In the first nine months of 2026, there were 97 units in PJM with a total installed capacity of 12,351 MW that requested a 24 hour minimum run time on their parameter limited schedules based on pipeline restrictions.

Table 3-21 Units with 24 hour minimum run times due to gas pipeline restrictions: January 2018 through September 2026

Year	Number of Units With 24 Hour Minimum Run Time Exceptions	Installed Capacity (MW) With 24 Hour Minimun Run Time Exceptions
2018	25	3,627
2019	37	5,616
2020	13	3,873
2021	61	7,514
2022	81	10,019
2023	75	9,824
2024	79	10,476
2025	93	11,137
2026	97	12,351

The increase in units requesting 24 hour minimum run times is a result of pipelines enforcing the pipeline tariff ratable take provisions. Pipelines have the authority to require ratable takes under their tariffs at any time although pipelines do not enforce ratable takes on a routine basis. Some generators have also requested extremely long notification times based on pipeline nomination deadlines. (See Table 3-67.) When pipelines enforce these deadlines, generators cannot obtain gas to flow for a given market hour once the deadline has passed for that hour and therefore they cannot start according to their normal notification plus start times (normally less than 30 minutes). For example, at 1700 EPT, the next nomination cycle is intraday 3 (ID3). The ID3 deadline is 2000 EPT for gas to flow starting at 2300 EPT. When these nomination deadlines are enforced, at 1700 EPT, a gas unit can only start at 2300 EPT (or in 6 hours). This effectively increases the time to start (notification time plus start time) from 30 minutes to 6 hours. The long notification times make the units unavailable for commitment in ITSCED and the units can only be committed manually in real time. Generators may request temporary exceptions based on pipeline restrictions in order to provide PJM with offers that accurately reflect their capabilities. Units operating inflexibly due to pipeline restrictions are eligible for uplift. Temporary exceptions should be limited to the duration of restrictions imposed by pipelines.

In the first nine months of 2026, PJM paid $321.1 million in day-ahead uplift to gas fired units with a 24 hour minimum run time, primarily during Winter

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Storm Fern. PJM paid an additional $270.9 million in balancing uplift for real-time commitments of units with a 24 hour minimum run time in the first nine months of 2026.

After observing the misuse of and the failure to use temporary exceptions during Winter Storm Elliott, on September 8, 2023, PJM and the MMU posted guidelines for the correct use of temporary exceptions for pipeline related restrictions. The guidelines detail exactly how units should use temporary exceptions to reflect pipeline restrictions in units' minimum run time, notification time and turn down ratio parameters.[64] During Winter Storm Elliott (December 22-24, 2022), 71 units on average (totaling 8,791 MW) requested temporary exceptions due to pipeline restrictions. During Winter Storm Gerri (January 16-18, 2024), 96 units on average (totaling 13,462 MW) requested temporary exceptions due to pipeline restrictions. During the 2025 Polar Vortex (January 18-23, 2025) 115 units on average (totaling 17,635 MW) requested exceptions due to pipeline restrictions. During Winter Storm Fern (January 24-February 2, 2026) 131 units on average (totaling 18,429 MW) requested exceptions due to pipeline restrictions.

The MMU recognizes that pipeline restrictions must be reflected in units' operating parameters in order for PJM to properly schedule and manage the system but it is important to prevent abuse through the submission of inflexible parameters not based on actual constraints. The MMU recommends that PJM only approve temporary exceptions that are based on pipeline tariff terms and/or pipeline notices when actually enforced by the pipelines.

Virtual Offers and Bids

Market participants may make virtual offers and bids in the PJM Day-Ahead Energy Market, and such offers and bids may be marginal.

Any market participant in the PJM Day-Ahead Energy Market may 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. Because virtual positions do not require physical generation or load, participants must buy or sell out of their virtual positions at real-time energy market prices. On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, interfaces and residual aggregate metered load nodes, and limiting the eligible bidding points for INCs and DECs to the same nodes plus active generation and load nodes.[65] Up to congestion transactions may be submitted between any two aggregates on a list of 46 aggregates eligible for up to congestion transaction bidding.[66] 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.

64 *See* "Temporary Operating Parameter Limit (PLS) Exceptions due to Pipeline Restrictions" PJM and MMU memorandum to PJM Market Participants (September 8, 2023) <https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Temporary_Operating_Parameter_Limit_(PLS)_Exceptions_due_to_Pipeline_Restrictions_20230908.pdf>.

65 See 162 FERC ¶ 61,139 (2018), *reh'g denied*, 164 FERC ¶ 61,170 (2018).

66 Prior to November 1, 2012, 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. 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>.

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Figure 3-20 shows an example of the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve of imports, the system aggregate supply curve without increment offers and imports, the system aggregate supply curve with increment offers, and the system aggregate supply curve with increment offers and imports for an example day in the first nine months of 2026.

Figure 3-20 Day-ahead aggregate supply curves: 2026 example day

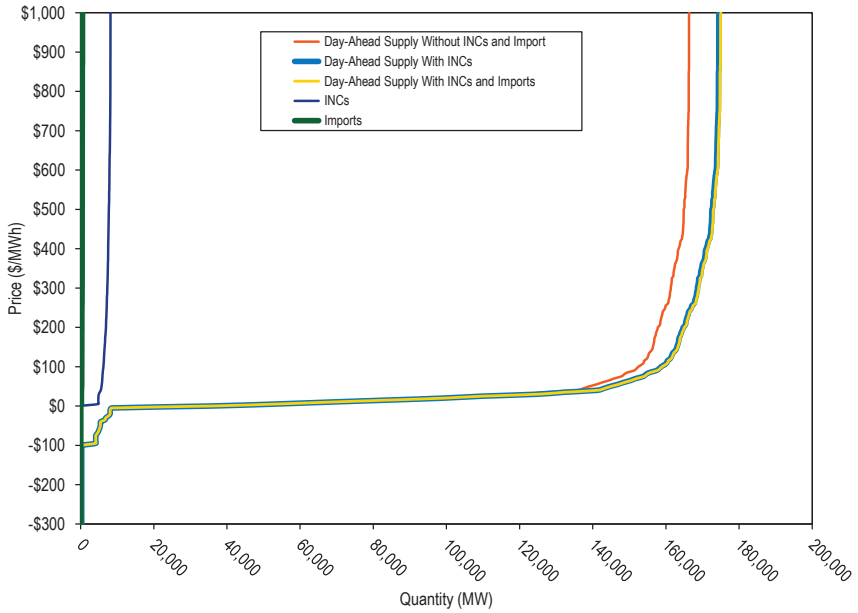


Table 3-22 shows the hourly average number of cleared and submitted increment offers and decrement bids by month in 2025 and the first nine months of 2026.[67] The hourly average submitted increment offer MW decreased by 5.1 percent and cleared increment MW decreased by 14.5 percent in the first nine months of 2026 compared to the first nine months of 2025. The hourly average submitted decrement bid MW increased by 18.6 percent and cleared decrement MW increased by 5.9 percent in the first nine months of 2026 compared to the first nine months of 2025.

67 Table 3-22 uses cleared day-ahead market data while final settlements data is used elsewhere in this report.

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Table 3-22 Average hourly number of cleared and submitted INCs and DECs by month: January 2025 through September 2026

		Increment Offers				Decrement Bids			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2025	Jan	6,024	12,413	535	1,821	5,068	14,037	420	1,914
2025	Feb	6,207	12,420	566	1,868	5,152	14,703	444	2,089
2025	Mar	6,239	12,836	603	1,920	5,177	15,163	464	2,262
2025	Apr	6,142	12,604	584	1,679	4,343	14,247	486	2,124
2025	May	5,007	10,837	543	1,480	4,947	13,199	452	1,703
2025	Jun	4,130	10,385	466	1,435	6,310	16,189	570	2,171
2025	Jul	4,609	10,299	481	1,366	6,414	15,731	541	2,262
2025	Aug	4,694	11,329	472	1,481	6,253	14,633	502	1,821
2025	Sep	4,679	10,619	536	1,653	6,606	17,145	591	2,464
2025	Oct	6,030	11,949	636	1,885	5,103	15,481	465	2,281
2025	Nov	6,706	14,332	646	2,150	4,818	15,756	469	2,532
2025	Dec	5,956	12,815	693	2,007	5,494	16,867	550	2,665
2025	Annual	5,531	11,898	563	1,728	5,476	15,261	496	2,190
2026	Jan	5,215	11,014	631	1,706	4,986	13,413	439	2,129
2026	Feb	5,463	11,938	602	1,885	4,979	14,819	501	2,400
2026	Mar	5,214	11,562	688	1,950	5,696	16,731	606	2,616
2026	Apr	5,871	12,725	737	1,992	5,878	17,367	555	2,432
2026	May	4,576	11,061	583	1,731	4,968	14,991	523	2,270
2026	Jun	4,378	11,401	582	1,916	6,594	18,960	664	3,059
2026	Jul	3,392	9,586	465	1,718	6,248	19,982	579	2,951
2026	Aug	3,255	9,804	490	1,746	6,967	20,793	657	2,720
2026	Sep	3,487	9,398	539	1,768	6,925	22,882	646	3,005
2026	Jan-Sep	4,528	10,930	590	1,822	5,920	17,782	575	2,620

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Table 3-23 shows the average hourly number of up to congestion transactions and the average hourly MW by month in 2025 and the first nine months of 2026. The hourly average submitted up to congestion bid MW decreased by 20.8 percent and cleared up to congestion bid MW decreased by 23.2 percent in the first nine months of 2026 compared to the first nine months of 2025.

Table 3-23 Average hourly cleared and submitted up to congestion bids by month: January 2025 through September 2026

		Up to Congestion			
Year	Month	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2025	Jan	10,955	34,709	911	2,194
2025	Feb	12,000	34,801	798	2,034
2025	Mar	10,512	34,843	741	2,095
2025	Apr	8,415	29,420	610	1,999
2025	May	7,851	21,973	503	1,574
2025	Jun	11,046	32,384	791	2,071
2025	Jul	9,595	29,536	913	2,229
2025	Aug	9,019	25,911	669	1,802
2025	Sep	9,844	33,392	741	2,383
2025	Oct	9,237	38,217	660	2,624
2025	Nov	11,445	38,188	764	2,769
2025	Dec	10,808	34,726	853	2,721
2025	Annual	10,043	32,311	746	2,208
2026	Jan	9,525	31,204	798	2,791
2026	Feb	7,617	24,926	838	2,600
2026	Mar	7,556	26,358	652	2,029
2026	Apr	7,184	25,582	815	2,188
2026	May	6,812	22,819	749	2,025
2026	Jun	7,660	23,028	777	2,088
2026	Jul	7,813	22,047	858	2,222
2026	Aug	7,281	21,016	714	1,987
2026	Sep	6,909	22,041	670	2,081
2026	Jan-Sep	7,601	24,343	763	2,221

Table 3-24 shows the average hourly number of day-ahead import/export transactions and the average hourly MW in 2025 and the first nine months of 2026.[68] In the first nine months of 2026, the average hourly submitted import transaction MW increased by 74.4 percent and the average hourly cleared import transaction MW increased by 78.3 percent compared to the first nine months of 2025. In the first nine months of 2026, the average hourly submitted export transaction MW decreased by 14.1 percent and the average hourly cleared export transaction MW decreased by 14.0 percent compared to the first nine months of 2025.

Table 3-24 Hourly average day-ahead number of cleared and submitted import and export transactions by month: January 2025 through September 2026

		Imports				Exports			
Year	Month	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2025	Jan	199	330	3	4	4,392	4,575	37	38
2025	Feb	355	403	5	6	4,948	4,992	41	42
2025	Mar	192	192	3	3	4,430	4,485	39	40
2025	Apr	366	384	5	6	3,789	3,821	26	27
2025	May	278	294	4	5	3,752	3,761	28	28
2025	Jun	193	215	3	4	4,426	4,467	33	34
2025	Jul	286	313	5	5	4,787	4,827	34	34
2025	Aug	213	242	4	5	5,232	5,268	39	40
2025	Sep	324	338	6	6	4,267	4,308	30	31
2025	Oct	740	752	10	13	2,829	2,875	21	25
2025	Nov	882	894	11	11	3,360	3,406	30	31
2025	Dec	827	870	11	12	4,540	4,578	35	36
2025	Annual	409	438	6	7	4,226	4,278	33	34
2026	Jan	495	540	7	8	4,458	4,513	37	38
2026	Feb	738	785	10	11	4,181	4,204	29	30
2026	Mar	434	452	6	6	3,779	3,798	32	32
2026	Apr	612	642	10	11	2,923	2,974	23	24
2026	May	627	663	9	10	2,447	2,477	19	19
2026	Jun	379	440	6	8	4,316	4,363	31	32
2026	Jul	286	356	6	7	4,439	4,481	35	35
2026	Aug	333	401	6	8	4,007	4,042	34	35
2026	Sep	390	452	7	8	3,893	3,968	30	31
2026	Jan-Sep	474	523	8	9	3,824	3,866	30	31

68 Table 3-24 uses cleared day-ahead market data, while final settlements data is used elsewhere in this report.

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Figure 3-21 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month from 2005 through the first nine months of 2026. Cleared volumes were greater in 2023 than any year since 2020, when uplift charges for up to congestion transactions took effect on November 1, 2020. The monthly MW volume of UTC bids in April 2023 was at its highest level since 2017 but decreased significantly beginning May 2023 and has remained stable beginning August 2023 through September 2026. September 2026 was the first month since December 2010 that submitted and cleared DEC volumes exceeded UTC volumes.

Figure 3-21 Monthly bid and cleared INCs, DECs and UTCs (GWh): January 2005 through September 2026

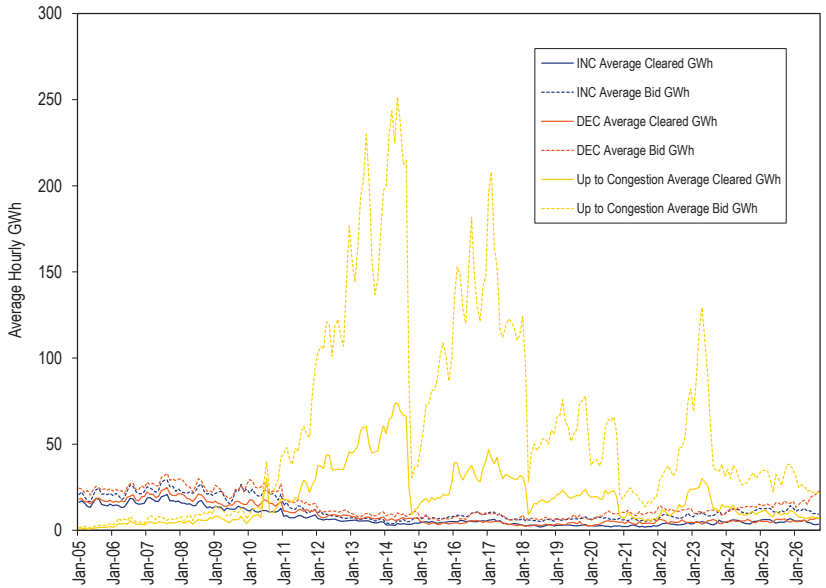
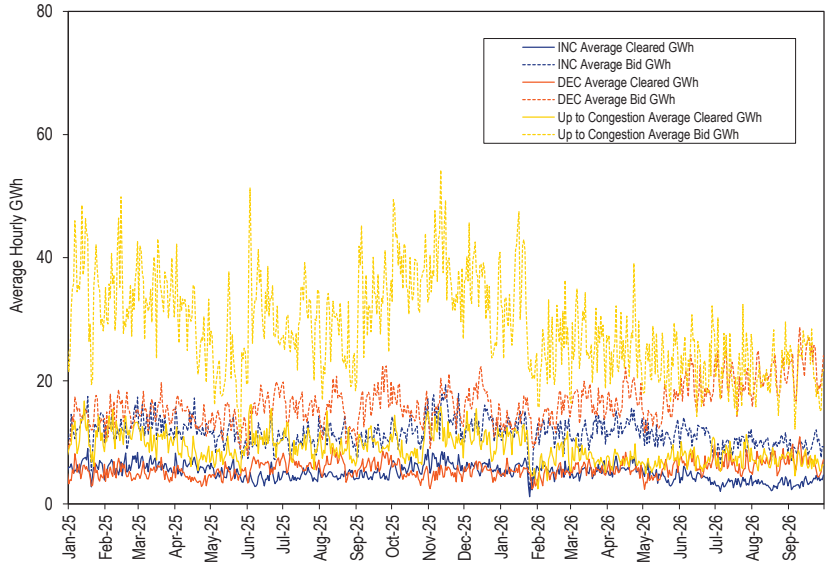


Figure 3-22 shows the daily volume of bid and cleared INC, DEC and up to congestion bids from January 2025 through September 2026.

Figure 3-22 Daily bid and cleared INCs, DECs, and UTCs (GWh): January 2025 through September 2026



In order to evaluate the ownership of virtual bids, the MMU categorizes all participants making virtual bids in PJM as either physical or financial at an account level.[69] Physical entities are defined as individual accounts in PJM's settlement systems that take physical positions in PJM markets and typically include utilities and customers. Financial entities are defined as individual accounts in PJM's settlement systems that take financial positions in PJM markets and typically include banks and trading firms. 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

69 The MMU modified the method for categorizing participants as physical and financial participants. See the explanation in the *2025 Quarterly State of the Market Report for PJM: January through March*, Section 13: Financial Transmission Rights at Market Structure (May 8, 2025).

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own countries. Financial entities' share of cleared MWh of INCs and DECs in the first nine months of 2026 decreased slightly to 97.0 percent from 97.1 percent in the first nine months of 2025.

Table 3-25 shows, in the first nine months of 2025 and 2026, the total increment offers and decrement bids and cleared MW by organization type.

Table 3-25 INC and DEC bids and cleared MWh by organization type (MWh): January through September, 2025 and 2026

	2025 (Jan-Sep)				2026 (Jan-Sep)			
Category	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent
Financial	170,893,071	98.4%	69,226,730	97.1%	185,105,294	98.4%	66,377,405	97.0%
Physical	2,837,159	1.6%	2,083,516	2.9%	2,983,370	1.6%	2,069,413	3.0%
Total	173,730,230	100.0%	71,310,247	100.0%	188,088,664	100.0%	68,446,818	100.0%

Table 3-26 shows the total up to congestion bid and cleared MWh by organization type in the first nine months of 2025 and 2026. Up to congestion bids submitted by financial entities decreased in the first nine months of 2026 compared to the first nine months of 2025, from 196.2 million MWh to 154.2 million MWh, while up to congestion bids submitted by physical entities decreased by 0.2 million MWh. Financial entities submitted 96.9 percent of all up to congestion bids, down from 97.5 percent, and cleared 94.5 percent of all up to congestion bids, down from 95.2 percent. In the first nine months of 2026, almost all up to congestion trading activity was by financial participants, while their submitted volumes decreased by 21.4 percent.

Table 3-26 Up to congestion transactions by organization type (MWh): January through September, 2025 and 2026

Year	Category	Total Up to Congestion Bid MWh	Percent	Total Up to Congestion Cleared MWh	Percent
2025 (Jan-Sep)	Financial	196,170,605	97.5%	61,675,259	95.2%
	Physical	5,069,592	2.5%	3,139,560	4.8%
	Total	201,240,197	100.0%	64,814,819	100.0%
2026 (Jan-Sep)	Financial	154,158,577	96.9%	46,919,346	94.5%
	Physical	4,893,661	3.1%	2,737,374	5.5%
	Total	159,052,238	100.0%	49,656,720	100.0%
(2026 minus 2025)	Financial	(42,012,028)	(21.4%)	(14,755,913)	(23.9%)
	Physical	(175,931)	(3.5%)	(402,186)	(12.8%)
	Difference	(42,187,959)	(21.0%)	(15,158,099)	(23.4%)

Table 3-27 shows the total import and export transactions by organization type in the first nine months of 2025 and 2026.

Table 3-27 Import and export transactions by organization type (MWh): January through September, 2025 and 2026

		2025 (Jan-Sep)		2026 (Jan-Sep)	
	Category	Total Import and Export MWh	Percent	Total Import and Export MWh	Percent
Day-Ahead	Financial	16,180,293	52.5%	13,505,265	48.0%
	Physical	14,622,339	47.5%	14,654,178	52.0%
	Total	30,802,631	100.0%	28,159,443	100.0%
Real-Time	Financial	31,378,872	57.6%	30,350,980	58.4%
	Physical	23,092,413	42.4%	21,648,079	41.6%
	Total	54,471,285	100.0%	51,999,059	100.0%

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Table 3-28 shows the top 10 locations by total cleared INC and DEC MWh in the first nine months of 2025 and 2026. The top 10 locations included four hubs, four interface pricing points, and two residual metered load aggregates. For generator and aggregate pnodes with elevated volumes that do not make the top 10 by total INC plus DEC volume, BUCKEYE – AEPOH cleared the most INC volume of 272,294 MWh and TIDD_AEP24 KV CD2 the most DEC volume of 356,615 MWh in the first nine months of 2026.

Table 3-28 Virtual offers and bids by top 10 locations (MWh): January through September, 2025 and 2026

2025 (Jan-Sep)					2026 (Jan-Sep)				
Aggregate/Bus Name	Aggregate/Bus Type	INC MWh	DEC MWh	Total MWh	Aggregate/Bus Name	Aggregate/Bus Type	INC MWh	DEC MWh	Total MWh
MISO	INTERFACE	365,157	4,662,100	5,027,257	SOUTH	INTERFACE	3,860,215	891,213	4,751,428
WESTERN HUB	HUB	2,512,398	1,673,987	4,186,385	WESTERN HUB	HUB	1,512,229	3,147,753	4,659,982
SOUTH	INTERFACE	2,943,317	626,681	3,569,997	MISO	INTERFACE	594,764	2,422,859	3,017,623
N ILLINOIS HUB	HUB	1,637,986	745,694	2,383,681	N ILLINOIS HUB	HUB	1,532,583	1,188,452	2,721,036
DOM_RESID_AGG	RESIDUAL METERED EDC	383,270	1,419,758	1,803,028	DOM_RESID_AGG	RESIDUAL METERED EDC	269,916	2,076,375	2,346,291
NYIS	INTERFACE	553,310	1,223,893	1,777,203	NYIS	INTERFACE	450,734	1,519,795	1,970,529
AEP-DAYTON HUB	HUB	508,545	778,574	1,287,119	AEP-DAYTON HUB	HUB	655,771	1,292,064	1,947,834
LINDENVFT	INTERFACE	42,895	1,212,347	1,255,242	LINDENVFT	INTERFACE	27,027	1,186,528	1,213,556
BGE_RESID_AGG	RESIDUAL METERED EDC	529,897	687,364	1,217,261	BGE_RESID_AGG	RESIDUAL METERED EDC	348,765	637,400	986,165
CHICAGO HUB	HUB	572,186	544,995	1,117,180	DOMINION HUB	HUB	287,501	585,516	873,017
Top ten total		10,048,962	13,575,392	23,624,354			9,539,504	14,947,956	24,487,461
PJM total		34,699,620	36,610,626	71,310,247			29,664,455	38,782,364	68,446,818
Top ten total as percent of PJM total		29.0%	37.1%	33.1%			32.2%	38.5%	35.8%

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Table 3-29 shows up to congestion transactions for the top 10 source and sink pairs and associated source, sink and overall profits on each path in the first nine months of 2025 and 2026. Total profits for up to congestion transactions in the first nine months of 2026 were $72.7 million, a 43.2 percent increase compared to profits of $50.8 million in the first nine months of 2025.[70] The UTCs from DOMINION HUB to DOM_RESID_AGG constituted 14.6 percent of all UTC cleared volume in the first nine months of 2026, yielding a profit of $22.7 million. A majority of this profit occurred on a single day, May 26, 2026, due to emergency transmission outages at the Greenway-Roundtable parallel lines in Data Center Alley, resulting in transmission constraint violations for several hours.

Table 3-29 Cleared up to congestion bids by top 10 source and sink pairs (MWh): January through September, 2025 and 2026[71]

2025 (Jan-Sep)							
Top 10 Paths by Cleared MWh							
Source	Source Type	Sink	Sink Type	Cleared MW	Source Revenue	Sink Revenue	UTC Profit
DOMINION HUB	HUB	DOM_RESID_AGG	AGGREGATE	6,934,245	$3,226,115	$19,595,592	$19,342,297
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	2,713,485	$3,830,128	($1,113,183)	$879,140
AEP GEN HUB	HUB	AEPOHIO_RESID_AGG	AGGREGATE	1,190,902	($163,051)	$2,321,086	$1,355,088
CHICAGO GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	1,157,365	$837,321	$197,409	$510,720
CHICAGO GEN HUB	HUB	CHICAGO HUB	HUB	1,131,621	($1,165,219)	$1,964,343	$48,034
AEP GEN HUB	HUB	AEPAPCO_RESID_AGG	AGGREGATE	707,058	$4,656,936	($1,321,860)	$2,191,444
CHICAGO GEN HUB	HUB	COMED_RESID_AGG	AGGREGATE	685,163	($374,408)	$947,193	$12,478
ATSI GEN HUB	HUB	DUQ_RESID_AGG	AGGREGATE	664,978	$1,352,792	($238,428)	$586,473
CHICAGO GEN HUB	HUB	OHIO HUB	HUB	643,910	$17,870	$310,263	($19,133)
CHICAGO GEN HUB	HUB	N ILLINOIS HUB	HUB	630,880	($111,352)	$478,255	($8,037)
Top ten total				16,459,605	$12,107,132	$23,140,671	$24,898,504
PJM total				64,814,819	$34,925,370	$62,087,104	$50,755,822
Top ten total as percent of PJM total				25.4%	34.7%	37.3%	49.1%
2026 (Jan-Sep)							
Top 10 Paths by Cleared MWh							
Source	Source Type	Sink	Sink Type	Cleared MWh	Source Revenue	Sink Revenue	UTC Profit
DOMINION HUB	HUB	DOM_RESID_AGG	AGGREGATE	7,235,456	($23,783,087)	$53,891,213	$22,734,550
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	1,408,937	$7,470,413	($1,947,215)	$3,378,095
AEP GEN HUB	HUB	AEPOHIO_RESID_AGG	AGGREGATE	1,371,853	($2,127,753)	$5,387,286	$1,733,850
CHICAGO GEN HUB	HUB	MISO	INTERFACE	913,239	$4,863,017	($860,823)	$2,152,307
WESTERN HUB	HUB	DOM_RESID_AGG	AGGREGATE	867,417	$3,065,343	$5,873,126	$7,922,269
SMECO_RESID_AGG	AGGREGATE	DOM_RESID_AGG	AGGREGATE	658,391	$792,653	$7,274,834	$6,936,894
SOUTH	INTERFACE	AEPAPCO_RESID_AGG	AGGREGATE	650,717	$2,815,083	$778,721	$2,919,749
ATSI GEN HUB	HUB	DUQ_RESID_AGG	AGGREGATE	643,907	($4,385,716)	$5,843,355	$746,557
SOUTH	INTERFACE	DOM_RESID_AGG	AGGREGATE	555,965	$343,194	$3,383,776	$3,279,719
CHICAGO GEN HUB	HUB	N ILLINOIS HUB	HUB	517,894	($2,220,652)	$3,308,348	$302,324
Top ten total				14,823,776	($13,167,505)	$82,932,620	$52,106,315
PJM total				49,662,594	($12,886,350)	$159,173,933	$72,698,333
Top ten total as percent of PJM total				29.8%	102.2%	52.1%	71.7%

70 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.

71 The columns "Source Revenue" and "Sink Revenue" are totals before uplift charges are subtracted. The column "UTC Profit" includes uplift charges, in addition to the source and sink revenue, and so is less than the sum of the revenue from each side of the transaction.

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Table 3-30 shows the average daily number of distinct source-sink pairs that were offered and cleared each month from January 2025 through September 2026. The average number of submitted source-sink pairs per day increased from 1,507 source-sink pairs submitted in the first nine months of 2025 to 1,517 in the first nine months of 2026. The average number of cleared source-sink pairs per day increased from 1,204 in the first nine months of 2025 to 1,234 per day in the first nine months of 2026.

Table 3-30 Number of offered and cleared UTC source and sink pairs: January 2025 through September 2026

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
2025	Jan	1,454	1,641	1,222	1,490
2025	Feb	1,411	1,617	1,174	1,399
2025	Mar	1,523	1,844	1,278	1,641
2025	Apr	1,477	1,718	1,123	1,428
2025	May	1,360	1,597	938	1,325
2025	Jun	1,521	1,847	1,208	1,622
2025	Jul	1,680	1,852	1,380	1,654
2025	Aug	1,572	1,836	1,249	1,554
2025	Sep	1,554	1,766	1,257	1,497
2025	Oct	1,520	1,674	1,168	1,430
2025	Nov	1,614	1,856	1,215	1,536
2025	Dec	1,560	1,804	1,224	1,474
2025	Annual	1,520	1,754	1,203	1,504
2026	Jan	1,477	1,712	1,118	1,521
2026	Feb	1,462	1,748	1,170	1,620
2026	Mar	1,531	1,701	1,222	1,456
2026	Apr	1,622	1,918	1,345	1,652
2026	May	1,501	1,738	1,229	1,534
2026	Jun	1,563	1,760	1,291	1,540
2026	Jul	1,581	1,852	1,334	1,634
2026	Aug	1,519	1,738	1,246	1,517
2026	Sep	1,395	1,659	1,147	1,560
2026	(Jan-Sep)	1,517	1,758	1,234	1,559

Table 3-31 and Figure 3-23 show total cleared up to congestion transactions and the share of the top 10 up to congestion paths by transaction type (import, export, wheel, or internal) in the first nine months of 2025 and 2026. Total cleared up to congestion transactions decreased by 23.4 percent from 64.8 million MWh in the first nine months of 2025 to 49.7 million MWh in the first nine months of 2026. Internal up to congestion transactions in the first nine months of 2026 were 83.8 percent of all up to congestion transactions, a decrease from 85.0 percent in the first nine months of 2025.

Table 3-31 Cleared up to congestion transactions and share of top 10 paths by type (MW): January through September, 2025 and 2026

	2025 (Jan-Sep)				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	2,714,664	1,563,471	886,913	16,459,605	21,624,653
PJM total (MW)	4,952,707	3,753,697	1,006,894	55,101,521	64,814,819
Top ten total as percent of PJM total	54.8%	41.7%	88.1%	29.9%	33.4%
PJM total as percent of all up to congestion transactions	7.6%	5.8%	1.6%	85.0%	100.0%
	2026 (Jan-Sep)				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	2,208,658	1,935,743	755,368	14,102,259	19,002,028
PJM total (MW)	3,838,857	3,314,859	912,356	41,596,521	49,662,594
Top ten total as percent of PJM total	57.5%	58.4%	82.8%	33.9%	38.3%
PJM total as percent of all up to congestion transactions	7.7%	6.7%	1.8%	83.8%	100.0%

Figure 3-23 shows the total volume of import, export, wheel, and internal up to congestion transactions by month from January 2005 through September 2026. An initial increase and continued increase in internal up to congestion transactions by month followed the November 1, 2012, rule change permitting such transactions, until September 8, 2014. The reduction in up to congestion transactions (UTC) that followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed.[72] There was an increase in up to congestion volume as a result of the expiration of the 15 month refund period for the proceeding related to uplift charges for UTC transactions. In 2018, total UTC activity and the percent of marginal up to congestion transactions again decreased significantly as the result of a FERC order issued on February 20, 2018, and implemented on

72 See 162 FERC ¶ 61,139 (2018), *reh'g denied*, 164 FERC ¶ 61,170 (2018).

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February 22, 2018.[73] The order limited UTC trading to hubs, residual metered load, and interfaces. UTC activity increased following that reduction.

UTC activity decreased again beginning November 1, 2020, after a FERC order requiring UTCs to pay day-ahead and balancing operating reserve charges equivalent to a DEC at the UTC sink point became effective on that date.[74] In 2022 and the first six months of 2023, the volume of cleared UTCs increased significantly, primarily internal transactions. The volume of cleared UTCs decreased consistently from July 2023 through September 2026.

Figure 3-23 Monthly cleared up to congestion transactions by type (GWh): January 2005 through September 2026

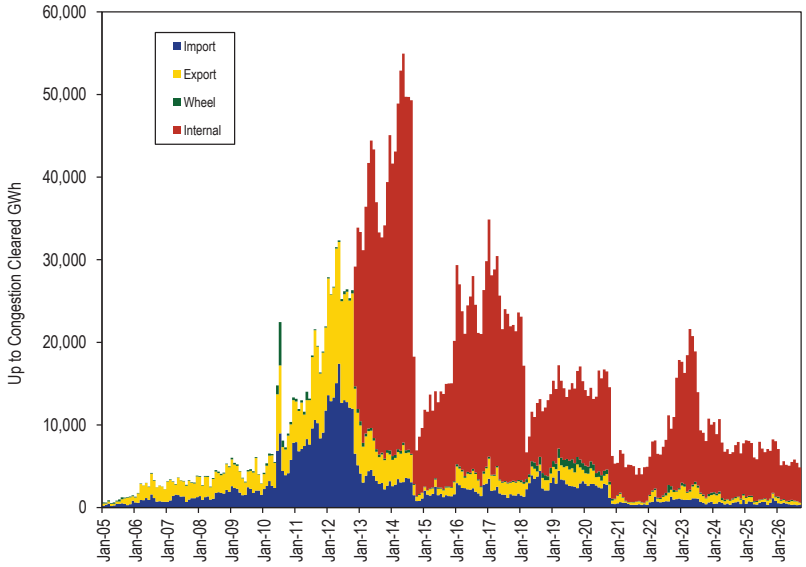
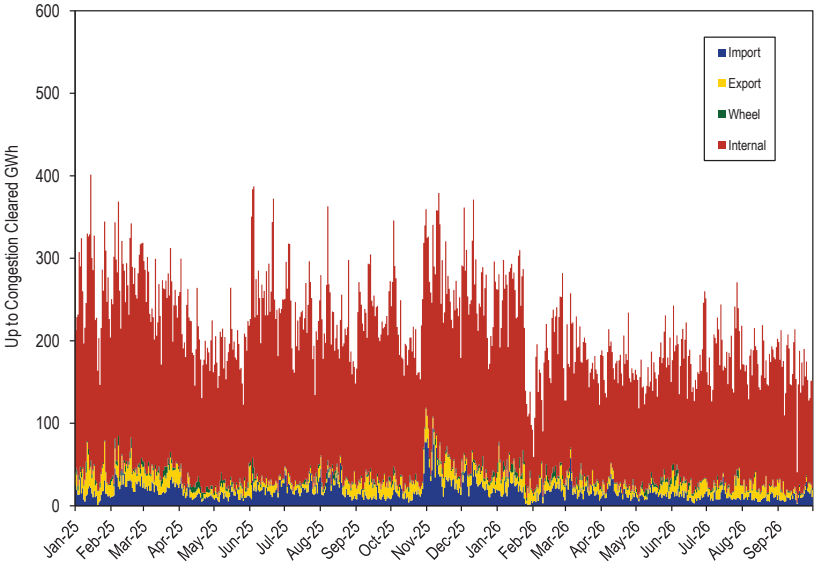


Figure 3-24 shows the daily cleared up to congestion GWh by transaction type from January 1, 2025, through September 30, 2026. In the first nine months of 2026, the total cleared GWh of import, export, and internal up to congestion transactions decreased significantly compared to the first nine months of 2025, especially during Winter Storm Fern.

Figure 3-24 Daily cleared up to congestion transaction by type (GWh): January 2025 through September 2026



One of the goals of the February 2018 FERC order accepting PJM's proposal limiting UTC bidding to hubs, interfaces and residual aggregate metered load nodes, and limiting INC and DEC bidding to the same nodes plus active generation nodes, was to limit the opportunities for traders to profit from opportunities for false arbitrage in which price spreads between the day-ahead and real-time energy markets result from differences in the models used to operate each market that cannot be corrected through virtual bidding.[75]

73 *Id.*
74 See 172 FERC ¶ 61,046 (2020).
75 PJM Interconnection, LLC, "Proposed Revisions To Reduce Bidding Points for Virtual Transactions," Docket No. ER18-88, October 17, 2017, at 9–10: "Discrepancies between the models can occur for various reasons despite PJM's best attempts to minimize them…Because individual nodes are more highly impacted by modeling discrepancies than aggregated locations due to averaging, they are often locations where Virtual Transactions can profit. Profits collected by Virtual Transactions in these cases lead to additional costs for PJM members without any benefits."

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A key assumption underlying the February 2018 order was that the limited set of nodes available for virtual trading is sufficiently protected from false arbitrage trades because price spreads resulting from modeling differences between the day-ahead and real-time markets are mitigated by the averaging of prices over a large number of buses at aggregate nodes.[76] This assumption is not correct, given the large share of INC, DEC, and UTC profits still attributable to modeling or operational differences between day-ahead and real-time models since the February 2018 order.

The assumption that modeling differences are averaged out over the multiple individual nodes included in aggregate nodes does not hold for multiple aggregate nodes in the current list of available up to congestion bidding nodes. The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets. For example, the MMU recommends eliminating UTC bidding at the following pricing points: DPLEASTON_RESID_AGG, GORHAM_RESID_AGG, PENNPOWER_RESID_AGG, UGI_RESID_AGG, SMECO_RESID_AGG, AEPKY_RESID_AGG, and VINELAND_RESID_AGG. In November 2025, GORHAM_RESID_AGG added to the list of UTC locations.

Prices at larger aggregate nodes can also be affected by transmission constraints, especially when the line ratings on constraints are violated and transmission constraint penalty factors are applied in the real-time energy market. This occurs both when line ratings are actually violated and when PJM operators reduce the line ratings in SCED. Even when the same constraints are modeled in day ahead and real time, constraint violations in real time may result from differences in the day-ahead and real-time operational environments such as intra hourly ramping limitations, changes to constraint limits, and unit commitments and decommitments. Price spreads due to modeling or operational differences can be significant, even when averaged over an aggregate node, and may persist for days or weeks. Virtual traders can often identify and profit from price spreads resulting from systematic modeling and operational differences between day-ahead and real-time affecting specific generators or aggregate nodes. The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues.

76 See 162 FERC ¶ 61,139 at PP 35–36 ("We accept PJM's proposal to limit eligible bidding points for UTCs to hubs, residual metered load, and interfaces. First, we agree with the IMM's statement that PJM's proposal to limit the UTC bid locations to interfaces, zones, and hubs will minimize false arbitrage opportunities for UTCs currently being pursued through penny bids, as the effect of modeling differences between the day-ahead and real-time markets are minimized at these aggregates.").

Market Performance

PJM locational marginal prices (LMPs) are a direct measure of market performance. The market performs optimally when the market structure provides incentives for market participants to behave competitively. In a competitive market, prices equal the short run marginal cost of the marginal unit of output and reflect the most efficient and least cost allocation of resources to meet demand.

LMP

The behavior 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, markup and local price differences caused by congestion. PJM also may administratively set prices with shortage pricing, the creation of closed loop interfaces related to demand side resources, surrogate constraints for reactive power and generator stability, or influence prices through manual interventions such as load biasing, changing constraint limits and transmission constraint penalty factors, and committing reserves beyond the requirement, or change price formation through fast start pricing.

The real-time average LMP in the first nine months of 2026 increased $19.77 per MWh, or 42.9 percent, from the first nine months of 2025, from $46.07 per MWh to $65.68 per MWh. The real-time load-weighted average LMP in the first nine months of 2026 increased $24.47 per MWh, or 48.4 percent, from the first nine months of 2025, from $50.51 per MWh to $74.98 per MWh.

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The costs of fuel and consumables, fundamental components of the real-time load-weighted average LMP, increased $5.73 per MWh from $29.63 per MWh in the first nine months of 2025 to $35.36 per MWh in the first nine months of 2026, or 23.4 percent of the increase in real-time load-weighted average LMP.

The day-ahead average LMP in the first nine months of 2026 increased $18.34 per MWh, or 40.1 percent, from the first nine months of 2025, from $45.69 per MWh to $64.04 per MWh. The day-ahead load-weighted average LMP in the first nine months of 2026 increased $22.85 per MWh, or 45.8 percent, from the first nine months of 2025, from $49.88 per MWh to $72.73 per MWh.

Occasionally, in a constrained market, the LMPs at some pricing nodes can exceed the offer price of the highest cleared generator in the supply curve.[77] In the nodal pricing system, the LMP at a pricing node is the total cost of meeting incremental demand at that node. When there are binding transmission constraints, satisfying the marginal increase in demand at a node may require increasing the output of some generators while simultaneously decreasing the output of other generators, to ensure that the transmission constraints are not violated. The total cost of redispatching multiple generators can at times exceed the cost of marginally increasing the output of the most expensive generator offered. Thus, the LMPs at some pricing nodes exceed $1,000 per MWh, the cap on the generators' offer price in the PJM market.[78]

LMP may, at times, be set by administratively defined transmission constraint penalty factors, which equal a default level of $30,000 per MWh in the day-ahead market dispatch run and $2,000 per MWh in the real-time market and in the day-ahead market pricing run. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, the transmission limits may be violated in the market dispatch solution. When this occurs, the shadow price of the constraint is set by transmission constraint penalty factors. The shadow price directly affects the LMP. Transmission constraint penalty factors are administratively determined and can be thought of as a form of administratively defined locational shortage pricing, although there is no basis for the level of these administrative prices. In addition, PJM operator interventions to reduce the control limits on transmission constraint line ratings used in the market clearing unnecessarily trigger transmission constraint penalty factors and significantly increase prices above the competitive level. A competitive market does not require that prices increase when PJM artificially triggers arbitrarily defined transmission constraint penalty factors.

77 See O'Neill R. P, Mead D. and Malvadkar P. "On Market Clearing Prices Higher than the Highest Bid and Other Almost Paranormal Phenomena." *The Electricity Journal* 2005; 18(2) at 19–27.

78 The offer cap in PJM was temporarily increased to $1,800 per MWh prior to the winter of 2014/2015. A new cap of $2,000 per MWh, only for offers with costs exceeding $1,000 per MWh, went into effect on December 14, 2015. See 153 FERC ¶ 61,289 (2015).

Fast Start Pricing: DLMP and PLMP

PJM implemented fast start pricing in both the day-ahead and real-time markets on September 1, 2021.[79] Fast start pricing is based on an incorrect LMP calculation called the pricing run. The pricing run LMP (PLMP) is now defined to be the official settlement LMP in PJM, replacing the dispatch run LMP (DLMP). Unless otherwise specified, the LMP tables and figures show the PLMP for September 1, 2021, and after.

The pricing run calculates LMP using the same optimal power flow algorithm as the dispatch run while simultaneously ignoring ("relaxing") the economic minimum and maximum output MW constraints for all eligible fast start units. Fast start units must have notification time plus start time less than or equal to one hour; minimum run time less than or equal to one hour; and can set price only when online and running for PJM, not self scheduled.

The goal of fast start pricing, as defined by PJM, is to allow inflexible resources to set prices based on the sum of their commitment costs per MWh and their marginal costs. As a result, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. Units that start in one hour are not actually fast start units, and their commitment costs are not marginal in a five minute market. The differences between the actual LMP and the fast start LMP distort the incentive for market participants to behave competitively and to follow PJM's dispatch instructions. One result is

79 *See* 175 FERC ¶ 61,130 (2021).

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that PJM is paying new forms of uplift in an attempt to counter the distorted incentives inherent in fast start pricing.

PJM has also introduced other differences between the dispatch run and pricing run that are not related to fast start pricing. For example, in the day-ahead market, PJM uses a default $30,000 per MWh transmission constraint penalty factor in the dispatch run and a $2,000 per MWh transmission constraint penalty factor in the pricing run. The day-ahead market dispatch violated multiple high voltage constraints into the Dominion and BGE Zones during Winter Storm Fern, particularly on January 27, 2026. The higher TCPF in the dispatch run than in the pricing run caused the pricing run day-ahead market price to be $5,060 per MWh less than the dispatch run day-ahead market price for the 7:00 AM hour, which coincided with the winter peak load.

Starting on October 1, 2022, PJM caps the system marginal price only in the pricing run, which affected real-time market prices for an extended period of time during Winter Storm Elliott in December 2022. Since then, PJM has applied the system marginal price cap on several occasions during shortage conditions for shorter periods of time. Details of those events are provided in the System Marginal Price Cap subsection of Section 3.

This system marginal price (SMP) capping process has not been reviewed by FERC or included in the PJM Operating Agreement.

DLMP and PLMP

Table 3-32 shows the day-ahead and real-time monthly load-weighted average PLMP and DLMP in 2025 and the first nine months of 2026.

The real-time load-weighted average PLMP was $74.98 per MWh for the first nine months of 2026, which is 13.5 percent, $8.90 per MWh, higher than the real-time load-weighted average DLMP of $66.07 per MWh. The intent of fast start pricing was to increase energy market prices, meaning that PLMP greater than DLMP was the expected and intended, although inefficient, result.[80] In the first nine months of 2026, the estimated impact of fast start pricing, based on the difference between the real-time PLMP and DLMP times real-time load, was $5.6 billion.[81] The maximum difference between the real-time load-weighted average PLMP and DLMP occurred during the July 2 and July 3 heat wave, when there was significantly more shortage pricing in the pricing run than in the dispatch run. This is an anticipated result of fast start pricing, which simply assumes, incorrectly, that resources can operate below their economic minimum output level but does not count those MW toward reserve requirements.[82] In July, September, and January 2026, the differences between the real-time load-weighted PLMP and DLMP were the highest since fast start pricing was implemented.

The day-ahead load-weighted average PLMP was $72.73 per MWh for the first nine months of 2026, which is -2.2 percent, -$1.66 per MWh, lower than the day-ahead load-weighted average DLMP of $74.39 per MWh. This counter intuitive result was a result of the use of a $30,000 per MWh transmission constraint penalty factor in the day-ahead DLMP calculation and a $2,000 per MWh transmission constraint penalty factor in the day-ahead PLMP calculation, rather than the fast start pricing logic. Specifically, the day-ahead DLMP was higher than the PLMP in January 2026 due to transmission constraint violations during Winter Storm Fern and the use of these very different transmission constraint penalty factors in the day-ahead DLMP and PLMP calculations.

80 See PJM Interconnection, L.L.C., Initial Brief of PJM Interconnection, L.L.C., FERC Docket No. EL18-34 (February 12, 2018).

81 See Monitoring Analytics, LLC, "Market Monitor Report," PJM Members Committee (October 28, 2026) at 35.

82 See the "Shortage" subsection for more details.

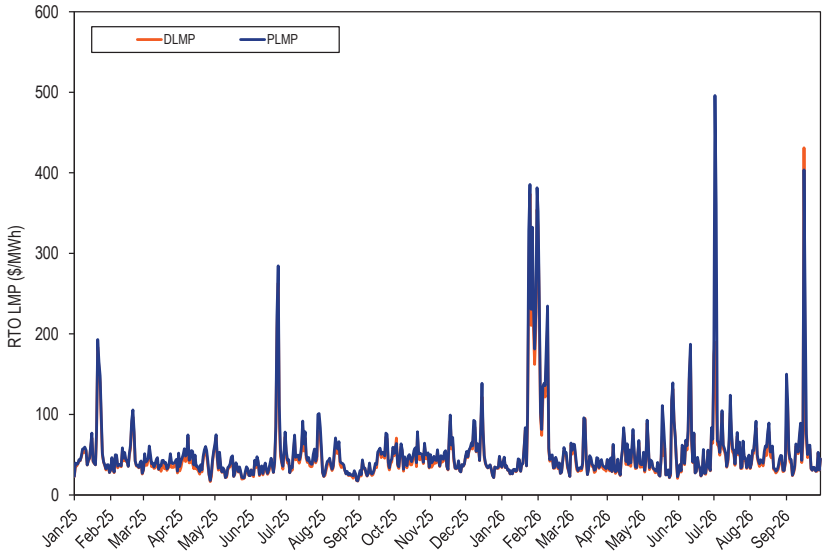
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Table 3-32 Day-ahead and real-time load-weighted average DLMP and PLMP: 2025 through September 2026

		Day-Ahead Load-Weighted Average				Real-Time Load-Weighted Average			
Year	Month	DLMP	PLMP	Difference	Percent Difference	DLMP	PLMP	Difference	Percent Difference
2025	Jan	$67.53	$67.74	$0.21	0.3%	$59.93	$62.87	$2.94	4.9%
2025	Feb	$48.85	$49.02	$0.16	0.3%	$46.27	$48.90	$2.62	5.7%
2025	Mar	$40.76	$40.74	($0.03)	(0.1%)	$37.82	$42.11	$4.30	11.4%
2025	Apr	$44.36	$44.35	($0.01)	(0.0%)	$40.07	$45.42	$5.35	13.4%
2025	May	$37.56	$37.40	($0.16)	(0.4%)	$33.98	$36.34	$2.36	6.9%
2025	Jun	$53.01	$53.14	$0.13	0.2%	$62.53	$68.13	$5.60	9.0%
2025	Jul	$66.56	$66.76	$0.20	0.3%	$52.41	$59.38	$6.97	13.3%
2025	Aug	$39.24	$39.27	$0.03	0.1%	$35.97	$39.52	$3.55	9.9%
2025	Sep	$41.26	$41.24	($0.02)	(0.0%)	$40.49	$43.71	$3.22	7.9%
2025	Oct	$50.56	$50.73	$0.17	0.3%	$47.32	$51.01	$3.69	7.8%
2025	Nov	$49.70	$49.85	$0.15	0.3%	$43.82	$47.08	$3.26	7.4%
2025	Dec	$57.97	$58.08	$0.11	0.2%	$52.55	$55.29	$2.74	5.2%
2025	Jan - Sep	$49.81	$49.88	$0.07	0.1%	$46.34	$50.51	$4.17	9.0%
2025		$50.61	$50.70	$0.09	0.2%	$46.79	$50.73	$3.93	8.4%
2026	Jan	$163.50	$148.80	($14.70)	(9.0%)	$106.94	$115.98	$9.04	8.5%
2026	Feb	$83.61	$83.95	$0.34	0.4%	$86.43	$93.41	$6.98	8.1%
2026	Mar	$42.07	$42.21	$0.14	0.3%	$43.35	$46.14	$2.79	6.4%
2026	Apr	$45.70	$45.95	$0.24	0.5%	$45.41	$48.46	$3.05	6.7%
2026	May	$48.75	$48.67	($0.08)	(0.2%)	$50.09	$56.00	$5.91	11.8%
2026	Jun	$56.92	$57.14	$0.22	0.4%	$58.59	$61.76	$3.17	5.4%
2026	Jul	$94.44	$94.57	$0.13	0.1%	$72.82	$102.03	$29.21	40.1%
2026	Aug	$50.29	$50.62	$0.32	0.6%	$47.93	$52.71	$4.78	10.0%
2026	Sep	$62.96	$63.20	$0.24	0.4%	$71.93	$82.39	$10.46	14.5%
2026	Jan - Sep	$74.39	$72.73	($1.66)	(2.2%)	$66.07	$74.98	$8.90	13.5%

Figure 3-25 shows the real-time daily average DLMP and PLMP in 2025 through September 2026.

Figure 3-25 Real-time daily average DLMP and PLMP: 2025 through September 2026



Fast start pricing created a larger difference between DLMP and PLMP in real time than in day ahead in the first nine months of 2026. Figure 3-26 shows the hourly difference between DLMP and PLMP in day-ahead and real-time for the first nine months of 2026.

For the first nine months of 2026, DA DLMP was higher than PLMP as a result of PJM's use of a $30,000 per MWh transmission constraint penalty factor only in the DA DLMP run and a $2,000 per MWh transmission constraint penalty factor in the DA PLMP run. That resulted in high DA DLMP values when triggered and DA DLMP values greater than DA PLMP values. In the day-ahead market, the DA DLMP was greater than the DA PLMP on January 27, 2026, by $5,060 per MWh. In the dispatch run, the penalty factor was set at $30,000, while in the pricing run the penalty factor was set at $2,000.

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In the real-time market, the large differences between RT DLMP and PLMP on July 2, July 3, September 1 and September 17 were a result of multiple constraint violations and primary reserve requirement violations in the pricing run only. The large differences between RT DLMP and PLMP on May 18 and 19 were a result of multiple constraint violations in the pricing run only. The RT DLMP was greater than the RT PLMP on September 16 as a result of the administrative price cap on SMP of $3,700 per MWh that is applied only in the pricing run.

Figure 3-26 Hourly difference between DLMP and PLMP for day-ahead and real-time: January through September, 2026 [83]

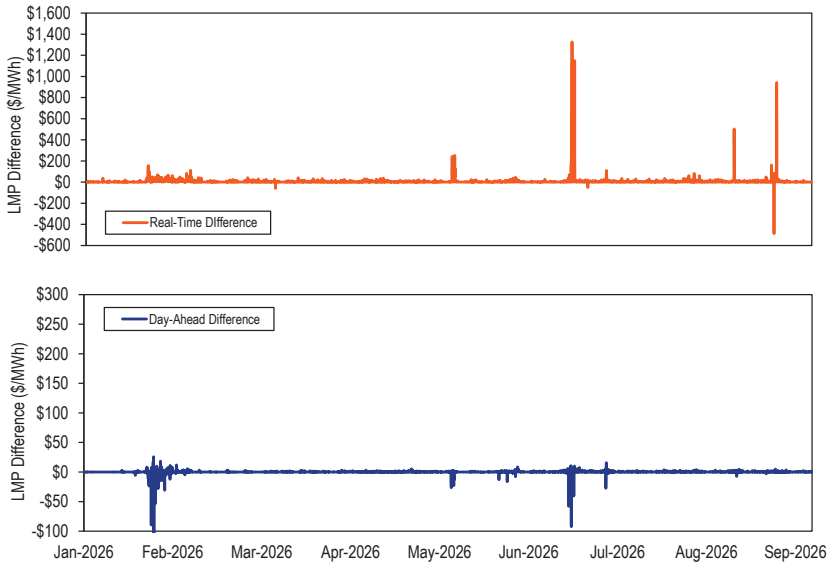
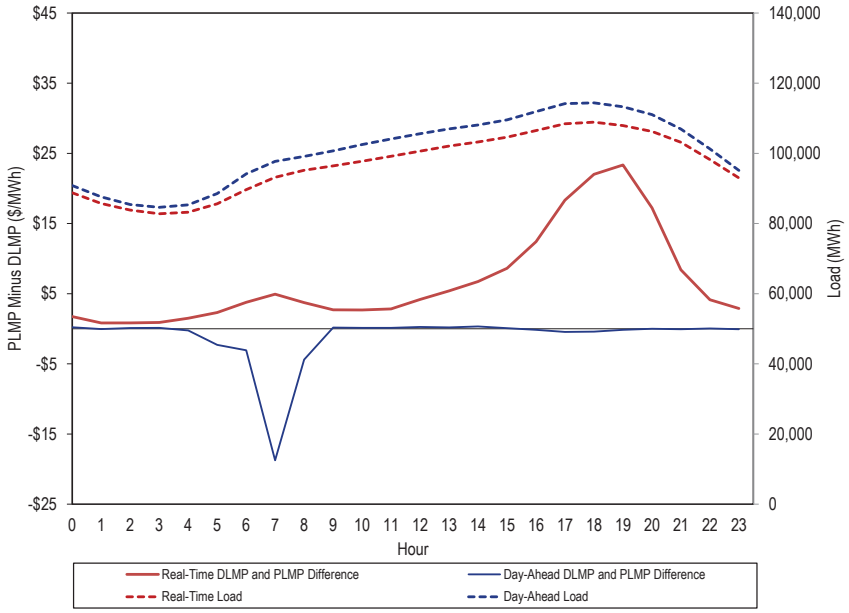


Figure 3-27 shows the hourly average load and the difference between DLMP and PLMP (DLMP minus PLMP) by hour of the day for the first nine months of 2026. In the real-time market, the difference between the PLMP and the DLMP was highest at the time of the evening peak load. In the day-ahead market, DLMP was greater than PLMP around 0700 as a result of the $30,000 per MWh transmission constraint penalty factor in the DA DLMP due to Winter Storm Fern constraint violations.

Figure 3-27 Hourly average load and LMP difference: January through September, 2026



83 This figure truncates a negative DA LMP difference of -$5,060 per MWh on January 27, 2026.

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Table 3-33 shows the percent of total marginal units that are fast start units by unit type in 2025 and the first nine months of 2026. While wind units are defined as fast start units, a wind unit on the margin does not result in a higher PLMP than DLMP when the unit has no commitment costs.

Table 3-33 Fast start units as a percent of real-time marginal units: 2025 through September 2026

		Dispatch Run				Pricing Run			
Year	Month	CT	Diesel	Wind	All Fast Start Units	CT	Diesel	Wind	All Fast Start Units
2025	Jan	0.8%	0.6%	0.1%	1.5%	4.5%	2.1%	0.1%	6.8%
2025	Feb	1.5%	0.1%	0.4%	2.0%	3.7%	0.6%	0.3%	4.6%
2025	Mar	0.5%	4.5%	0.1%	5.2%	3.4%	5.0%	0.1%	8.6%
2025	Apr	1.9%	1.8%	0.3%	4.1%	7.1%	2.2%	0.3%	9.7%
2025	May	0.6%	0.3%	0.0%	1.0%	3.9%	1.5%	0.0%	5.4%
2025	Jun	1.4%	0.2%	0.0%	1.6%	6.2%	0.8%	0.0%	7.0%
2025	Jul	2.6%	0.6%	0.0%	3.2%	11.2%	1.5%	0.0%	12.8%
2025	Aug	2.2%	0.5%	0.0%	2.7%	7.8%	1.1%	0.0%	8.9%
2025	Sep	1.2%	0.4%	0.0%	1.6%	5.7%	1.2%	0.0%	6.9%
2025	Oct	1.4%	0.3%	0.2%	1.8%	4.8%	0.6%	0.2%	5.6%
2025	Nov	0.7%	0.5%	0.6%	1.8%	3.8%	1.3%	0.5%	5.7%
2025	Dec	1.8%	0.1%	0.1%	1.9%	6.1%	0.6%	0.1%	6.7%
2025	Jan - Sep	1.4%	1.0%	0.1%	2.6%	5.9%	1.8%	0.1%	7.9%
2026	Jan	1.0%	0.2%	0.3%	1.6%	5.9%	0.7%	0.2%	6.8%
2026	Feb	1.5%	0.6%	0.9%	3.0%	6.3%	1.3%	0.8%	8.5%
2026	Mar	0.7%	0.4%	0.2%	1.4%	3.0%	0.6%	0.1%	3.8%
2026	Apr	1.1%	0.5%	0.5%	2.2%	4.2%	1.2%	0.4%	5.8%
2026	May	0.9%	0.5%	0.4%	1.9%	4.2%	1.2%	0.4%	6.0%
2026	Jun	1.0%	0.4%	0.2%	1.9%	3.6%	0.9%	0.2%	4.9%
2026	Jul	2.0%	0.7%	0.1%	3.3%	8.9%	1.2%	0.1%	10.6%
2026	Aug	1.5%	1.0%	0.0%	2.9%	6.6%	2.0%	0.0%	9.1%
2026	Sep	1.2%	4.1%	0.0%	5.3%	4.0%	4.7%	0.0%	8.7%
2026	Jan - Sep	1.2%	0.9%	0.3%	2.6%	5.2%	1.5%	0.3%	7.1%

Table 3-34 shows the difference between day-ahead and real-time zonal average DLMP and PLMP for the first nine months of 2026.

Fast start pricing affects some zones more than others. The average difference in real-time DLMP and PLMP in BGE was $8.74 per MWh, while the average difference in real-time DLMP and PLMP in COMED was $5.14 per MWh. In the day-ahead market, the average DLMP was greater than PLMP in BGE and PEPCO. This was primarily a result of constraint violations during Winter Storm Fern, especially in peak load hours. Constraint violations occurred for several high voltage constraints, including Bedington – Black Oak and BC/PEPCO Doubles, which constrain power flows into Northern Virginia, Washington, DC, and Baltimore.

Table 3-34 Day-ahead and real-time zonal average DLMP and PLMP (Dollars per MWh): January through June, 2026

	2026 (Jan-Sep)							
	Day-Ahead				Real-Time			
Zone	Average DLMP	Average PLMP	Difference	Percent Difference	Average DLMP	Average PLMP	Difference	Percent Difference
ACEC	$52.92	$53.00	$0.08	0.2%	$45.93	$52.16	$6.23	13.6%
AEP	$59.56	$59.55	($0.01)	(0.0%)	$54.67	$61.12	$6.45	11.8%
APS	$73.62	$71.23	($2.38)	(3.2%)	$65.46	$72.74	$7.28	11.1%
ATSI	$57.00	$57.30	$0.31	0.5%	$51.53	$58.05	$6.52	12.6%
BGE	$101.27	$93.44	($7.83)	(7.7%)	$83.43	$92.17	$8.74	10.5%
COMED	$43.58	$43.99	$0.40	0.9%	$35.36	$40.50	$5.14	14.5%
DAY	$62.07	$62.15	$0.08	0.1%	$56.15	$62.90	$6.75	12.0%
DUKE	$62.40	$62.53	$0.12	0.2%	$56.66	$63.55	$6.89	12.2%
DOM	$89.60	$86.98	($2.62)	(2.9%)	$86.89	$94.63	$7.74	8.9%
DPL	$58.75	$58.89	$0.15	0.3%	$50.14	$57.85	$7.71	15.4%
DUQ	$55.25	$55.74	$0.49	0.9%	$50.25	$56.79	$6.54	13.0%
EKPC	$58.25	$58.27	$0.02	0.0%	$52.63	$58.93	$6.30	12.0%
JCPLC	$53.98	$53.94	($0.03)	(0.1%)	$46.93	$53.19	$6.26	13.3%
MEC	$53.27	$53.01	($0.27)	(0.5%)	$46.54	$52.79	$6.25	13.4%
OVEC	$57.75	$57.90	$0.15	0.3%	$51.45	$57.83	$6.38	12.4%
PECO	$51.70	$51.78	$0.08	0.2%	$45.00	$51.09	$6.08	13.5%
PE	$58.63	$58.49	($0.13)	(0.2%)	$51.01	$57.63	$6.62	13.0%
PEPCO	$98.16	$90.34	($7.82)	(8.0%)	$82.00	$90.49	$8.48	10.3%
PPL	$51.21	$51.03	($0.18)	(0.4%)	$44.52	$50.57	$6.06	13.6%
PSEG	$54.34	$54.37	$0.02	0.0%	$47.69	$53.94	$6.25	13.1%
REC	$56.19	$56.27	$0.08	0.1%	$50.24	$56.54	$6.30	12.5%

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Table 3-35 shows the difference between day-ahead and real-time average DLMP and PLMP for PJM hubs for the first nine months of 2026.

The average difference in real-time prices for the EASTERN HUB was $7.44 per MWh, while the average difference in real-time prices for the CHICAGO GEN HUB was $5.07 per MWh.

Table 3-35 Day-ahead and real-time average DLMP and PLMP for PJM hubs (Dollars per MWh): January through September, 2026

	2026 (Jan-Sep)							
	Day-Ahead				Real-Time			
Hub	Average DLMP	Average PLMP	Difference	Percent Difference	Average DLMP	Average PLMP	Difference	Percent Difference
AEP GEN HUB	$55.31	$55.54	$0.23	0.4%	$49.69	$55.67	$5.98	12.0%
AEP-DAYTON HUB	$58.05	$58.13	$0.08	0.1%	$52.16	$58.45	$6.29	12.1%
ATSI GEN HUB	$55.60	$55.94	$0.35	0.6%	$50.04	$56.39	$6.35	12.7%
CHICAGO GEN HUB	$42.97	$43.37	$0.40	0.9%	$35.10	$40.16	$5.07	14.4%
CHICAGO HUB	$43.81	$44.21	$0.40	0.9%	$35.43	$40.57	$5.14	14.5%
DOMINION HUB	$73.70	$71.86	($1.83)	(2.5%)	$69.26	$76.11	$6.85	9.9%
EASTERN HUB	$57.43	$57.59	$0.15	0.3%	$49.31	$56.74	$7.44	15.1%
N ILLINOIS HUB	$43.44	$43.84	$0.41	0.9%	$35.22	$40.32	$5.10	14.5%
NEW JERSEY HUB	$53.87	$53.88	$0.02	0.0%	$47.03	$53.27	$6.24	13.3%
OHIO HUB	$57.83	$57.96	$0.13	0.2%	$52.00	$58.28	$6.29	12.1%
WEST INT HUB	$64.31	$63.83	($0.48)	(0.8%)	$58.98	$65.60	$6.62	11.2%
WESTERN HUB	$76.27	$72.84	($3.43)	(4.5%)	$65.01	$72.43	$7.42	11.4%

Table 3-36 shows the frequency of the real-time pricing interval differences in DLMP and PLMP by price range for PJM zones for the first nine months of 2026.

Table 3-36 Frequency of real-time interval difference (dollars per MWh) between zonal DLMP and PLMP: January through September, 2026

	2026 (Jan-Sep)								
Zone	< ($50)	($50) to ($10)	($10) to $0	$0	$0 to $10	$10 to $20	$20 to $50	$50 to $100	$100 to $200	>= $200
PJM-RTO	0.0%	0.0%	1.0%	47.9%	38.7%	6.6%	4.1%	1.0%	0.3%	0.4%
AECO	0.0%	0.1%	4.6%	48.4%	37.2%	4.1%	3.7%	1.1%	0.4%	0.3%
AEP	0.0%	0.0%	1.8%	48.0%	37.6%	6.8%	4.0%	1.0%	0.3%	0.4%
APS	0.0%	0.1%	1.3%	47.9%	37.4%	6.9%	4.4%	1.3%	0.4%	0.4%
ATSI	0.0%	0.0%	1.7%	47.9%	38.2%	6.7%	3.9%	0.9%	0.3%	0.4%
BGE	0.1%	0.4%	3.4%	47.8%	33.3%	6.9%	5.6%	1.5%	0.5%	0.5%
COMED	0.1%	0.2%	4.8%	48.7%	36.8%	5.4%	2.8%	0.7%	0.2%	0.3%
DAY	0.0%	0.1%	1.7%	48.0%	37.2%	7.0%	4.2%	1.0%	0.3%	0.4%
DEOK	0.0%	0.1%	1.8%	48.1%	36.9%	7.1%	4.2%	1.1%	0.3%	0.4%
DOM	0.1%	0.2%	2.9%	48.0%	35.1%	7.0%	4.6%	1.3%	0.4%	0.5%
DPL	0.0%	0.2%	5.9%	48.4%	34.9%	3.9%	3.5%	1.6%	1.2%	0.4%
DUQ	0.0%	0.1%	1.6%	47.9%	38.2%	6.7%	3.9%	1.0%	0.3%	0.4%
EKPC	0.0%	0.1%	1.9%	48.1%	37.7%	6.8%	4.0%	0.9%	0.3%	0.4%
JCPL	0.0%	0.0%	3.2%	48.3%	38.6%	4.2%	3.7%	1.1%	0.4%	0.3%
METED	0.0%	0.4%	6.5%	48.0%	35.1%	4.3%	3.7%	1.2%	0.4%	0.4%
OVEC	0.0%	0.1%	1.9%	48.1%	37.5%	6.8%	4.0%	0.9%	0.3%	0.4%
PECO	0.0%	0.1%	5.3%	48.4%	36.5%	4.1%	3.7%	1.1%	0.4%	0.3%
PENELEC	0.0%	0.1%	1.4%	47.9%	39.4%	5.5%	3.9%	1.1%	0.4%	0.4%
PEPCO	0.1%	0.3%	3.1%	47.9%	34.2%	7.0%	5.1%	1.4%	0.5%	0.5%
PPL	0.0%	0.2%	6.0%	48.0%	36.2%	4.1%	3.6%	1.1%	0.4%	0.4%
PSEG	0.0%	0.0%	2.9%	48.3%	38.8%	4.2%	3.8%	1.1%	0.4%	0.3%
RECO	0.0%	0.1%	2.7%	48.0%	39.0%	4.4%	3.9%	1.1%	0.4%	0.3%

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Real-Time Average LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[84]

PJM Real-Time Average LMP

Table 3-37 shows the real-time average LMP for the first nine months of 1998 through 2026.[85] The real-time average LMP in the first nine months of 2026 increased $19.77 per MWh, or 42.9 percent, from the first nine months of 2025, from $46.07 per MWh to $65.68 per MWh.

Table 3-37 Real-time average LMP (Dollars per MWh): January through September, 1998 through 2026

	Real-Time LMP			Year to Year Change			
Jan-Sep	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
1998	$23.18	$16.86	$36.00	NA	NA	NA	NA
1999	$31.65	$18.77	$83.28	$8.47	36.6%	11.3%	131.3%
2000	$25.88	$18.22	$23.70	($5.77)	(18.2%)	(2.9%)	(71.5%)
2001	$36.00	$25.48	$51.30	$10.12	39.1%	39.9%	116.4%
2002	$28.13	$20.70	$23.92	($7.88)	(21.9%)	(18.8%)	(53.4%)
2003	$40.42	$33.68	$26.00	$12.30	43.7%	62.7%	8.7%
2004	$43.85	$39.99	$21.82	$3.43	8.5%	18.7%	(16.1%)
2005	$54.69	$44.53	$33.67	$10.83	24.7%	11.4%	54.3%
2006	$51.79	$43.50	$34.93	($2.90)	(5.3%)	(2.3%)	3.7%
2007	$57.34	$49.40	$35.52	$5.55	10.7%	13.6%	1.7%
2008	$71.94	$61.33	$41.64	$14.59	25.4%	24.2%	17.2%
2009	$37.42	$33.00	$17.92	($34.51)	(48.0%)	(46.2%)	(57.0%)
2010	$46.13	$37.89	$26.99	$8.70	23.3%	14.8%	50.6%
2011	$45.79	$37.05	$32.25	($0.33)	(0.7%)	(2.2%)	19.5%
2012	$32.45	$28.78	$21.94	($13.34)	(29.1%)	(22.3%)	(32.0%)
2013	$37.30	$32.44	$22.84	$4.85	15.0%	12.7%	4.1%
2014	$52.72	$36.06	$74.17	$15.42	41.3%	11.2%	224.8%
2015	$35.96	$27.88	$30.75	($16.76)	(31.8%)	(22.7%)	(58.5%)
2016	$27.43	$23.61	$15.73	($8.53)	(23.7%)	(15.3%)	(48.8%)
2017	$28.79	$25.28	$16.81	$1.36	5.0%	7.1%	6.9%
2018	$36.52	$27.26	$33.22	$7.73	26.8%	7.8%	97.6%
2019	$26.30	$23.39	$17.69	($10.22)	(28.0%)	(14.2%)	(46.8%)
2020	$19.95	$17.87	$10.48	($6.34)	(24.1%)	(23.6%)	(40.7%)
2021	$33.49	$26.82	$24.08	$13.54	67.9%	50.1%	129.8%
2022	$72.57	$59.66	$59.73	$39.08	116.7%	122.4%	148.0%
2023	$29.29	$25.56	$18.21	($43.28)	(59.6%)	(57.2%)	(69.5%)
2024	$31.50	$24.73	$26.35	$2.21	7.6%	(3.2%)	44.7%
2025	$46.07	$34.73	$53.62	$14.57	46.2%	40.5%	103.5%
2026	$65.84	$35.49	$118.58	$19.77	42.9%	2.2%	121.2%

84 See the *Technical Reference for PJM Markets*, at "Calculating Locational Marginal Price," p 16-18 for detailed definition of Real-Time LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

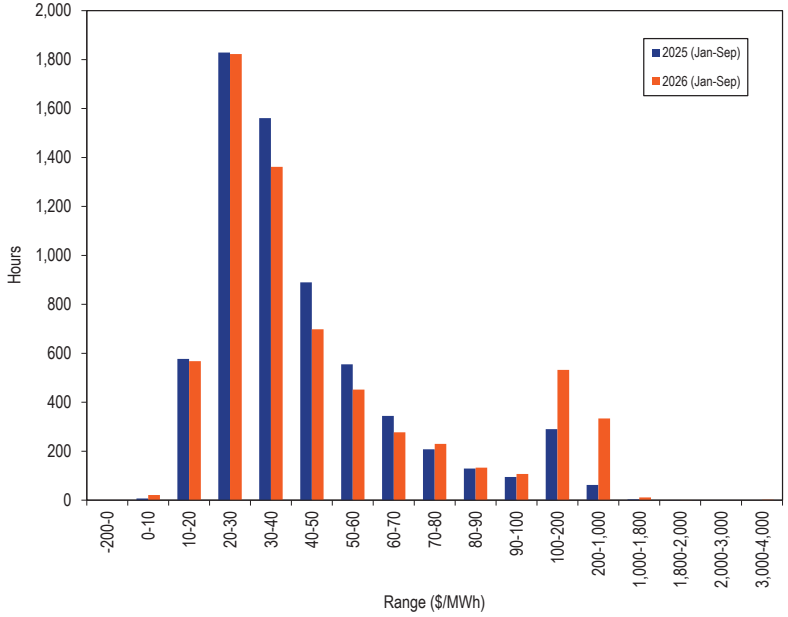
85 The system average LMP is the average of the hourly LMP without any weighting. The only exception is that market-clearing prices (MCPs) are included for January to April 1998. MCP was the single market-clearing price calculated by PJM prior to implementation of LMP.

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PJM Real-Time Average LMP Duration

Figure 3-28 shows the hourly distribution of the real-time average LMP in the first nine months of 2025 and 2026. In the first nine months of 2025, the most common price range was $20 to $30 per MWh. In the first nine months of 2026, the most common price range was $20 to $30 per MWh.

Figure 3-28 Distribution of real-time LMP: January through September, 2025 and 2026



Real-Time Load-Weighted Average LMP

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

PJM Real-Time Load-Weighted Average LMP

Table 3-38 shows the real-time load-weighted average LMP for the first nine months of 1998 through 2026. The real-time load-weighted average LMP in the first nine months of 2026 increased $24.47 per MWh, or 48.4 percent, from the first nine months of 2025, from $50.51 per MWh to $74.98 per MWh.

Table 3-38 Real-time load-weighted average LMP (Dollars per MWh): January through September, 1998 through 2026

	Real-Time Load-Weighted Average LMP			Year to Year Change			
Jan-Sep	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
1998	$26.06	$18.20	$44.65	NA	NA	NA	NA
1999	$38.65	$20.02	$104.17	$12.59	48.3%	10.0%	133.3%
2000	$28.49	$19.30	$26.89	($10.16)	(26.3%)	(3.6%)	(74.2%)
2001	$40.96	$28.18	$64.57	$12.47	43.8%	46.0%	140.1%
2002	$31.95	$23.09	$29.14	($9.01)	(22.0%)	(18.1%)	(54.9%)
2003	$43.57	$38.17	$26.53	$11.61	36.3%	65.3%	(9.0%)
2004	$46.44	$43.03	$21.89	$2.87	6.6%	12.7%	(17.5%)
2005	$60.44	$50.10	$36.52	$14.01	30.2%	16.4%	66.9%
2006	$56.39	$46.82	$40.70	($4.06)	(6.7%)	(6.5%)	11.4%
2007	$61.83	$55.12	$37.98	$5.45	9.7%	17.7%	(6.7%)
2008	$77.27	$66.73	$43.80	$15.43	25.0%	21.1%	15.3%
2009	$39.57	$34.57	$19.04	($37.70)	(48.8%)	(48.2%)	(56.5%)
2010	$49.91	$40.33	$29.65	$10.35	26.2%	16.7%	55.7%
2011	$49.48	$38.72	$37.02	($0.44)	(0.9%)	(4.0%)	24.8%
2012	$35.02	$29.84	$25.44	($14.46)	(29.2%)	(22.9%)	(31.3%)
2013	$39.75	$33.61	$26.47	$4.72	13.5%	12.6%	4.0%
2014	$58.60	$37.93	$86.22	$18.86	47.4%	12.8%	225.8%
2015	$38.94	$29.09	$33.95	($19.66)	(33.5%)	(23.3%)	(60.6%)
2016	$29.32	$24.60	$17.13	($9.62)	(24.7%)	(15.4%)	(49.6%)
2017	$30.36	$26.26	$18.81	$1.04	3.5%	6.7%	9.8%
2018	$39.43	$28.78	$36.82	$9.08	29.9%	9.6%	95.7%
2019	$27.60	$24.23	$18.69	($11.83)	(30.0%)	(15.8%)	(49.2%)
2020	$21.22	$18.66	$11.53	($6.38)	(23.1%)	(23.0%)	(38.3%)
2021	$35.68	$28.41	$26.03	$14.46	68.1%	52.3%	125.8%
2022	$77.84	$63.39	$68.59	$42.16	118.2%	123.1%	163.5%
2023	$30.87	$26.78	$19.67	($46.97)	(60.3%)	(57.8%)	(71.3%)
2024	$34.31	$26.40	$29.31	$3.44	11.1%	(1.4%)	49.0%
2025	$50.51	$37.12	$64.05	$16.20	47.2%	40.6%	118.5%
2026	$74.98	$38.28	$135.56	$24.47	48.4%	3.1%	111.7%

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PJM Real-Time Monthly Load-Weighted Average LMP

Figure 3-29 shows the real-time monthly and yearly load-weighted average LMP for 1999 through the first nine months of 2026.

Figure 3-29 Real-time monthly and yearly load-weighted average LMP: 1999 through September 2026

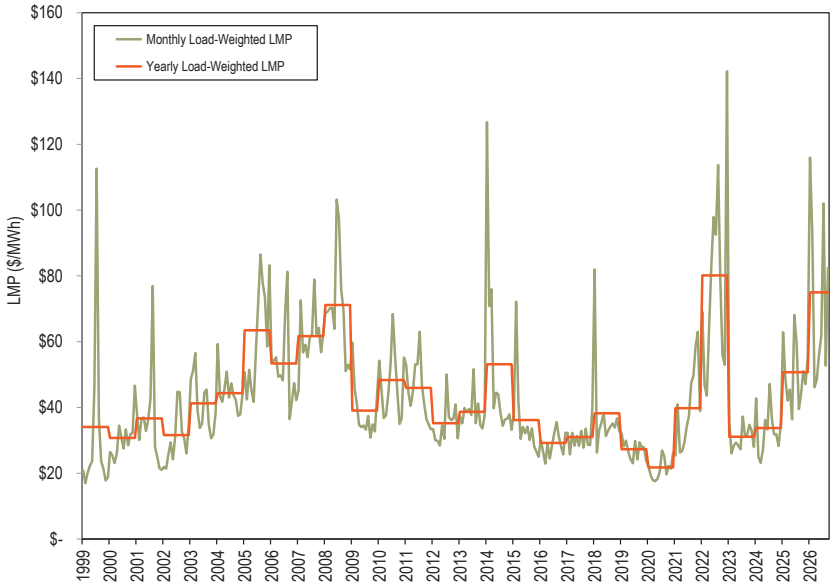


Table 3-39 shows the real-time monthly on peak and off peak load-weighted average LMP for 2025 through the first nine months of 2026.

Table 3-39 Real-time monthly on peak and off peak load-weighted average LMP (Dollars per MWh): 2025 through September 2026

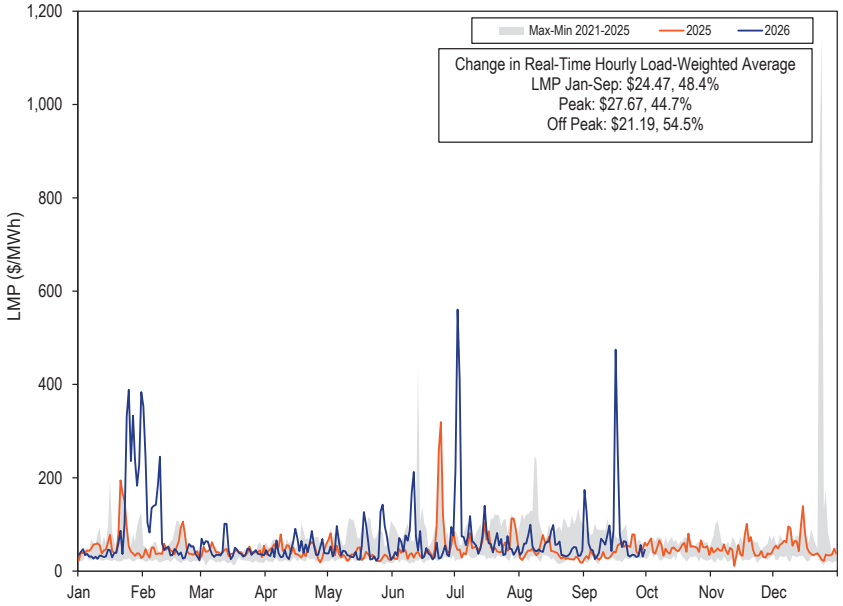
	2025				2026			
	Off Peak	On Peak	Difference	Percent Difference	Off Peak	On Peak	Difference	Percent Difference
Jan	$55.29	$70.54	$15.25	27.6%	$127.59	$102.73	($24.86)	(19.5%)
Feb	$43.75	$54.12	$10.37	23.7%	$106.39	$79.83	($26.56)	(25.0%)
Mar	$38.89	$45.68	$6.79	17.5%	$38.30	$53.85	$15.55	40.6%
Apr	$38.15	$52.08	$13.93	36.5%	$38.77	$57.19	$18.42	47.5%
May	$27.32	$45.53	$18.21	66.7%	$37.27	$77.10	$39.83	106.9%
Jun	$39.62	$94.51	$54.89	138.5%	$38.86	$81.82	$42.96	110.5%
Jul	$39.08	$77.77	$38.68	99.0%	$47.27	$147.73	$100.46	212.5%
Aug	$29.15	$49.92	$20.77	71.2%	$39.88	$65.60	$25.72	64.5%
Sep	$34.41	$52.55	$18.14	52.7%	$45.18	$117.78	$72.61	160.7%
Oct	$41.55	$59.43	$17.88	43.0%				
Nov	$40.52	$55.12	$14.59	36.0%				
Dec	$49.92	$60.68	$10.76	21.6%				

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PJM Real-Time Daily Load-Weighted Average LMP

Figure 3-30 shows the real-time daily load-weighted average LMP for January 2025 through September 2026.

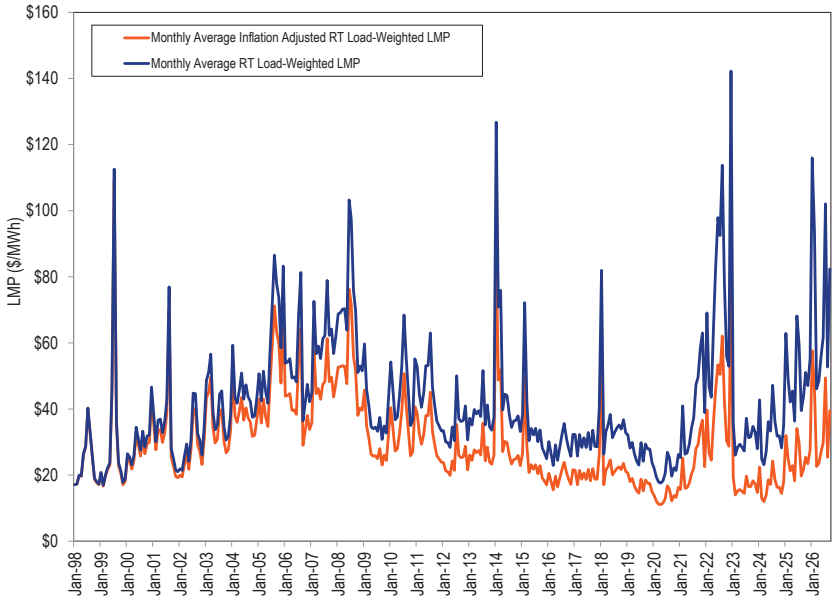
Figure 3-30 Real-time daily load-weighted average LMP: January 2025 through September 2026



PJM Real-Time Monthly Inflation Adjusted Load-Weighted Average LMP

Figure 3-31 shows the PJM real-time monthly load-weighted average LMP and inflation adjusted monthly load-weighted average LMP from January 1998 through September 2026.[86] [87] Table 3-40 shows the PJM real-time load-weighted average LMP and inflation adjusted load-weighted average LMP for the first nine months of every year from 1998 through 2026.

Figure 3-31 Real-time monthly load-weighted average LMP unadjusted and adjusted for inflation: January 1998 through September 2026



86 To obtain the inflation adjusted, monthly, load-weighted, average LMP, the PJM system-wide load-weighted average LMP is deflated using the US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (Accessed October 14, 2026)

87 The U.S. Bureau of Labor Statistics did not publish CPI data for October 2025. October 2025 CPI data was approximated using the geometric mean of September and November 2025 index values. Further information on approximating BLS data for missing data points can be found at: <https://www.bls.gov/cpi/factsheets/approximating-missing-data.htm>.

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Table 3-40 Real-time load-weighted and inflation adjusted load-weighted average LMP: January through September, 1998 through 2026

	Load-Weighted Average LMP	Inflation Adjusted Load-Weighted Average LMP
	Jan-Sep	Jan-Sep
1998	$26.06	$25.86
1999	$38.65	$37.55
2000	$28.49	$26.82
2001	$40.96	$37.39
2002	$31.95	$28.72
2003	$43.57	$38.33
2004	$46.44	$39.85
2005	$60.44	$50.09
2006	$56.39	$45.16
2007	$61.83	$48.36
2008	$77.27	$57.70
2009	$39.57	$29.93
2010	$49.91	$37.04
2011	$49.48	$35.59
2012	$35.02	$24.68
2013	$39.75	$27.58
2014	$58.60	$40.11
2015	$38.94	$26.60
2016	$29.32	$19.77
2017	$30.36	$20.05
2018	$39.43	$25.45
2019	$27.60	$17.49
2020	$21.22	$13.27
2021	$35.68	$21.39
2022	$77.84	$43.04
2023	$30.87	$16.41
2024	$34.31	$17.71
2025	$50.51	$25.40
2026	$74.98	$36.55

Real-Time Dispatch and Pricing

On November 1, 2021, PJM implemented a new real-time dispatch process that aligned the timing of dispatch and pricing in the real-time energy market. The PJM Real-Time Energy Market is based on applications that produce the generator dispatch for energy and reserves, and five minute locational marginal prices (LMPs). These applications include the real-time security constrained economic dispatch (RT SCED), the locational pricing calculator (LPC), and the ancillary services optimizer (ASO).[88] The final real-time LMPs and ancillary service clearing prices are determined for every five minute interval by LPC.

Real-Time SCED and LPC

The LPC uses data from an approved RT SCED solution that was used to dispatch the resources in the system. RT SCED solves to meet load and reserve requirements forecast for a future point in time, called the target time. Prior to 2021, on average, PJM operators approved more than one RT SCED solution per five minute target time to send dispatch signals to resources. From 2021 through the first nine months of 2026, on average, PJM operators approved one RT SCED solution per five minute target time to send dispatch signals to resources. PJM uses a subset of these approved RT SCED solutions in LPC to calculate real-time LMPs every five minutes. Prior to October 15, 2020, LPC used the latest available approved RT SCED solution to calculate prices, regardless of the target dispatch time of the RT SCED solution, but LPC assigned the prices to a five minute interval that did not contain the target time of the RT SCED case it used. On November 1, 2021, PJM implemented changes to RT SCED that solved the energy dispatch case using a five-minute dispatch period, and ramped resources for five minutes to meet the load and reserve requirements at the end of each five minute period. The approved RT SCED solution that dispatched units for each five minute period was also used to calculate prices for the same five minute interval, aligning the prices with the dispatch signals.

Table 3-41 shows the number of RT SCED case solutions, the number of solutions that were approved, and the number and percent of approved solutions used in LPC. The RT SCED execution frequency is once every five minutes. PJM operators have the ability to execute additional RT SCED cases. Each execution of RT SCED produces five solutions, using five different levels of load bias. Since prices are calculated every five minutes while five SCED solutions are produced every five minutes, there is, by definition, a larger number of SCED solutions than there are five minute intervals in any given period.

88 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 133 (Dec. 17, 2024).

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Table 3-41 shows that in the first nine months of 2026, 98.3 percent of approved RT SCED solutions that were used to send dispatch signals to generators were used in calculating real-time energy market prices, compared to 98.0 percent in all of 2025.

Table 3-41 RT SCED cases solved, approved and used in pricing: January 2025 through September 2026

	2025				2026			
Month	Number of RT SCED Solutions	Number of Approved RT SCED Solutions	Number of Approved RT SCED Solutions Used in LPC	RT SCED Solutions Used in LPC as Percent of Approved RT SCED Solutions	Number of RT SCED Solutions	Number of Approved RT SCED Solutions	Number of Approved RT SCED Solutions Used in LPC	RT SCED Solutions Used in LPC as Percent of Approved RT SCED Solutions
Jan	46,098	9,146	8,895	97.3%	45,724	9,048	8,878	98.1%
Feb	41,310	8,213	8,020	97.7%	41,058	8,151	7,982	97.9%
Mar	46,674	9,013	8,823	97.9%	45,526	8,981	8,838	98.4%
Apr	44,215	8,766	8,608	98.2%	44,628	8,708	8,575	98.5%
May	45,702	9,053	8,867	97.9%	45,867	8,969	8,874	98.9%
Jun	44,319	8,812	8,582	97.4%	44,214	8,743	8,582	98.2%
Jul	45,713	9,076	8,889	97.9%	45,636	9,067	8,889	98.0%
Aug	45,491	9,022	8,860	98.2%	45,535	9,035	8,871	98.2%
Sep	43,744	8,736	8,556	97.9%	44,331	8,695	8,573	98.6%
Oct	45,271	8,991	8,859	98.5%				
Nov	44,285	8,731	8,586	98.3%				
Dec	45,514	8,990	8,855	98.5%				
Total	538,336	106,549	104,400	98.0%	402,519	79,397	78,062	98.3%

Recalculation of Five Minute Real-Time Prices

PJM's five minute interval LMPs are obtained from solved LPC cases. PJM recalculates five minute interval real-time LMPs as it believes necessary to correct errors. To do so, PJM reruns LPC cases with modified inputs. The PJM OATT allows for posting of recalculated real-time prices no later than 1700 (EPT) of the tenth calendar day following the operating day. The OATT also requires PJM to notify market participants of the underlying error no later than 1700 (EPT) of the second business day following the operating day.[89] Table 3-42 shows the number of five minute intervals in each month and number of five minute intervals in each month for which PJM recalculated real-time prices in 2025 and the first nine months of 2026. In the first nine months of 2026, PJM recalculated LMPs for 1,048 five minute intervals, or 1.3 percent of the total 78,612 five minute intervals.

Table 3-42 Number of five minute interval real-time prices recalculated: January 2025 through September 2026

	2025			2026		
Month	Number of Five Minute Intervals	Number of Five Minute Intervals for Which LMPs Were Recalculated	Percent	Number of Five Minute Intervals	Number of Five Minute Intervals for Which LMPs Were Recalculated	Percent
January	8,928	154	1.7%	8,928	123	1.4%
February	8,064	189	2.3%	8,064	136	1.7%
March	8,916	680	7.6%	8,916	87	1.0%
April	8,640	126	1.5%	8,640	104	1.2%
May	8,928	153	1.7%	8,928	79	0.9%
June	8,640	162	1.9%	8,640	150	1.7%
July	8,928	183	2.0%	8,928	98	1.1%
August	8,928	137	1.5%	8,928	91	1.0%
September	8,640	142	1.6%	8,640	180	2.1%
October	8,928	132	1.5%			
November	8,652	93	1.1%			
December	8,928	115	1.3%			
Total	105,120	2,266	2.2%	78,612	1,048	1.3%

Day-Ahead Average LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[90]

PJM Day-Ahead Average LMP

Table 3-43 shows the day-ahead average LMP for the first nine months of 2001 through 2026. The day-ahead average LMP in the first nine months of 2026 increased $18.34 per MWh, or 40.1 percent, from the first nine months of 2025, from $45.69 per MWh to $64.04 per MWh.

89 OA Attachment K Section 1 § 1.10.8(e).

90 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>.

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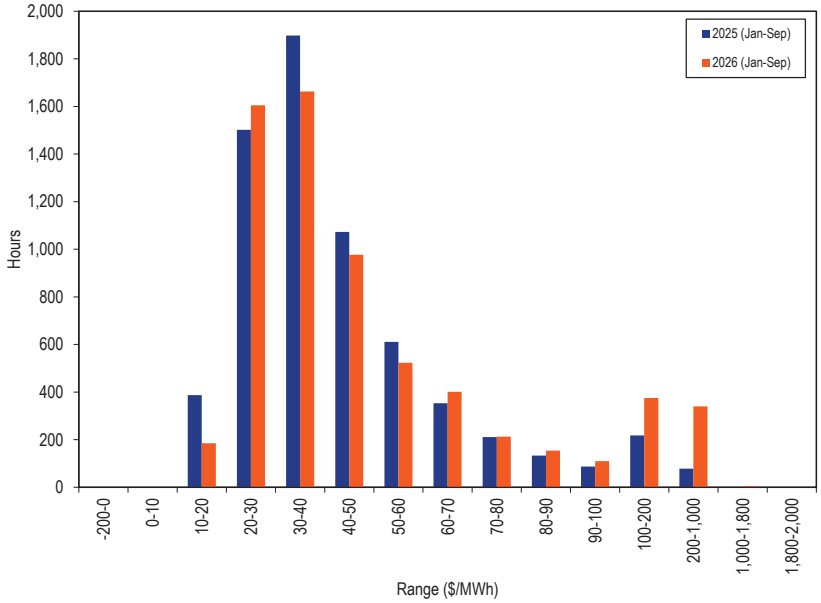
Table 3-43 Day-ahead average LMP (Dollars per MWh): January through September, 2001 to 2026

	Day-Ahead LMP			Year to Year Change			
Jan-Sep	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
2001	$36.07	$30.02	$34.25	NA	NA	NA	NA
2002	$28.29	$22.54	$19.09	($7.78)	(21.6%)	(24.9%)	(44.3%)
2003	$41.20	$38.24	$22.02	$12.91	45.6%	69.7%	15.4%
2004	$42.64	$42.07	$17.47	$1.44	3.5%	10.0%	(20.7%)
2005	$54.48	$46.67	$28.83	$11.85	27.8%	10.9%	65.1%
2006	$50.45	$46.32	$24.93	($4.03)	(7.4%)	(0.8%)	(13.5%)
2007	$54.24	$51.40	$24.95	$3.79	7.5%	11.0%	0.1%
2008	$71.43	$66.38	$33.11	$17.19	31.7%	29.2%	32.7%
2009	$37.35	$35.29	$14.32	($34.08)	(47.7%)	(46.8%)	(56.8%)
2010	$45.81	$41.03	$19.59	$8.46	22.7%	16.3%	36.8%
2011	$45.14	$40.20	$22.68	($0.67)	(1.5%)	(2.0%)	15.7%
2012	$32.16	$30.10	$14.54	($12.98)	(28.8%)	(25.1%)	(35.9%)
2013	$37.50	$34.70	$16.96	$5.34	16.6%	15.3%	16.6%
2014	$53.76	$39.92	$58.98	$16.26	43.4%	15.0%	247.8%
2015	$36.67	$30.56	$25.21	($17.09)	(31.8%)	(23.4%)	(57.3%)
2016	$27.90	$25.23	$11.37	($8.76)	(23.9%)	(17.4%)	(54.9%)
2017	$28.90	$26.60	$10.73	$0.99	3.6%	5.4%	(5.6%)
2018	$36.04	$29.75	$25.12	$7.14	24.7%	11.8%	134.2%
2019	$26.41	$24.76	$9.58	($9.63)	(26.7%)	(16.8%)	(61.9%)
2020	$19.72	$18.47	$6.99	($6.69)	(25.3%)	(25.4%)	(27.0%)
2021	$33.34	$28.28	$16.54	$13.63	69.1%	53.1%	136.7%
2022	$72.36	$63.56	$33.81	$39.02	117.0%	124.8%	104.4%
2023	$30.10	$27.83	$15.28	($42.26)	(58.4%)	(56.2%)	(54.8%)
2024	$31.09	$25.71	$21.00	$0.99	3.3%	(7.6%)	37.5%
2025	$45.69	$36.75	$35.12	$14.60	47.0%	42.9%	67.2%
2026	$64.04	$38.68	$89.45	$18.34	40.1%	5.2%	154.7%

PJM Day-Ahead Average LMP Duration

Figure 3-32 shows the hourly distribution of the day-ahead average LMP for the first nine months of 2025 and 2026.

Figure 3-32 Distribution of day-ahead LMP: January through September, 2025 and 2026



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, with each hourly LMP weighted by the PJM total cleared day-ahead total hourly load, including day-ahead fixed load, price-sensitive load, decrement bids and up to congestion.

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PJM Day-Ahead Load-Weighted Average LMP

Table 3-44 shows the day-ahead load-weighted average LMP in the first nine months of 2001 through 2026. The day-ahead load-weighted average LMP in the first nine months of 2026 increased $22.85 per MWh, or 45.8 percent, from the first nine months of 2025, from $49.88 per MWh to $72.73 per MWh.

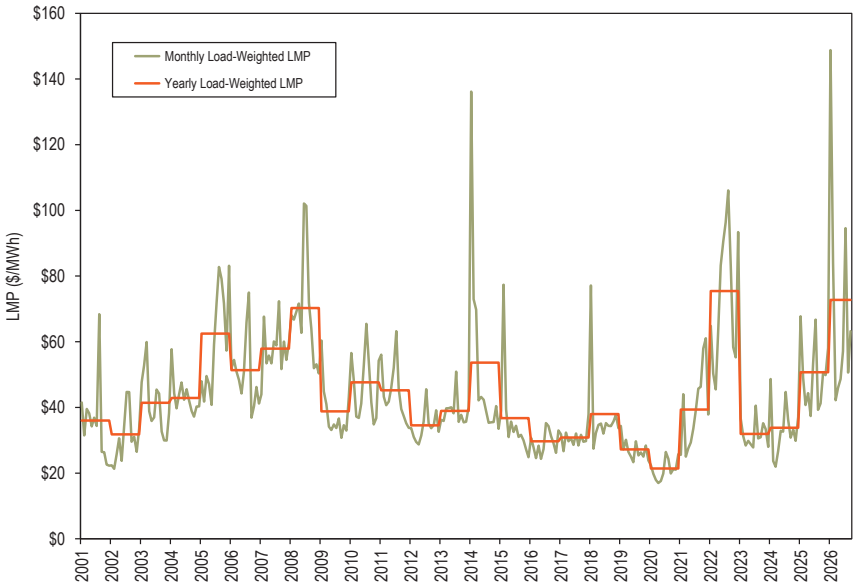
Table 3-44 Day-ahead load-weighted average LMP (Dollars per MWh): January through September, 2001 to 2026

	Day-Ahead Load-Weighted Average LMP			Year to Year Change			
Jan-Sep	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
2001	$39.88	$32.68	$42.01	NA	NA	NA	NA
2002	$32.29	$25.22	$22.81	($7.59)	(19.0%)	(22.8%)	(45.7%)
2003	$44.11	$41.51	$22.34	$11.82	36.6%	64.6%	(2.1%)
2004	$44.59	$44.47	$17.40	$0.49	1.1%	7.1%	(22.1%)
2005	$59.51	$51.33	$31.13	$14.92	33.5%	15.4%	78.9%
2006	$54.19	$48.87	$28.35	($5.32)	(8.9%)	(4.8%)	(8.9%)
2007	$57.79	$55.62	$26.07	$3.59	6.6%	13.8%	(8.0%)
2008	$75.96	$70.35	$35.19	$18.18	31.5%	26.5%	35.0%
2009	$39.35	$36.92	$14.98	($36.61)	(48.2%)	(47.5%)	(57.4%)
2010	$49.12	$43.33	$21.35	$9.77	24.8%	17.4%	42.6%
2011	$48.34	$42.35	$26.54	($0.78)	(1.6%)	(2.3%)	24.3%
2012	$34.29	$31.17	$17.12	($14.05)	(29.1%)	(26.4%)	(35.5%)
2013	$39.49	$35.96	$19.90	$5.20	15.1%	15.4%	16.3%
2014	$59.09	$42.08	$67.27	$19.60	49.6%	17.0%	238.0%
2015	$39.51	$32.15	$28.05	($19.58)	(33.1%)	(23.6%)	(58.3%)
2016	$29.69	$26.60	$12.38	($9.82)	(24.8%)	(17.3%)	(55.8%)
2017	$30.26	$27.95	$11.59	$0.56	1.9%	5.1%	(6.4%)
2018	$38.71	$31.62	$27.75	$8.45	27.9%	13.1%	139.5%
2019	$27.70	$25.85	$10.40	($11.01)	(28.4%)	(18.3%)	(62.5%)
2020	$20.95	$19.23	$7.75	($6.75)	(24.4%)	(25.6%)	(25.4%)
2021	$35.51	$30.01	$17.97	$14.57	69.5%	56.0%	131.8%
2022	$76.97	$67.42	$36.82	$41.46	116.7%	124.7%	104.9%
2023	$31.90	$29.08	$17.68	($45.07)	(58.6%)	(56.9%)	(52.0%)
2024	$33.85	$27.47	$23.62	$1.95	6.1%	(5.5%)	33.6%
2025	$49.88	$39.06	$40.28	$16.03	47.4%	42.2%	70.5%
2026	$72.73	$41.65	$102.06	$22.85	45.8%	6.6%	153.4%

PJM Day-Ahead Monthly Load-Weighted Average LMP

Figure 3-33 shows the day-ahead monthly and yearly load-weighted average LMP in 2001 through the first nine months of 2026.

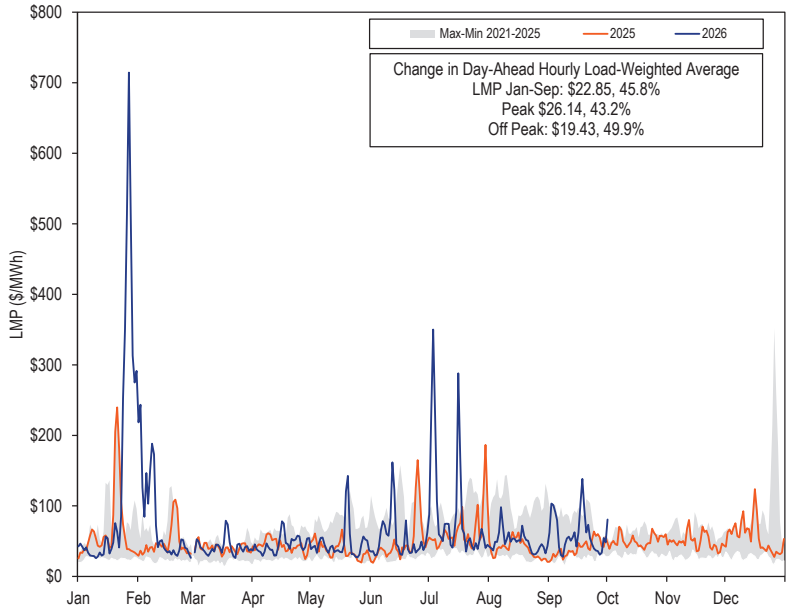
Figure 3-33 Day-ahead monthly and yearly load-weighted average LMP: 2001 through September 2026



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Figure 3-34 shows the day-ahead daily load-weighted average LMP in January 2025 through September 2026 compared to the historic five year price range.

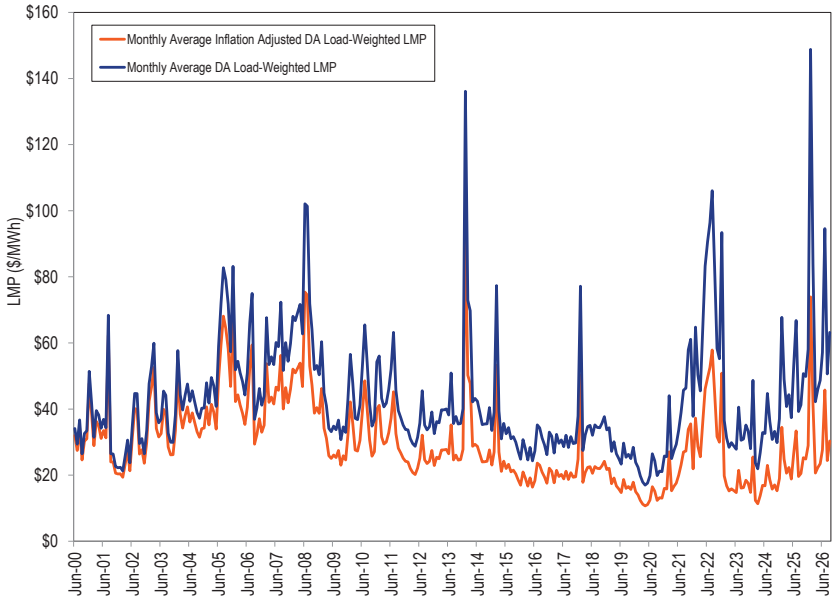
Figure 3-34 Day-ahead daily load-weighted average LMP: 2025 through September 2026



PJM Day-Ahead Monthly Inflation Adjusted Load-Weighted Average LMP

Figure 3-35 shows the PJM day-ahead monthly load-weighted average LMP and inflation adjusted monthly day-ahead load-weighted average LMP for June 2000 through September 2026.[91] [92] Table 3-45 shows the PJM day-ahead load-weighted average LMP and inflation adjusted load-weighted average LMP for the first nine months every year from 2000 through 2026.

Figure 3-35 Day-ahead monthly load-weighted and inflation adjusted load-weighted average LMP: June 2000 through September 2026



91 To obtain the inflation adjusted monthly load-weighted average LMP, the PJM system-wide load-weighted average LMP is deflated using US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (Accessed October 14, 2026).

92 The U.S. Bureau of Labor Statistics did not publish CPI data for October 2025. October 2025 CPI data was approximated using the geometric mean of September and November 2025 index values. Further information on approximating BLS data for missing data points can be found at: <https://www.bls.gov/cpi/factsheets/approximating-missing-data.htm>.

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Table 3-45 Day-ahead yearly load-weighted and inflation adjusted load-weighted average LMP: January through September, 2000 through 2026

	Load-Weighted Average LMP	Inflation Adjusted Load-Weighted Average LMP
	Jan-Sep	Jan-Sep
2000	$31.81	$29.74
2001	$39.88	$36.41
2002	$32.29	$29.02
2003	$44.11	$38.81
2004	$44.59	$38.26
2005	$59.51	$49.32
2006	$54.19	$43.40
2007	$57.79	$45.19
2008	$75.96	$56.73
2009	$39.35	$29.77
2010	$49.12	$36.46
2011	$48.34	$34.79
2012	$34.29	$24.17
2013	$39.49	$27.40
2014	$59.09	$40.45
2015	$39.51	$26.99
2016	$29.69	$20.03
2017	$30.26	$19.99
2018	$38.71	$24.98
2019	$27.70	$17.55
2020	$20.95	$13.09
2021	$35.51	$21.30
2022	$76.97	$42.57
2023	$31.90	$16.96
2024	$33.85	$17.48
2025	$49.88	$25.09
2026	$72.73	$35.51

Price Convergence

The introduction of the PJM Day-Ahead Energy Market with virtuals as part of the design created the possibility that competition, exercised through the use of virtual offers and bids, could tend to cause prices in the day-ahead and real-time energy markets to converge more than would be the case without virtuals. Convergence is not the goal of virtual trading, but it is a possible outcome.

In practice, virtuals can receive a positive profit whenever there is a difference in prices at any location in any hour between the day-ahead and real-time energy markets that is greater than uplift and administrative charges.

Virtual trading can only result in price convergence at a given location and market hour if the factors affecting prices at that location and hour, such as modeled contingencies, transmission constraint limits and sources of flows, are the same in both the day-ahead and real-time models.

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 result in positive profits for the virtual but cannot change the underlying reason for the price difference. The virtual transactions will continue to profit from the activity for that reason regardless of the volume of those transactions and without improving the efficiency of the energy market. This is termed false arbitrage.

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 uplift 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.

INCs, DECs and UTCs allow participants to benefit from price differences between the day-ahead and real-time energy market. In theory, virtual transactions receive positive profits, after uplift and administrative charges, when they contribute to price convergence, but with false arbitrage, profits result with little or no price convergence. 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

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price for energy, after uplift and administrative charges, the INC is profitable. 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, after uplift and administrative charges, the DEC is profitable.

The profit of a UTC transaction is the net of the separate revenues of the component INC and DEC, after uplift and administrative charges. A UTC can be profitable if the profits on one side of the UTC transaction exceed the losses on the other side.

Virtual transactions, including UTCs since November 1, 2020, are required to pay uplift charges. Cleared INCs and DECs pay deviation charges based on the daily RTO and applicable regional operating reserve charge rates. DECs pay day-ahead operating reserve charges in addition to deviation charges. Cleared UTCs are treated, for uplift purposes, like DECs at the UTC sink point, and pay the regional and RTO deviation rates in addition to the day-ahead rate. Uplift charges for deviations may not apply if the virtual transaction is partially or fully offset by a corresponding real-time physical transaction at the same location.

In the day-ahead market, load bids are submitted by market buyers at aggregate pnodes, and PJM uses historic bus level load data to distribute the aggregate bids among the bus level pnodes that comprise the aggregate pnode. Effective December 14, 2023, PJM modified the method used to assign load bids to nodes from a single snapshot at 8:00 AM the week prior to the hourly demand data from one week prior to the Operating Day for each hour. [93]

Profitability of Virtual Transactions

The profit of a virtual transaction equals its net day-ahead and real-time energy market revenues minus uplift and administrative charges.

Table 3-46 shows, for cleared UTCs, the number of UTCs, the number of profitable UTCs, and the number of UTCs profitable at their source point, at their sink point, and at both source and sink points in the first nine months of 2025 and 2026. In the first nine months of 2026, 41.2 percent of all cleared UTC transactions were profitable. Of cleared UTC transactions, 62.7 percent were profitable on the source side and 34.1 percent were profitable on the sink side, but only 9.4 percent were profitable on both the source and sink side.

Table 3-46 Cleared UTCs with positive profits at source and sink points: January through September, 2025 and 2026[94]

(Jan-Sep)	Number of Cleared UTCs	Number of Profitable UTCs	Profitable at Source	Profitable at Sink	Profitable at Source and Sink	Share Profitable Overall	Share Profitable Source	Share Profitable Sink	Share Profitable Source and Sink
2025	4,857,966	1,966,078	3,047,678	1,707,527	388,730	40.5%	62.7%	35.1%	8.0%
2026	4,985,432	2,052,866	3,123,573	1,700,776	467,053	41.2%	62.7%	34.1%	9.4%

93 PJM Interconnection, L.L.C., Tariff Revisions to Improve the Determination of Day-Ahead Zonal Load Factors, Docket No. ER23-1529 (March 31, 2023).
94 Calculations exclude PJM administrative charges.

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Table 3-47 shows the number of cleared INC and DEC transactions and the number of profitable transactions in the first nine months of 2025 and 2026. Of cleared INC and DEC transactions in the first nine months of 2026, 53.4 percent of INCs were profitable and 31.3 percent of DECs were profitable.

Table 3-47 Cleared INC and DEC transactions with positive profits: January through September, 2025 and 2026

(Jan-Sep)	Cleared INC	Profitable INC	Profitable INC Share	Cleared DEC	Profitable DEC	Profitable DEC Share
2025	3,480,378	1,799,151	51.7%	3,253,797	1,006,479	30.9%
2026	3,875,842	2,070,824	53.4%	3,777,074	1,182,428	31.3%

Figure 3-36 shows the positive, negative, and net daily profits for UTCs in the first nine months of 2026.

Figure 3-36 Positive, negative, and net daily UTC profits: January through September, 2026

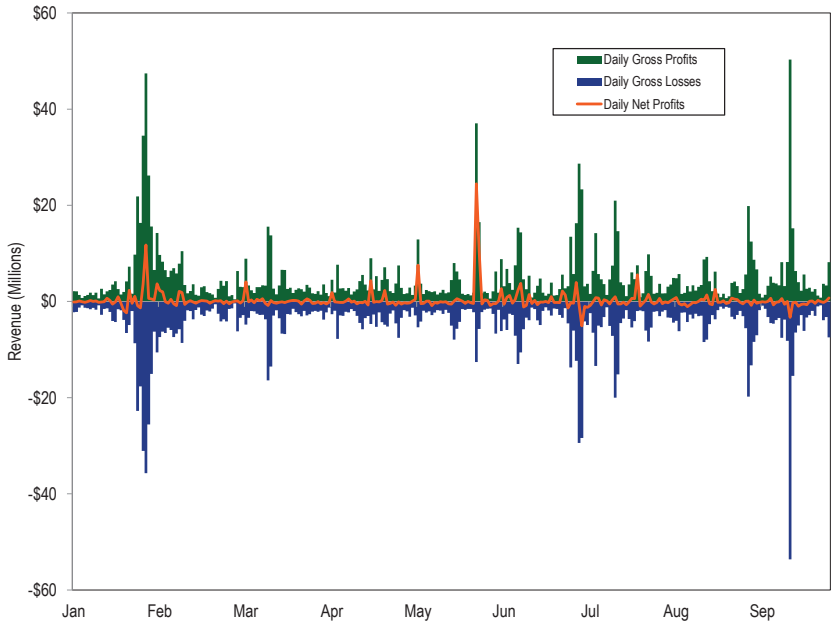


Figure 3-37 shows the cumulative UTC daily total net profits for each year from 2013 through the first nine months of 2026.[95] Administrative charges are included for all dates, and uplift charges are included starting from November 1, 2020, when uplift was first charged to UTCs.

Figure 3-37 Cumulative daily UTC profits: January 2013 through September 2026

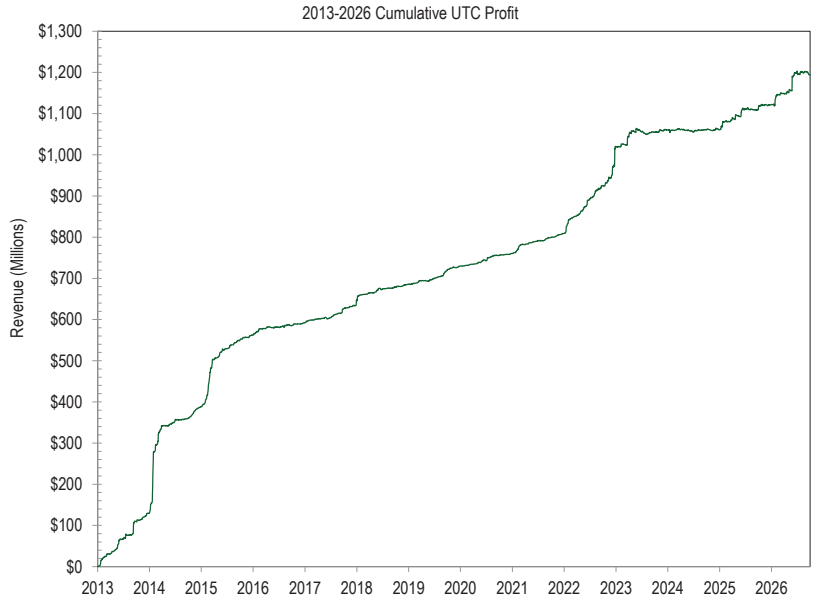


Table 3-48 shows UTC monthly total net profits for January 2013 through September 2026. Administrative charges are included for all months and uplift charges are included starting from November 1, 2020, when uplift was first charged to UTCs. UTC profits were $211 million in 2022, higher than any year since 2014, with the largest monthly total in December 2022 at $75 million. In 2023, the most profitable UTC transactions were concentrated in the Dominion Zone and on dates with high real-time congestion in the Dominion Zone, which occurred primarily in January through May, 2023. The

95 UTCs paid uplift only after October 31, 2020.

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year 2024 was the least profitable year ever for UTC transactions, with very large profitable days occurring with less frequency than prior years. DOMINION HUB to DOM_RESID_AGG UTC remains the path with the highest cleared volume in 2025 and the first nine months of 2026. May 2026 was the most profitable month since December 2022, driven by emergency transmission outages at the Greenway-Roundtable parallel lines in Data Center Alley in the last week of the month.

Table 3-48 UTC profits by month: January 2013 through September 2026

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2013	$17,048,654	$8,304,767	$5,629,392	$7,560,773	$25,219,947	$3,484,372	$8,781,526	$2,327,168	$31,160,618	$4,393,583	$8,730,701	$6,793,990	$129,435,490
2014	$148,973,434	$23,235,621	$39,448,716	$1,581,786	$3,851,636	$7,353,460	$3,179,356	$287,824	$2,727,763	$10,889,817	$11,042,443	$6,191,101	$258,762,955
2015	$16,132,319	$53,830,098	$44,309,656	$6,392,939	$19,793,475	$824,817	$8,879,275	$5,507,608	$6,957,012	$4,852,454	$392,876	$6,620,581	$174,493,110
2016	$8,874,363	$6,118,477	$1,119,457	$2,768,591	($1,333,563)	$841,706	$3,128,346	$3,200,573	($2,518,408)	$4,216,717	$254,684	$3,271,368	$29,942,312
2017	$5,716,757	($17,860)	$3,083,167	$944,939	$1,245,988	$868,400	$7,053,390	$4,002,063	$10,960,012	$2,360,817	$2,716,950	$15,936,217	$54,870,839
2018	$13,184,346	$506,509	$3,410,577	$688,796	$9,499,735	($768,614)	$1,163,380	$692,736	$2,845,649	$1,452,515	$4,339,363	$1,358,446	$38,373,436
2019	$574,901	$2,407,307	$5,287,985	$332,036	$1,833,879	$3,382,009	$4,066,461	$2,442,971	$12,599,278	$5,914,042	$1,171,145	$3,722,403	$43,734,418
2020	$664,972	$2,497,856	$1,720,037	$1,865,139	$5,508,276	$1,123,429	$8,573,276	$3,957,296	($141,240)	$1,628,186	$1,170,367	$2,319,727	$30,887,320
2021	$6,421,567	$13,241,294	$1,788,961	$4,529,921	$2,542,898	$3,384,291	($1,199,849)	$5,330,600	$2,649,331	$2,148,861	$5,091,590	$2,665,873	$48,595,339
2022	$30,954,077	$7,236,325	$4,411,627	$11,317,095	$11,658,586	$16,398,181	$9,481,970	$17,376,381	$6,783,480	$7,325,933	$13,116,641	$75,067,601	$211,127,897
2023	($374,877)	$5,180,921	$18,722,180	$13,543,116	$5,121,917	($6,820,656)	($5,587,077)	$3,667,565	$1,041,650	$787,185	$3,734,966	$1,259,381	$40,276,272
2024	($798,085)	$741,801	$505,530	($1,048,989)	($1,481,223)	($1,997,609)	$3,605,145	($28,816)	$440,898	($852,701)	$472,000	$677,521	$235,473
2025	$19,307,539	$965,550	$9,446,437	$5,569,957	($1,921,483)	$17,309,458	($1,634,565)	($406,499)	$1,936,052	$10,057,277	($1,107,552)	$1,903,108	$61,425,280
2026	$17,607,904	$5,488,600	$2,880,710	$3,168,987	$38,539,496	$9,713,489	$2,121,964	$376,850	($7,199,714)				$72,698,285

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Figure 3-38 shows the positive, negative, and net daily profits for INCs and DECs in the first nine months of 2026. Differences in the modeling of transmission constraints between day ahead and real time, including the use of different constraint limits or a constraint being modeled in one market but not the other, remain a principal source of false arbitrage profits and a major reason for the overall profitability of virtual transactions.

Figure 3-38 Daily gross profits, gross losses, and net profits of all INC and DEC transactions: January through September, 2026[96]

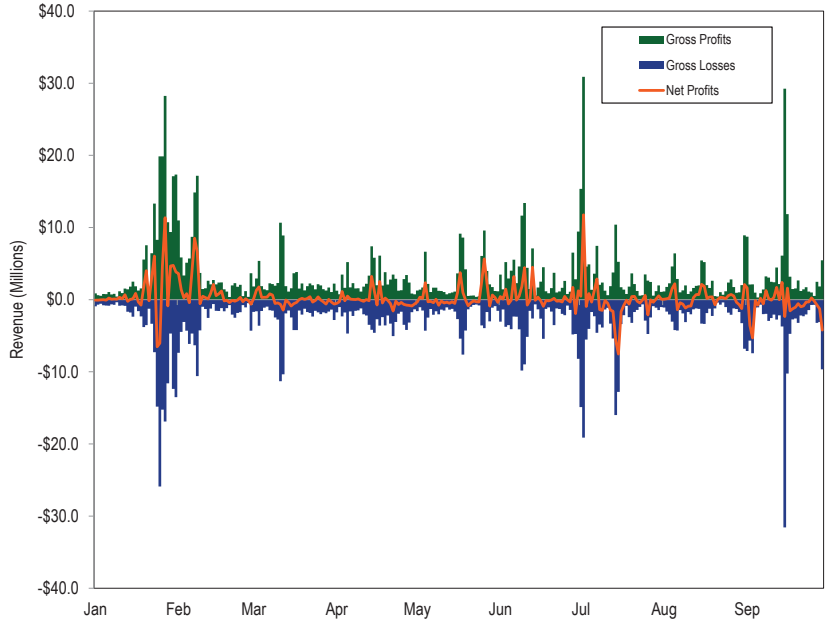
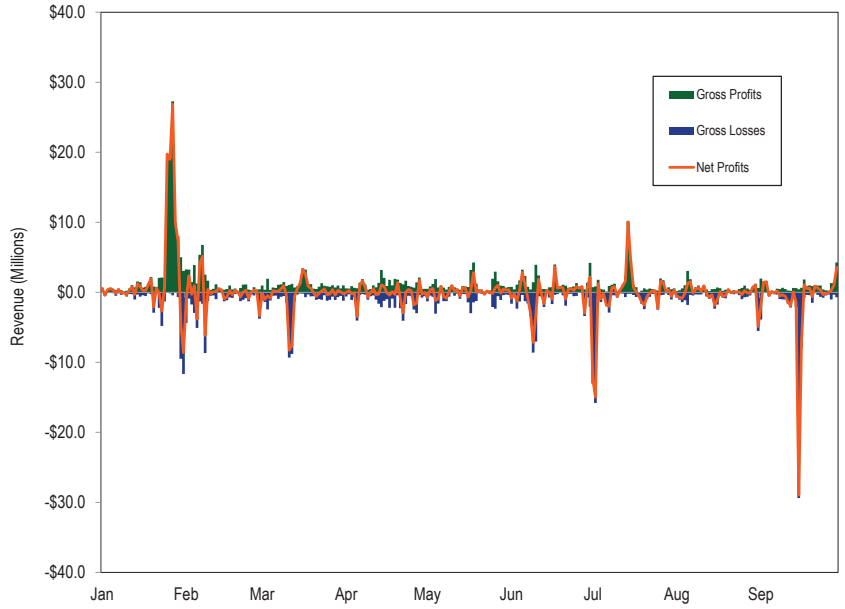


Figure 3-39 shows the positive, negative, and net daily profits for INCs in the first nine months of 2026.

Figure 3-39 Daily gross profits, gross losses, and net profits for INC transactions: January through September, 2026[97]



96 Calculations exclude PJM administrative charges.

97 Calculations exclude PJM administrative charges.

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Figure 3-40 shows the positive, negative, and net daily profits for DECs in the first nine months of 2026.

Figure 3-40 Daily gross profits, gross losses, and net profits for DEC transactions: January through September, 2026

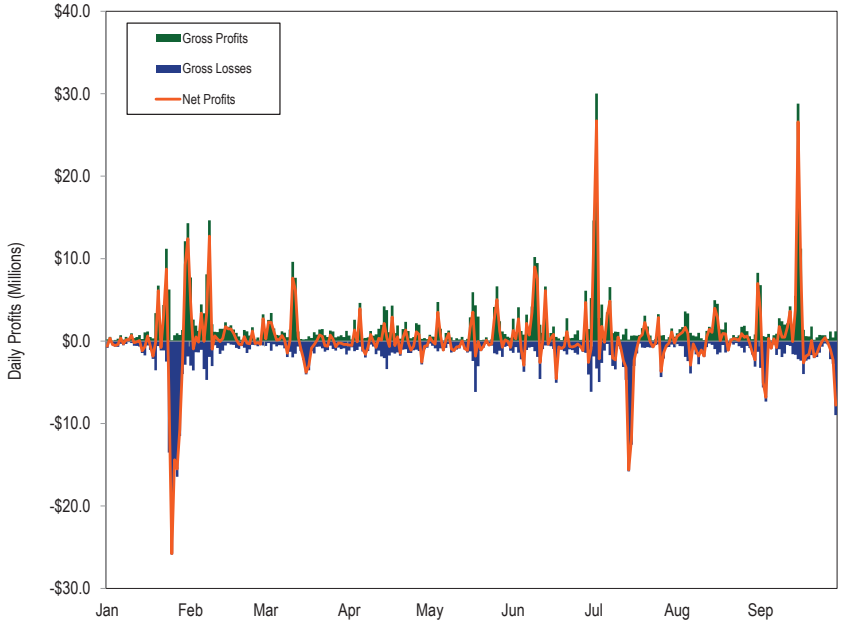
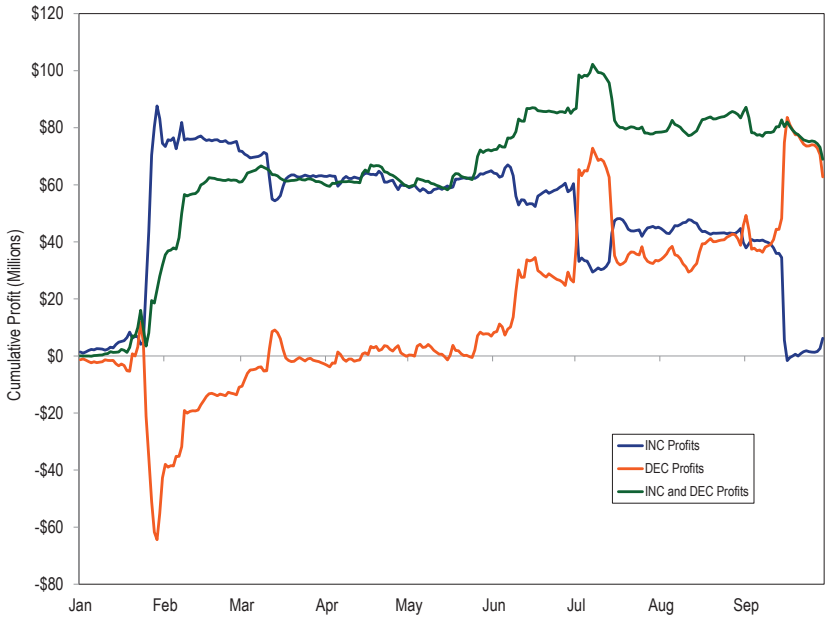


Figure 3-41 shows the cumulative INC and DEC daily profits in the first nine months of 2026. Virtual trading can be profitable without contributing to price convergence because the addition of virtual supply or demand in the day-ahead market does not and cannot correct for factors not included in the day-ahead model, such as the use of different transmission constraint limits in day ahead versus real time. Real-time prices on September 16, 2026, experienced several shortage pricing intervals during the evening peak, yielding the highest net daily losses for INC transactions and bringing the cumulative profit to a loss for the year to date.

Figure 3-41 Cumulative daily INC and DEC profit: January through September, 2026



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Table 3-49 shows INC and DEC profits in the first nine months of 2026.

Table 3-49 INC and DEC profits by month: January through September, 2026

Month	January	February	March	April	May	June	July	August	September	Total
INCs	$83,146,285	($7,955,876)	($12,003,647)	($3,426,507)	$4,800,435	($6,339,014)	($13,361,510)	($192,337)	($38,488,458)	$6,179,371
DECs	($55,167,048)	$41,539,310	$11,250,384	$2,815,316	$7,280,485	$19,096,430	$6,705,921	$5,243,211	$24,013,566	$62,777,576
INCs and DECs	$27,979,237	$33,583,434	($753,263)	($611,192)	$12,080,920	$12,757,416	($6,655,589)	$5,050,874	($14,474,892)	$68,956,947

All virtual transactions are subject to uplift charges. Each cleared MWh of a virtual transaction pays uplift at the daily operating reserve charge rates, but UTCs pay uplift only at the transaction sink. Cleared increment offers pay the regional and RTO deviation rates, and cleared decrement bids pay the day-ahead rate in addition. Cleared up to congestion transactions pay the same rate as a decrement bid but only at the transaction's sink point. DECs and UTCs pay the day-ahead rate and RTO and regional deviation rates.

In the first nine months of 2026, INCs paid a total of $41.4 million, DECs paid a total of $65.6 million, and UTCs paid a total of $73.6 million in uplift. This compares to total INC profits of $6.2 million, total DEC profits of $62.8 million, and total UTC profits of $72.7 million.

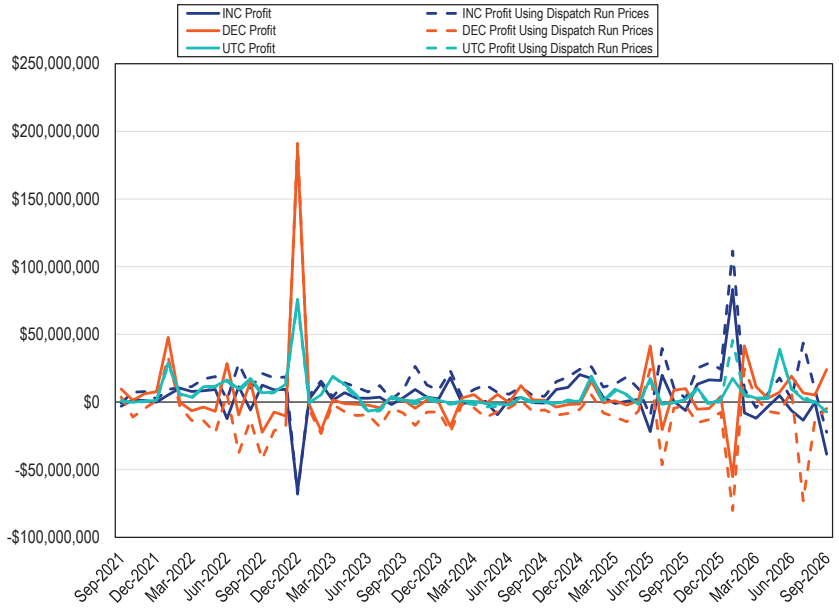
Effect of Fast Start Pricing on Virtuals

The implementation of fast start pricing on September 1, 2021, resulted in changes to the settlement of virtual transactions. Prior to fast start pricing, virtual products were cleared and settled based on a single set of prices. The dispatch and pricing run prices were the same. With fast start pricing, all virtual products are cleared using day-ahead dispatch run prices, but pay and receive the day-ahead and real-time pricing run prices. The use of fast start pricing has a direct effect on virtual settlements through the use of prices different from those used to dispatch virtuals. This means that a DEC may clear in the day-ahead market, based on the dispatch run, even though its offer is lower than the final, pricing run price. This means that an INC may clear even though its offer is higher than the day-ahead market price. The use of fast start pricing also results in divergence between day-ahead and real-time prices, which can be targeted by virtual traders. The fact that fast start pricing increases prices more in the real-time market, all else held equal, increases the profitability of DECs and decreases the profitability of INCs.

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Figure 3-42 shows the total monthly profits received by INCs, DECs, and UTCs, compared to the profits they would have received if dispatch run prices had been used in settlement for each month since the initial implementation of fast start pricing in September 2021. Since its implementation, fast start pricing has consistently increased profits for DECs and decreased profits for INCs but has not significantly affected profits for UTCs. Fast start pricing creates a difference between day-ahead and real-time prices. Virtual traders can benefit from this difference without contributing to price convergence.

Figure 3-42 Monthly profits for virtuals using pricing run versus dispatch run prices: September 1, 2021 through September 30, 2026



From the implementation of fast start pricing on September 1, 2021, through September 30, 2026, the cumulative difference in profit resulting from the difference between the pricing run and the dispatch run for INCs was -$586.8 million, the cumulative difference in profit for DECs was $742.9 million, and the cumulative difference in profit for UTCs was $21.5 million. Fast start pricing led to a net increase of $177.7 million in cumulative profits for virtual transactions since September 1, 2021.

There are incentives to use virtual transactions to profit from price differences between the day-ahead and real-time energy markets, but there is no reason to believe 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, about modeling differences 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. PJM markets do not provide a mechanism that could ever result in convergence in the presence of modeling differences.

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.

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Day-ahead and Real-time Prices

Table 3-50 shows the difference between the day-ahead and the real-time average LMP in the first nine months of 2025 and 2026.

Table 3-50 Day-ahead and real-time average LMP (Dollars per MWh): January through September, 2025 and 2026[98]

	2025 (Jan-Sep)				2026 (Jan-Sep)			
	Day-Ahead	Real-Time	Difference	Percent of Real Time	Day-Ahead	Real-Time	Difference	Percent of Real Time
Average	$45.69	$46.07	$0.38	0.8%	$64.04	$65.84	$1.80	2.7%
Median	$36.75	$34.73	($2.02)	(5.8%)	$38.68	$35.49	($3.19)	(9.0%)
Standard deviation	$35.12	$53.62	$18.49	34.5%	$89.45	$118.58	$29.13	24.6%
Peak average	$56.19	$57.01	$0.81	1.4%	$77.86	$80.32	$2.46	3.1%
Peak median	$44.51	$41.89	($2.62)	(6.3%)	$48.17	$43.89	($4.28)	(9.7%)
Peak standard deviation	$43.36	$71.50	$28.14	39.4%	$106.10	$150.72	$44.62	29.6%
Off peak average	$36.51	$36.51	($0.00)	(0.0%)	$51.83	$53.05	$1.22	2.3%
Off peak median	$31.64	$30.41	($1.23)	(4.1%)	$32.71	$30.64	($2.07)	(6.8%)
Off peak standard deviation	$22.08	$26.90	$4.81	17.9%	$69.35	$77.92	$8.57	11.0%

Table 3-51 shows the difference between the day-ahead and the real-time load-weighted LMP in the first nine months of 2001 through 2026.

Table 3-51 Day-ahead and real-time load-weighted average LMP (Dollars per MWh): January through September, 2001 through 2026

	Load-Weighted Average LMP					
Jan-Sep	Day-Ahead	Real-Time	Difference	Percent of Real-Time	Average Absolute Difference	Average Absolute Difference as a Percent of Real-Time
2001	$39.88	$40.96	$1.09	2.7%	$11.88	29.0%
2002	$32.29	$31.95	($0.33)	(1.0%)	$7.16	22.4%
2003	$44.11	$43.57	($0.54)	(1.2%)	$12.54	28.8%
2004	$44.59	$46.44	$1.84	4.0%	$9.92	21.4%
2005	$59.51	$60.44	$0.93	1.5%	$12.35	20.4%
2006	$54.19	$56.39	$2.19	3.9%	$12.02	21.3%
2007	$57.79	$61.83	$4.05	6.5%	$14.63	23.7%
2008	$75.96	$77.27	$1.30	1.7%	$17.70	22.9%
2009	$39.35	$39.57	$0.21	0.5%	$6.19	15.7%
2010	$49.12	$49.91	$0.79	1.6%	$9.82	19.7%
2011	$48.34	$49.48	$1.14	2.3%	$10.05	20.3%
2012	$34.29	$35.02	$0.73	2.1%	$6.33	18.1%
2013	$39.49	$39.75	$0.26	0.7%	$6.47	16.3%
2014	$59.09	$58.60	($0.49)	(0.8%)	$16.25	27.7%
2015	$39.51	$38.94	($0.57)	(1.5%)	$9.14	23.5%
2016	$29.69	$29.32	($0.37)	(1.3%)	$5.76	19.6%
2017	$30.26	$30.36	$0.10	0.3%	$4.71	15.5%
2018	$38.71	$39.43	$0.73	1.8%	$8.38	21.2%
2019	$27.70	$27.60	($0.10)	(0.4%)	$4.64	16.8%
2020	$20.95	$21.22	$0.28	1.3%	$3.52	16.6%
2021	$35.51	$35.68	$0.17	0.5%	$6.87	19.2%
2022	$76.97	$77.84	$0.87	1.1%	$13.91	17.9%
2023	$31.90	$30.87	($1.03)	(3.3%)	$6.95	22.5%
2024	$33.85	$34.31	$0.46	1.3%	$8.79	25.6%
2025	$49.88	$50.51	$0.63	1.2%	$13.15	26.0%
2026	$72.73	$74.98	$2.25	3.0%	$25.88	34.5%

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

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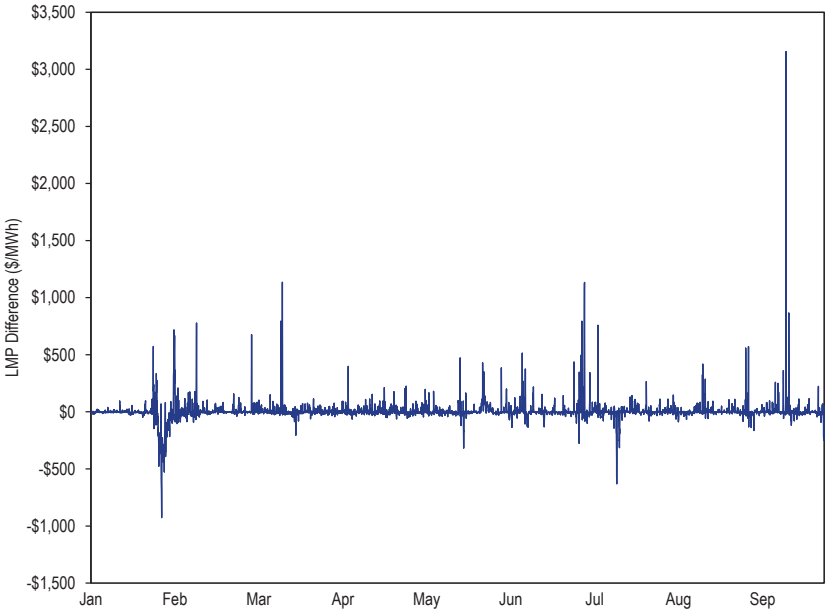
Table 3-52 includes frequency distributions of the differences between the day-ahead and the real-time load-weighted LMP in the first nine months of 2025 and 2026.

Table 3-52 Frequency distribution by hours of real-time load-weighted LMP minus day-ahead load-weighted LMP (Dollars per MWh): January through September, 2025 and 2026

	2026 Jan - Sep		2025 Jan - Sep	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($200)	73	1.1%	6	0.1%
($200) to ($100)	65	2.1%	31	0.6%
($100) to ($50)	142	4.3%	72	1.7%
($50) to $0	4,004	65.4%	3,988	62.5%
$0 to $50	1,832	93.4%	2,295	97.6%
$50 to $100	258	97.3%	108	99.2%
$100 to $200	94	98.7%	35	99.8%
$200 to $400	49	99.5%	8	99.9%
$400 to $800	28	99.9%	4	99.9%
>= $800	6	100.0%	4	100.0%

Figure 3-43 shows the differences between day-ahead and real-time hourly average LMP in the first nine months of 2026.

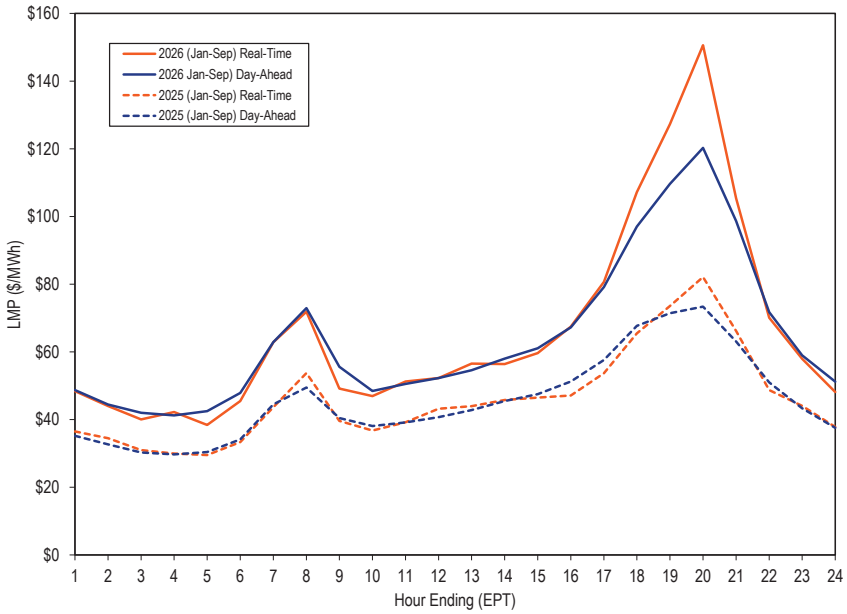
Figure 3-43 Real-time hourly average LMP minus day-ahead hourly average LMP: January through September, 2026



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Figure 3-44 shows day-ahead and real-time load-weighted average LMP by hour of the day in the first nine months of 2025 and 2026.

Figure 3-44 System hourly average LMP: January through September, 2025 and 2026



Zonal LMP and Dispatch

Table 3-53 shows real-time zonal average and load-weighted average LMP for the first nine months of 2025 and 2026.

Table 3-53 Real-time zonal average and load-weighted average LMP (Dollars per MWh): January through September, 2025 and 2026

	Real-Time Average LMP			Real-Time Load-Weighted Average LMP		
	2025	2026		2025	2026	
Zone	Jan-Sep	Jan-Sep	Percent Change	Jan-Sep	Jan-Sep	Percent Change
ACEC	$40.34	$52.16	29.3%	$47.19	$62.57	32.6%
AEP	$45.00	$61.12	35.8%	$48.10	$67.24	39.8%
APS	$46.12	$72.74	57.7%	$50.50	$84.97	68.3%
ATSI	$44.17	$58.05	31.4%	$47.53	$64.24	35.2%
BGE	$55.16	$92.17	67.1%	$62.73	$112.33	79.1%
COMED	$36.27	$40.50	11.7%	$40.72	$46.47	14.1%
DAY	$44.72	$62.90	40.6%	$48.47	$71.32	47.1%
DUKE	$43.25	$63.55	46.9%	$46.80	$73.11	56.2%
DOM	$58.40	$94.63	62.0%	$64.13	$108.09	68.5%
DPL	$43.46	$57.85	33.1%	$51.57	$73.71	42.9%
DUQ	$43.13	$56.79	31.7%	$46.64	$64.29	37.9%
EKPC	$43.91	$58.93	34.2%	$48.65	$69.79	43.5%
JCPLC	$40.59	$53.19	31.1%	$47.59	$64.82	36.2%
MEC	$42.63	$52.79	23.8%	$47.58	$61.92	30.1%
OVEC	$41.75	$57.83	38.5%	$42.31	$59.78	41.3%
PECO	$39.25	$51.09	30.1%	$44.43	$60.61	36.4%
PE	$46.44	$57.63	24.1%	$49.94	$64.33	28.8%
PEPCO	$54.19	$90.49	67.0%	$61.79	$110.73	79.2%
PPL	$38.82	$50.57	30.3%	$43.21	$59.64	38.0%
PSEG	$41.43	$53.94	30.2%	$46.85	$62.78	34.0%
REC	$45.05	$56.54	25.5%	$51.59	$65.74	27.4%
PJM	$46.07	$65.84	42.9%	$50.51	$74.98	48.4%

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Table 3-54 shows day-ahead zonal average and load-weighted average LMP in the first nine months of 2025 and 2026.

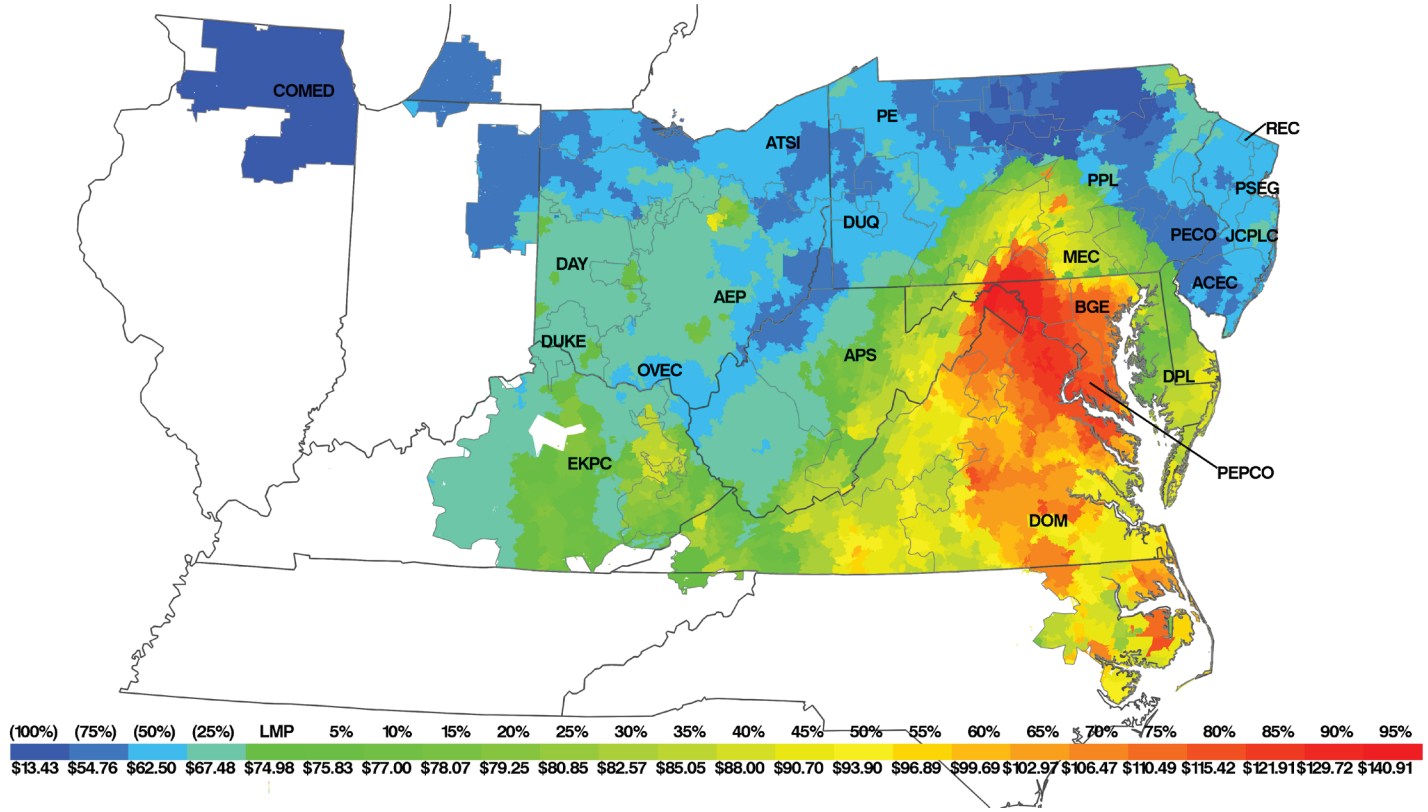
Table 3-54 Day-ahead zonal average and load-weighted average LMP (Dollars per MWh): January through September, 2025 and 2026

	Day-Ahead Average LMP			Day-Ahead Load-Weighted Average LMP		
	2025	2026		2025	2026	
Zone	Jan-Sep	Jan-Sep	Percent Change	Jan-Sep	Jan-Sep	Percent Change
ACEC	$40.75	$53.00	30.1%	$46.30	$62.30	34.6%
AEP	$44.65	$59.55	33.4%	$47.73	$65.46	37.1%
APS	$45.54	$71.23	56.4%	$49.21	$82.44	67.5%
ATSI	$44.62	$57.30	28.4%	$47.71	$62.97	32.0%
BGE	$55.00	$93.44	69.9%	$62.03	$112.77	81.8%
COMED	$36.40	$43.99	20.9%	$40.47	$49.96	23.5%
DAY	$45.24	$62.15	37.4%	$48.87	$70.01	43.3%
DUKE	$43.83	$62.53	42.7%	$47.35	$70.98	49.9%
DOM	$57.38	$86.98	51.6%	$63.63	$101.35	59.3%
DPL	$44.29	$58.89	33.0%	$52.37	$74.69	42.6%
DUQ	$43.01	$55.74	29.6%	$46.24	$62.12	34.3%
EKPC	$43.48	$58.27	34.0%	$48.68	$70.74	45.3%
JCPLC	$40.92	$53.94	31.8%	$46.19	$63.47	37.4%
MEC	$43.31	$53.01	22.4%	$47.77	$60.67	27.0%
OVEC	$42.39	$57.90	36.6%	$41.61	$50.11	20.4%
PECO	$39.71	$51.78	30.4%	$44.14	$60.70	37.5%
PE	$46.92	$58.49	24.7%	$50.04	$62.86	25.6%
PEPCO	$54.11	$90.34	67.0%	$61.38	$109.96	79.2%
PPL	$39.18	$51.03	30.2%	$43.21	$59.43	37.6%
PSEG	$41.11	$54.37	32.3%	$45.31	$61.22	35.1%
REC	$44.83	$56.27	25.5%	$49.44	$62.64	26.7%
PJM	$45.69	$64.04	40.1%	$49.88	$72.73	45.8%

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Figure 3-45 is a map of the real-time load-weighted average LMP for the first nine months of 2026. In the legend, green represents the real-time load-weighted average LMP for the first nine months of 2026 and each increment to the right represents five percent of the pricing nodes above the real-time load-weighted average LMP for the first nine months of 2026 and each increment to the left represents 25 percent of the pricing nodes below the real-time load-weighted average LMP for the first nine months 2026.

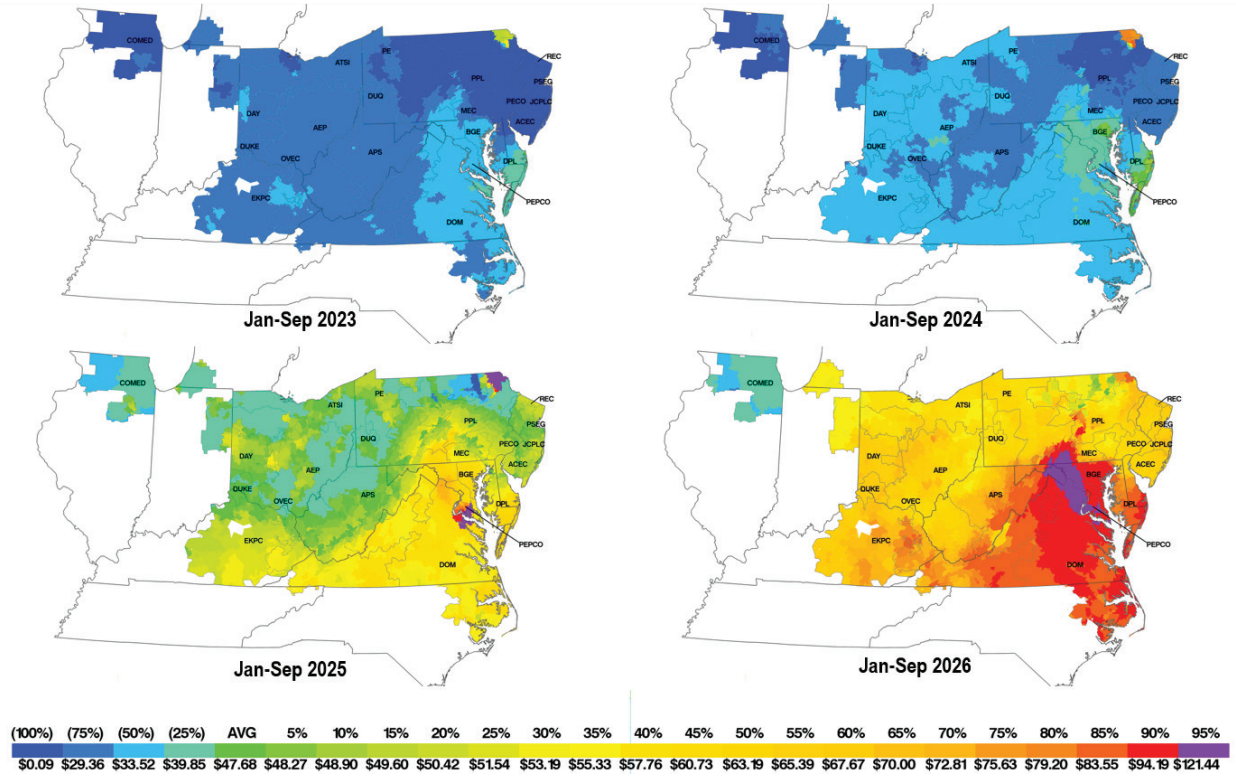
Figure 3-45 Real-time load-weighted average LMP: January through September, 2026



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Figure 3-46 includes maps of the real-time load-weighted average LMP for the first nine months of 2023 through 2026. In the legend, green represents the average price and each color increment to the right represents five percent of the pricing nodes above the average price and each color increment to the left represents 25 percent of the pricing nodes below the average price. The scale is based on prices for the first nine months of all four years.

Figure 3-46 Real-time load-weighted average LMP map: January through September, 2023 through 2026



Transmission Constraint Penalty Factors (TCPF)

LMPs are generally set by the offer prices of marginal resources. When a transmission constraint is binding, the flow on the constraint is equal to its limit and the shadow price of the constraint is a function of offer prices of marginal resources. LMP may, at times, be set by transmission constraint penalty factors. When a transmission constraint is limiting and there are no generation alternatives to resolve the constraint, system operators may allow the transmission limit to be violated. When this occurs, the shadow price of the constraint is set by transmission constraint penalty factors. The shadow price directly affects the LMP.

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Transmission constraint penalty factors are administratively determined and can be thought of as a form of locational shortage pricing, but only when properly applied. The TCPFs are applied incorrectly about 94 percent of the time. In addition, it is not clear that the line ratings are correctly defined, by duration of the flow and ambient conditions, by the transmission owners who have sole control over the line ratings with no meaningful oversight.

PJM operators routinely reduce the control limits on transmission constraint line ratings used in the market clearing software (SCED) by setting the control limits to 95 percent of the actual line ratings.[99] The result is that transmission constraint penalty factors set price much more frequently than needed or appropriate. PJM reduces the control limits both to control for actual flows and for flows that would only result from a contingency (N-1).

Since the implementation of fast start pricing on September 1, 2021, PJM set the default level of the transmission constraint penalty factor in the pricing run of the day-ahead market at $2,000 per MWh. The default level of the transmission constraint penalty factor in the dispatch run of the day-ahead market was left unchanged at $30,000 per MWh.

Table 3-55 shows the frequency and average shadow price of transmission constraints in the PJM real-time market. In the first nine months of 2026, there were 197,821 transmission constraint five minute intervals in the real-time market with a nonzero shadow price. For 31,240, or 15.8 percent, of these transmission constraint intervals, the control limit was violated, meaning that the flow exceeded the facility limit used in SCED.[100] The data on violations includes both violations that result from reductions in the SCED control limit by PJM and violations that are based on the actual line ratings. Of the 31,240 constraint intervals, PJM used the actual line limits for 3,792 or 12.1 percent. For the remaining 27,448 or 87.9 percent of the constraint intervals, PJM used reduced line limits. In those cases, the actual line limit was not violated. In all cases where violations resulted from reductions by PJM from actual line ratings, the shadow prices and resulting LMPs were set by the transmission constraint penalty factors. In the first nine months of 2026, the average shadow price of transmission constraints ($1,995.20 per MWh) when the line limit used in SCED was violated with a reduced line limit was 7.3 times higher than when the transmission constraint was binding but not violated ($272.18 per MWh) at its limit used in SCED.

Of the 31,240 violated transmission constraint intervals in the first nine months of 2026, 5,821 or 18.6 percent of the transmission constraint violations were during the Winter Storm Fern between January 22, 2026, and January 30, 2026.

Market to Market Transmission Constraints are categorized separately because of the unique rules governing the congestion management of these constraints by PJM and MISO. In the real-time market, PJM and MISO initiate a joint congestion management process commonly referred as "market to market" if they recognize substantial flows originating from the other RTO on their constraints. The identified constraints are then modeled in the dispatch optimizations of both RTOs. After every approved solution, the shadow prices are exchanged between the RTOs. In the absence of violations, PJM's shadow price is used as the upper limit for the same constraint in the MISO dispatch optimization. Similarly, MISO's shadow price is used as the upper limit for the same constraint in PJM's dispatch optimization.

Table 3-55 Frequency and average shadow price of transmission constraints in the real-time market: January through September, 2025 and 2026

	Frequency (Constraint Intervals)		Average Shadow Price	
Description	2025 (Jan - Sep)	2026 (Jan - Sep)	2025 (Jan - Sep)	2026 (Jan - Sep)
Violated Transmission Constraints (Actual)	2,773	3,792	$943.53	$1,662.09
Violated Transmission Constraints (Reduced Limit)	15,724	27,448	$1,995.20	$1,999.84
Binding Transmission Constraints	104,982	106,384	$310.95	$272.18
Market to Market Transmission Constraints	35,347	60,197	$426.85	$452.66
All Transmission Constraints	158,826	197,821	$514.53	$593.46

99 Actual transmission line limits are set by the transmission owner. PJM chooses the control limits. At present the actual line rating methods are not reviewed by FERC, or PJM, or the MMU.

100 The line limit of a facility associated with a transmission constraint is not necessarily the rated line limit. In PJM, the dispatcher has the discretion to lower the rated line limit.

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Table 3-56 shows the frequency and average shadow price of transmission constraints in the PJM day-ahead market. In the first nine months of 2026, there were 59,619 transmission constraint hours in the day-ahead market with a nonzero shadow price. For 764, or 1.3 percent, of these transmission constraint hours, the line limit was violated, meaning that the flow exceeded the facility limit used in the day-ahead pricing run solution.

Table 3-56 Frequency and average shadow price of transmission constraints in the day-ahead market: January through September, 2025 and 2026

	Frequency (Constraint Intervals)		Average Shadow Price	
Description	2025 (Jan - Sep)	2026 (Jan - Sep)	2025 (Jan - Sep)	2026 (Jan - Sep)
Violated Transmission Constraints (Actual)	145	581	$2,000.00	$1,849.63
Violated Transmission Constraints (Reduced)	-	183	$0.00	$2,000.00
Binding Transmission Constraints	48,900	49,364	$103.01	$123.46
Market to Market Transmission Constraints	7,341	9,491	$145.23	$156.06
All Transmission Constraints	56,386	59,619	$113.39	$151.23

Table 3-57 shows the frequency of violated transmission constraints by voltage level in the real-time market. In the first nine months of 2026, 59.9 percent of the violated transmission constraint intervals had a voltage level at or below 230 kV.

Of the 10,366 violated 500 kV transmission constraint intervals in the real-time market in the first nine months of 2026, 3,606 or 34.8 percent of the 500 kV transmission constraint violations were during the Winter Storm Fern between January 22, 2026, and January 30, 2026. This is a 171.0 percent increase in constraint violation intervals for the 500 kV constraints. All else being equal, transmission constraint violations at higher voltage levels have a greater impact on market prices. Of the 8,487 230 kV violated constraint intervals, 425 or 5.0 percent were located near the Data Center Alley in Virginia on May 26, 2026.

Table 3-57 Frequency of PJM violated transmission constraints in the real-time market by voltage: January through September, 2025 and 2026

	2025 (Jan - Sep)		2026 (Jan - Sep)	
Voltage	Frequency (Constraint Intervals)	Percent	Frequency (Constraint Intervals)	Percent
1 kV	269	1.5%	43	0.1%
69 kV	1,069	5.8%	1,899	6.1%
115 kV	5,794	31.3%	2,903	9.3%
138 kV	3,422	18.5%	5,395	17.3%
230 kV	3,585	19.4%	8,487	27.2%
345 kV	486	2.6%	2,081	6.7%
500 kV	3,825	20.7%	10,366	33.2%
765 kV	47	0.3%	66	0.2%
Total	18,497	100.0%	31,240	100.0%

Transmission constraint penalty factors should be applied without discretion, but not without additional rules that prevent unintended consequences. PJM adopted the MMU's recommendation to remove the constraint relaxation logic and allow transmission constraint penalty factors to set prices in the day-ahead and real-time markets for all internal transmission constraints in 2019.[101] But the potential for prolonged and excessively high administrative pricing in the energy market due to transmission constraint penalty factors remains an issue that needs to be addressed. There can be situations in which the application of transmission constraint penalty factors in real time for significant periods creates manipulation opportunities for virtuals and creates inefficient wealth transfers when market participants do not have the ability to react to the high prices either on the supply or demand side.[102] This could be the result of a lengthy planned transmission outage, for example.[103] It can also result from PJM administratively reducing the control limit on the line rating in RT SCED below 100 percent of the actual line limit and triggering the transmission constraint penalty factor, while operating the system below the actual line limit for a prolonged period. PJM should not reduce the control limit on the transmission line ratings in SCED to trigger the inclusion of transmission

101 PJM applied a procedure that PJM termed constraint relaxation logic, under which a revised SCED dispatch solution was obtained with an artificially increased limit for the violated transmission facility. The logic typically resulted in reducing the shadow prices to be slightly below the defined constraint violation penalty factor.

102 See Comments of the Independent Market Monitor for PJM, Docket No. EL22-26-000 et al. (February 1, 2022); 178 FERC ¶ 61,104 (2022).

103 See *id.*

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constraint penalty factors in price. In addition, PJM has no information about the accuracy of the line ratings that are determined by each transmission owner. It is not clear whether the line ratings that trigger the transmission constraint penalty factors are defined for the actual expected period of the power flow on the line. Line ratings vary significantly by duration of power flows, and by ambient conditions.

PJM also revised the tariff to list the conditions under which transmission constraint penalty factors would be changed from their default value of $2,000 per MWh. The new rules went into effect on February 1, 2019. The Commission approved the PJM and MISO joint filing to remove the constraint relaxation logic for market to market constraints on March 6, 2020. PJM and MISO implemented the changes to their dispatch software in the second half of 2020. On March 21, 2023, FERC approved new rules proposed by PJM to allow for reducing the transmission constraint penalty factors below the default $2,000 per MWh for constraints that are violated due to a transmission outage caused by the construction of upgrades to relieve congestion, for which limited generation resources are available to provide relief.[104]

PJM routinely, based on discretion, reduces the control limits on the transmission constraint line ratings modeled in SCED to below 100 percent, generally to 95 percent of the actual limit, administratively triggering the use of transmission constraint penalty factors.[105] The control limits set the limit of the constraint modeled in SCED. For example, in SCED, a transmission facility with a 100 MW line rating set at a 90 percent control limit would be modeled as a constraint with a limit of 90 MW. Table 3-58 shows the frequency of changes to the control limits for transmission constraints for binding and violated transmission constraints in the PJM real-time market. In the first nine months of 2026, there were 27,448, or 88 percent, of 31,240 violated transmission constraint intervals in the real-time market with a control limit less than 100 percent. In the first nine months of 2026, among the violated transmission constraints with a reduced control limit, the constraint limit was reduced on average by 5.1 percent. In the first nine months of 2026, there were 103,752, or 98 percent, of 106,384 binding transmission constraint intervals in the real-time market with a control limit less than 100 percent. In the first nine months of 2026, among the binding transmission constraints with a reduced control limit, the constraint limit was reduced on average by 5.8 percent. By arbitrarily lowering transmission facility limits, PJM is not using the full transmission system capacity available to serve the load to achieve the least cost dispatch solution. The cost to serve the load and the load payments would be lower had PJM not reduced the transmission line ratings.

Table 3-58 Frequency of reduction in control limit of line ratings (constraint intervals) in the real-time market: January through September, 2025 and 2026

	Frequency (Constraint Intervals)		Constraints with Reduced Control Percent (Constraint Intervals)		Average Reduction (Percent)	
Description	2025 (Jan - Sep)	2026 (Jan - Sep)	2025 (Jan -Sep)	2026 (Jan -Sep)	2025 (Jan - Sep)	2026 (Jan -Sep)
Violated Transmission Constraints (Actual)	2,773	3,792	-	-	0.0%	0.0%
Violated Transmission Constraints (Reduced Limit)	15,724	27,448	15,724	27,448	5.1%	5.1%
Binding Transmission Constraints	104,982	106,384	101,632	103,752	5.8%	5.8%
Market to Market Transmission Constraints	35,347	60,197	13,056	26,530	7.2%	6.0%
All Transmission Constraints	158,826	197,821	130,412	157,730	5.9%	5.7%

Table 3-59 shows the reasons provided by the PJM operators for changing the control limit on the line rating for violated transmission constraints. In the first nine months of 2026, of the 27,448 violated transmission constraint intervals with reduced control limits, no reason was provided for 22,385 cases, or 81.6 percent of all the cases. In 2,709 cases, or 9.9 percent, the control limits were reduced because the relief calculated by the SCED optimization was less than the operator's desired relief for the transmission constraint. Although there were no cases in the first nine months of 2026, the control limits can be reduced because PJM designates the constraint as a thermal surrogate. Thermal surrogate constraints are constraints that PJM activates and for which PJM generally reduces the line rating to enable specific resources called on to control a constraint to set price.

104 See 182 FERC ¶ 61,183 (March 21, 2023). The Commission approved PJM's proposed tariff revisions to allow PJM to lower transmission constraint penalty factors generally for any situation similar to the high prices caused by Lanexa-Dunnsville-Northern Neck line outage in the Northern Neck peninsula in Virginia.

105 Actual transmission line limits are set by the transmission owner. PJM chooses the control limits. At present the actual line rating methods are not reviewed by FERC, or PJM, or the MMU.

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The MMU recommends that PJM end the practice of manual and automated discretionary reductions in the control limits on transmission constraint line ratings used in the market clearing software (SCED) and included in LMP. This practice has significant market effects by limiting economic power flows and increasing prices above the level that would exist if 100 percent of the actual line rating were used in clearing the market and setting energy market prices. In addition, PJM should take steps to verify that the line ratings used by the Transmission Owner and used in SCED correctly reflect the appropriate duration of flow.

Table 3-59 PJM's reasons for reduction in control limits of line ratings (constraint intervals) in the real-time market: January through September, 2025 and 2026

	Constraint Intervals		Average Reduction (Percent)	
Reason	2025 (Jan - Sep)	2026 (Jan - Sep)	2025 (Jan - Sep)	2026 (Jan - Sep)
Modeled constraint is a thermal surrogate	13	-	52.2%	0.0%
No reason provided	12,698	22,385	4.4%	4.6%
Prepositioning of generation resources to support an operational requirement	313	310	8.7%	7.9%
Inadequate relief calculated by the SCED optimization	1,952	2,709	7.6%	7.3%
Transmission owner identified the flow on their constraint to be greater than PJM's calculated flow on the same constraint.	195	219	7.6%	8.2%
Power flow on the constraint is volatile due to various system conditions	553	1,825	7.3%	7.1%
All violated constraints	15,724	27,448	5.1%	5.1%

Table 3-60 shows the impact on LMP of PJM dispatchers reducing the control limit of line ratings of transmission constraints and causing artificial line limit violations.[106] The transmission constraint penalty factor contribution to the load-weighted average LMP in the first nine months of 2026 was $14.11 per MWh or $9.0 billion of the total $47.6 billion cost of real-time load. This impact includes reductions to the line limits of violated constraints during Winter Storm Fern. If 100 percent of the line limits had been used for the PJM transmission constraints and everything else remained unchanged, fewer constraints would have been violated and the transmission constraint penalty factor's contribution to the load-weighted average LMP would have decreased to $0.06 per MWh, a 99.6 percent reduction.

106 The MMU calculates the impact on system prices based on analysis using sensitivity factors. The transmission constraint penalty factor contribution with actual line limits is not based on a counterfactual redispatch of the system. See Technical Reference for PJM Markets, "Calculation and Use of Generator Sensitivity/Unit Participation Factors," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Table 3-60 Real-time LMP effect of reduced control limits on transmission constraint line ratings (Dollars per MWh): January through September, 2025 and 2026

	Contribution to LMP	
Line Limit Scenario for Violated Constraints	2025 (Jan - Sep)	2026 (Jan - Sep)
Line Limits Reduced by PJM (Actual)	$5.31	$14.11
Hypothetical Use of Full Line Limits	$0.03	$0.06
Change in Contribution to LMP	($5.27)	($14.06)
Percent Change in Contribution to LMP	(99.4%)	(99.6%)

Table 3-61 shows the frequency of changes to the magnitude of transmission constraint penalty factors for binding and violated transmission constraints in the PJM Real-Time Energy Market. In the first nine months of 2025, there were 30,530, or 98 percent, of the total 31,240 violated transmission constraint intervals, which includes 3,082 violated transmission constraint intervals with actual line limits and 27,448 violated transmission constraint intervals with reduced line limits, in the real-time market with a transmission constraint penalty factor equal to the default $2,000 per MWh.

Table 3-61 Frequency of changes to the magnitude of transmission constraint penalty factor (constraint intervals) in the real-time market: January through September, 2025 and 2026

	2025 (Jan - Sep)			2026 (Jan - Sep)		
Description	$2,000 per MWh (Default)	Above $2,000 per MWh	Below $2,000 per MWh	$2,000 per MWh (Default)	Above $2,000 per MWh	Below $2,000 per MWh
Violated Transmission Constraints (Actual)	1,032	-	1,741	3,082	-	710
Violated Transmission Constraints (Reduced)	15,707	-	17	27,448	-	-
Binding Transmission Constraints	102,497	-	2,485	105,004	-	1,380
Market to Market Transmission Constraints	8,703	19	26,625	6,355	172	53,670
All Transmission Constraints	127,939	19	30,868	141,889	172	55,760

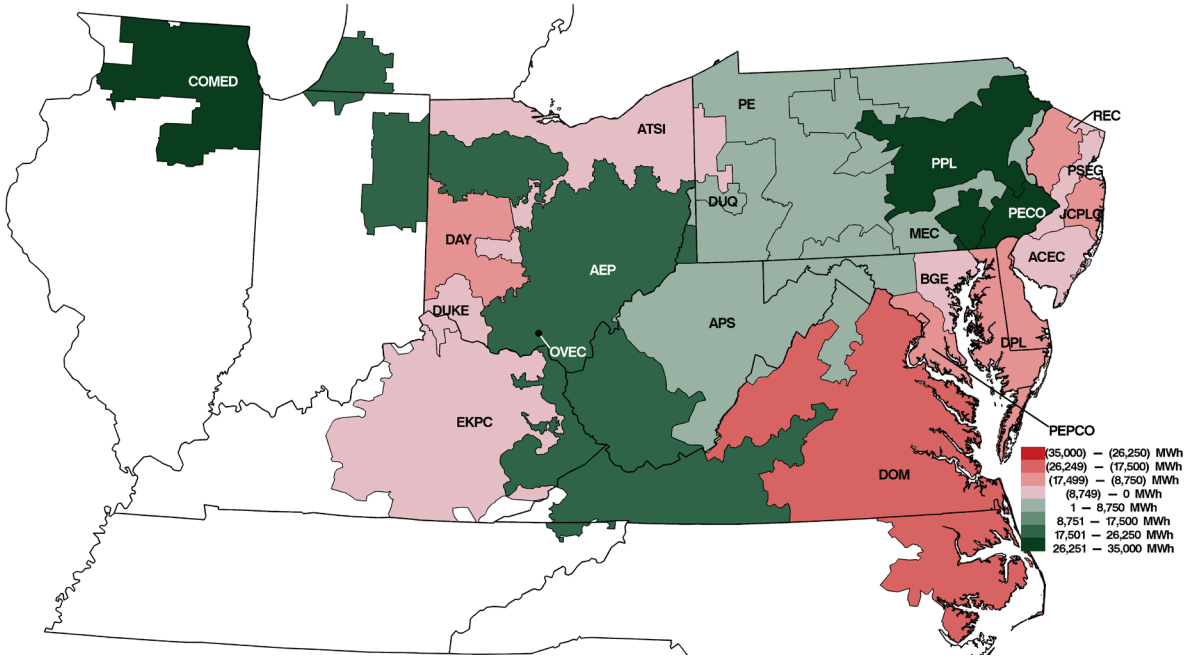
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Prior to September 1, 2022, transmission constraint penalty factors frequently set prices when PJM modeled a stability surrogate constraint to limit the dispatch of a generator that would experience voltage instability at its full output due to a transmission outage. Since September 1, 2022, PJM uses a generator output limit constraint to manage generator voltage instability issues. In the first nine months of 2026, there were 83,330 constraint intervals during which PJM reduced the output of generators to manage instability. Changes to the surrogate constraint limit that exceed the unit's ability to reduce output cause constraint violations. Constraint violations also occur when the unit follows the regulation signal or increases its minimum operating parameters above the surrogate constraint limit. Prices set at the $2,000 per MWh penalty factor are not useful signals to the market under these conditions and create false arbitrage opportunities for virtuals.

Net Generation by Zone

Figure 3-47 shows the difference between the PJM real-time generation and real-time load by zone in the first nine months of 2026. Figure 3-47 is color coded using 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. Table 3-62 shows the difference between the real-time generation and real-time load by zone in the first nine monthsof 2025 and 2026.

Figure 3-47 Map of real-time generation less real-time load by zone: January through September, 2026[107]



107 Real-time zonal 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>.

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Table 3-62 Real-time generation less real-time load by zone (GWh): January through September, 2025 and 2026

Zonal Generation and Load (GWh)						
	2025 (Jan-Sep)			2026 (Jan-Sep)		
Zone	Generation	Load	Net	Generation	Load	Net
ACEC	632	7,491	(6,859)	1,722	7,628	(5,907)
AEP	124,054	102,527	21,527	132,283	110,982	21,301
APS	37,656	36,912	744	40,363	37,364	2,999
ATSI	40,512	50,593	(10,081)	46,314	51,119	(4,805)
BGE	12,929	23,008	(10,078)	14,868	23,304	(8,436)
COMED	106,540	71,211	35,329	105,430	71,370	34,061
DAY	2,184	13,306	(11,122)	2,201	13,386	(11,184)
DUKE	10,559	20,234	(9,674)	11,793	20,205	(8,412)
DOM	85,191	98,947	(13,756)	82,626	107,341	(24,715)
DPL	4,334	14,153	(9,819)	4,469	14,452	(9,983)
DUQ	12,722	9,938	2,784	12,319	9,831	2,488
EKPC	8,414	10,690	(2,277)	8,657	10,805	(2,148)
JCPLC	6,545	16,623	(10,077)	5,533	16,978	(11,445)
MEC	15,090	11,339	3,751	12,878	11,526	1,351
OVEC	8,326	84	8,241	8,366	85	8,281
PECO	56,936	29,221	27,715	57,227	29,670	27,557
PE	23,737	12,260	11,477	20,809	12,322	8,488
PEPCO	9,086	21,357	(12,271)	9,911	21,431	(11,520)
PPL	58,098	30,545	27,553	60,796	30,781	30,014
PSEG	32,448	32,196	252	32,295	32,744	(449)
REC	0	1,085	(1,085)	0	1,107	(1,107)

Net Generation and Load

PJM sums all negative (injections) and positive (withdrawals) at each designated load bus when calculating net load (accounting load). PJM sums all of the negative (withdrawals) and positive (injections) 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, power to onsite customers, 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 intervals 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 intervals 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.

Fuel Prices, LMP, and Dispatch

Energy Production by Fuel Source

Table 3-63 shows PJM generation by fuel source in GWh for the first nine months of 2025 and 2026.

In the first nine months of 2026, generation from coal units increased 0.4 percent, generation from natural gas units increased 2.5 percent, generation from oil units increased 13.7 percent, generation from wind units increased 5.5 percent, and generation from solar units increased 20.1 percent compared to the first nine months of 2025.

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Table 3-63 Generation (By fuel source (GWh)): January through September, 2025 and 2026[108] [109]

	2025 (Jan-Sep)		2026 (Jan-Sep)		Change in
	GWh	Percent	GWh	Percent	Output
Coal	111,408.4	16.7%	111,816.4	16.5%	0.4%
Bituminous	93,212.5	14.0%	94,511.8	13.9%	1.4%
Sub Bituminous	12,837.2	1.9%	12,382.8	1.8%	(3.5%)
Other Coal	5,358.7	0.8%	4,921.8	0.7%	(8.2%)
Nuclear	204,130.4	30.7%	204,703.7	30.1%	0.3%
Gas	286,643.1	43.1%	293,682.3	43.2%	2.5%
Natural Gas CC	256,276.0	38.5%	255,904.7	37.7%	(0.1%)
Natural Gas CT	17,712.2	2.7%	20,210.9	3.0%	14.1%
Natural Gas Other Units	11,853.6	1.8%	16,787.6	2.5%	41.6%
Other Gas	801.2	0.1%	779.2	0.1%	(2.7%)
Hydroelectric	12,696.9	1.9%	12,388.8	1.8%	(2.4%)
Pumped Storage	5,295.3	0.8%	5,343.5	0.8%	0.9%
Run of River	5,886.6	0.9%	5,363.2	0.8%	(8.9%)
Other Hydro	1,515.0	0.2%	1,682.1	0.2%	11.0%
Wind	22,209.4	3.3%	23,419.8	3.4%	5.5%
Waste	2,926.0	0.4%	2,944.6	0.4%	0.6%
Oil	4,136.1	0.6%	4,704.8	0.7%	13.7%
Heavy Oil	183.8	0.0%	421.4	0.1%	129.3%
Light Oil	2,549.8	0.4%	2,835.3	0.4%	11.2%
Diesel	107.1	0.0%	176.9	0.0%	65.1%
Other Oil	1,295.4	0.2%	1,271.3	0.2%	(1.9%)
Solar	20,375.1	3.1%	24,480.3	3.6%	20.1%
Battery	50.4	0.0%	153.0	0.0%	203.4%
Biofuel	931.6	0.1%	937.5	0.1%	0.6%
Total	665,507.5	100.0%	679,231.3	100.0%	2.1%

108 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, power to run pumped hydro pumps or power to charge batteries.

109 Other Gas includes: Landfill, Propane, Butane, Hydrogen, Gasified Coal, and Refinery Gas. Other Coal includes: Lignite, Liquefied Coal, Gasified Coal, and Waste Coal. Other oil includes: Gasoline, Jet Oil, Kerosene, and Petroleum-Other.

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Table 3-64 Monthly generation (By fuel source (GWh)): January through September, 2026

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Coal	17,020.1	13,544.4	9,408.6	9,161.7	9,250.7	11,471.8	16,419.8	13,566.5	11,972.8	111,816.4
Bituminous	14,256.7	11,492.0	8,144.1	7,927.6	8,010.9	9,953.7	13,975.5	11,141.7	9,609.6	94,511.8
Sub Bituminous	2,109.5	1,410.2	677.5	827.9	689.6	950.0	1,854.4	1,907.0	1,956.8	12,382.8
Other Coal	653.9	642.2	587.0	406.3	550.1	568.1	590.0	517.9	406.3	4,921.8
Nuclear	24,959.6	21,526.0	22,284.1	19,988.4	22,560.5	23,540.6	24,174.9	24,220.7	21,449.0	204,703.7
Gas	35,496.0	32,024.7	28,390.5	24,112.8	25,545.9	33,740.0	40,679.4	40,490.9	33,202.1	293,682.3
Natural Gas CC	31,395.4	28,898.7	25,744.9	21,184.0	22,835.4	29,809.4	33,964.9	34,367.1	27,704.9	255,904.7
Natural Gas CT	2,422.4	1,855.5	1,395.7	1,542.3	1,423.7	1,787.1	3,609.4	3,191.5	2,983.2	20,210.9
Natural Gas Other Units	1,593.6	1,196.7	1,174.2	1,301.9	1,197.4	2,059.0	3,004.2	2,831.3	2,429.4	16,787.6
Other Gas	84.8	73.8	75.7	84.6	89.4	84.4	100.9	101.0	84.6	779.2
Hydroelectric	1,202.8	1,051.8	1,666.9	1,447.8	1,427.2	1,295.1	1,489.7	1,523.6	1,283.9	12,388.8
Pumped Storage	508.6	491.3	577.2	488.3	544.5	624.2	767.9	752.4	589.1	5,343.5
Run of River	557.9	430.6	936.2	809.8	730.5	446.9	445.8	509.1	496.5	5,363.2
Other Hydro	136.3	129.9	153.6	149.7	152.1	224.0	276.0	262.1	198.3	1,682.1
Wind	3,865.8	2,906.5	3,953.2	3,793.4	2,623.3	2,197.8	1,187.6	1,300.5	1,591.8	23,419.8
Waste	312.1	278.5	338.6	308.5	329.7	340.2	359.9	368.6	308.5	2,944.6
Oil	895.0	493.7	266.7	409.4	428.0	493.0	749.4	468.0	501.5	4,704.8
Heavy Oil	68.6	58.7	25.4	27.8	90.0	21.9	80.4	9.6	38.9	421.4
Light Oil	592.3	278.6	104.3	289.9	187.3	303.4	482.4	282.5	314.5	2,835.3
Diesel	93.8	31.8	0.3	2.2	11.7	7.0	26.0	2.5	1.6	176.9
Other Oil	140.2	124.7	136.7	89.5	139.0	160.8	160.7	173.4	146.4	1,271.3
Solar	1,337.0	1,689.6	2,369.4	3,052.7	3,293.3	3,500.6	3,514.9	3,150.0	2,572.8	24,480.3
Battery	9.8	9.5	11.6	11.4	11.3	18.7	29.1	26.8	24.7	153.0
Biofuel	123.4	115.4	60.5	75.0	114.7	102.1	122.2	135.1	89.0	937.5
Total	85,221.6	73,640.0	68,750.2	62,361.2	65,584.5	76,699.9	88,726.9	85,250.9	72,996.1	679,231.3

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Table 3-65 shows the difference between the day-ahead and the real-time average generation by fuel source.

Table 3-65 Day-ahead and real-time average generation (By fuel source (GWh)): January through September, 2026

	2026 (Jan -Sep)					
	Day-Ahead		Real-Time			Percent
	GWh	Percent	GWh	Percent	RT - DA	Difference
Coal	111,914.1	16.8%	111,816.4	16.5%	(97.7)	(0.1%)
Bituminous	94,031.2	14.1%	94,511.8	13.9%	480.6	0.5%
Sub Bituminous	13,125.0	2.0%	12,382.8	1.8%	(742.2)	(5.7%)
Other Coal	4,757.9	0.7%	4,921.8	0.7%	164.0	3.4%
Nuclear	202,903.5	30.4%	204,703.7	30.1%	1,800.2	0.9%
Gas	290,637.0	43.6%	293,682.3	43.2%	3,045.3	1.0%
Natural Gas CC	253,781.7	38.1%	255,904.7	37.7%	2,122.9	0.8%
Natural Gas CT	19,097.3	2.9%	20,210.9	3.0%	1,113.6	5.8%
Natural Gas Other Units	16,978.6	2.5%	16,787.6	2.5%	(191.0)	(1.1%)
Other Gas	779.4	0.1%	779.2	0.1%	(0.2)	(0.0%)
Hydroelectric	12,139.1	1.8%	12,388.8	1.8%	249.7	2.1%
Pumped Storage	6,739.8	1.0%	5,343.5	0.8%	(1,396.3)	(20.7%)
Run of River	5,399.3	0.8%	5,363.2	0.8%	(36.1)	(0.7%)
Other Hydro	0.0	0.0%	1,682.1	0.2%	1,682.1	NA
Wind	18,381.0	2.8%	23,419.8	3.4%	5,038.8	27.4%
Waste	2,892.8	0.4%	2,944.6	0.4%	51.9	1.8%
Oil	4,228.9	0.6%	4,704.8	0.7%	475.9	11.3%
Heavy Oil	34.2	0.0%	421.4	0.1%	387.1	1,131.7%
Light Oil	2,773.4	0.4%	2,835.3	0.4%	61.9	2.2%
Diesel	186.4	0.0%	176.9	0.0%	(9.5)	(5.1%)
Other Oil	1,234.9	0.2%	1,271.3	0.2%	36.4	2.9%
Solar	22,394.0	3.4%	24,480.3	3.6%	2,086.3	9.3%
Battery	94.6	0.0%	153.0	0.0%	58.4	61.7%
Biofuel	1,071.9	0.2%	937.5	0.1%	(134.4)	(12.5%)
Total	666,656.9	100.0%	679,231.3	100.0%	12,574.3	1.9%

Table 3-66 shows the share of generation by natural gas, coal, nuclear and other fuel types in the real-time energy market since 2014.

Table 3-66 Share of generation by fuel source: January through September, 2014 through 2026

Jan - Sep	Natural Gas	Coal	Nuclear	Solar	Wind	Other Fuel Type
2014	17.0%	41.6%	36.6%	0.1%	1.8%	3.0%
2015	19.7%	38.6%	37.1%	0.1%	1.8%	2.8%
2016	24.1%	34.4%	36.5%	0.1%	2.0%	2.9%
2017	24.5%	31.7%	37.9%	0.2%	2.4%	3.3%
2018	29.5%	28.9%	35.1%	0.3%	2.4%	3.8%
2019	34.4%	25.1%	34.3%	0.3%	2.7%	3.3%
2020	40.0%	19.2%	34.2%	0.4%	2.9%	3.2%
2021	36.8%	24.0%	32.2%	0.9%	3.0%	3.1%
2022	39.6%	20.9%	31.9%	1.2%	3.4%	3.0%
2023	44.5%	15.0%	32.8%	1.4%	3.2%	3.1%
2024	44.9%	14.8%	31.5%	2.1%	3.4%	3.3%
2025	43.0%	16.7%	30.7%	3.1%	3.3%	3.2%
2026	43.1%	16.5%	30.1%	3.6%	3.4%	3.2%

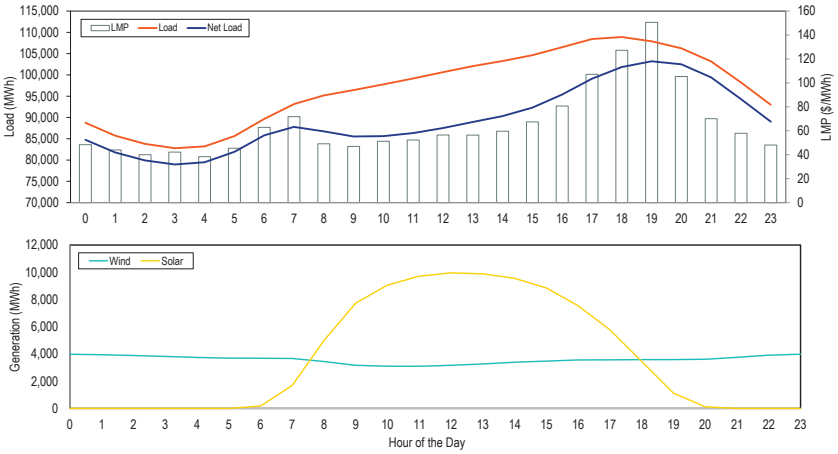
Net Load and LMP

Net load is defined to be the total real-time demand in PJM minus the power generated by wind and solar. Net load is the load that must be met by nonintermittent, dispatchable resources. As wind and solar output grow, there is a direct impact on the daily net load shape and an indirect impact on the hourly LMP pattern. Figure 3-48 shows PJM load, net load, LMP, solar and wind output by the hour of the day in the first nine months of 2026.

In the first nine months of 2026, solar output increased during the morning hours to a maximum close to 10,000 MWh from hours 10 to 14, net load decreased correspondingly and average LMPs declined. The higher the solar output, the lower the LMPs during the period of solar output. LMPs during the period of highest solar output were close to the same average price level as at midnight. As solar generation decreased in the late afternoon and evening hours, net load increased and average LMPs increased. The highest LMPs occurred during the evening ramp period when solar output declined rapidly and net load reached its daily peak.

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Figure 3-48 Net Load, Load, LMP, Solar and Wind Generation by Hour of the Day: January through September, 2026



Fuel Diversity

Figure 3-49 shows the fuel diversity index (FDI_e) for PJM energy generation.[110] The FDI_e is defined as $\mathbf{1 - \sum_{i=1}^{N} s_i^2}$, where s_i is the share of fuel type *i*. The minimum possible value for the FDI_e is zero, corresponding to all generation from a single fuel type. The maximum possible value for the FDI_e results when each fuel type has an equal share of total generation. For a generation fleet composed of 10 fuel types, the maximum achievable index is 0.9. The fuel type categories used in the calculation of the FDI_e are the 10 primary fuel sources in Table 3-63 with nonzero generation values. As fuel diversity has increased, seasonality in the FDI_e has decreased and the FDI_e has exhibited less volatility. Since 2012, the monthly FDI_e has been less volatile as a result of the decline in the share of coal from 51.3 percent prior to 2012 to 27.1 percent from 2012 through September 2026. A significant drop in the FDI_e occurred in the fall of 2004 as a result of the expansion of the PJM market footprint into ComEd, AEP, and Dayton Power & Light Zones and the increased shares of coal and nuclear that resulted.[111] The increasing trend that began in 2008 is a result of decreasing coal generation, increasing gas generation and increasing renewable generation. Coal generation as a share of total generation was 55.0 percent for the first nine months of 2008 and 16.5 percent for the first nine months of 2026. Gas generation as a share of total generation was 7.7 percent for the first nine months of 2008 and 43.2 percent for the first nine months of 2026. Wind and solar generation as a share of total generation was 0.5 percent for the first nine months of 2008 and 7.0 percent for the first nine months of 2026.

The FDI_e increased 0.1 percent in the first nine months of 2026 compared to the first nine months of 2025. Increased gas generation and less generation from coal fired and nuclear generators led to the decrease in the FDI_e.

The FDI_e was also used to measure the impact on fuel diversity of potential retirements in 2026 through 2030. A total of 10,963 MW of capacity are at risk of retirement, consisting of 8,330 MW currently planning to retire and 2,633 MW expected to be uneconomic.[112] This capacity consists primarily of coal steam plants and CTs. The units expected to retire by the end of 2026 generated 5,274.5 GWh in the first nine months of 2026. The dashed line (green) in Figure 3-49 shows a counterfactual result for FDI_e assuming the 5,274.5 GWh of generation from uneconomic units and expected 2026 retirements were replaced by gas generation.[113] The FDI_e for the first nine months of 2026 under this counterfactual assumption would have been 0.5 percent lower than the actual FDI_e. The units expected to retire by the end of 2030 generated 18,551.4 GWh in the first nine months of 2026. Replacing this generation with wind and solar generation results in a counterfactual FDI_e that is 1.0 percent higher than the actual FDI_e.[114] The dashed line (blue) in Figure

110 The MMU developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity.

111 See the *2019 Annual State of the Market Report for PJM*, Volume 2, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the ComEd Control Area occurred in May 2004 and the integration of the AEP and Dayton Zones occurred in October 2004.

112 See Units At Risk of Retirement in the *2025 Annual State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

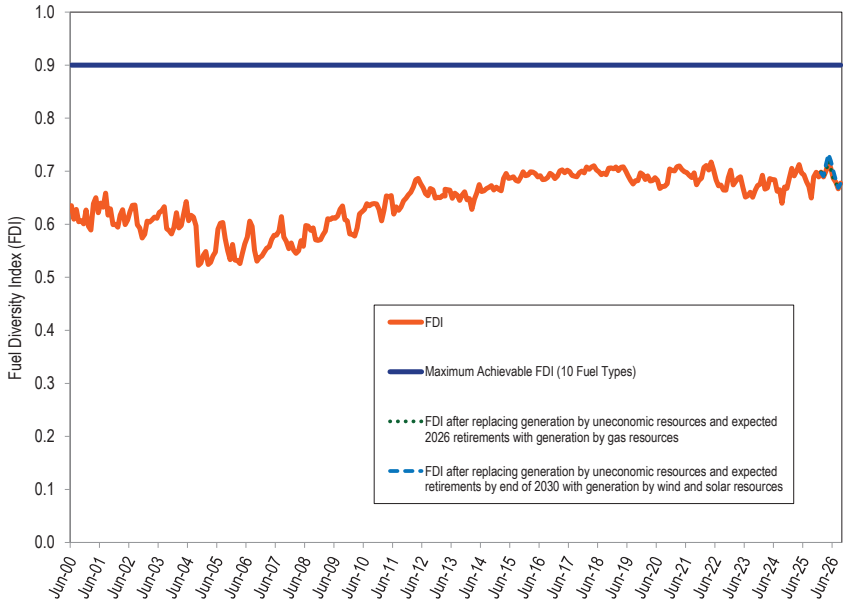
113 It is assumed that all of the replacement energy is from gas units. In previous reports, solar and wind energy have also been used for replacement energy with the amounts based on the expected increase in the PJM RPS obligation for the upcoming year. But the PJM RPS obligation will decrease in 2027 in comparison to 2026 due to the termination of the Ohio RPS in 2027.

114 The split between solar (74.7 percent) and wind (25.3 percent) is based on queue data and 2026 capacity factors in Table 8-33 and Table 8-37. In previous reports, the replacement energy was sourced from gas units in addition to solar and wind units with the amount of solar and gas replacement energy being based on the expected increase in the PJM RPS obligation in 2030 in comparison to current year. But the RPS increase for 2030 exceeds the energy attributable to the expected retirements, and only solar and wind are used for replacement energy in this scenario.

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3-49 shows a counterfactual result for FDI_e assuming that this generation is replaced with gas, wind and solar generation.

Figure 3-49 Fuel diversity index for monthly generation: June 2000 through September 2026



Natural Gas Supply Issues

Both pipeline transportation capacity and commodity natural gas are needed to deliver natural gas to power plants. Generators have a number of options which vary by pipeline and market area. A generator could purchase a delivered service in which the seller bundles the transportation and commodity, on a term contract or a spot basis. A generator could purchase pipeline transportation and commodity natural gas separately with a term supply contract or through daily purchases in the spot market. Generators could purchase storage service. Storage services can be bundled with pipeline transportation, or storage and transportation purchased separately to move gas to or from a storage facility.

The storage service will determine the total storage capacity and the injection and withdrawal rights. Storage offers the owner the ability to have on demand supplies, or the ability to redirect unused supplies to storage. Predetermined allocation (PDA) nominations can be used to direct the pipeline as to how to treat an excess or a deficiency of gas at a delivery point. Combinations of these options are also available.

Pipelines build transportation capacity and sell firm capacity to customers. Most of the transportation capacity is sold at tariff rates but in some cases negotiated rates are agreed to. A majority of firm capacity is contracted with gas utilities, gas marketers, industrial customers and generators. The purchasers of firm transportation capacity have the right to resell their capacity. Any such release must be done on the pipeline's electronic bulletin board. Bidders must be approved by the pipeline. When firm capacity on the pipelines is not being used, the pipeline tariffs provide for interruptible service.

In order to be able to actually use the purchased pipeline transportation service, pipelines may enforce nomination deadlines to require generation owners to nominate the flow of gas by defined deadlines. Some pipelines may also impose site specific restrictions that limit the ability of generators to nominate and schedule gas beyond the nomination deadlines. Table 3-67 shows the approved nomination deadlines and corresponding start time of gas flow.[115] Pipelines provide that firm service requests may replace, or bump, interruptible nominations on the pipeline under defined conditions.

Table 3-67 Approved nomination deadlines

	Nomination Cycle	Nom Deadline (EPT)	Time of Flow (EPT)	Bumping	Hours left in gas day for supply to flow
Day Before Flow	Timely	1400	1000		24
Day Before Flow	Evening	1900	1000	Yes	24
Day of Flow	Intraday 1	1100	1500	Yes	19
Day of Flow	Intraday 2	1530	1900	Yes	15
Day of Flow	Intraday 3	2000	2300	No	11

115 Nomination deadlines approved in FERC Order No. 809, implemented April 1, 2016.

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In the winter period from November 2025 through March 2026, some interstate gas pipelines that provide service in the PJM service territory issued notices limiting the flexibility of firm and nonfirm transportation services. These notices included alerts, constraints, warnings of operational flow orders (OFO) and actual OFOs. These notices generally permit the pipelines to enforce nomination deadlines and to restrict the provision of gas to 24 hour ratable takes, meaning that nominations must be the same for each hour in the gas day. Pipelines may also enforce strict balancing constraints which limit the ability of gas users to deviate from the 24 hour ratable take and which may limit the ability of users to have access to unused gas. The pipelines providing service in the PJM service territory that issued notices were: ANR Pipeline, Columbia Gas Transmission, Cove Point, Eastern Gas Transmission Pipeline System, Eastern Shore Natural Gas Pipeline, East Tennessee Natural Gas, Eastern Gas Transmission & Storage, Horizon Pipeline, Natural Gas Pipeline, Northern Border Pipeline, Texas Eastern, Tennessee Gas Pipeline and Transcontinental Gas Pipeline.

Pipeline operators use restrictive and inflexible rules to manage the balance of supply and demand during constrained operating conditions determined by the pipeline. The independent operations of geographically overlapping pipelines during extreme conditions highlight the shortcomings of a gas pipeline network that relies on individual pipelines to manage the balancing of total supply and demand across a broad geographical area that includes multiple pipelines. The independent operational restrictions imposed by pipelines and the impact on electric generators during extreme conditions demonstrate the potential benefits to creating a separate gas ISO/RTO structure to coordinate the supply of gas across pipelines and with the electric RTOs and to facilitate the interoperability of the pipelines in an explicit network.

The increase in natural gas fired capacity in PJM, and the expected further increase, has highlighted issues with the dependence of PJM system reliability on the fuel transportation arrangements entered into by generators. The risks to the fuel supply for gas generators, including the risk of interruptible supply on cold days and the ability to get gas on short notice during times of critical pipeline operations, create risks for the bulk power system.

In general, the availability status of gas generators in the PJM energy market does not accurately reflect their ability to procure and nominate gas on the pipelines based on the rules defined by the pipelines. If the result of the pipeline rules is that some gas generators cannot reliably procure gas during the operating day in order to respond to PJM directions to generate, the result could be an inflated estimate of reserves on the PJM system, if the generator does not have back up fuel. Gas units should be required to be on forced outage if they cannot obtain gas during the operating day to meet their must offer requirement.

PJM requires real-time situational awareness of the availability of all generators, including gas-fired generators, during the operating day, in order to operate the system effectively including knowledge of the level of available reserves. The MMU recommends: that gas generators be required to confirm, regularly during the operating day, that they can obtain gas if requested to operate at their economic maximum level; that gas generators provide that information to PJM during the operating day; and that gas generators be required to be on forced outage if they cannot obtain gas during the operating day to meet their must offer requirement as a result of pipeline restrictions, and they do not have backup fuel. As part of this, the MMU recommends that PJM collect data on each individual generator's fuel supply arrangements at least annually or when such arrangements change, and analyze the associated locational and regional risks to reliability.

Notification time is the period between PJM's notification and the beginning of the start sequence for a generating resource. Combustion turbines normally have notification times between six and 30 minutes. When pipelines require generators to nominate gas per the NAESB deadlines, generators must nominate gas well in advance and cannot start in six or 30 minutes. Instead, generators need significantly more time to nominate gas. This increase in the time needed should be requested and reflected in the units' notification time.

For example, the last nomination cycle available per NAESB is intraday 3 (ID3), see Table 3-67. The ID3 deadline is 20:00 EPT for gas that starts flowing at 23:00 (in three hours). The previous cycle, intraday 2 (ID2) deadline is at

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15:30 EPT for gas that starts flowing at 19:00. A generator that has not nominated gas by ID2 cannot start until 23:00. Therefore, at 19:00, the unit has an implied time to start of four hours. Four hours is equal to 23:00 (the earliest the unit can start) minus 19:00. Table 3-68 shows the notification time gas fired generators should be requesting and submitting when pipelines require nominating per the NAESB cycle deadlines.

Table 3-68 Generator notification times when pipeline NAESB cycle deadlines are imposed

Hour	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12
Notification Time	15	14	13	12	11	10	9	8	7	6	9	8
Time On (If Called)	15:00	15:00	15:00	15:00	15:00	15:00	15:00	15:00	15:00	15:00	19:00	19:00
Nearest Cycle	ID1	ID1	ID1	ID1	ID1	ID1	ID1	ID1	ID1	ID1	ID2	ID2

Hour	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
Notification Time	7	6	9	8	7	6	5	20	19	18	17	16
Time On (If Called)	19:00	19:00	23:00	23:00	23:00	23:00	23:00	15:00	15:00	15:00	15:00	15:00
Nearest Cycle	ID2	ID2	ID3	ID3	ID3	ID3	ID3	ID1	ID1	ID1	ID1	ID1

The MMU proposed enhancements for situational awareness and transparency to improve the scheduling problem that PJM and gas fired units face, addressing how to reflect pipeline constraints in generator operating parameters, including how generators should submit notification times, and minimum run times and request temporary parameter exceptions.[116] The resultant guidelines were posted by the MMU and PJM on September 8, 2023.[117]

Types 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 3-69 shows the type of fuel used and technology by marginal resources in the real-time energy market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In the first nine months of 2026, coal units were 9.5 percent and natural gas units were 71.3 percent of marginal resources. In the first nine months of 2026, natural gas combined cycle units were 57.5 percent of marginal resources. In the first nine months of 2025, coal units were 7.6 percent and natural gas units were 77.9 percent of the total marginal resources. In the first nine months of 2025, natural gas combined cycle units were 63.9 percent of the total marginal resources. In the first nine months of 2026, 74.3 percent of the wind marginal units had negative offer prices, 24.4 percent had zero offer prices and 1.3 percent of the wind marginal units had positive offer prices. In the first nine months of 2025, 68.7 percent of the wind marginal units had negative offer prices, 30.2 percent had zero offer prices and 1.1 percent had positive offer prices.

116 "Gas Nomination Cycles and Units Operating Parameters," Electric Gas Coordination Senior Task Force (EGCSTF), August 15, 2023.

117 *See* Guidelines posted by the MMU and PJM: Temporary Operating Parameter Limit (PLS) Exceptions due to Pipeline Restrictions. <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Temporary_Operating_Parameter_Limit_(PLS)_Exceptions_due_to_Pipeline_Restrictions_20230908.pdf>.

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The proportion of marginal nuclear units increased from 0.11 percent in the first nine months of 2025 to 0.19 percent in the first nine months of 2026. Most nuclear units are offered as fixed generation in the PJM market. A small number of nuclear units have been offered with a dispatchable range since 2015. The dispatchable nuclear units do not always respond to dispatch instructions.

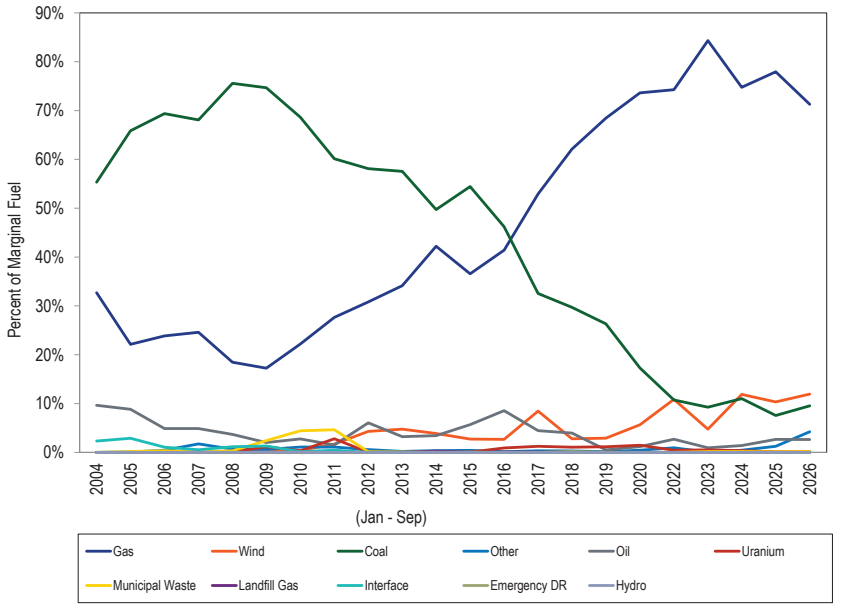
PJM implemented fast start pricing on September 1, 2021. The marginal resources shown in Table 3-69 are from the pricing run, which may not be the same as marginal resources from the dispatch run.

Table 3-69 Type of fuel used and technology (By real-time marginal units): January through September, 2022 through 2026[118]

		(Jan - Sep)				
Fuel	Technology	2022	2023	2024	2025	2026
Gas	CC	60.40%	71.16%	61.48%	63.88%	57.46%
Wind	Wind	10.86%	4.75%	11.87%	10.34%	11.94%
Gas	CT	11.53%	10.24%	9.99%	10.56%	9.86%
Coal	Steam	10.73%	9.26%	11.01%	7.56%	9.53%
Other	Solar	0.90%	0.01%	0.39%	1.16%	4.13%
Gas	Steam	1.46%	1.78%	2.67%	2.55%	2.85%
Oil	CT	2.61%	0.52%	1.11%	1.58%	1.96%
Gas	RICE	0.87%	1.15%	0.64%	0.93%	1.12%
Oil	RICE	0.04%	0.07%	0.07%	0.93%	0.53%
Other	Other	0.03%	0.16%	0.17%	0.16%	0.22%
Uranium	Steam	0.45%	0.51%	0.35%	0.11%	0.19%
Oil	Steam	0.02%	0.07%	0.19%	0.08%	0.12%
Other	Steam	0.05%	0.05%	0.06%	0.07%	0.06%
Oil	CC	0.04%	0.27%	0.02%	0.07%	0.02%

Figure 3-50 shows the type of fuel used by marginal resources in the real-time energy market for the first nine months of every year since 2004. The role of coal as a marginal resource has declined while the role of gas as a marginal resource has increased.

Figure 3-50 Type of fuel used (By real-time marginal units): January through September, 2004 through 2026



118 The unit type RICE refers to Reciprocating Internal Combustion Engines. The fuel and technology categories with fewer than four parent companies were grouped under the Other fuel type to meet PJM's confidentiality standards.

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Table 3-70 shows the type of fuel and technology by fast start marginal resources and other marginal resources in the real-time energy market in the first nine months of 2026. In the first nine months of 2026, marginal fast start resources accounted for 7.1 percent of all marginal resources in the pricing run.

Table 3-70 Fuel type and technology (Real-time marginal units and fast start marginal units): January through September, 2026[119]

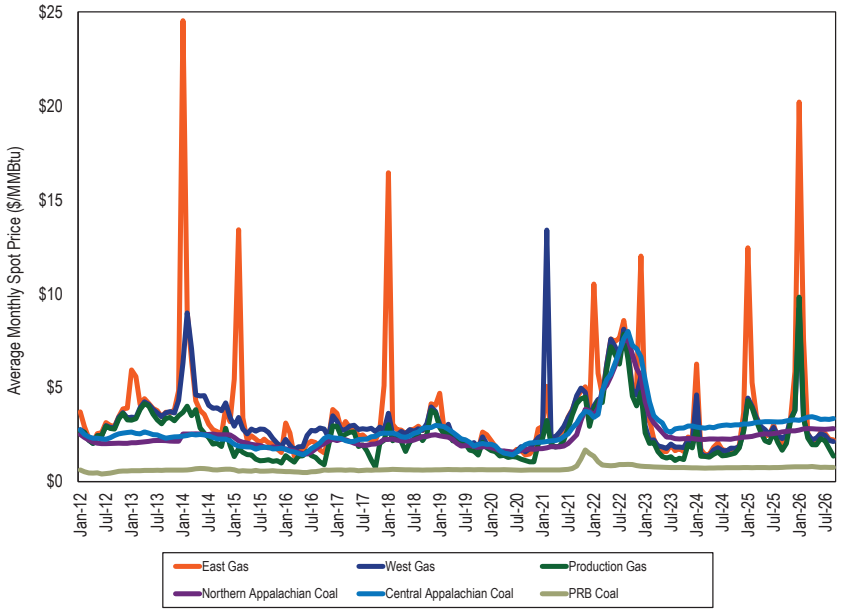
		2026 (Jan - Sep)		
Fuel	Technology	Fast Start	Other	Both
Coal	Steam	0.00%	9.53%	9.53%
Gas	CC	0.00%	57.46%	57.46%
Gas	CT	4.32%	5.55%	9.86%
Gas	RICE	1.10%	0.02%	1.12%
Gas	Steam	0.00%	2.85%	2.85%
Landfill Gas	CT	0.00%	0.00%	0.00%
Oil	CC	0.00%	0.02%	0.02%
Oil	CT	0.76%	1.21%	1.96%
Oil	RICE	0.53%	0.00%	0.53%
Oil	Steam	0.00%	0.12%	0.12%
Other	Other	0.01%	0.21%	0.22%
Other	Solar	0.12%	4.01%	4.13%
Other	Steam	0.00%	0.06%	0.06%
Uranium	Steam	0.00%	0.19%	0.19%
Wind	Wind	0.24%	11.70%	11.94%
All Marginal Units		7.07%	92.93%	100.00%

Fuel Price Trends and LMP

In a competitive market, changes in LMP follow 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 short run 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 also contribute to changes in the marginal cost of marginal units.

Figure 3-51 shows fuel prices in PJM for 2012 through September 2026. Natural gas prices, coal prices and oil prices increased in the first nine months of 2026 compared to the first nine months of 2025. In the first nine months of 2026, the price of eastern natural gas was 22.2 percent higher and the price of western natural gas was 4.6 percent higher than in the first nine months of 2025. The price of Northern Appalachian coal was 11.2 percent higher; the price of Central Appalachian coal was 6.3 percent higher; and the price of Powder River Basin coal was 3.9 percent higher.[120] The price of ULSD NY Harbor Barge (ultra low sulfur diesel) was 58.6 percent higher in the first nine months of 2026 than in the first nine months of 2025.

Figure 3-51 Spot average fuel price comparison: 2012 through September 2026 ($/MMBtu)



119 The fuel and technology categories with fewer than four parent companies were grouped under the Other fuel type to meet PJM's confidentiality standards.

120 Eastern natural gas consists of the average of Texas M3, Transco Zone 6 non-NY, Transco Zone 6 NY and Transco Zone 5 daily indices. Western natural gas prices are the average of Columbia Appalachia and Chicago Citygate daily indices. Production gas prices are the average of Dominion South Point, Tennessee Zone 4, and Transco Leidy Line receipts daily 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.

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Components of LMP

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 the offers of marginal units determine system LMPs, based on their offers and forecasts of system conditions up to 14 minutes ahead. Those offers can be decomposed into components including fuel costs, emission costs, variable operation and maintenance (VOM) costs, markup, FMU adder and the 10 percent cost adder. As a result, it is possible to decompose LMP by the components of the offers of marginal units.

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 participated in RGGI in the first nine months of 2026: Delaware, Maryland, and New Jersey for the full nine months and Virginia for the last three months.[121] 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 October 1, 2012, PJM jointly optimizes the commitment and dispatch of energy and reserves. 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 will contribute to LMP. The component, ancillary service redispatch cost, shows the contribution of this cost to PJM's load-weighted LMP. In addition, in periods when the pricing run solution does not meet the reserve requirements, PJM invokes shortage pricing. In shortage conditions, the LMPs reflect the administratively defined shortage pricing component, implemented through the operating reserve demand curve.[122]

Starting on September 1, 2021, the components shown in Table 3-71 and Table 3-73 are from the pricing run, which includes the impact of amortized start cost and amortized no load cost of the fast start marginal units. The components of LMP are shown in Table 3-71, including markup using unadjusted cost-based offers.[123] The percent column is the difference (in percentage points) in the proportion of LMP represented by each component in the first nine months of 2025 and 2026. Table 3-71 shows that in the first nine months of 2026, 6.1 percent of the load-weighted LMP was the result of coal costs, 32.0 percent was the result of gas costs and 5.2 percent was the result of the cost of carbon emission allowances. 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. Using unadjusted cost-based offers, negative markup was -7.6 percent of the load-weighted LMP. Using unadjusted cost-based offers, positive markup was 8.4 percent of the load-weighted LMP. LMP may, at times, be set by transmission constraint penalty factors. In the first nine months of 2026, 18.8 percent of the load-weighted LMP was the result of transmission constraint penalty factors.

In the first nine months of 2026, the number of violated constraint intervals increased by 69 percent from 18,497 constraint intervals in the first nine months of 2025 to 31,240 constraint intervals in the first nine months of 2026. Of the 31,240 violated constraint intervals in the first nine months of 2026, 18.6 percent were during the 11 days between January 20 and January 31 of 2026, and 34.8 percent involved high voltage (500 kV and above) constraints, which have a larger effect on market prices. More than 99 percent (99.6 percent) of this impact occurred as a result of PJM's administrative reductions to transmission line ratings in SCED that caused the constraints to violate (Table 3-60). The percent contribution of transmission constraint penalty factors has increased substantially since PJM allowed penalty factors to affect LMPs starting February 1, 2019.

121 New Jersey withdrew from RGGI, effective January 1, 2012, and rejoined RGGI effective January 1, 2020. Virginia joined RGGI effective January 1, 2021, left RGGI on December 31, 2023, and rejoined RGGI effective July 1, 2026. Pennsylvania took action to join RGGI on April 23, 2023. The action was enjoined in the course of litigation. The litigation ended after the legislative basis for Pennsylvania's participation in RGGI was removed on November 12, 2025.

122 Operating Reserve Demand Curve component includes ancillary service redispatch cost component during periods of shortage.

123 These components are explained in the *Technical Reference for PJM Markets*, at p 27 "Calculation and Use of Generator Sensitivity/ Unit Participation Factors," <http://www. monitoringanalytics.com/reports/Technical_References/references.shtml>.

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Table 3-71 Components of real-time (Unadjusted) load-weighted average LMP: January through September, 2025 and 2026[124]

	2025 (Jan - Sep)		2026 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$21.97	43.5%	$24.00	32.0%	(11.5%)
Transmission Constraint Penalty Factor	$5.31	10.5%	$14.11	18.8%	8.3%
Positive Markup	$3.64	7.2%	$6.33	8.4%	1.2%
Oil	$2.66	5.3%	$4.98	6.6%	1.4%
Coal	$3.62	7.2%	$4.59	6.1%	(1.0%)
CO2 Cost	$2.08	4.1%	$3.86	5.2%	1.0%
Variable Maintenance	$3.46	6.9%	$3.77	5.0%	(1.8%)
Ten Percent Adder	$3.06	6.1%	$3.71	4.9%	(1.1%)
Operating Reserve Demand Curves	$1.32	2.6%	$3.48	4.6%	2.0%
Opportunity Cost Adder	$1.17	2.3%	$2.90	3.9%	1.6%
Market-to-Market	$0.59	1.2%	$2.66	3.5%	2.4%
Ancillary Service Redispatch Cost	$1.21	2.4%	$2.00	2.7%	0.3%
Variable Operations	$1.30	2.6%	$1.64	2.2%	(0.4%)
Increase Generation Differential	$0.50	1.0%	$1.22	1.6%	0.6%
NA	$1.41	2.8%	$0.69	0.9%	(1.9%)
Price Responsive Demand	$0.00	0.0%	$0.66	0.9%	0.9%
LPA Rounding Difference	$0.38	0.8%	$0.54	0.7%	(0.0%)
NOx Cost	$0.07	0.1%	$0.20	0.3%	0.1%
Landfill Gas	$0.08	0.2%	$0.15	0.2%	0.0%
Emergency Demand Response	$0.89	1.8%	$0.06	0.1%	(1.7%)
Other	$0.02	0.0%	$0.02	0.0%	(0.0%)
SO2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
LPA-SCED Differential	($0.00)	(0.0%)	($0.00)	(0.0%)	0.0%
Decrease Generation Differential	($0.25)	(0.5%)	($0.13)	(0.2%)	0.3%
PJM Administrative Cap	($0.11)	(0.2%)	($0.34)	(0.5%)	(0.2%)
Renewable Energy Credits	($0.14)	(0.3%)	($0.45)	(0.6%)	(0.3%)
Negative Markup	($3.74)	(7.4%)	($5.68)	(7.6%)	(0.2%)
Total	$50.51	100.0%	$74.98	100.0%	0.0%

Components of Change in LMP

Table 3-72 shows the components of the increase in real-time load-weighted average LMP from the first nine months of 2025 to the first nine months of 2026. In the first nine months of 2026, the real-time load-weighted average LMP increased by $$24.47 per MWh, 48.4 percent. The transmission constraint penalty factor increased the LMP by $8.81 per MWh, 36.0 percent of the total increase, primarily as a result of PJM's reduction of line ratings in SCED. Increases in the fuel and consumables cost components of LMP (the sum of gas, coal, oil, landfill gas, variable operations expense) increased the LMP by $5.73 per MWh, 23.4 percent of increase in LMP. Increases in the emissions cost components of LMP (the sum of NO_X, CO_2, opportunity cost adder, SO_2, and renewable energy credits) increased the LMP by $3.32 per MWh, 13.6 percent of the increase in LMP. Increases in the sum of the positive and negative markups, ten percent adder, and maintenance cost components, all of which reflect market power, increased the LMP by $1.71 per MWh, 7.0 percent of the increase in LMP. The administrative operating reserve demand curve setting LMP increased the LMP by $2.16 per MWh, 8.8 percent of the increase in the LMP. The ancillary service redispatch cost, the opportunity cost of reduced marginal generation to meet reserve requirements, increased the LMP by $0.79 per MWh, 3.2 percent. The reduction in pre-emergency demand response and price responsive demand decreased LMP by $0.17 per MWh, -0.7 percent of the increase in LMP. The administrative cap component decreased LMP by $0.23 per MWh, -1.0 percent of the increase in LMP.

124 The component NA is the unexplained portion of load-weighted LMP. For several intervals, PJM failed 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 NA component is the cumulative effect of excluding those five minute intervals.

Table 3-72 Components of change in real-time load-weighted average LMP: January through September, 2025 and 2026

Component	2025 (Jan - Sep)	2026 (Jan - Sep)	Change in LMP	Percent of Total Change
Fuel and Consumables	$29.63	$35.36	$5.73	23.4%
Emission Related	$3.18	$6.51	$3.32	13.6%
Market Power Related	$6.43	$8.13	$1.71	7.0%
Operating Reserve Demand Curves	$1.32	$3.48	$2.16	8.8%
Transmission Constraint Penalty Factor	$5.31	$14.11	$8.81	36.0%
Ancillary Service Redispatch Cost	$1.21	$2.00	$0.79	3.2%
Pre-emergency Demand Response and Price Responsive Demand	$0.89	$0.72	($0.17)	(0.7%)
PJM Administrative Cap	($0.11)	($0.34)	($0.23)	(1.0%)
All Other	$2.66	$5.01	$2.35	9.6%
Total Change	$50.51	$74.98	$24.47	100.0%

In order to understand the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach (Table 3-71) markup is the difference between the price offer and the cost-based offer (unadjusted markup). In the second approach (Table

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3-73), the 10 percent markup is removed from the cost-based offers of coal, gas, and oil units and treated as part of the overall markup (adjusted markup).

Table 3-73 Components of real-time (Adjusted) load-weighted average LMP: January through September, 2025 and 2026

	2025 (Jan - Sep)		2026 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$21.97	43.5%	$24.00	32.0%	(11.5%)
Transmission Constraint Penalty Factor	$5.31	10.5%	$14.11	18.8%	8.3%
Positive Markup	$5.43	10.8%	$8.49	11.3%	0.6%
Oil	$2.66	5.3%	$4.98	6.6%	1.4%
Coal	$3.62	7.2%	$4.59	6.1%	(1.0%)
CO2 Cost	$2.08	4.1%	$3.86	5.2%	1.0%
Variable Maintenance	$3.46	6.9%	$3.77	5.0%	(1.8%)
Operating Reserve Demand Curves	$1.32	2.6%	$3.48	4.6%	2.0%
Opportunity Cost Adder	$1.17	2.3%	$2.90	3.9%	1.6%
Market-to-Market	$0.59	1.2%	$2.66	3.5%	2.4%
Ancillary Service Redispatch Cost	$1.21	2.4%	$2.00	2.7%	0.3%
Variable Operations	$1.30	2.6%	$1.64	2.2%	(0.4%)
Increase Generation Differential	$0.50	1.0%	$1.22	1.6%	0.6%
NA	$1.41	2.8%	$0.69	0.9%	(1.9%)
Price Responsive Demand	$0.00	0.0%	$0.66	0.9%	0.9%
LPA Rounding Difference	$0.38	0.8%	$0.55	0.7%	(0.0%)
NOx Cost	$0.07	0.1%	$0.20	0.3%	0.1%
Landfill Gas	$0.08	0.2%	$0.15	0.2%	0.0%
Emergency Demand Response	$0.89	1.8%	$0.06	0.1%	(1.7%)
Other	$0.02	0.0%	$0.02	0.0%	(0.0%)
Ten Percent Adder	$0.01	0.0%	$0.02	0.0%	(0.0%)
SO2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
LPA-SCED Differential	($0.00)	(0.0%)	($0.00)	(0.0%)	0.0%
Decrease Generation Differential	($0.25)	(0.5%)	($0.13)	(0.2%)	0.3%
PJM Administrative Cap	($0.11)	(0.2%)	($0.34)	(0.5%)	(0.2%)
Renewable Energy Credits	($0.14)	(0.3%)	($0.45)	(0.6%)	(0.3%)
Negative Markup	($2.48)	(4.9%)	($4.15)	(5.5%)	(0.6%)
Total	$50.51	100.0%	$74.98	100.0%	0.0%

The components of LMP for the dispatch run and the pricing run are shown in Table 3-74, including markup using unadjusted cost-based offers for the first nine months of 2026.

Table 3-74 Comparison of components of real-time (Unadjusted) load-weighted average LMP in the dispatch run and pricing run: January through September, 2026

	Dispatch		Pricing		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$22.93	34.7%	$24.00	32.0%	(2.7%)
Transmission Constraint Penalty Factor	$13.85	21.0%	$14.11	18.8%	(2.1%)
Positive Markup	$5.46	8.3%	$6.33	8.4%	0.2%
Oil	$2.65	4.0%	$4.98	6.6%	2.6%
Coal	$4.89	7.4%	$4.59	6.1%	(1.3%)
CO2 Cost	$4.00	6.0%	$3.86	5.2%	(0.9%)
Variable Maintenance	$2.37	3.6%	$3.77	5.0%	1.4%
Ten Percent Adder	$3.31	5.0%	$3.71	4.9%	(0.1%)
Operating Reserve Demand Curves	$1.71	2.6%	$3.48	4.6%	2.1%
Opportunity Cost Adder	$2.52	3.8%	$2.90	3.9%	0.1%
Market-to-Market	$2.63	4.0%	$2.66	3.5%	(0.4%)
Ancillary Service Redispatch Cost	$1.13	1.7%	$2.00	2.7%	1.0%
Variable Operations	$1.50	2.3%	$1.64	2.2%	(0.1%)
Increase Generation Differential	$0.97	1.5%	$1.22	1.6%	0.2%
NA	$0.32	0.5%	$0.69	0.9%	0.4%
Price Responsive Demand	$0.85	1.3%	$0.66	0.9%	(0.4%)
LPA Rounding Difference	$0.44	0.7%	$0.54	0.7%	0.1%
NOx Cost	$0.17	0.3%	$0.20	0.3%	0.0%
Landfill Gas	$0.18	0.3%	$0.15	0.2%	(0.1%)
Emergency Demand Response	$0.06	0.1%	$0.06	0.1%	(0.0%)
Other	$0.02	0.0%	$0.02	0.0%	0.0%
SO2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
LPA-SCED Differential	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Decrease Generation Differential	($0.12)	(0.2%)	($0.13)	(0.2%)	0.0%
PJM Administrative Cap	$0.00	0.0%	($0.34)	(0.5%)	(0.5%)
Renewable Energy Credits	($0.46)	(0.7%)	($0.45)	(0.6%)	0.1%
Negative Markup	($5.30)	(8.0%)	($5.68)	(7.6%)	0.5%
Total	$66.07	100.0%	$74.98	100.0%	0.0%

The components of the total cost to real-time load ($M) are shown in Table 3-75, including markup using unadjusted cost-based offers. The components of the total cost to real-time load are shown in Table 3-76, including markup using adjusted cost-based offers. In the first nine months of 2026, the cost to real-time load was $47,566.5 million. Of the $47,566.5 million in the total cost to real-time load in the first nine months of 2026, $15,229.4 million was a result of the cost of gas, $8,954.6 million was a result of the transmission

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constraint penalty factor, $4,015.0 million was a result of the positive markup, $3,160.5 was a result of the cost of oil, $2,909.9 million was a result of the cost of coal, $2,450.3 million was a result of the cost of CO_2 emissions.

Table 3-75 Components of the cost of real-time (Unadjusted) load: January through September, 2025 and 2026

	Contribution to Real Time Cost of Load ($Million)			
Element	2025 (Jan - Sep)	2026 (Jan - Sep)	Change	Percent
Gas	$13,483.7	$15,229.4	$1,745.8	10.5%
Transmission Constraint Penalty Factor	$3,256.1	$8,954.6	$5,698.4	34.4%
Positive Markup	$2,235.3	$4,015.0	$1,779.8	10.7%
Oil	$1,631.7	$3,160.5	$1,528.8	9.2%
Coal	$2,221.5	$2,909.9	$688.3	4.2%
CO2 Cost	$1,279.4	$2,450.3	$1,170.9	7.1%
Variable Maintenance	$2,125.6	$2,394.2	$268.6	1.6%
Ten Percent Adder	$1,879.0	$2,352.3	$473.3	2.9%
Operating Reserve Demand Curves	$809.5	$2,206.1	$1,396.6	8.4%
Opportunity Cost Adder	$716.9	$1,838.9	$1,122.0	6.8%
Market-to-Market	$364.1	$1,687.6	$1,323.4	8.0%
Ancillary Service Redispatch Cost	$740.0	$1,267.8	$527.8	3.2%
Variable Operations	$797.6	$1,040.9	$243.4	1.5%
Increase Generation Differential	$308.0	$774.4	$466.4	2.8%
NA	$865.3	$439.5	($425.7)	(2.6%)
Price Responsive Demand	$0.0	$419.0	$419.0	2.5%
LPA Rounding Difference	$233.7	$345.5	$111.8	0.7%
NOx Cost	$41.7	$128.2	$86.6	0.5%
Landfill Gas	$51.5	$92.3	$40.8	0.2%
Emergency Demand Response	$545.0	$38.5	($506.5)	(3.1%)
Other	$9.8	$14.0	$4.3	0.0%
SO2 Cost	$0.1	$0.1	$0.0	0.0%
LPA-SCED Differential	($0.0)	($0.0)	$0.0	0.0%
Decrease Generation Differential	($151.0)	($84.4)	$66.6	0.4%
PJM Administrative Cap	($68.0)	($218.2)	($150.3)	(0.9%)
Renewable Energy Credits	($83.9)	($288.1)	($204.2)	(1.2%)
Negative Markup	($2,295.9)	($3,601.7)	($1,305.9)	(7.9%)
Total	$30,996.6	$47,566.5	$16,569.9	100.0%

Table 3-76 Components of the (Adjusted) cost of real-time load: January through September, 2025 and 2026

	Contribution to Real Time Cost of Load ($Million)			
Element	2025 (Jan - Sep)	2026 (Jan - Sep)	Change	Percent
Gas	$13,483.7	$15,229.4	$1,745.8	10.5%
Transmission Constraint Penalty Factor	$3,256.1	$8,954.6	$5,698.4	34.4%
Positive Markup	$3,333.6	$5,388.1	$2,054.5	12.4%
Oil	$1,631.7	$3,160.5	$1,528.8	9.2%
Coal	$2,221.5	$2,909.9	$688.3	4.2%
CO2 Cost	$1,279.4	$2,450.3	$1,170.9	7.1%
Variable Maintenance	$2,125.6	$2,394.2	$268.6	1.6%
Operating Reserve Demand Curves	$809.5	$2,206.1	$1,396.6	8.4%
Opportunity Cost Adder	$716.9	$1,838.9	$1,122.0	6.8%
Market-to-Market	$364.1	$1,687.6	$1,323.4	8.0%
Ancillary Service Redispatch Cost	$740.0	$1,267.8	$527.8	3.2%
Variable Operations	$797.6	$1,040.9	$243.4	1.5%
Increase Generation Differential	$308.0	$774.4	$466.4	2.8%
NA	$865.1	$439.5	($425.6)	(2.6%)
Price Responsive Demand	$0.0	$419.0	$419.0	2.5%
LPA Rounding Difference	$233.7	$345.8	$112.1	0.7%
NOx Cost	$41.7	$128.2	$86.6	0.5%
Landfill Gas	$51.5	$92.3	$40.8	0.2%
Emergency Demand Response	$545.0	$38.5	($506.5)	(3.1%)
Other	$9.8	$14.0	$4.3	0.0%
Ten Percent Adder	$6.9	$10.5	$3.6	0.0%
SO2 Cost	$0.1	$0.1	$0.0	0.0%
LPA-SCED Differential	($0.0)	($0.0)	$0.0	0.0%
Decrease Generation Differential	($151.0)	($84.4)	$66.6	0.4%
PJM Administrative Cap	($68.0)	($218.2)	($150.3)	(0.9%)
Renewable Energy Credits	($83.9)	($288.1)	($204.2)	(1.2%)
Negative Markup	($1,522.0)	($2,633.4)	($1,111.4)	(6.7%)
Total	$30,996.6	$47,566.5	$16,569.9	100.0%

Table 3-77 shows the components of the increase in the cost of real-time load from the first nine months of 2025 to the first nine months of 2026. In the first nine months of 2026, the cost to real-time load increased by $16,569.9 million or 53.5 percent compared to the first nine months of 2025. Fuel and consumables cost components of LMP (the sum of gas, coal, oil, landfill gas, variable operations) increased the cost of real-time load by $4,247.1 million, 25.6 percent of the increase in the cost of real-time load. The transmission constraint penalty factor increased the cost of real-time load by $5,698.4 million, 34.4 percent. The emissions cost components (the sum of NO_X, CO_2, opportunity cost adder, SO_2, and renewable energy credits) increased the real-

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time cost of load by $2,175.3 million, 13.1 percent of the increase in the cost of real-time load. The sum of the positive and negative markups, ten percent adder, and maintenance cost components, all of which reflect market power, increased the cost of real-time load by $1,215.8 million, 7.3 percent of the increase in the cost of real time load. The administrative operating reserve demand curves increased the cost of real-time load by $1,396.6 million, 8.4 percent of the increase in the cost of real-time load. The ancillary service redispatch cost, the opportunity cost of reduced marginal generation to meet reserve requirements, increased the cost of real-time load by $527.8, 3.2 percent of the cost of real-time load. The pre-emergency demand response and price responsive demand decreased the cost of real-time load by $87.6 million, 0.5 percent of the increase in the cost of real-time load. The administrative cap component decreased LMP more in the first nine months of 2026 than the first nine months of 2025, -0.9 percent of the increase in LMP.

Table 3-77 Components of Change in the cost of real-time load: January through September, 2025 and 2026

	($ Million)			Percent of Total
Component	2025 (Jan - Sep)	2026 (Jan - Sep)	Change	Change
Fuel and Consumables	$18,186.0	$22,433.0	$4,247.1	25.6%
Emission Related	$1,954.2	$4,129.4	$2,175.3	13.1%
Market Power Related	$3,943.9	$5,159.7	$1,215.8	7.3%
Operating Reserve Demand Curves	$809.5	$2,206.1	$1,396.6	8.4%
Transmission Constraint Penalty Factor	$3,256.1	$8,954.6	$5,698.4	34.4%
Ancillary Service Redispatch Cost	$740.0	$1,267.8	$527.8	3.2%
Pre-emergency Demand Response and Price Responsive Demand	$545.0	$457.5	($87.6)	(0.5%)
PJM Administrative Cap	($68.0)	($218.2)	($150.3)	(0.9%)
All Other	$1,629.8	$3,176.6	$1,546.7	9.3%
Total Change	$30,996.6	$47,566.5	$16,569.9	100.0%

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, 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 energy market with an offer price that cannot be decomposed. Using identified marginal resource offers and the components of unit offers, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

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Table 3-78 shows the components of the PJM day-ahead annual load-weighted average LMP. In the first nine months of 2026, 18.0 percent of the load-weighted LMP was the result of gas costs, 6.0 percent of the load-weighted LMP was the result of coal costs, 12.4 percent was the result of INCs, 26.7 percent was the result of DECs, 2.9 percent was the result of UTCs, and 6.5 percent was the result of positive markup.[125] [126]

Table 3-78 Components of day-ahead (Unadjusted) load-weighted average LMP (Dollars per MWh): January through September, 2026

	2026 (Jan - Sep)	
Element	Contribution to LMP	Percent
DEC	$19.43	26.7%
Gas	$13.12	18.0%
NA	$9.10	12.5%
INC	$9.04	12.4%
Positive Markup	$4.69	6.5%
Coal	$4.40	6.0%
CO2 Cost	$2.97	4.1%
Transmission Constraint Penalty Factor	$2.72	3.7%
Up to Congestion	$2.07	2.9%
Ten Percent Adder	$2.06	2.8%
Variable Maintenance	$1.37	1.9%
Variable Operations	$1.09	1.5%
Oil	$0.97	1.3%
Ancillary Service Redispatch Cost	$0.80	1.1%
Increase Generation Differential	$0.51	0.7%
Opportunity Cost Adder	$0.32	0.4%
NOx Cost	$0.12	0.2%
Scarcity	$0.01	0.0%
Landfill Gas	$0.01	0.0%
SO2 Cost	$0.00	0.0%
Other	($0.00)	(0.0%)
Decrease Generation Differential	($0.05)	(0.1%)
Renewable Energy Credits	($0.29)	(0.4%)
Negative Markup	($1.74)	(2.4%)
Total	$72.73	100.0%

125 The MMU identified an error in the marginal resource identification algorithm within the day ahead clearing optimization in April 2024. The calculation of generator sensitivity factors requires accurate identification of marginal resources. The error was fixed by the PJM software vendor in March 2025. The MMU was unable to calculate the component breakdown for 2024 and the first quarter of 2025 due to the inaccurate identification of marginal resources.

126 The MMU identified missing and erroneous distribution factors and shadow prices, primarily within the pricing run. The calculation of generator sensitivity factors requires accurate distribution factors and shadow prices. Where available, MMU used distribution factors from the dispatch run. The MMU also calculated missing shadow prices for the relevant transmission constraints when feasible. This approach reduced the impact of the errors. Any remaining errors contributed to the NA component.

Table 3-79 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, gas and oil units.[127]

Table 3-79 Components of day-ahead (Adjusted) load-weighted average LMP (Dollars per MWh): January through September, 2026

	2026 (Jan - Sep)	
Element	Contribution to LMP	Percent
DEC	$19.43	26.7%
Gas	$13.12	18.0%
NA	$9.10	12.5%
INC	$9.04	12.4%
Positive Markup	$5.96	8.2%
Coal	$4.40	6.0%
CO2 Cost	$2.97	4.1%
Transmission Constraint Penalty Factor	$2.72	3.7%
Up to Congestion	$2.07	2.9%
Variable Maintenance	$1.37	1.9%
Variable Operations	$1.09	1.5%
Oil	$0.97	1.3%
Ancillary Service Redispatch Cost	$0.80	1.1%
Increase Generation Differential	$0.51	0.7%
Opportunity Cost Adder	$0.32	0.4%
NOx Cost	$0.12	0.2%
Scarcity	$0.01	0.0%
Landfill Gas	$0.01	0.0%
Ten Percent Adder	$0.00	0.0%
SO2 Cost	$0.00	0.0%
Other	($0.00)	(0.0%)
Decrease Generation Differential	($0.05)	(0.1%)
Renewable Energy Credits	($0.29)	(0.4%)
Negative Markup	($0.95)	(1.3%)
Total	$72.73	100.0%

127 Id.

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Shortage

PJM's real-time energy market experienced five-minute shortage pricing for one or more reserve products for 345 unique five-minute intervals across 36 days in the first nine months of 2026. PJM implemented fast start pricing on September 1, 2021, creating the possibility that the pricing run and the dispatch run could classify different intervals as short. In the first nine months of 2026, in the pricing run, there were 345 unique five-minute intervals with real-time shortage pricing for one or more reserve products. In the first nine months of 2026, in the dispatch run, there were 168 unique intervals with real-time shortage pricing for one or more reserve products. This resulted in higher energy and reserve prices due to false shortage pricing in 177 real-time market intervals.

Emergency Procedures

PJM can give members advance notice of possible emergency actions that could occur during an operating day. These notifications are classified by urgency. Advisories are usually issued several days in advance. Alerts are declared at least a day in advance. Warnings are issued on the same operating day, usually for an expected emergency action.

Some emergency actions serve as triggers for performance assessment intervals (PAIs) when declared for the RTO or the active subzone. Some emergency actions trigger PAIs unconditionally while others only trigger PAIs when there is a primary reserve shortage for that area.[128] [129] The declaration of such emergency actions for smaller areas, such as for specific control zones, does not trigger a PAI. When communicating emergency procedures, PJM will also post NERC energy emergency alert (EEA) levels.[130] Table 3-80 provides a description of PJM declared emergency procedures, in alphabetical order, including whether they are a trigger for PAIs and the NERC EEA level triggered with the procedure, if any.[131] [132] [133] [134]

128 See PJM. "PJM Manual 18: PJM Capacity Market," § 8.4A Non-Performance Assessment, Rev. 62 (Dec. 17, 2025).
129 OATT, Part I (Common Service Provisions) § 1.
130 NERC Attachment 1-EOP-011-4. "Energy Emergency Alerts," February 15, 2024. <https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-4.pdf>.
131 See PJM. "PJM Manual 13: Emergency Operations," § 3.3 Cold Weather Advisory / Alert, Rev. 97 (Nov. 20, 202).
132 See PJM. "PJM Manual 13: Emergency Operations," § 3.4 Hot Weather Alert, Rev. 97 (Nov. 20, 2025).
133 See PJM. "PJM Manual 13: Emergency Operations," § 2.3.1 Advanced Notice Emergency Procedures: Alerts, Rev. 97 (Nov. 20, 2025).
134 See PJM. "PJM Manual 13: Emergency Operations," § 2.3.2 Real-Time Emergency Procedures (Warnings and Actions), Rev. 97 (Nov. 20, 2025).

NERC energy emergency alerts (EEAs) are declared by reliability coordinators, such as PJM, on their own initiative or by request from a NERC regional entity, such as ReliabilityFirst. NERC Attachment 1-EOP-011-4 defines three EEA levels, each having associated circumstances and responsibilities.[135] PJM is a reliability coordinator, a balancing authority and a transmission operator.

Under NERC EEA 1 ("EEA1"), all available generation resources are being used. Under this alert, "all available generation resources are committed to meet firm load, firm transactions, and reserve commitments," the balancing authority is "concerned" about maintaining contingency reserves, and non-firm wholesale energy sales are curtailed. PJM declares an EEA1 when entering into capacity emergencies.[136] For example, PJM declares an EEA1 in the process of issuing a maximum generation emergency/load management alert.

Under NERC EEA 2 ("EEA2"), the balancing authority has activated load management procedures and is no longer able to meet its expected energy requirements but it is still able to meet its contingency reserve requirement. Under an EEA2, PJM must communicate and coordinate with other reliability coordinators. PJM must work with transmission owners to see whether equipment can be returned to service. For example, PJM declares an EEA2 in the process of issuing an emergency load management reduction action.

Under NERC EEA 3 ("EEA3"), the balancing authority is unable to meet its contingency reserve requirement and load is actively being dumped or will soon be dumped. An EEA3 can only be declared after all available generation is online and demand-side response resources are called. During an EEA3, PJM must continue steps begun in an EEA2. For example, PJM declares an EEA3 in the process of issuing a manual load dump warning and, when PJM is not able to meet its contingency reserve requirement, in the process of issuing a voltage reduction action.

In the first nine months of 2026, PJM revised Manual 13, adding new emergency procedures and clarifying existing ones.[137] Several procedures

135 NERC Attachment 1-EOP-011-4. "Energy Emergency Alerts," February 15, 2024. <https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-4.pdf>.
136 See PJM. "PJM Manual 13: Emergency Operations," § 2.3.2 Real-Time Emergency Procedures (Warnings and Actions), Rev. 97 (Nov. 20, 2025).
137 See "Manual 13, Emergency Operations Revision 98 – Annual Review," PJM presentation to the Operations Committee. (June 1, 2026) <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2026/20260601-special/item-02---1-manual-

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were renamed to include the phrase "Capacity Emergency" or "Transmission Security". The newly renamed or clarified versions of the procedures are treated as new, distinct procedures

Table 3-80 Description of emergency procedures

Emergency Procedure	Priority Level	Triggers NERC Energy Emergency Alert	Triggers Performance Assessment Interval	Purpose
Cold Weather Advisory	Advisory			To notify personnel and facilities that PJM may issue a Cold Weather Alert.
Cold Weather Alert	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.
Conservative Operations	Alert			To notify personnel and facilities that PJM may operate more conservatively. This can be due to natural phenomena, weather events, security events, and other conditions. Conservative operations may result in the use of larger contingencies and stricter transfer limits.
Emergency Mandatory Load Management Reduction Action	Action	EEA2		To request load reductions from customers registered in the PJM Demand Response program that need 30, 60, or 120 minute lead time to provide additional load relief.
Geomagnetic Disturbance Action	Action			To inform members that PJM will operate the grid with more conservative transfer limits developed for such disturbances. Transmission owners must coordinate with PJM before acting upon their own disturbance procedures.
Geomagnetic Disturbance Warning	Warning			To warn members that the National Oceanic and Atmospheric Administration predict a possible geomagnetic storm of severity K7 or greater, which can induce currents in the system and equipment.
Heavy Load Voltage (HLV) Schedule Action	Action			To direct transmission owners and generation owners to implement the heavy load voltage schedule.
Heavy Load Voltage (HLV) Schedule Warning	Warning			To warn transmission owners and generation owners to prepare to maximumly support voltages during peak load.
High System Voltage Action	Action			To prepare the system for possible high voltages and to coordinate with transmission owners and generation owners for managing those high voltages.
Hot Weather Alert	Alert			To prepare personnel and facilities for extreme hot and/or humid weather conditions, generally when forecast temperatures exceed 90 degrees with high humidity.
Load Shed Directive	Action		Yes, when for RTO or subzone	To shed load in a local area, reserve subzone, or the entire RTO. A load shed directive for the reserve subzone or the entire RTO triggers a Performance Assessment Interval.
Low Voltage Alert	Alert			To alert transmission owners and generation owners that a period of low voltage and high load are expected.
Maintenance Outage Recall	Informational			To request that generation owners make units available by canceling any maintenance outages within at least 72 hours of posting. After that time, maintenance outages are converted into forced outages.
Maximum Emergency Action	Action		Yes, when PR short in same subzone or RTO	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.
Maximum Generation Emergency Action - Capacity Emergency	Action		Yes, when PR short in same subzone or RTO	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.
Maximum Emergency Generation/Load Management Alert	Alert	EEA1		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.
Maximum Generation Emergency/Load Management Alert - Capacity Emergency - NERC EEA 1	Alert	EEA1		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.
Non-Market Post Contingency Local Load Relief Warning	Warning			To warn transmission owners of the possibility of load shed in their area for non-market facilities.
Post Contingency Local Load Relief Warning	Warning			To warn transmission owners of the possibility of load shed in their area.
Pre-Emergency Mandatory Load Management Reduction Action	Action			To request load reductions from customers registered in the PJM Demand Response program that need 30, 60, or 120 minute lead time before declaring emergency load management reductions.
Transmission Loading Relief (TLR)	Informational			To maintain transmission operating security limits. This can involve curtailing external transactions and charging outside customers for the cost of congestion.
Transmission Security - Deploy All Resources Action	Action			To inform members that all generators are should immediately be online and that all load reduction should immediately reduce in order to support tranmission security.
Transmission Security - Emergency Use of Back-Up Generator Action	Action			To have large loads activate backup generation, triggering a Tranmission Security - Manual Load Dump Warning.
Transmission Security - Emergency Use of Back-Up Generator Warning	Warning			To warn members that PJM may need large loads to activate backup generators.
Transmission Security - Load Management Alert	Alert			To alert load response resources that they may need to be deployed to support transmission security.
Transmission Security - Local Maximum Generation Emergency Action	Action			To alert resources that they may need to increase generation above their economic levels to support transmission security.
Unit Startup Notification Alert	Alert			To direct generation owners to prepare units so that long lead time units can come online within 48 hours. This notice is given days in advance of the predicted need.
Voltage Reduction Action	Action	EEA2 or EEA3 depending on circumstance	Yes	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.

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Not all emergency procedures defined in Table 3-80 are included in Table 3-81, Table 3-82, Figure 3-52, Figure 3-54 and Figure 3-55, even if they did occur in the first nine months of 2026. Synchronized reserve events are covered in more detail in Section 10.[138] Information about frequent events is treated separately. Post Contingency Local Load Relief Warnings (PCLLRWs) and Non-Market Post Contingency Local Load Relief Warnings (NMPCLLRWs) are shown in Figure 3-56 and Figure 3-57. Transmission loading relief informational postings (TLRs) are discussed in the Interchange Transactions section of this report.[139] Local load relief warnings provide transmission owners advanced warning of possible local load shed in an area in order to relieve a local constraint and are separate from manual load dump warnings. Transmission loading relief (TLR) is a NERC procedure for curtailing interchange transactions to avoid violating operational limits of the system.[140] [141]

Table 3-81 shows the dates affected by emergency alerts, warnings, actions, and informational postings in the first nine months of 2026. Events in Table 3-81 can span multiple days, but only the first day is shown. Advisories, alerts, warnings, and informational postings do not necessarily take effect immediately. For example, for cold weather alerts, the dates affected are when PJM expects the cold weather requiring the alert to occur. For maintenance outage recalls, the dates affected are from the date PJM initiates the recall until the date the units are expected to be available. Figure 3-52 shows the timeline of the advisories, alerts, warnings, actions, and the maintenance outage recall during the cold weather event in late January and early February, which included Winter Storm Fern. Figure 3-53 shows the timeline of the advisories, alerts, warnings, actions, and the maintenance outage recall during the hot weather event in late June and early July, which included a maximum generation action in the MAD Reserve Subzone.

138 See *2026 Quarterly State of the Market Report for PJM: January through September,* Section 10: Ancillary Services.
139 See *2026 Quarterly State of the Market Report for PJM: January through September,* Section 9: Interchange Transactions.
140 NERC IRO-006-5. "Reliability Coordination — Transmission Loading Relief (TLR)," November 4, 2010. <https://www.nerc.com/pa/Stand/Reliability%20Standards/IRO-006-5.pdf>.
141 NERC IRO-006-EAST-2. "Transmission Loading Relief Procedure for the Eastern Interconnection," August 13, 2015. <https://www.nerc.com/pa/Stand/Reliability%20Standards/IRO-006-EAST-2.pdf>.

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Table 3-81 Starting days of declared emergency alerts, warnings actions, and certain informational postings: January through September, 2026

Date	Cold Weather Alert	Hot Weather Alert	Conservative Operations	Transmission Security - Load Management Alert	Pre-Emergency Mandatory Load Management Reduction	Emergency Mandatory Load Management Reduction	Transmission Security - Emergency Use of Back-Up Generator Warning	Transmission Security - Emergency Use of Back-Up Generator Action	Geomagnetic Disturbance Warning	Geomagnetic Disturbance Action	Low Voltage Alert	High System Voltage Action	Heavy Load Voltage (HLV) Schedule Warning	Heavy Load Voltage (HLV) Schedule Action	Unit Startup Notification Alert	Maintenance Outage Recall	Maximum Emergency Generation Alert	Maximum Generation Emergency/Load Management Alert - Capacity Emergency - NERC EEA 1	Maximum Emergency Generation Action	Maximum Generation Emergency Action - Capacity Emergency	Transmission Security - Local Maximum Generation Emergency Action	Transmission Security - Deploy All Resources Action
19-Jan-26	Western								PJM RTO													
20-Jan-26	PJM RTO								PJM RTO													
21-Jan-26									PJM RTO							PJM RTO						
23-Jan-26	Western																					
24-Jan-26	PJM RTO		PJM RTO																			
25-Jan-26																						
27-Jan-26											PJM RTO						PJM RTO					
7-Feb-26	PJM RTO																					
3-Apr-26									PJM RTO													
14-Apr-26		Mid-Atlantic, Southern																				
16-Apr-26		Mid-Atlantic, Southern																				
9-May-26												PJM RTO										
10-May-26												PJM RTO										
14-May-26																PJM RTO						
18-May-26		PJM RTO									PJM RTO		PJM RTO					PJM RTO				
19-May-26		Western except COMED; Mid-Atlantic; Southern			AEP_MARION								Western except COMED; Mid-Atlantic; Southern					PJM RTO				
20-May-26		Mid-Atlantic, Southern									Mid-Atlantic, Southern		Southern, Mid-Atlantic									
5-Jun-26		Mid-Atlantic, Southern							PJM RTO													
11-Jun-26		Mid-Atlantic, Southern																				
18-Jun-26		Mid-Atlantic, Southern																				
25-Jun-26																PJM RTO						
29-Jun-26		Western																				
30-Jun-26		PJM RTO																				
1-Jul-26											PJM RTO		PJM RTO					PJM RTO				
2-Jul-26					FE-AP, FE-ATSI, FE-JC, FE-ME, FE-PN	FE-AP, FE-ATSI, FE-JC, FE-ME, FE-PN	Mid-Atlantic, Southern				PJM RTO		PJM RTO	PJM RTO				PJM RTO		Mid-Atlantic, Southern		Southern, BGE, PEPCO
3-Jul-26					FE-AP, FE-ATSI, FE-JC, FE-ME, FE-PN	FE-AP, FE-ATSI, FE-JC, FE-ME, FE-PN	Southern				PJM RTO		PJM RTO	PJM RTO				PJM RTO			Southern, BGE, PEPCO	
4-Jul-26		PJM RTO							PJM RTO		PJM RTO											
5-Jul-26		Mid-Atlantic, Southern																				
14-Jul-26		PJM RTO																				
15-Jul-26													PJM RTO					PJM RTO				
16-Jul-26													PJM RTO					PJM RTO				
9-Aug-26		Mid-Atlantic, Southern																				
10-Aug-26		Mid-Atlantic, Southern																				
11-Aug-26		Mid-Atlantic, Southern																				
31-Aug-26		PJM RTO																				
1-Sep-26																		PJM RTO				
2-Sep-26																		PJM RTO				
3-Sep-26																		PJM RTO				
4-Sep-26		PJM RTO																				
17-Sep-26					FE-AP, FE-ATSI													PJM RTO				

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Figure 3-52 Days with applicable alerts, actions, and recalls January 17 through February 4, 2026[142]

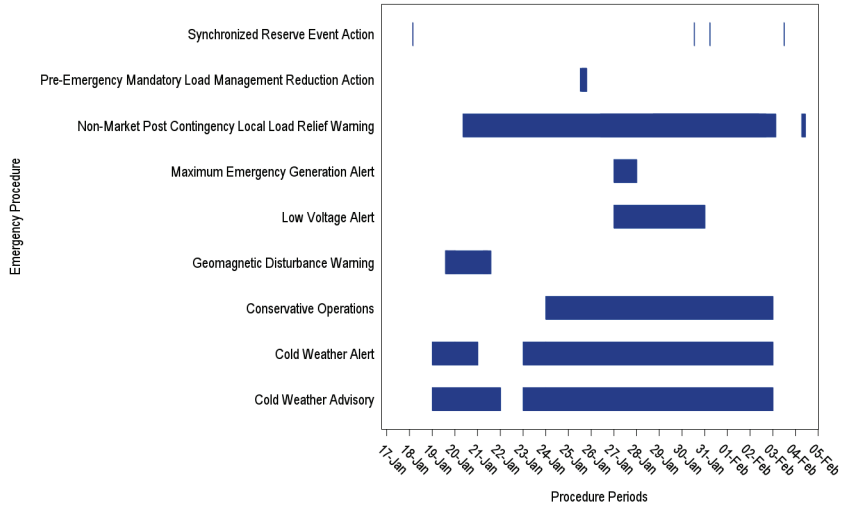


Figure 3-53 Days with applicable alerts, actions, and recalls: June 28 through July 6, 2026

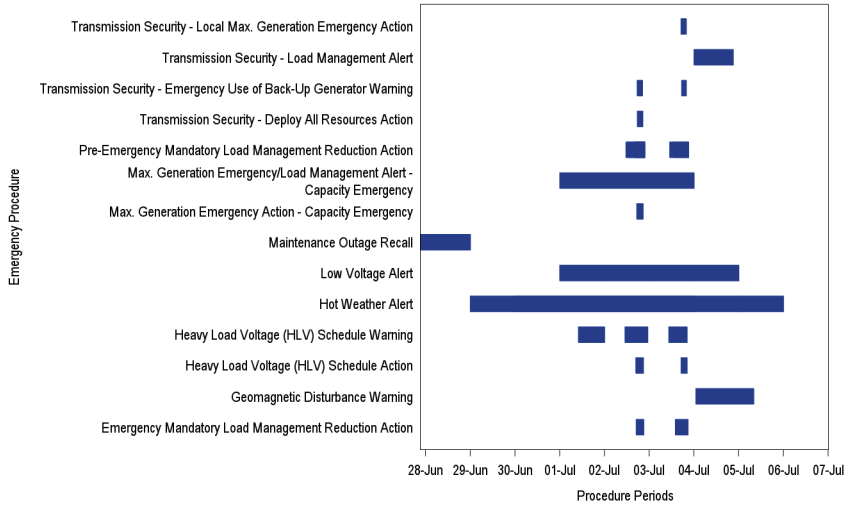


Table 3-82 shows the number of days for which emergency alerts, warnings, actions, and informational postings were declared by PJM in the first nine months of 2025 and the first nine months of 2026. In the first nine months of 2026, there were zero days with emergency actions and shortages that triggered Performance Assessment Intervals (PAIs).[143] The maximum generation action on July 2, 2026, did not trigger PAIs because the affected regions were not also short of primary reserve, even though the RTO as a whole was considered short during that time.

142 To be consistent with other statistics in this section, the length of the maintenance outage recall has been reduced to the days starting from when the recall was issued until the time units were expected to be available. In the previous report, the recall was shown as lasting until near the end of the cold weather.

143 A PAI is triggered when PJM takes an emergency action and there is a shortage of primary reserves in the same zone or subzone. See 184 FERC ¶ 61,058 (2023).

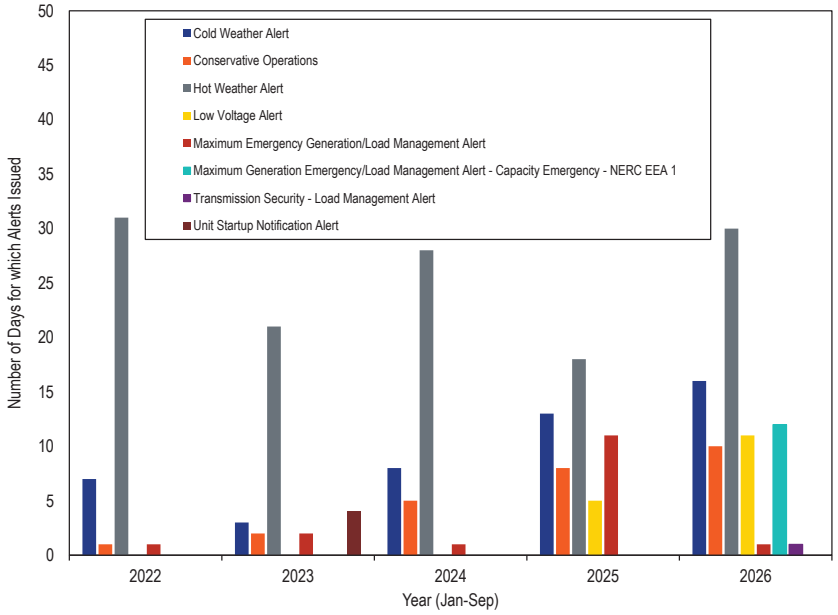
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Table 3-82 Number of days for which PJM declared events (alerts, warnings, actions, and certain informational postings): January through September, 2025 and 2026[144] [145]

	Number of days for which events declared	
Event Type	2025 (Jan-Sep)	2026 (Jan-Sep)
Cold Weather Alert	13	16
Conservative Operations	8	10
Emergency Mandatory Load Management Reduction Action	1	3
Geomagnetic Disturbance Action	1	0
Geomagnetic Disturbance Warning	13	7
Heavy Load Voltage (HLV) Schedule Action	0	2
Heavy Load Voltage (HLV) Schedule Warning	0	8
High System Voltage Action	18	2
Hot Weather Alert	18	30
Load Shed Directive	1	0
Low Voltage Alert	5	11
Maintenance Outage Recall	28	10
Maximum Generation Emergency Action - Capacity Emergency	0	1
Maximum Emergency Generation/Load Management Alert	11	1
Maximum Generation Emergency/Load Management Alert - Capacity Emergency - NERC EEA 1	0	12
Pre-Emergency Mandatory Load Management Reduction Action	7	7
Transmission Security - Deploy All Resources Action	0	1
Transmission Security - Emergency Use of Back-Up Generator Warning	0	2
Transmission Security - Load Management Alert	0	1
Transmission Security - Local Maximum Generation Emergency Action	0	1
Voltage Reduction Action	1	0
Shortage Pricing	22	36
Energy export recalls from PJM capacity resources	0	0

Figure 3-54 shows the number of days for which emergency alerts were issued by PJM in the first nine months of 2022 through 2026. In June 2026, maximum generation load management alerts were split into those for capacity emergencies and those for transmission security. As a result, the count of alerts in the category Maximum Emergency Generation/Load Management Alert is smaller in 2026 compared to previous years.

Figure 3-54 Number of days for which emergency alerts declared: January through September, 2022 through 2026



144 TLRs, Post Contingency Local Load Relief Warnings, and Non-Market Post Contingency Local Load Relief Warnings are excluded due to their high frequency.

145 PJM can recall energy exports as needed as part of triggering emergency procedures. See PJM. "PJM Manual 13: Emergency Operations," § 2.3.2 Real-Time Emergency Procedures (Warnings and Actions), Rev. 98 (Jun. 24, 2026).

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Figure 3-55 shows the number of days for which emergency warnings and actions were declared by PJM in the first nine months of 2022 through 2026. Actions beginning with "Transmission Security" did not exist before 2026.

Figure 3-55 Declared emergency warnings and actions: January through September, 2022 through 2026

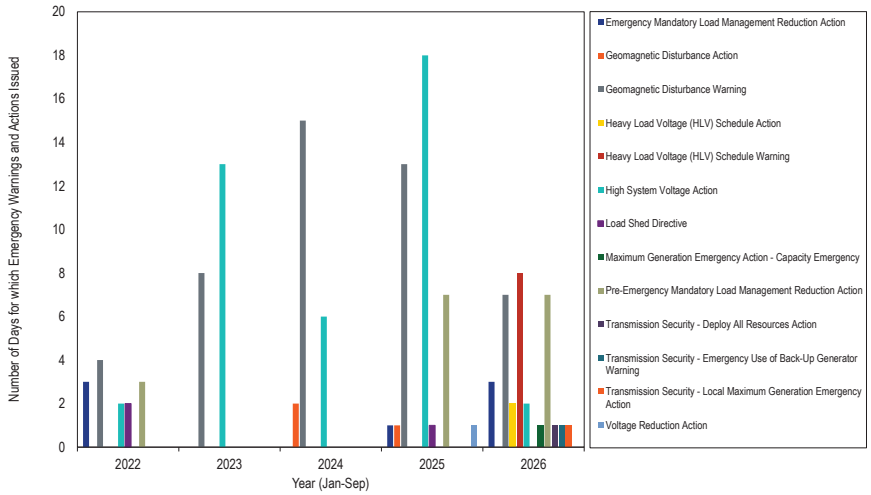
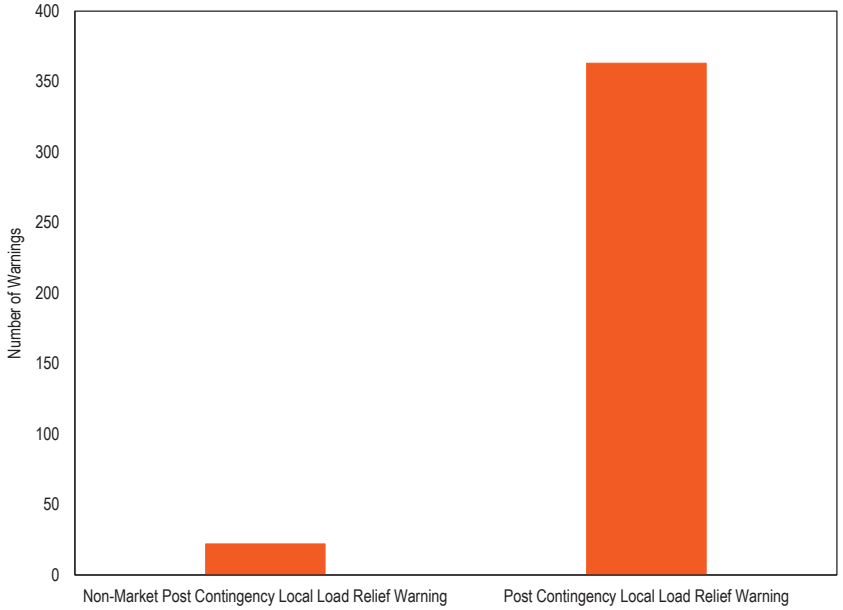


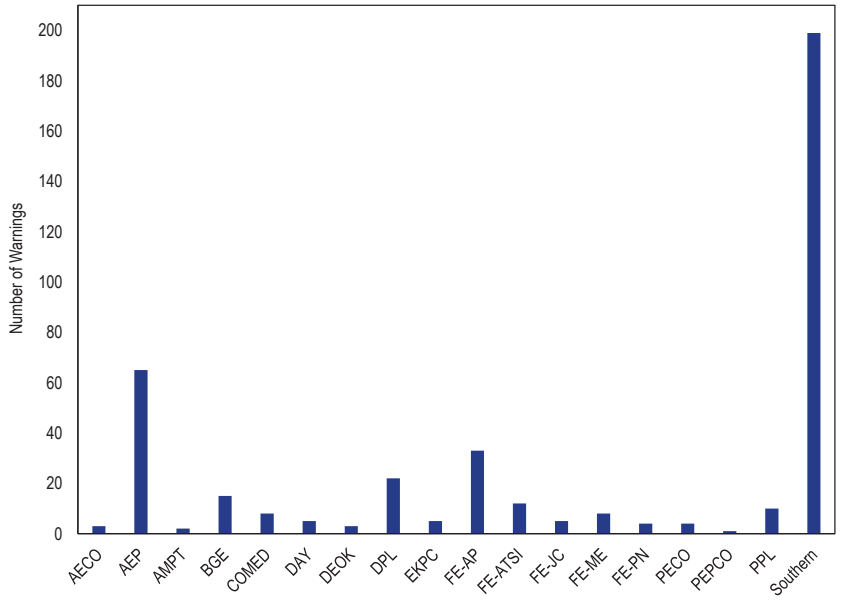
Figure 3-56 shows the number of post contingency local load relief warnings (PCLLRWs) and non-market post contingency local load relief warnings (NMPCLLRWs) declared in PJM in the first nine months of 2026. Figure 3-57 shows the number of post contingency local load relief warnings (PCLLRWs) for each area targeted by a PCLLRW's declaration. A single PCLLRW can be declared for multiple regions.

Figure 3-56 Declared local load relief warnings: January through September, 2026



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Figure 3-57 Number of post contingency local load relief warnings per declared area: January through September, 2026[146]



Power Balance Constraint Violation

The purpose of the real-time energy market is to dispatch sufficient supply to meet demand. In the RT SCED optimization, the power balance constraint enforces the requirement that total dispatched generation (supply) equals the sum total of forecasted load, losses and net interchange (demand). The power balance constraint is violated when supply is less than demand but, for a number of reasons, it is difficult to determine when there is an actual power balance constraint violation.

The current process for meeting energy and reserve requirements in real time, and for pricing the system conditions when RT SCED forecasts that energy supply is less than the demand for energy and reserves, is opaque and not defined in the PJM governing documents. It is unclear whether and how PJM converts reserves to energy before violating the power balance constraint. It is unclear whether and when PJM uses its authority under the tariff to curtail energy exports from PJM capacity resources to meet the power balance constraint. It is unclear why PJM does not include demand side capacity resources in the definition of reserves. It is unclear whether PJM would maintain a minimum level of synchronized reserves even if that would result in a controlled load shed. The current RT SCED does not have a mechanism to convert inflexible reserves procured by the ASO to energy to satisfy the power balance constraint.[147] SCED solutions from October 1, 2019, February 16, 2020, and April 21, 2020, indicate that the defined logic met transmission constraint limits and reserve requirements but violated the power balance constraint. The definitions and implementation of reserves, combined with operator discretion to bias load, make it difficult to define when there is an actual power balance constraint violation. Effective August 8, 2024, PJM updated SCED and LPC to convert reserves to energy before violating the power balance constraint.[148]

During Winter Storm Elliott, on December 23, and December 24, 2022, PJM created what PJM termed virtual generation in real time to satisfy the power balance constraint. PJM did not convert any inflexible reserves to energy. In summary, the power balance constraint was violated solely as a result of the load bias added by PJM and that violation was corrected by PJM adding generation that does not actually exist to the supply (virtual generation). To the extent that there was not an actual violation of the power balance constraint, it was appropriate that PJM did not take actions to address the nonexistent violation.

The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should include: the exact definition of the power balance constraint including the role of PJM load bias; a SCED process to economically

146 Definitions of the regions used in emergency procedures are available at <https://emergencyprocedures.pjm.com/ep/pages/regions.jsf>. Not all regions are used for all procedures. Regions beginning with "FE" are First Energy companies, such as "FE-ME" being Met-Ed.

147 Inflexible reserves are those reserves that clear in the hour ahead Ancillary Service Optimizer (ASO) but cannot be dispatched in the real time dispatch tool, RT SCED. Although the ASO started scheduling regulation in 30-minute intervals on October 1, 2025, the ASO continues scheduling inflexible reserves in one-hour blocks.

148 These changes were not documented publicly in PJM manuals or elsewhere.

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convert reserves to energy; a process for the recall of energy exports from capacity resources to address any actual or potential power balance issue; a process to call on demand side capacity resources, and the minimum level of synchronized reserves that would trigger load shedding.

Table 3-83 shows the number of five minute intervals for which the RT SCED solutions did not balance demand and supply. Prior to August 8, 2024, PJM reran the RT SCED with artificially increased supply to satisfy the power balance constraint. In the first nine months of 2026, there were 16 five-minute intervals that used an RT SCED solution with an apparently violated power balance constraint. Across all intervals with violations, PJM's positive load bias exceeded the apparent MW shortfall. Among those 16 intervals, PJM capped the energy LMP at $3,700 per MWh for six intervals.

Table 3-83 Number of five minute intervals using RT SCED solutions with apparently violated power balance constraint by year

Year	Number of five minute intervals	Average Energy Component of LMP in SCED ($/MWh)	Average Energy Component of LMP in Pricing Run ($/MWh)
2013	0	$0.00	$0.00
2014	655	$36.29	$36.29
2015	71	($0.76)	($0.76)
2016	42	$93.06	$93.06
2017	31	$279.86	$279.86
2018	16	$268.21	$268.21
2019	36	$845.48	$845.48
2020	5	$351.56	$351.56
2021	10	$976.06	$976.06
2022	121	$2,347.33	$2,066.21
2023	23	$357.34	$361.14
2024	6	$907.95	$907.95
2025	8	$3,408.63	$2,937.25
2026 (Jan - Sep)	16	$3,309.56	$3,123.38

Shortage and Shortage Pricing

In electricity markets, shortage means that demand, including reserve requirements, is nearing the limits of the currently available capacity of the system. Shortage pricing is a mechanism for signaling shortage conditions through higher energy prices. Under the PJM rules that were in place through September 30, 2012, shortage pricing resulted from the exercise of aggregate market power by individual generation owners for specific units when the system was close to its available capacity. That was not an efficient way to manage shortage pricing and made it difficult to distinguish between market power and shortage pricing. Shortage pricing is an administrative pricing mechanism that sets a defined higher price when the system operates with real-time reserves that are lower than the target level.

In the first nine months of 2026, there were 345 five minute intervals with real-time shortage pricing in the pricing run for one or more reserve products that occurred on 36 days in PJM.

In Order No. 825, the Commission required each RTO/ISO to trigger shortage pricing for any dispatch and pricing interval in which a shortage of energy or operating reserves is indicated by the RTO/ISO's software.[149] Prior to May 11, 2017, if the dispatch tools (Intermediate-Term SCED and Real-Time SCED) reflected a shortage of reserves (primary or synchronized) for a time period shorter than a defined threshold (30 minutes), it was considered a transient shortage, a shortage event was not declared, and shortage pricing was not implemented. As of May 11, 2017, the rule requires PJM to trigger shortage pricing for any five minute interval for which the Real-Time SCED (Security Constrained Economic Dispatch) indicates a shortage of synchronized reserves or primary reserves. In January 2019, PJM updated its business rules in Manual 11 to describe PJM's implementation of the five minute shortage pricing process. PJM Manual 11 states that shortage pricing is triggered when an approved RT SCED case that was used in the Locational Pricing Calculator (LPC) indicates a shortage of reserves. The implementation is not fully algorithmic or well defined because RT SCED can indicate a shortage that PJM does not use in pricing and because the load bias added to SCED may artificially create or suppress shortages. On June 22, 2020, PJM reduced the frequency of automatic RT SCED executions to every five minutes in order to match the frequency of pricing in the LPC, which reduced the frequency of unpriced shortage solutions.

149 *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, 155 FERC ¶ 61,276 at P 162 (2016).

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Prior to September 1, 2021, the reserves calculated in the LPC solution, and the reserves calculated in the reference RT SCED case used by the LPC solution were the same. With the implementation of fast start pricing on September 1, 2021, shortage pricing is now triggered by the pricing run in LPC.[150] This can lead to differences between the dispatched reserves in RT SCED and the reserves calculated in the pricing run in LPC. In the pricing run in LPC, shortage pricing could be triggered even when there is no actual shortage in dispatched reserves as determined by the reference RT SCED solution. This occurred for 177 intervals in the first nine months of 2026.

Voltage reduction actions and manual load dump actions are also triggers for shortage pricing, reflecting the fact that when operators need to take these emergency actions to maintain reliability, the system is short reserves and prices should reflect the actual short run marginal costs of meeting load under those conditions, even if the administrative reduction of load means that the power balance constraint is met and there is no defined shortage of reserves.[151]

Operating Reserve Demand Curves

Shortage pricing in the PJM Energy Market can occur in either the day-ahead or the real-time market for any of five reserve requirements: RTO Synchronized Reserves, Subzone Synchronized Reserves, RTO Primary Reserves, Subzone Primary Reserves, and 30-Minute Reserves. Each requirement is modelled in the market clearing engines as a demand curve priced administratively at $850 per MWh up to the minimum reserve requirement (MRR) and at $300 per MWh for additional reserves of at least 190 MW.[152] [153] The logic for the choice of the $850 and $300 shortage prices is not defined and its actual basis is not clear. During a reserve shortage, the marginal cost of the short reserve service is set to the administrative value of the ORDC ($850 per MWh if clearing less than the minimum reserve requirement, otherwise $300 per MWh). This is called shortage pricing, and this increases the LMP and the reserve product market clearing prices. This is why the values on the ORDC are sometimes called penalty factors. The penalty for being short of reserves is the increased cost administratively defined by the ORDC.

Based on the current ORDC, the market clearing engine will incur up to $850 per MWh to maintain reserves equal to the minimum reserve requirement. If there are reserve MW available at a marginal cost equal to or less than $850 per MWh to satisfy the reserve requirement, the optimization will use resources to meet the demand for energy instead of reserves until the marginal price per MW of reserves is $850. At cleared reserve levels below the minimum reserve requirement, the marginal cost of converting reserve MW into energy MW to meet the load is administratively defined to be the $850 penalty price. Because an additional MW of energy on the margin would require another MW of reserves shortage, the administrative marginal cost of reserves defined by the ORDC is added to LMP. The marginal cost of energy under these circumstances is the marginal cost of the marginal energy resource plus the $850 marginal penalty for converting reserves to energy.

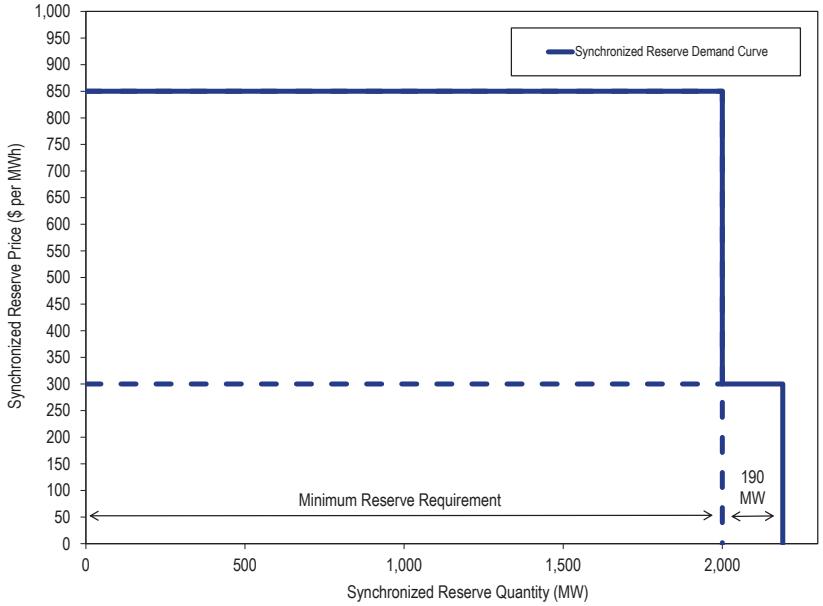
Shortage Pricing and Energy Price Formation

The current operating reserve demand curves (ORDC) in PJM define an administrative price for estimated reserves (synchronized, primary, and 30-minute reserves) up to the extended reserve requirement quantities, which for each reserve service is the sum of that service's minimum reserve requirement (MRR) and an extended requirement of at least 190 MW. The price is $850 per MWh for reserve quantities less than the MRR. The price is $300 per MWh for reserve quantities between the MRR and the sum of the MRR and the extended requirement. The example demand curve shown in Figure 3-58 drops to a zero price for quantities above the extended reserve requirement.

150 *See* PJM Operating Agreement, Schedule 1 § 2.5.1(a).
151 *See, e.g.*, Scarcity and Shortage Pricing, Offer Mitigation and Offer Caps Workshop, Docket No. AD14-14-000, Transcript 29:21–30:14 (Oct. 28, 2014).
152 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3.3 Reserve Demand Curves and Penalty Factors, Rev. 137 (July 28, 2026).
153 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3 Reserve Requirement Determination, Rev. 137 (July 28, 2026).

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Figure 3-58 Example real-time extended synchronized reserve demand curve showing the permanent second step



Historically, the minimum reserve requirement for each operating interval has equaled the size of the largest single source of supply on the PJM system during that operating interval, known as the most severe single contingency. Beginning May 12, 2023, PJM unilaterally increased the minimum reserve requirement based on what appeared to be low response rates from reserves but not based on any evidence about reliability issues. The changes to the reserve requirements are discussed in more detail in Section 10: Ancillary Service Markets.

The $850 per MWh price on the ORDCs has been in place since June 2015.[154] The age of the penalty factor does not determine its effectiveness. There is no evidence that the $850 per MWh value was too low through the first nine months of 2026. PJM proposes to increase the ORDC prices, citing the age of the $850 per MWh value as its only justification.[155] The length of time that the ORDC prices have been in place is irrelevant. Reserve shortages have become more frequent in 2025 and the first nine months of 2026 with load growth, including data center load growth.[156] Unnecessarily increasing shortage pricing during shortage events by arbitrarily raising the ORDC prices, as PJM proposes in the Reserve Certainty Senior Task Force, would increase the costs imposed on all customers from data center load growth, counter to the Principles of the PJM governors and the White House, as well as the Ratepayer Protection Pledge.[157] [158]

Nesting

The reserve requirements are nested such that the reserves with shorter allowed response times and stricter synchronization requirements count toward the requirements for reserves with longer allowed response times and less strict synchronization requirements, and such that the reserves in the subzone count toward the total RTO requirement. For example, synchronized reserves count toward the primary reserve requirement, and Mid-Atlantic Dominion reserves count toward the PJM RTO reserve requirement. This nesting means that the effect of reserve constraints on prices can be additive.

The effect of the reserve constraints on pricing depends on the constraint shadow price. The market uses constraints to ensure that reliability requirements are met while production costs are minimized. A binding constraint means that the market incurred some additional production cost to satisfy the constraint. A violated constraint has no associated production cost, so an administrative cost is used instead. The shadow price of a constraint is the change in the total production cost (the objective function of the market dispatch software) if that constraint limit were increased at the margin. A reserve constraint violation (a shortage) means that the constraint cannot be satisfied at a defined marginal

154 See Monitoring Analytics, LLC. *2015 State of the Market Report for PJM*, Vol. 2, Section 10: Ancillary Services, p. 369.

155 PJM. "Powering Reliability Through Market Design: Addressing Rising Demand and Constrained Supply, and Stimulating Investment To Support Durable Reliability," (May 6, 2026) at 47.

156 See PJM. "PJM Load Forecast Accuracy Report," (May 29, 2025), <https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/2026-load-forecast-accuracy-report.pdf>.

157 See Statement of Principles Regarding PJM, National Energy Dominance Council and PJM State Governors (February 15, 2026), <https://www.energy.gov/documents/statement-principles-regarding-pjm>.

158 See Fact Sheet: President Donald J. Trump Advances Energy Affordability with the Ratepayer Protection Pledge, The White House (March 4, 2026); Ratepayer Protection Pledge, The White House (March 4, 2026), <https://www.whitehouse.gov/fact-sheets/2026/03/fact-sheet-president-donald-j-trump-advances-energy-affordability-with-the-ratepayer-protection-pledge/>.

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cost, and the administratively defined cost is used instead. For the RTO synchronized reserve constraint, the shadow price during a shortage is defined to equal the ORDC value. For the MAD synchronized reserve constraint, when reserves from both the RTO and MAD can be used, the shadow price equals the sum of the ORDC value for each constraint when both are violated. The same occurs for the primary and 30-minute reserve constraints. The total shadow price of reserve violations can reach five times the highest ORDC value of $850 per MWh, which is $4,250 per MWh. This value exceeds the PJM $1,700 per MWh price caps on reserve prices and the $3,700 per MWh price cap applied to the energy component of LMP (the system marginal price or SMP component of LMP). There is no underlying economic analysis that supports these extremely high prices when reserves are short. There is no evidence that the demand for electricity responds to these high prices which generally occur during extreme weather when the demand and need for power is high.

Energy and Reserve Price Caps

Table 3-84 shows six example scenarios, under the current ORDCs, with combinations of energy offers, reserve shortage penalty factors and transmission constraint penalty factors that can add up to produce high LMPs at sample pnodes in the MAD Reserve Subzone and outside the MAD Reserve Subzone.

Scenario A shows a simple shortage in the RTO Reserve Zone. In scenario B, there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones that results in a $1,700 per MWh reserve shortage penalty in the RTO Zone LMP and a $3,400 per MWh reserve shortage penalty in the MAD Zone LMP. The price is lower when the marginal resource for energy is in the RTO Zone. If the RTO to MAD reserve transfer constraint is binding, the higher MAD reserve penalty does not affect the rest of RTO LMP.

In scenario C, there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones and a violated transmission constraint that affects the marginal congestion costs in the system marginal price. In scenario C, the sum of the marginal unit cost, reserve and transmission constraint penalty factors equals $5,450 per MWh, which exceeds $3,700 per MWh, so SMP capping is triggered whether the marginal unit for energy can provide reserves for the MAD Zone or only the RTO Zone.

In scenario D, with a $1,000 per MWh offer price for the marginal unit for energy, violation of four reserve penalty factors does not trigger SMP capping, because the marginal unit for energy cannot serve the MAD reserve requirement. Scenario E and F show that LMPs can exceed $3,700 per MWh if there is a violated transmission constraint that is not exacerbated by an increase in load at the load weighted reference pricing node, which determines the SMP.[159]

In Scenario F, the energy component of LMP is at its highest level, $2,000 per MWh and there is a reserve shortage for primary and synchronized reserves in both MAD and RTO Reserve Zones and a shortage of 30 minute reserves, resulting in a capped $1,700 per MWh shortage adder, and a violated transmission constraint with a $2,000 per MWh penalty factor that results in a $5,700 per MWh LMP. The LMPs in Scenario F are not the highest possible LMPs in the PJM energy market under the current rules. If there are multiple violated transmission constraints, the congestion costs contributing to the LMP at a pnode can exceed $2,000 per MWh resulting in LMPs higher than $5,700 per MWh.

Scenarios G and H are similar to conditions during the highest priced hours of Winter Storm Elliott on December 23 and 24, 2022. In G, the marginal unit offer price is $500 per MWh. The synchronized and primary reserve requirements are violated for the RTO and MAD zones. Transmission constraints affect both the system marginal price and other locations. The SMP in G is capped at $3,700 per MWh. In H, the marginal unit offer price is lower, at $40 per MWh, and the 30 minute reserve constraint is also violated. With the offer caps, the SMP is also at $3,700 per MWh.

The extent to which each transmission constraint penalty factor for a constraint affects the LMP at a pnode is directly proportional to the pnode's

159 The impact of the transmission constraint penalty factor at a pnode depends on its distribution factor (dfax) with respect to the constraint. The scenarios here assume a single violated transmission constraint with dfax of 1.0. If there are multiple violated transmission constraints, the total impact at a pnode is the sum of the product of transmission constraint penalty factors and distribution factors.

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distribution factor (dfax) with respect to that constraint. In addition, the LMP at a pnode includes a loss component calculated as the product of the marginal loss factor and the uncapped system marginal price.

Table 3-84 Real-time additive penalty factors under reserve shortage and transmission constraint violations: Status Quo

		Synchronized Reserve Penalty Factor		Primary Reserve Penalty Factor		30 Minute Reserve Penalty Factor	Transmission Constraint Penalty Factor	System Marginal Price		Transmission Constraint Penalty Factor	Total LMP	
Scenario	Marginal Unit Offer Price	RTO	MAD	RTO	MAD	RTO	in SMP	RTO Marginal	MAD Marginal	in CLMP	RTO Marginal	MAD Marginal
A	$50	$850	$0	$0	$0	$0	$0	$900	$900	$0	$900	$900
B	$50	$850	$850	$850	$850	$0	$0	$1,750	$3,450	$0	$1,750	$3,450
C	$50	$850	$850	$850	$850	$0	$2,000	$3,700	$3,700	$0	$3,700	$3,700
D	$1,000	$850	$850	$850	$850	$0	$0	$2,700	$3,700	$0	$2,700	$3,700
E	$1,000	$850	$850	$850	$850	$850	$2,000	$3,700	$3,700	$2,000	$5,700	$5,700
F	$2,000	$850	$850	$850	$850	$850	$2,000	$3,700	$3,700	$2,000	$5,700	$5,700
G	$500	$850	$850	$850	$850	$0	$2,000	$3,700	$3,700	$2,000	$5,700	$5,700
H	$40	$850	$850	$850	$850	$850	$2,000	$3,700	$3,700	$2,000	$5,700	$5,700

Shortage Pricing During Synchronized Reserve Events

Synchronized reserves are deployed when PJM declares a synchronized reserve event, also known as a spinning event. PJM's methods of communication prior to December 2024 failed to result in reliably timely responses, defined to be within 10 minutes. For units that could receive an electronic signal, PJM's instruction to units supplying reserves was to ignore the dispatch signals sent by RT SCED and to instead ramp their units up until the spin event ends. A significant number of resources did not have the capability to receive the electronic signals that PJM offered. The ALL-CALL system only calls a limited number of contacts at the same time. Although PJM's stated goal was an immediate response, in practice it took minutes for a generator's designated contact to respond to the ALL-CALL, who could then take minutes more to call personnel at the plant. If a unit was following automatic generation control when an event was declared, then additional minutes could also be lost switching to manual control. The end result of these communications issues was that resources started responding only after minutes into an event, even when everything went well.[160] In December 2024, PJM added an automated communication method that would add the reserve deployment instruction to the dispatch signal, which will allow generators following automatic generation control to automatically follow the signal. The new method did not affect any synchronized reserve events in 2024. The new method applied to the 28 events in 2025 (of which only seven lasted at least ten minutes) and the 12 events in the first nine months of 2026 (of which only one lasted at least ten minutes). Synchronized reserve performance improved in 2025 and the first nine months of 2026. The new method did not resolve the communications issues for all resources. Significant communications issues remain unresolved.

Although PJM signals resources to increase their output, the approved SCED cases are solved with the reserve requirement intact, which dispatches the system to meet the load and reserve requirements 8 to 10 minutes into the future. Currently, RT SCED has the ability to back down units during events to create available reserves, which counteracts PJM's recovery effort. This results in a discrepancy between the RT SCED solutions and the operational need during a spinning event. While PJM recovers from a disturbance during a spinning event, PJM should adjust the operating reserve demand curve (ORDC) for synchronized reserves to ensure that RT SCED does not have a competing objective of immediately replacing reserves that have been paid for and are being used as intended. Without

160 See the *2024 State of the Market Report for PJM*, Vol. 2, Section 10: Ancillary Service Markets for a more detailed discussion of these issues.

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such an adjustment, the prices are artificially inflated, potentially triggering shortage pricing, during the times when reserves are used for their intended purpose. For example, three shortage pricing intervals were artificially triggered during the spin event on March 1, 2026. The MMU recommends that PJM adjust the ORDCs during spin events to reduce the reserve requirements by the amount of the reserves deployed.

Reserve Shortages in the First Nine Months of 2026

Reserve Shortage in Real-Time SCED

The MMU analyzed the RT SCED solutions to determine how many of the five minute target time RT SCED solutions indicated a shortage of any of the reserve products in the RTO Reserve Zone and the MAD Reserve Subzone (synchronized reserve and primary reserve in both areas and 30-minute reserve in the RTO), when multiple solutions indicated shortage of reserves, and how many of these resulted in shortage prices in LPC. Reserves are considered short if the quantity (MW) of reserves dispatched by RT SCED for a five minute interval is less than the extended reserve requirement. To trigger shortage pricing, PJM operators must approve an LPC case in which the MW of reserves in the pricing run of the LPC are short of the extended reserve requirement.

Until June 2, 2021, PJM generally solved one RT SCED case with three solutions per case, for each five minute target time.[161] [162] On June 3, 2021, PJM updated RT SCED to solve two additional scenarios, or a total of five solutions per case. In 2021, the frequency with which RT SCED solutions were approved increased to one solution per five minute interval. This approval frequency increased the proportion of approved SCED solutions that are reflected in LMPs. However, the process of selecting the SCED solution to approve, among the solutions available to PJM operators, is subjective and is not based on clearly defined criteria. The criteria are especially important when only some of the SCED solutions reflect shortage pricing.

The MMU analyzed the target times for which one or more RT SCED case solutions indicated a shortage of one or more reserve products. Table 3-85 shows, in 2025 and the first nine months of 2026, the total number of target times, the number of target times for which at least one RT SCED solution showed a shortage of reserves, the number of target times for which multiple RT SCED solutions showed a shortage of reserves, and the number of five-minute pricing intervals for which the LPC solution showed a shortage of reserves. Each execution of RT SCED produces five solutions, using five different levels of load bias. Table 3-85 shows that, in 2025, 5,496 target times, or 5.2 percent of all five-minute target times, had at least one RT SCED solution showing a shortage of reserves, and 1,824 target times, or 1.7 percent of all five-minute target times, had more than one RT SCED solution showing a shortage of reserves. In the first nine months of 2026, there were 3,342 target times, or 4.3 percent of all five-minute target times, that had at least one RT SCED solution showing a shortage of reserves, and 1,213 target times, or 1.5 percent of all five-minute target times, that had multiple RT SCED solutions showing a shortage of reserves.

161 A case is executed when it begins to solve. Most, but not all, cases are solved. RT SCED cases take about one to two minutes to solve.
162 PJM updated the RT SCED execution frequency to solve one case for each five minute target time beginning June 22, 2020. PJM dispatchers may solve additional cases at their discretion.

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Table 3-85 Real-time monthly five minute SCED target times and pricing intervals with shortage: January 2025 through September 2026 [163] [164]

Year	Month	Number of Five Minute Intervals	Number of Target Times With At Least One SCED Solution Short of Reserves	Percent Target Times With At Least One SCED Solution Short of Reserves	Number of Target Times With Multiple SCED Solutions Short of Reserves	Percent Target Times With Multiple SCED Solutions Short of Reserves	Number of Five Minute Intervals With Shortage Prices in LPC	Percent RT SCED Target Times With Reserve Shortage With Shortage Prices in LPC
2025	Jan	8,928	248	2.8%	75	0.8%	0	0.0%
2025	Feb	8,064	379	4.7%	91	1.1%	3	0.8%
2025	Mar	8,916	653	7.3%	220	2.5%	11	1.7%
2025	Apr	8,640	630	7.3%	224	2.6%	3	0.5%
2025	May	8,928	595	6.7%	195	2.2%	2	0.3%
2025	Jun	8,640	360	4.2%	170	2.0%	79	21.9%
2025	Jul	8,928	384	4.3%	124	1.4%	16	4.2%
2025	Aug	8,928	365	4.1%	109	1.2%	7	1.9%
2025	Sep	8,640	468	5.4%	160	1.9%	9	1.9%
2025	Oct	8,928	711	8.0%	237	2.7%	4	0.6%
2025	Nov	8,652	366	4.2%	125	1.4%	13	3.6%
2025	Dec	8,928	337	3.8%	94	1.1%	0	0.0%
2025	Total	105,120	5,496	5.2%	1,824	1.7%	147	2.7%
2026	Jan	8,928	293	3.3%	102	1.1%	24	8.2%
2026	Feb	8,064	493	6.1%	171	2.1%	41	8.3%
2026	Mar	8,916	659	7.4%	213	2.4%	21	3.2%
2026	Apr	8,640	363	4.2%	126	1.5%	4	1.1%
2026	May	8,928	283	3.2%	89	1.0%	4	1.4%
2026	Jun	8,640	239	2.8%	96	1.1%	9	3.8%
2026	Jul	8,928	370	4.1%	166	1.9%	148	40.0%
2026	Aug	8,928	340	3.8%	103	1.2%	1	0.3%
2026	Sep	8,640	302	3.5%	147	1.7%	93	30.8%
2026	Total	78,612	3,342	4.3%	1,213	1.5%	345	10.3%

As shown in Table 3-85, in 2025, there were 1,824 unique five-minute target times for which multiple RT SCED solutions showed a shortage of reserves for one or more reserve services, while there were 147 unique five-minute intervals with real-time shortage pricing for one or more reserve products. In the first nine months of 2026, there were 1,213 unique five-minute target times for which multiple RT SCED solutions showed a shortage of reserves for one or more reserve services, while there were 345 unique five-minute intervals with real-time shortage pricing for one or more reserve products. Clear criteria for approval of shortage cases are needed.

The PJM Real-Time Energy Market produces an efficient outcome only when prices are allowed to reflect the fundamental supply and demand conditions in the market in real time. There are two related issues, the definition of a shortage and the definition of an efficient shortage price. While it is appropriate for operators to ensure that cases use data that reflect the actual state of the system, it is essential that operator discretion not extend beyond what is necessary and that operator discretion not prevent shortage pricing when there are shortage conditions or implement shortage pricing when there are no shortage conditions. This is a critical issue now that PJM settles all real-time energy transactions on a five minute basis using the prices calculated by LPC. The MMU recommends that PJM define clear criteria for operator approval of RT SCED cases, including shortage cases that are used to send dispatch signals to resources, and for pricing, to minimize discretion. A rule based approach is essential for defining how LMPs are determined so that all market participants can be confident that energy market pricing is efficient. However, whether the triggered shortage pricing results in an efficient outcome is a function both of the rules defining a shortage and the rules defining the level of shortage pricing. It has not been demonstrated that PJM's administratively defined shortage pricing is efficient.

Prolonged and excessively high administrative shortage pricing in the energy market would impose inefficient wealth transfers. Inefficient wealth transfers from load to generation, among generators, or from physical to financial market participants occur when administrative pricing creates arbitrarily high price signals to which participants cannot respond. A solution would be to lower the default emergency pricing levels to avoid inefficient wealth transfers while providing an appropriate price signal.

163 The previous version of this chart incorrectly displayed data from 2024 as data from 2025.
164 The previous version of this chart showed 8 intervals with shortage pricing in the LPC instead of the correct 9 for June 2026.

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Shortage Pricing Intervals in LPC

Beginning October 1, 2022, shortage pricing can occur in both the PJM Day-Ahead and Real-Time Energy Markets for Synchronized Reserves, Primary Reserves, and 30-Minute Reserves.

In May 2023, PJM increased reserve requirements in response to poor reserve performance by the units selected to provide reserves. PJM unilaterally increased the synchronized reserve reliability requirement by 30 percentage points to 130 percent of the most severe single contingency (MSSC), which consequently increased the primary reserve reliability requirement by 45 percentage points to 195 percent of the MSSC. On January 9, 2026, the synchronized reserve reliability requirement was decreased by 10 percentage points to be 120 percent of the MSSC, which made the primary reserve reliability requirement 180 percent of the MSSC. While the intervals listed in this section were short of their target requirements, many of these intervals still cleared above the average values of the requirements from before the increase. The average primary reserve requirement from January 2023 through April 2023 was 2,511.4 MW and the average synchronized reserve requirement was 1,741.7 MW. Many of the intervals with shortage pricing were not short in the sense of failing to clear a sufficient amount of reserves for recovering from a contingency event. They were short because of PJM's unilateral increase to the synchronized reserve reliability requirement. Table 3-86 shows the count of intervals with shortage pricing for synchronized reserve (SR), primary reserve (PR), and 30-minute reserve (TMR) in the RTO. As seen in Table 3-86, the majority of intervals with shortage pricing cleared reserves in excess of the original reserve requirements absent PJM's adder. The adder does not apply to the MAD Reserve Subzone and does not apply to the RTO when the RTO MSSC is the MAD MSSC.

Table 3-86 Number of shortage pricing intervals which satisfied the unmodified reserve service requirement: January through September, 2026

	Reserve Service		
	SR	PR	TMR
Intervals with Shortage Pricing	64	333	7
Intervals where RT SCED Satisfied Original Requirement	37	264	7
Percentage of Intervals where RT SCED Satisfied Original Requirement	57.8%	79.3%	100.0%
Intervals where RT SCED Did Not Satisfy Original Requirement	27	69	0

There were 345 unique real-time five-minute intervals with shortage pricing for one or more reserve products in the first nine months of 2026, compared to 130 intervals in the first nine months of 2025. In the first nine months of 2026, there were 168 unique real-time five-minute intervals with shortage in the dispatch run for one or more reserve products, compared to 111 intervals in the first nine months of 2025. Table 3-87 through Table 3-90 show intervals with shortage pricing in the pricing run for each reserve service for the RTO Reserve Zone and the MAD Reserve Zone. PJM implemented fast start pricing on September 1, 2021. Fast start pricing can result in differences in reserve shortages between the dispatch run and the pricing run. This applied to 177 intervals in the first nine months of 2026.

In 2025, there were four hours with shortage pricing in the day-ahead reserve markets. In the first nine months of 2026, there were 16 unique day-ahead hours with shortage pricing for one or more reserve products. For January 27, 2026, in the day-ahead market, there were two hours with shortage pricing for primary reserves in the RTO Reserve Subzone. For January 28, 2026, in the day-ahead market, there were two hours with shortage pricing for primary reserves in the RTO Reserve Zone. For July 1, 2026, in the day-ahead market, there were three hours with shortage pricing for primary reserves in the RTO Reserve Zone. For July 2, 2026, in the day-ahead market, there were four hours with shortage pricing for primary reserves in the RTO Reserve Zone. For July 3, 2026, in the day-ahead market, there was one hour with shortage pricing for primary reserves in the RTO Reserve Zone. For July 15, 2026, in the

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day-ahead market, there were four hours with shortage pricing for primary reserves in the RTO Reserve Zone.

Table 3-87 shows the extended synchronized reserve requirement, the total synchronized reserves, the synchronized reserve shortage, and the synchronized reserve clearing prices for the RTO Reserve Zone during the 64 intervals with shortage pricing in the pricing run due to synchronized reserve shortage in the first nine months of 2026. Table 3-87 shows that 63 of the 64 intervals were short of synchronized reserves in both the pricing run and the dispatch run. Thirteen intervals were also short of synchronized reserves in MAD in the pricing and dispatch run. Fifty-two intervals were also short of primary reserves in the RTO in the pricing run and fifty-one intervals were also short of primary reserves in the RTO in the dispatch run. Thirty-five intervals were also short of primary reserves in MAD in the pricing and dispatch runs. Three intervals overlapped with a spinning event on March 1, 2026.

Table 3-88 shows the extended synchronized reserve requirement, the total synchronized reserves, the synchronized reserve shortage, and the synchronized reserve clearing prices for the MAD Reserve Subzone during the 13 intervals with shortage pricing in the pricing run due to synchronized reserve shortage in the first nine months of 2026. Table 3-88 shows that the 13 intervals were short of synchronized reserves in both the pricing run and the dispatch run. Twelve intervals were also short of primary reserves in the RTO in the pricing and dispatch run. Ten intervals were also short of primary reserves in the MAD Reserve Subzone in the pricing and dispatch run.

Table 3-89 shows a summary of the extended primary reserve requirement, the total primary reserves, the primary reserve shortage, and the primary reserve clearing prices for the RTO Reserve Zone during the 333 intervals with shortage pricing in the pricing run due to primary reserve shortage in the first nine months of 2026. The full version of Table 3-89 is published separately.[165] Of the 333 intervals with shortage pricing in the pricing run, 157 were short in both the pricing run and the dispatch run. Seven intervals were also short of 30-minute reserve in the RTO Reserve Zone in the pricing run and the dispatch run. Sixty-eight intervals were also short of primary reserve in the MAD Reserve Subzone in the pricing run and 41 were short in the dispatch run. Fifty-two intervals were also short of synchronized reserve in the RTO Reserve Zone in the dispatch run and pricing run. Twelve intervals were also short of synchronized reserve in the MAD Reserve Subzone in the dispatch run and pricing run. The three intervals on March 1 overlapped with a synchronized reserve event.

Table 3-90 shows the extended primary reserve requirement, the total primary reserves, the primary reserve shortage, and the primary reserve clearing prices for the MAD Reserve Subzone during the 68 intervals with shortage pricing in the pricing run due to primary reserve shortage in the first nine months of 2026. Table 3-89 shows that 41 of the 68 intervals were short of primary reserves in both the pricing run and the dispatch run. Four intervals were also short of 30-minute reserves in the RTO Reserve Zone in the pricing run and the dispatch run. Sixty-eight intervals were also short of primary reserves in the RTO Reserve Zone in the pricing run and forty-three intervals were also short of primary reserves in the RTO Reserve Zone in the dispatch run. Thirty-five intervals were also short of synchronized reserve in the RTO Reserve Zone in the pricing run and the dispatch run. Ten intervals were also short of synchronized reserve in the MAD Reserve Subzone in the pricing run and the dispatch run. The intervals on March 1 overlapped with a synchronized reserve event.

Table 3-91 shows the extended 30-minute reserve requirement, the total 30-minute reserves, the 30-minute reserve shortage, and the 30-minute reserve clearing prices for the RTO Reserve zone during the 7 intervals with shortage pricing in the pricing run due to 30-minute reserve shortage in the first nine months of 2026. These intervals occurred during the maximum generation action for the Mid-Atlantic and Southern regions on July 2, 2026. Table 3-91 shows that none of the intervals were short in the dispatch run. Seven intervals were also short of primary reserves in the RTO Reserve Zone in the pricing run. Four intervals were also short of primary reserve in the MAD Reserve Subzone in the pricing run.

165 See Monitoring Analytics LLC, "Reserve Shortages," (November 12, 2026) https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2026/IMM_Reserve_Shortages_20261112.xlsx..

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PJM enforces an RTO wide reserve requirement and a reserve requirement for the MAD region. The MAD Reserve Subzone is inside the RTO Reserve Zone. Resources located in the MAD Reserve Subzone can simultaneously satisfy the synchronized reserve requirement of the RTO Reserve Zone and the synchronized reserve requirement of the MAD Reserve Subzone. Resources located outside the MAD Reserve Subzone can satisfy the synchronized reserve requirement of the RTO Reserve Zone, and subject to transfer limits defined by transmission constraints, satisfy the reserve requirement of the MAD Subzone. The synchronized reserve clearing price of the RTO Reserve Zone is set by the shadow price of the binding reserve requirement constraint of the RTO Reserve Zone.[166] The synchronized reserve clearing price of the MAD Reserve Subzone is set by the sum of the shadow prices of the binding reserve requirement constraint of the RTO Reserve Zone and the shadow price of the binding reserve requirement constraint of the MAD Reserve Subzone.

The MCP for secondary reserves is capped by the PJM tariff at the 30-minute reserve penalty factor for the RTO ($850 per MWh).[167] The MCP for nonsynchronized reserves is capped at one and a half times the primary reserve penalty factor for each zone or subzone ($1,275 per MWh).[168] The MCP for synchronized reserves is capped at the sum of two of the three penalty factors for synchronized reserve, primary reserve, and 30-minute reserve ($1,700 per MWh).[169] However, the PJM tariff does not explicitly specify a cap on the system marginal price. The system marginal price cap of $3,700 per MWh that is actually applied by PJM should be included in the PJM tariff and Operating Agreement.

The intervals with 0.00001 shortage MW in Table 3-87 and the full version of Table 3-89 were not truly short; they result from a software issue.[170] PJM sets the synchronized reserve requirement for the RTO based on the largest generation contingency in the entire PJM system, including the MAD Reserve Subzone. Similarly, PJM sets the synchronized reserve requirement of the MAD Reserve Subzone based on the largest generation contingency located within the MAD Reserve Subzone. When the largest generation contingency on the system is located in the MAD Reserve Subzone, both the MAD and the RTO reserve requirements are set by the same generation contingency, and the reserve requirement quantities for MAD and RTO are identical. In the real-time market clearing software, to avoid an issue with inaccurate prices that result from such situations, the software adds a small quantity (0.00001 MW) to the RTO reserve requirement, to differentiate the constraint from the MAD reserve requirement constraint.[171] When the RT SCED solves with the RTO reserve requirement short by this quantity (0.00001 MW), there is no actual shortage of reserves, since this was an artificially added quantity to resolve a modeling issue. The market clearing prices for reserves and the LMPs should not include the penalty factor for the reserve product when the reserves are short by 0.00001 MW. The market clearing prices and LMPs during these intervals are not stated in the shortage pricing rules in the PJM tariff. Embedding a rule in nontransparent market software is not the same thing as including an explicit rule in the tariff.

The process of calculating reserve constraint shadow prices and implementing reserve price caps in PJM is not clearly defined or transparent. The MMU recommends that PJM clearly document the calculation of shortage prices and implementation of reserve price caps in the PJM manuals, including definitions of all the components of reserve prices, and all the constraints whose shadow prices are included in reserve prices.

166 If the reserve requirement cannot be met by the resources located within the reserve zone, the shadow price of the reserve requirement is set by the applicable operating reserve demand curve.
167 OATT, Attachment K - Appendix § 3.2.3A.01(d).
168 OATT, Attachment K - Appendix § 3.2.3A.001(c).
169 OATT, Attachment K - Appendix § 3.2.3A(d).
170 For the full version of Table 3-10, see Monitoring Analytics LLC, "Reserve Shortages," (November 12, 2026) <https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2026/IMM_Reserve_Shortages_20261112.xlsx>.

171 Adding 0.00001 MW only to the RTO reserve requirement constraint ensures that the MAD reserve requirement constraint is violated before the violation of the RTO reserve requirement constraint. However, this modeling feature may result in situations where it might be cheaper for the market to not satisfy 0.00001 MW of reserves and incur a small penalty ($850*0.00001). Under those conditions, PJM system would show 0.00001 MW shortage.

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Table 3-87 Intervals with shortage pricing in the pricing run for real-time RTO synchronized reserve: January through September, 2026

	Pricing Run					Dispatch Run				
Interval (EPT)	RTO Extended Synchronized Reserve Requirement (MW)	Total RTO Synchronized Reserves (MW)	RTO Synchronized Reserve Shortage (MW)	Uncapped RTO Synchronized Reserve Clearing Price ($/MWh)	Capped RTO Synchronized Reserve Clearing Price ($/MWh)	RTO Extended Synchronized Reserve Requirement (MW)	Total RTO Synchronized Reserves (MW)	RTO Synchronized Reserve Shortage (MW)	Uncapped RTO Synchronized Reserve Clearing Price ($/MWh)
23-Jan-26 17:50	2,448.4	1,692.9	755.475	$850.00	$850.00	2,448.4	1,692.9	755.475	$850.00
24-Jan-26 05:35	2,451.8	2,317.3	134.435	$1,150.00	$1,150.00	2,451.8	2,317.3	134.435	$1,150.00
24-Jan-26 05:40	2,456.1	2,066.4	389.673	$1,700.00	$1,700.00	2,456.1	2,066.4	389.673	$1,700.00
30-Jan-26 17:50	1,920.0	1,920.0	0.000	$300.00	$300.00	1,920.0	1,920.0	0.000	$300.00
01-Feb-26 03:20	1,904.0	1,904.0	0.000	$300.00	$300.00	1,904.0	1,904.0	0.000	$300.00
01-Feb-26 03:30	1,904.0	1,904.0	0.000	$300.00	$300.00	1,904.0	1,904.0	0.000	$300.00
01-Feb-26 03:50	1,904.0	1,904.0	0.000	$300.00	$300.00	1,904.0	1,904.0	0.000	$300.00
01-Feb-26 08:15	1,930.0	1,930.0	0.000	$300.00	$300.00	1,930.0	1,930.0	0.000	$300.00
04-Feb-26 22:25	1,917.0	1,917.0	0.000	$300.00	$300.00	1,917.0	1,917.0	0.000	$300.00
06-Feb-26 18:00	1,898.0	1,898.0	0.000	$300.00	$300.00	1,898.0	1,898.0	0.000	$300.00
07-Feb-26 18:05	1,920.0	1,920.0	0.000	$300.00	$300.00	1,920.0	1,920.0	0.000	$300.00
01-Mar-26 19:30	2,417.6	2,032.6	384.958	$1,700.00	$1,700.00	2,417.6	2,032.6	384.958	$1,700.00
01-Mar-26 19:35	2,413.5	1,915.6	497.929	$1,700.00	$1,700.00	2,413.5	1,915.6	497.929	$1,700.00
12-Mar-26 18:55	2,386.6	1,903.0	483.575	$1,700.00	$1,700.00	2,386.6	1,903.0	483.575	$1,700.00
12-Mar-26 19:00	2,392.8	1,868.0	524.829	$1,700.00	$1,700.00	2,392.8	1,868.0	524.829	$1,700.00
12-Mar-26 19:05	2,387.0	2,223.2	163.744	$1,150.00	$1,150.00	2,387.0	2,223.2	163.744	$1,150.00
12-Mar-26 19:10	2,391.2	1,730.3	660.883	$1,700.00	$1,700.00	2,391.2	1,730.3	660.883	$1,700.00
13-Mar-26 07:10	2,401.7	2,299.1	102.605	$1,150.00	$1,150.00	2,401.7	2,299.1	102.605	$1,150.00
13-Mar-26 07:15	2,408.0	1,452.5	955.472	$1,700.00	$1,700.00	2,408.0	1,452.5	955.472	$1,700.00
13-Mar-26 07:20	2,405.9	1,364.6	1,041.279	$1,700.00	$1,700.00	2,405.9	1,364.6	1,041.279	$1,700.00
13-Mar-26 07:25	2,402.6	1,934.6	468.000	$1,700.00	$1,700.00	2,402.6	1,934.6	468.000	$1,700.00
14-Mar-26 00:30	2,360.8	2,309.5	51.290	$300.00	$300.00	2,360.8	2,309.5	51.290	$300.00
06-Apr-26 19:55	1,803.8	1,555.7	248.032	$1,700.00	$1,700.00	1,803.8	1,555.7	248.032	$1,700.00
06-Apr-26 20:00	1,803.8	1,555.7	248.032	$1,700.00	$1,700.00	1,803.8	1,555.7	248.032	$1,700.00
18-May-26 11:40	2,359.8	2,311.3	48.497	$1,150.00	$1,150.00	2,359.8	2,311.3	48.497	$1,150.00
18-May-26 11:45	2,359.8	2,311.3	48.497	$1,150.00	$1,150.00	2,359.8	2,311.3	48.497	$1,150.00
02-Jun-26 20:05	2,371.6	2,044.0	327.629	$1,700.00	$1,700.00	2,371.6	2,044.0	327.629	$1,700.00
17-Jun-26 22:15	1,810.0	1,810.0	0.000	$300.00	$300.00	1,810.0	1,810.0	0.000	$300.00
29-Jun-26 20:00	2,217.3	2,216.1	1.220	$1,150.00	$1,150.00	2,217.3	2,216.1	1.220	$1,150.00
02-Jul-26 11:45	2,232.0	2,182.2	49.844	$1,150.00	$1,150.00	2,232.0	2,182.2	49.844	$1,150.00
02-Jul-26 21:20	2,260.0	2,252.0	8.000	$782.83	$782.83	2,260.0	2,442.0	0.000	$0.00
08-Jul-26 18:40	2,271.6	2,091.5	180.140	$1,150.00	$1,150.00	2,271.6	2,091.5	180.140	$1,150.00
08-Jul-26 18:45	2,260.0	2,220.1	39.930	$1,150.00	$1,150.00	2,260.0	2,220.1	39.930	$1,150.00
08-Jul-26 18:55	2,266.7	1,154.4	1,112.298	$1,700.00	$1,700.00	2,266.7	1,154.4	1,112.298	$1,700.00
08-Jul-26 19:00	2,270.8	2,006.1	264.733	$1,700.00	$1,700.00	2,270.8	2,006.1	264.733	$1,700.00

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	Pricing Run					Dispatch Run			
Interval (EPT)	RTO Extended Synchronized Reserve Requirement (MW)	Total RTO Synchronized Reserves (MW)	RTO Synchronized Reserve Shortage (MW)	Uncapped RTO Synchronized Reserve Clearing Price ($/MWh)	Capped RTO Synchronized Reserve Clearing Price ($/MWh)	RTO Extended Synchronized Reserve Requirement (MW)	Total RTO Synchronized Reserves (MW)	RTO Synchronized Reserve Shortage (MW)	Uncapped RTO Synchronized Reserve Clearing Price ($/MWh)
01-Sep-26 16:40	2,237.7	2,074.4	163.327	$300.00	$300.00	2,237.7	2,237.7	0.000	$290.01
16-Sep-26 17:45	2,230.0	1,694.6	535.410	$1,700.00	$1,700.00	2,230.0	1,694.6	535.410	$1,700.00
16-Sep-26 17:50	2,230.0	2,011.3	218.692	$1,150.00	$1,150.00	2,230.0	2,011.3	218.692	$1,150.00
16-Sep-26 17:55	2,230.0	2,127.5	102.526	$1,150.00	$1,150.00	2,230.0	2,140.9	89.086	$1,150.00
16-Sep-26 18:05	2,237.2	1,972.9	264.285	$1,700.00	$1,700.00	2,237.2	1,972.9	264.285	$1,700.00
16-Sep-26 18:10	2,237.2	2,007.9	229.318	$1,700.00	$1,700.00	2,237.2	2,007.9	229.316	$1,700.00
16-Sep-26 18:15	2,237.2	1,463.2	774.020	$1,700.00	$1,700.00	2,237.2	1,463.2	774.020	$1,700.00
16-Sep-26 18:20	2,237.2	1,490.0	747.227	$1,700.00	$1,700.00	2,237.2	1,485.4	751.759	$1,700.00
16-Sep-26 18:25	2,237.2	2,040.6	196.605	$1,700.00	$1,700.00	2,237.2	2,040.6	196.605	$1,700.00
16-Sep-26 18:30	2,237.2	2,018.2	219.044	$1,700.00	$1,700.00	2,237.2	2,018.2	219.044	$1,700.00
16-Sep-26 18:35	2,237.2	1,774.5	462.700	$1,700.00	$1,700.00	2,237.2	1,774.5	462.700	$1,700.00
16-Sep-26 18:40	2,237.2	1,599.0	638.200	$1,700.00	$1,700.00	2,237.2	1,599.0	638.200	$1,700.00
16-Sep-26 18:45	2,237.2	1,599.3	637.900	$1,700.00	$1,700.00	2,237.2	1,599.3	637.900	$1,700.00
16-Sep-26 18:50	2,237.2	1,763.1	474.113	$1,700.00	$1,700.00	2,237.2	1,763.1	474.113	$1,700.00
16-Sep-26 18:55	2,237.2	1,497.7	739.541	$1,700.00	$1,700.00	2,237.2	1,497.7	739.541	$1,700.00
16-Sep-26 19:00	2,258.8	1,774.5	484.300	$1,700.00	$1,700.00	2,258.8	1,774.5	484.300	$1,700.00
16-Sep-26 19:05	2,258.8	1,565.2	693.647	$1,700.00	$1,700.00	2,258.8	1,565.2	693.647	$1,700.00
16-Sep-26 19:10	2,258.8	1,454.0	804.811	$1,700.00	$1,700.00	2,258.8	1,454.0	804.811	$1,700.00
16-Sep-26 19:15	2,258.8	1,775.9	482.950	$1,700.00	$1,700.00	2,258.8	1,775.9	482.950	$1,700.00
16-Sep-26 19:20	2,258.8	1,602.0	656.800	$1,700.00	$1,700.00	2,258.8	1,602.0	656.800	$1,700.00
16-Sep-26 19:25	2,258.8	1,779.0	479.800	$1,700.00	$1,700.00	2,258.8	1,781.3	477.518	$1,700.00
16-Sep-26 19:30	2,258.8	1,779.0	479.800	$1,700.00	$1,700.00	2,258.8	1,779.0	479.800	$1,700.00
16-Sep-26 19:35	2,258.8	1,779.0	479.800	$1,700.00	$1,700.00	2,258.8	1,779.0	479.800	$1,700.00
16-Sep-26 19:40	2,258.8	1,779.0	479.800	$1,700.00	$1,700.00	2,258.8	1,779.0	479.800	$1,700.00
16-Sep-26 19:45	2,258.8	1,409.8	848.979	$1,700.00	$1,700.00	2,258.8	1,409.8	848.979	$1,700.00
16-Sep-26 19:50	2,258.8	1,645.1	613.661	$1,700.00	$1,700.00	2,258.8	1,645.1	613.661	$1,700.00
16-Sep-26 19:55	2,258.8	1,753.8	504.964	$1,700.00	$1,700.00	2,258.8	1,753.8	504.964	$1,700.00
16-Sep-26 20:00	2,282.8	1,723.4	559.448	$1,700.00	$1,700.00	2,282.8	1,723.4	559.448	$1,700.00
16-Sep-26 20:05	2,282.8	2,092.8	190.000	$1,465.20	$1,465.20	2,282.8	2,108.7	174.131	$1,150.00

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Table 3-88 Intervals with shortage pricing in the pricing run for real-time MAD synchronized reserve: January through September, 2026

	Pricing Run					Dispatch Run			
Interval (EPT)	MAD Extended Synchronized Reserve Requirement (MW)	Total MAD Synchronized Reserves (MW)	MAD Synchronized Reserve Shortage (MW)	Uncapped MAD Synchronized Reserve Clearing Price ($/MWh)	Capped MAD Synchronized Reserve Clearing Price ($/MWh)	MAD Extended Synchronized Reserve Requirement (MW)	Total MAD Synchronized Reserves (MW)	MAD Synchronized Reserve Shortage (MW)	Uncapped MAD Synchronized Reserve Clearing Price ($/MWh)
23-Jan-26 17:50	1,877.0	1,692.9	184.1	$1,150.00	$1,150.00	1,877.0	1,692.9	184.1	$1,150.00
12-Mar-26 18:55	1,907.0	1,903.0	4.0	$2,000.00	$1,700.00	1,907.0	1,903.0	4.0	$2,000.00
12-Mar-26 19:00	1,907.0	1,868.1	39.0	$2,000.00	$1,700.00	1,907.0	1,868.1	39.0	$2,000.00
12-Mar-26 19:10	1,908.0	1,730.3	177.7	$2,850.00	$1,700.00	1,908.0	1,730.3	177.7	$2,850.00
13-Mar-26 07:15	1,917.0	1,452.5	464.5	$3,400.00	$1,700.00	1,917.0	1,452.5	464.5	$3,400.00
13-Mar-26 07:20	1,916.0	1,364.6	551.4	$3,400.00	$1,700.00	1,916.0	1,364.6	551.4	$3,400.00
08-Jul-26 18:55	1,799.0	1,154.4	644.6	$3,400.00	$1,700.00	1,799.0	1,154.4	644.6	$3,400.00
16-Sep-26 18:15	1,599.0	1,463.2	135.8	$2,850.00	$1,700.00	1,599.0	1,463.2	135.8	$2,850.00
16-Sep-26 18:20	1,599.0	1,490.0	109.0	$2,850.00	$1,700.00	1,599.0	1,485.5	113.6	$2,850.00
16-Sep-26 18:55	1,599.4	1,497.7	101.7	$2,850.00	$1,700.00	1,599.4	1,497.7	101.7	$2,850.00
16-Sep-26 19:05	1,599.0	1,565.2	33.8	$2,850.00	$1,700.00	1,599.0	1,565.2	33.8	$2,850.00
16-Sep-26 19:10	1,599.5	1,454.0	145.5	$2,850.00	$1,700.00	1,599.5	1,454.0	145.5	$2,850.00
16-Sep-26 19:45	1,602.7	1,409.8	192.9	$3,400.00	$1,700.00	1,602.7	1,409.8	192.9	$3,400.00

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Table 3-89 Daily summary of intervals with shortage pricing in the pricing run for real-time RTO primary reserve: January through September, 2026[172] [173]

			Pricing Run					Dispatch Run				
Day	Number of Intervals Short in Pricing Run	Number of Intervals Also Short in Dispatch Run	Average RTO Extended Primary Reserve Requirement (MW)	Average Total RTO Primary Reserves (MW)	Average RTO Primary Reserve Shortage (MW)	Average Uncapped RTO Primary Reserve Clearing Price ($/MWh)	Average Capped RTO Primary Reserve Clearing Price ($/MWh)	Average RTO Extended Primary Reserve Requirement (MW)	Average Total RTO Primary Reserves (MW)	Average RTO Primary Reserve Shortage (MW)	Average Uncapped RTO Primary Reserve Clearing Price ($/MWh)
24-Jan-26	6	5	3,582.6	3,254.2	328.393	$575.00	$575.00	3,582.6	3,260.9	321.738	$555.43
31-Jan-26	16	16	2,741.7	2,741.7	0.000	$300.00	$300.00	2,741.7	2,741.7	0.000	$300.00
2-Feb-26	12	10	2,777.5	2,777.5	0.000	$300.00	$300.00	2,777.5	2,777.5	0.000	$288.29
6-Feb-26	5	5	2,770.3	2,770.3	0.000	$300.00	$300.00	2,770.3	2,770.3	0.000	$300.00
9-Feb-26	15	12	2,749.5	2,597.3	152.219	$410.00	$410.00	2,749.5	2,601.1	148.424	$404.24
13-Feb-26	1	1	2,792.5	2,792.5	0.000	$300.00	$300.00	2,792.5	2,792.5	0.000	$300.00
16-Feb-26	1	1	3,430.0	3,420.3	9.745	$300.00	$300.00	3,430.0	3,420.3	9.745	$300.00
1-Mar-26	3	3	3,524.1	2,718.1	805.961	$850.00	$850.00	3,524.1	2,718.1	805.961	$850.00
12-Mar-26	9	9	3,489.3	2,951.0	538.322	$727.78	$727.78	3,489.3	2,951.5	537.868	$727.78
13-Mar-26	7	7	3,513.5	2,711.2	802.329	$700.57	$700.57	3,513.5	2,711.2	802.329	$700.57
22-Mar-26	1	1	3,403.0	3,364.9	38.053	$300.00	$300.00	3,403.0	3,364.9	38.053	$300.00
6-Apr-26	4	4	2,611.3	2,056.5	554.878	$850.00	$850.00	2,611.3	2,056.5	554.878	$850.00
15-May-26	1	1	3,461.9	3,207.6	254.252	$850.00	$850.00	3,461.9	3,207.6	254.252	$850.00
18-May-26	3	3	3,442.3	3,088.6	353.661	$850.00	$850.00	3,442.3	3,088.6	353.661	$850.00
2-Jun-26	2	2	3,462.4	3,177.8	284.615	$737.65	$737.65	3,462.4	3,177.8	284.615	$737.65
11-Jun-26	1	0	3,295.0	3,253.5	41.500	$300.00	$300.00	3,295.0	3,295.0	0.000	$289.64
29-Jun-26	5	5	3,233.5	2,841.7	391.847	$780.55	$780.55	3,233.5	2,841.7	391.847	$780.55
1-Jul-26	17	12	3,208.8	2,892.8	315.971	$600.77	$600.77	3,208.8	2,922.6	286.169	$567.74
2-Jul-26	66	4	3,202.8	2,735.2	467.540	$833.94	$833.94	3,202.8	3,182.4	20.347	$107.81
3-Jul-26	42	0	3,195.1	2,715.7	479.355	$751.88	$751.88	3,195.1	3,195.1	0.000	$24.28
5-Jul-26	4	4	3,297.4	2,977.5	319.875	$509.99	$509.99	3,297.4	2,977.5	319.875	$509.99
8-Jul-26	5	5	3,306.3	2,093.6	1,212.707	$850.00	$850.00	3,306.3	2,093.6	1212.707	$850.00
15-Jul-26	14	10	3,211.0	3,048.4	162.521	$434.48	$434.48	3,211.0	3,071.5	139.416	$387.57
17-Aug-26	1	0	3,323.8	3,276.8	47.000	$300.00	$300.00	3,323.8	3,323.8	0.000	$262.11
1-Sep-26	18	0	3,278.8	3,147.7	131.186	$320.29	$320.29	3,278.8	3,278.8	0.000	$177.60
13-Sep-26	2	1	3,322.0	3,315.0	7.004	$300.00	$300.00	3,322.0	3,301.0	20.980	$283.47
15-Sep-26	11	4	3,296.1	3,193.6	102.559	$337.94	$337.94	3,296.1	3,247.7	48.401	$286.72
16-Sep-26	32	32	3,282.6	2,282.4	1,000.254	$814.68	$814.68	3,282.6	2,283.2	999.409	$809.10
17-Sep-26	29	0	3,300.3	3,053.8	246.493	$690.69	$690.69	3,300.3	3,300.3	0.000	$136.04

172 For the full version, see Monitoring Analytics LLC, "Reserve Shortages," (November 12, 2026) <https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2026/IMM_Reserve_Shortages_20261112.xlsx>.
173 June data has been corrected to include the shortage interval on June 11, 2026, which was not present in the previous version of this chart.

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Table 3-90 Intervals with shortage pricing in the pricing run for real-time MAD primary reserve: January through September, 2026

	Pricing Run					Dispatch Run			
Interval (EPT)	MAD Extended Primary Reserve Requirement (MW)	Total MAD Primary Reserves (MW)	MAD Primary Reserve Shortage (MW)	Uncapped MAD Primary Reserve Clearing Price ($/MWh)	Capped MAD Primary Reserve Clearing Price ($/MWh)	MAD Extended Primary Reserve Requirement (MW)	Total MAD Primary Reserves (MW)	MAD Primary Reserve Shortage (MW)	Uncapped MAD Primary Reserve Clearing Price ($/MWh)
24-Jan-26 05:40	2,780.5	2,659.4	121.1	$1,150.00	$1,150.00	2,780.5	2,659.4	121.1	$1,150.00
09-Feb-26 07:15	2,749.0	2,703.6	45.4	$600.00	$600.00	2,749.0	2,749.0	0.0	$322.08
09-Feb-26 07:20	2,749.0	2,058.0	691.0	$1,700.00	$1,275.00	2,749.0	2,058.0	691.0	$1,700.00
09-Feb-26 07:25	2,749.0	1,965.9	783.2	$1,700.00	$1,275.00	2,749.0	1,965.9	783.2	$1,700.00
09-Feb-26 07:30	2,750.5	1,998.3	752.2	$1,700.00	$1,275.00	2,750.5	1,998.3	752.2	$1,700.00
09-Feb-26 07:35	2,752.0	2,740.5	11.6	$600.00	$600.00	2,752.0	2,752.0	0.0	$579.55
01-Mar-26 19:30	2,693.5	2,497.5	196.0	$1,700.00	$1,275.00	2,693.5	2,497.5	196.0	$1,700.00
01-Mar-26 19:35	2,698.0	2,380.5	317.5	$1,700.00	$1,275.00	2,698.0	2,380.5	317.5	$1,700.00
12-Mar-26 19:05	2,765.5	2,688.2	77.4	$1,150.00	$1,150.00	2,765.5	2,688.2	77.4	$1,150.00
12-Mar-26 19:10	2,767.0	2,195.2	571.8	$1,700.00	$1,275.00	2,767.0	2,195.2	571.8	$1,700.00
13-Mar-26 07:10	2,779.0	2,764.1	15.0	$1,150.00	$1,150.00	2,779.0	2,764.1	15.0	$1,150.00
13-Mar-26 07:15	2,780.5	1,917.4	863.1	$1,700.00	$1,275.00	2,780.5	1,917.4	863.1	$1,700.00
13-Mar-26 07:20	2,779.0	1,829.5	949.5	$1,700.00	$1,275.00	2,779.0	1,829.5	949.5	$1,700.00
13-Mar-26 07:25	2,779.0	2,399.5	379.5	$1,700.00	$1,275.00	2,779.0	2,399.5	379.5	$1,700.00
06-Apr-26 19:55	2,206.0	1,871.7	334.3	$1,700.00	$1,275.00	2,206.0	1,871.7	334.3	$1,700.00
06-Apr-26 20:00	2,206.0	1,871.7	334.3	$1,700.00	$1,275.00	2,206.0	1,871.7	334.3	$1,700.00
06-Apr-26 20:05	2,206.0	2,151.3	54.6	$1,150.00	$1,150.00	2,206.0	2,151.3	54.6	$1,150.00
01-Jul-26 20:25	2,609.5	2,465.9	143.6	$1,150.00	$1,150.00	2,609.5	2,465.9	143.6	$1,150.00
02-Jul-26 17:55	2,545.0	2,355.0	190.0	$1,397.17	$1,275.00	2,545.0	2,545.0	0.0	$306.80
02-Jul-26 18:10	2,554.0	2,364.0	190.0	$1,477.67	$1,275.00	2,554.0	2,554.0	0.0	$325.63
02-Jul-26 18:25	2,554.0	2,366.9	187.1	$1,378.87	$1,275.00	2,554.0	2,554.0	0.0	$283.97
02-Jul-26 18:30	2,554.0	2,364.0	190.0	$1,322.30	$1,275.00	2,554.0	2,554.0	0.0	$371.02
02-Jul-26 18:35	2,554.0	2,444.1	109.9	$1,318.20	$1,275.00	2,554.0	2,554.0	0.0	$320.08
02-Jul-26 18:40	2,554.0	2,485.4	68.7	$1,283.93	$1,275.00	2,554.0	2,554.0	0.0	$277.98
02-Jul-26 18:45	2,554.0	2,506.8	47.2	$1,263.78	$1,263.78	2,554.0	2,554.0	0.0	$236.35
02-Jul-26 18:50	2,554.0	2,502.9	51.1	$1,383.09	$1,275.00	2,554.0	2,554.0	0.0	$219.98
02-Jul-26 19:10	2,545.0	2,355.0	190.0	$1,176.32	$1,176.32	2,545.0	2,545.0	0.0	$228.74
02-Jul-26 19:20	2,545.0	2,525.2	19.8	$1,286.77	$1,275.00	2,545.0	2,545.0	0.0	$263.78
02-Jul-26 19:25	2,545.0	2,380.6	164.4	$1,150.00	$1,150.00	2,545.0	2,545.0	0.0	$121.11
02-Jul-26 19:30	2,545.0	2,421.4	123.6	$1,329.43	$1,275.00	2,545.0	2,545.0	0.0	$200.45
02-Jul-26 19:35	2,545.0	2,474.7	70.3	$1,401.62	$1,275.00	2,545.0	2,545.0	0.0	$244.42
02-Jul-26 19:40	2,545.0	2,473.5	71.5	$1,450.00	$1,275.00	2,545.0	2,545.0	0.0	$372.44
02-Jul-26 19:45	2,545.0	2,490.4	54.6	$1,374.26	$1,275.00	2,545.0	2,545.0	0.0	$242.04
02-Jul-26 19:50	2,545.0	2,366.7	178.3	$1,450.00	$1,275.00	2,545.0	2,545.0	0.0	$277.32
02-Jul-26 20:05	2,545.0	2,410.4	134.6	$1,538.38	$1,275.00	2,545.0	2,545.0	0.0	$114.12
02-Jul-26 20:10	2,545.0	2,441.8	103.2	$1,482.81	$1,275.00	2,545.0	2,545.0	0.0	$25.94

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	Pricing Run					Dispatch Run				
Interval (EPT)	MAD Extended Primary Reserve Requirement (MW)	Total MAD Primary Reserves (MW)	MAD Primary Reserve Shortage (MW)	Uncapped MAD Primary Reserve Clearing Price ($/MWh)	Capped MAD Primary Reserve Clearing Price ($/MWh)	MAD Extended Primary Reserve Requirement (MW)	Total MAD Primary Reserves (MW)	MAD Primary Reserve Shortage (MW)	Uncapped MAD Primary Reserve Clearing Price ($/MWh)
03-Jul-26 17:55	2,558.5	2,483.9	74.6	$1,150.00	$1,150.00	2,558.5	2,558.5	0.0	$118.61
03-Jul-26 18:00	2,555.5	2,365.5	190.0	$1,212.65	$1,212.65	2,555.5	2,555.5	0.0	$247.15
03-Jul-26 18:10	2,554.0	2,364.0	190.0	$1,194.34	$1,194.34	2,554.0	2,554.0	0.0	$143.38
03-Jul-26 18:30	2,549.5	2,522.7	26.8	$1,150.00	$1,150.00	2,549.5	2,549.5	0.0	$60.83
03-Jul-26 18:35	2,548.0	2,459.2	88.9	$1,150.00	$1,150.00	2,548.0	2,548.0	0.0	$67.14
03-Jul-26 18:55	2,549.5	2,436.6	112.9	$1,150.00	$1,150.00	2,549.5	2,549.5	0.0	$96.25
03-Jul-26 19:20	2,554.0	2,364.0	190.0	$1,175.90	$1,175.90	2,554.0	2,554.0	0.0	$48.17
08-Jul-26 18:40	2,603.5	2,413.5	190.0	$1,308.46	$1,275.00	2,603.5	2,413.5	190.0	$1,308.46
08-Jul-26 18:45	2,603.5	2,542.0	61.4	$1,150.00	$1,150.00	2,603.5	2,542.0	61.4	$1,150.00
08-Jul-26 18:50	2,603.5	2,352.0	251.6	$1,700.00	$1,275.00	2,603.5	2,352.0	251.6	$1,700.00
08-Jul-26 18:55	2,603.5	1,154.4	1,449.1	$1,700.00	$1,275.00	2,603.5	1,154.4	1,449.1	$1,700.00
08-Jul-26 19:00	2,603.5	2,006.1	597.4	$1,700.00	$1,275.00	2,603.5	2,006.1	597.4	$1,700.00
16-Sep-26 18:15	2,303.5	1,802.2	501.3	$1,700.00	$1,275.00	2,303.5	1,802.2	501.3	$1,700.00
16-Sep-26 18:20	2,303.5	1,829.0	474.5	$1,700.00	$1,275.00	2,303.5	1,824.5	479.1	$1,700.00
16-Sep-26 18:35	2,303.5	2,113.5	190.0	$1,179.92	$1,179.92	2,303.5	2,113.5	190.0	$1,179.92
16-Sep-26 18:40	2,303.5	1,938.0	365.5	$1,700.00	$1,275.00	2,303.5	1,938.0	365.5	$1,700.00
16-Sep-26 18:45	2,303.9	1,938.3	365.7	$1,700.00	$1,275.00	2,303.9	1,938.3	365.7	$1,700.00
16-Sep-26 18:50	2,303.8	2,102.1	201.7	$1,700.00	$1,275.00	2,303.8	2,102.1	201.7	$1,700.00
16-Sep-26 18:55	2,304.1	1,836.7	467.4	$1,700.00	$1,275.00	2,304.1	1,836.7	467.4	$1,700.00
16-Sep-26 19:00	2,303.5	2,113.5	190.0	$1,648.14	$1,275.00	2,303.5	2,113.5	190.0	$1,648.14
16-Sep-26 19:05	2,303.5	1,904.2	399.3	$1,700.00	$1,275.00	2,303.5	1,904.2	399.3	$1,700.00
16-Sep-26 19:10	2,304.3	1,793.0	511.3	$1,700.00	$1,275.00	2,304.3	1,793.0	511.3	$1,700.00
16-Sep-26 19:15	2,304.8	2,114.9	190.0	$1,669.12	$1,275.00	2,304.8	2,114.9	190.0	$1,669.12
16-Sep-26 19:20	2,308.0	1,941.0	367.0	$1,700.00	$1,275.00	2,308.0	1,941.0	367.0	$1,700.00
16-Sep-26 19:25	2,308.0	2,118.0	190.0	$1,170.53	$1,170.53	2,308.0	2,120.3	187.7	$1,150.00
16-Sep-26 19:30	2,308.0	2,118.0	190.0	$1,563.84	$1,275.00	2,308.0	2,118.0	190.0	$1,563.84
16-Sep-26 19:35	2,308.0	2,118.0	190.0	$1,320.50	$1,275.00	2,308.0	2,118.0	190.0	$1,320.50
16-Sep-26 19:40	2,308.0	2,118.0	190.0	$1,232.54	$1,232.54	2,308.0	2,118.0	190.0	$1,232.54
16-Sep-26 19:45	2,309.1	1,748.8	560.2	$1,700.00	$1,275.00	2,309.1	1,748.8	560.2	$1,700.00
16-Sep-26 19:50	2,308.0	1,984.1	323.9	$1,700.00	$1,275.00	2,308.0	1,984.1	323.9	$1,700.00
16-Sep-26 19:55	2,310.3	2,092.8	217.4	$1,700.00	$1,275.00	2,310.3	2,092.8	217.4	$1,700.00
16-Sep-26 20:00	2,309.5	2,062.4	247.1	$1,700.00	$1,275.00	2,309.5	2,062.4	247.1	$1,700.00

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Table 3-91 Intervals with shortage pricing in the pricing run for real-time RTO 30-minute reserve: January through September, 2026

	Pricing Run					Dispatch Run			
Interval (EPT)	RTO Extended 30-Minute Reserve Requirement (MW)	Total RTO 30-Minute Reserves (MW)	RTO 30-Minute Reserve Shortage (MW)	Uncapped RTO 30-Minute Reserve Clearing Price ($/MWh)	Capped RTO 30-Minute Reserve Clearing Price ($/MWh)	RTO Extended 30-Minute Reserve Requirement (MW)	Total RTO 30-Minute Reserves (MW)	RTO 30-Minute Reserve Shortage (MW)	Uncapped RTO 30-Minute Reserve Clearing Price ($/MWh)
02-Jul-26 19:15	3,192.0	3,168.8	23.2	$300.00	$300.00	3,192.0	3,201.2	0.0	$0.00
02-Jul-26 19:40	3,190.1	3,118.4	71.7	$300.00	$300.00	3,190.1	3,199.3	0.0	$0.00
02-Jul-26 19:50	3,190.1	3,014.6	175.5	$300.00	$300.00	3,190.1	3,354.3	0.0	$0.00
02-Jul-26 19:55	3,190.4	3,134.3	56.1	$300.00	$300.00	3,190.4	3,354.6	0.0	$0.00
02-Jul-26 20:00	3,230.2	3,167.9	62.3	$300.00	$300.00	3,230.2	3,394.4	0.0	$0.00
02-Jul-26 20:05	3,230.2	3,040.2	190.0	$388.38	$388.38	3,230.2	3,394.4	0.0	$0.00
02-Jul-26 20:10	3,230.2	3,040.2	190.0	$332.81	$332.81	3,230.2	3,394.4	0.0	$0.00

System Marginal Price Cap

Prior to PJM's implementation of the modified reserve markets on October 1, 2022, in the PJM real-time market, the SMP was capped at $3,750 per MWh. This cap was the sum of the Energy Offer Cap ($2,000 per MWh under defined conditions), the Synchronous Reserve Penalty Factor from the first step on the demand curve ($850 per MWh), the Primary Reserve Penalty Factor from the first step on the demand curve ($850 per MWh) and a threshold ($50 per MWh). The Operating Agreement stated that only two of the four reserve penalty factors may be applied.

In that prior implementation, if the SMP would otherwise exceed $3,750 per MWh, PJM solved the SCED optimization by progressively relaxing reserve requirement constraints until the SMP fell below the cap. For instance, if the original SMP was above $3,750, PJM would solve the SCED optimization by disabling the subzone (MAD) primary reserve requirement constraint. If the SMP from the relaxed SCED optimization was still above $3,750, PJM would solve the SCED optimization by disabling subzone (MAD) primary and synchronized reserve requirement constraints. If the relaxed SCED optimization was still above $3,750, PJM would solve the SCED optimization by disabling subzone (MAD) primary and synchronized reserve requirement constraints and the RTO primary reserve constraint.

Starting with PJM's implementation of the new Reserve Price Formation rules on October 1, 2022, in the PJM real-time market, the SMP has an administrative maximum price of $3,700 per MWh. Unlike the prior implementation, PJM's new cap does not include a $50 per MWh threshold and is not enforced by progressively relaxing reserve requirement constraints. PJM's new cap is an ex post administrative override of the SMP calculated in the pricing run (LPC). The SMP is not capped in the dispatch run (SCED). The congestion component of the LMP and the loss component of the LMP are not subject to this maximum price. The LMP at a pricing node could still exceed $3,700 per MWh. Unlike other administrative caps, such as the cap on the shadow price of a transmission constraint enforced through transmission penalty factor within the optimization, the SMP cap is not enforced within the optimization. When the SMP cap is enforced, the resulting LMPs are not consistent and do not accurately reflect the marginal cost of serving energy and reserves.

Table 3-92 shows the number of five minute intervals in the real-time market where the SMP was capped for each year since 2018. In the first nine months of 2026, there were 18 five minute intervals in the real-time market in which the SMP was capped.

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Table 3-92 Number of five minute intervals with capped SMP: 2018 through September 2026

Year	Number of Five Minute Intervals with Capped SMP
2018	0
2019	1
2020	1
2021	2
2022	51
2023	1
2024	0
2025	6
2026 (Jan - Sep)	18

The MMU recommends that PJM stop capping the system marginal price and instead limit the sum of violated reserve constraint shadow prices used in LPC to $1,700 per MWh.

Accuracy of Reserve Measurement

The definition of a shortage of synchronized and primary reserves is based on the measured and estimated levels of load, generation, interchange, demand response, and reserves from the real-time SCED software. The definition of such shortage also includes discretionary operator inputs to the ASO (Ancillary Service Optimizer) or RT SCED software, such as operator load bias. For shortage pricing to be accurate, there must be accurate measurement of real-time reserves. That does not appear to be the case at present in PJM, but there does not appear to be any reason that PJM cannot accurately measure reserves. Without accurate measurement of reserves on a minute by minute basis, system operators cannot know with certainty that there is a shortage condition and a reliable trigger for five minute shortage pricing does not exist. The benefits of five minute shortage pricing are based on the assumption that a shortage can be precisely and transparently defined.[174] PJM cannot accurately measure or price reserves due to the inaccuracy of its generator models. PJM's commitment and dispatch models rely on generator data to properly commit and dispatch generators. Generator data includes offers and parameters. When the models do not properly account for the different generator characteristics, both PJM dispatchers and generators have to make simplifications and assumptions using the tools available. Most of these actions taken by generators and by PJM dispatchers are not transparent. PJM manuals do not provide clarity regarding what actions generators can take when the PJM models and tools do not reflect their operational characteristics and PJM manuals do not provide sufficient clarity regarding the actions PJM dispatchers can take when generators do not follow dispatch.

In the energy and reserve markets, the actions that both generators and PJM dispatchers take have a direct impact on the amount of supply available for energy and reserves and the prices for energy and reserves. These flaws in PJM's models do not allow PJM to accurately calculate the amount of reserves available. PJM does not accurately model discontinuities in generator ramp rates, such as duct burners on combined cycle plants. PJM's generator models do not account for the complexities that may result in generators underperforming their submitted ramp rates. PJM should address these complexities through generator modeling improvements. PJM also fails to accurately model unit starts. The market software does not account for the energy output a resource produces prior to reaching its economic minimum output level, during its soak time.

Generators can deselect themselves from providing reserves by communicating to PJM that their resources will not follow the dispatch signal (e.g. offer fixed gen or operate as nondispatchable). These actions allow generators to withhold reserves and result in a violation of the reserve must offer requirement when the resources operate below their economic maximum.

Winter Storm Fern

Winter Storm Fern affected the PJM region from January 22 through January 30, 2026. The storm brought significant snow and ice precipitation from Friday, January 23 through Monday January 26, 2026. Cold temperatures persisted through the following week (January 27 through January 30).[175]

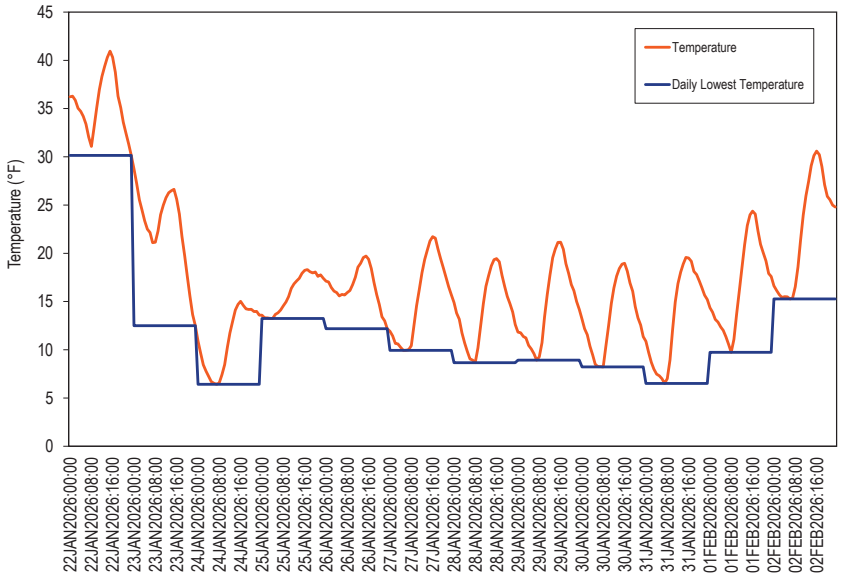
174 See Comments of the Independent Market Monitor for PJM, Docket No. RM15-24-000 (December 1, 2015) at 9.

175 See PJM. "January Cold Weather Operations," Operating Committee (February 5, 2026). <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2026/20260205/20260205-item-03---cold-weather-update---revised.pdf>.

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Figure 3-59 shows the PJM load weighted average temperatures from January 22 through February 2, 2026.

Figure 3-59 PJM Load Weighted Average Temperatures: January 22 through February 2, 2026



In preparation for the weather event, PJM declared several operating procedures including an Energy Emergency Alert 1 (EEA1) on January 27. See Figure 3-52 for the list of operating procedures declared by PJM during Winter Storm Fern and their duration.

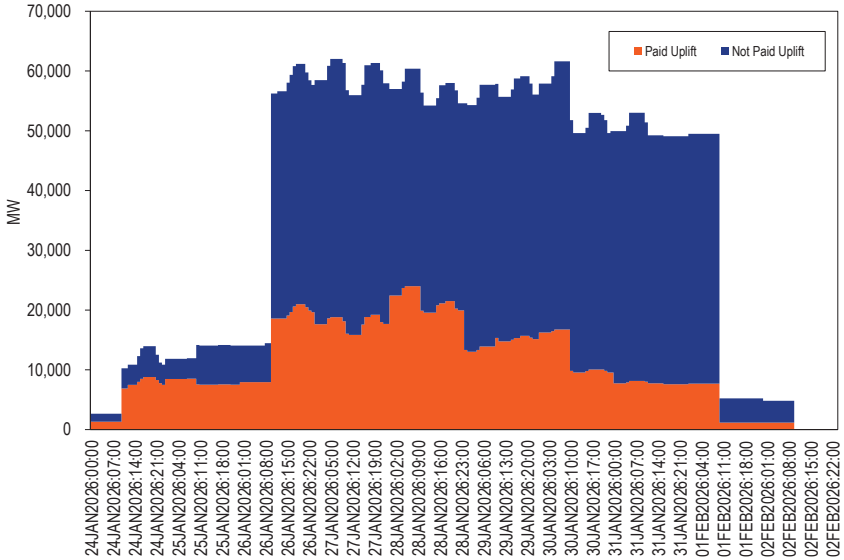
On Thursday, January 22, PJM peak load forecast for the following week was 147,347 MWh (on Tuesday 27), higher than PJM's all time winter peak load of 143,714 MWh on January 22, 2025. The actual highest load was 139,047 MWh on January 29, 2026. PJM stated that warmer actual temperatures and building closures were reasons for the over forecast. The 10 day period between January 24 and February 2, 2026, had the highest average load in PJM's history at 125,573 MWh (5.6 percent higher than the previous 10 day period between June 22 through July 1, 2025).

For this event, PJM continued its approach of scheduling units in advance of the Day-Ahead Energy Market. PJM began this approach after Winter Storm Elliott in December 2022 to address supply uncertainty resulting from performance risk. The performance risk is attributable to units that cannot operate and/or start reliably in cold weather, based on data collected from the generators by PJM, and/or natural gas fired units that face fuel procurement uncertainty when the fuel is not purchased during the active trading window. This issue is especially critical during weekends since the trading window occurs on Friday for the next three days (known as the weekend package).

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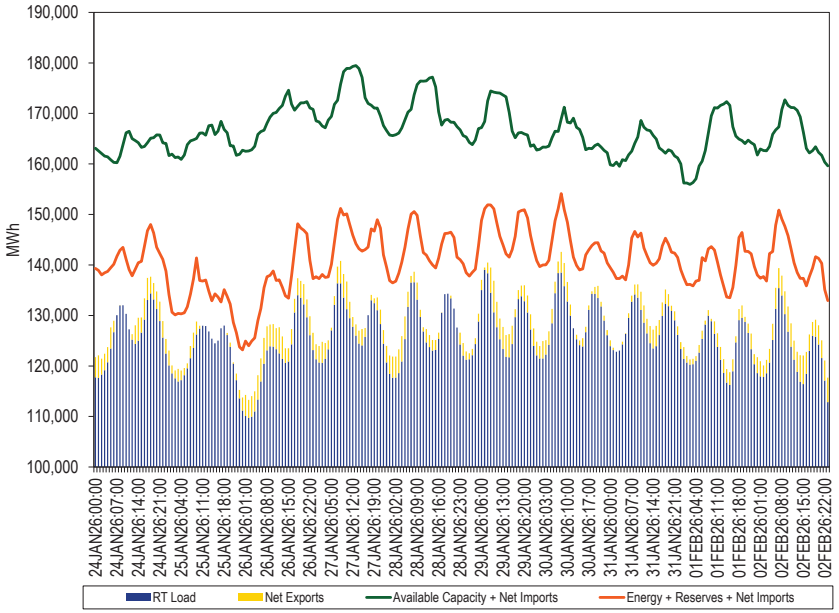
Figure 3-60 shows the economic maximum of all units committed in advance of the day-ahead energy market. Figure 3-60 separates the MW between units that were paid uplift because their operation was uneconomic and units that did not receive uplift because either their operation was economic or self scheduled.

Figure 3-60 Economic Maximum (MW) of units committed in advance of the day-ahead energy market during Winter Storm Fern



The impact of the advance commitment is shown in Figure 3-61. Figure 3-61 shows the available capacity (green line) and the energy plus reserves that the generation resources provided (orange line). The difference between the green and the orange lines are the MW not being used (headroom available) to provide either energy or reserves. At its lowest point the amount of headroom available was 14,792 MW. This is a reflection of the improved performance from generating units resulting mainly from PJM's advanced commitment approach. Figure 3-61 also show the load and exports in the blue and yellow bars. The difference between the red line and the sum of the blue and yellow bars are the reserve MW (synchronized, primary or 30 minute reserves).

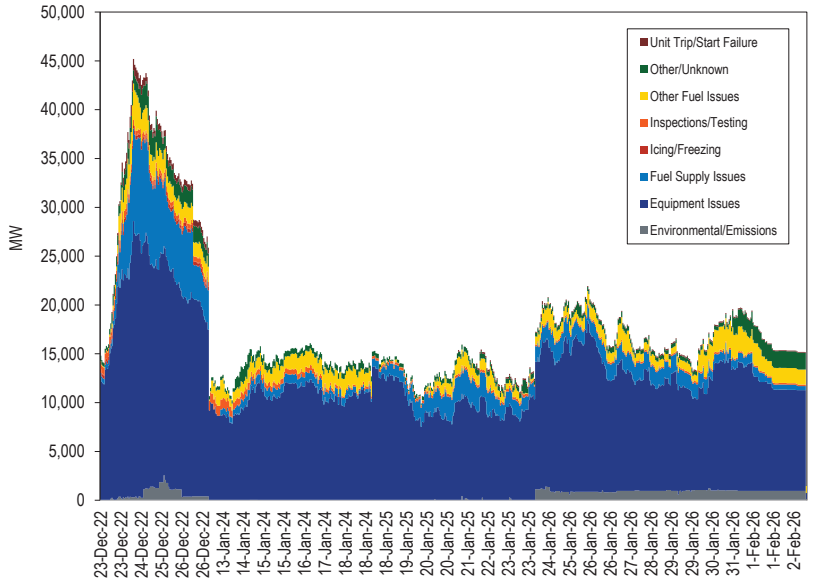
Figure 3-61 Supply and demand during Winter Storm Fern



The improved performance incorporated a reduction in outages. Figure 3-62 shows the outages during the last three significant winter events and its comparison with Winter Storm Elliott (2022). Outages during Winter Storm Gerri (2024), Polar Vortex 2025 and Winter Storm Fern (2026) were much lower than the outages during Winter Storm Elliott. Fuel related outages, in particular, were significantly lower in the last three events than in Winter Storm Elliott. This demonstrates the results of PJM's implementation of advanced commitment in preparation for the last three events but not for Winter Storm Elliott.

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Figure 3-62 Outages during the last three significant winter events and Winter Storm Fern

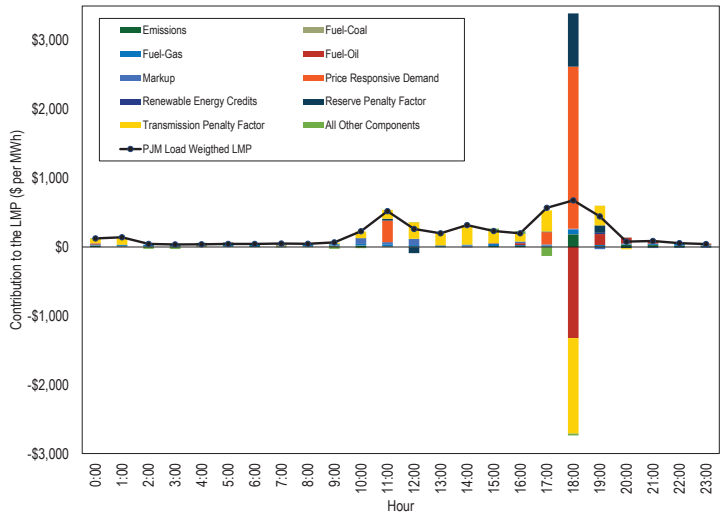


The uplift associated with Winter Storm Fern was an expected outcome of conservative operations and a preferred result to the penalties that resulted from Winter Storm Elliott. This uplift is part of the way that PJM markets work and was the result of PJM's successful conservative operations approach to dealing with cold weather risks. The market results of PJM's actions in preparation for and during Winter Storm Gerri, Polar Vortex 2025 and Winter Storm Fern were better than the market results of PJM's actions during Winter Storm Elliott. Nonetheless, improvements are needed to make the advance commitment process more predictable and transparent and formalized, and made as market based as possible, in order to ensure that uplift is at an efficient and effective level.

Hot Weather Days in 2026

PJM region experienced high temperatures between June 29, 2026, and July 5, 2026. On July 2 and July 3, 2026, real-time load-weighted average hourly LMP was high, with the peak pricing run LMP exceeding $1,800 per MWh. The highest metered load ever settled in the PJM territory, 162,221 MW was recorded on July 2, 2026. Figure 3-63 shows the components of the PJM real-time load-weighted average hourly LMP in the dispatch run for each hour on July 2. Figure 3-64 shows the components of the PJM real-time load-weighted average hourly LMP in the pricing run for each hour on July 2. Figure 3-65 shows the components of the PJM real-time load-weighted average hourly LMP in the dispatch run for each hour on July 3. Figure 3-66 shows the components of the PJM real-time load-weighted average hourly LMP in the pricing run for each hour on July 3. On July 2, for the hour beginning at 1800 (EPT), 71.9 percent of the load-weighted average LMP in the pricing run was due to operating reserve demand curve penalty factors, 26.0 percent was due to transmission constraint penalty factors and the remaining 2.1 percent was due to the other components of LMP.

Figure 3-63 Components of real-time (Unadjusted) dispatch run load-weighted average LMP: July 2, 2026



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Figure 3-64 Components of real-time (Unadjusted) pricing run load-weighted average LMP: July 2, 2026

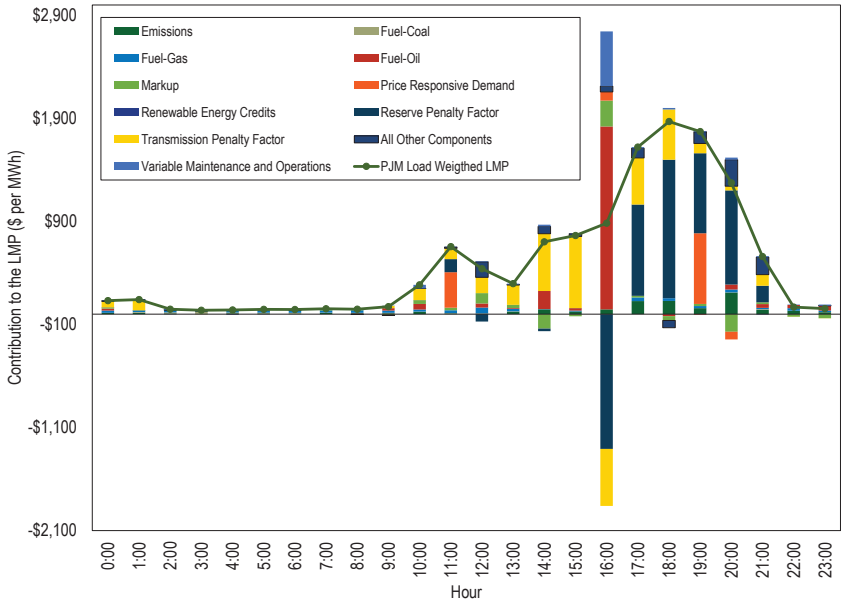
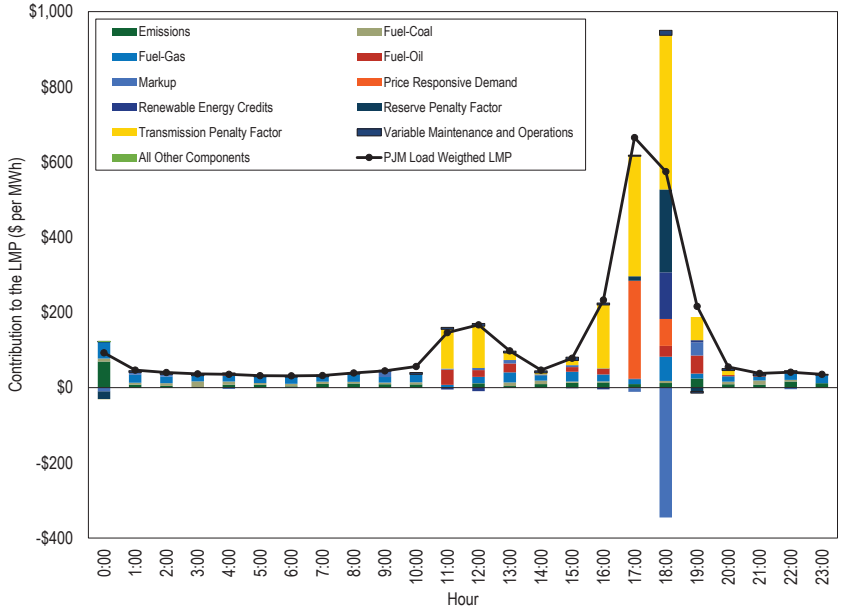


Figure 3-65 Components of real-time (Unadjusted) dispatch run load-weighted average LMP: July 3, 2026



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Figure 3-66 Components of real-time (Unadjusted) pricing run load-weighted average LMP: July 3, 2026

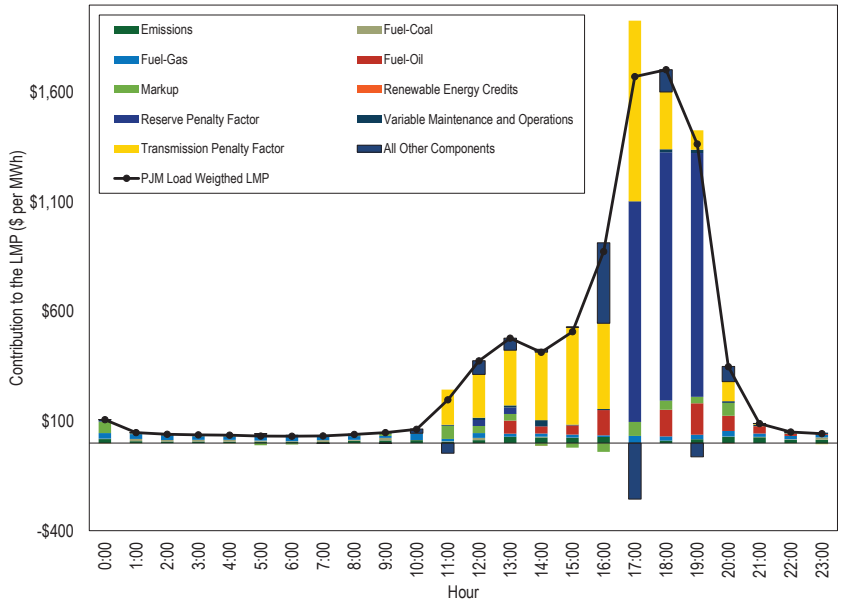
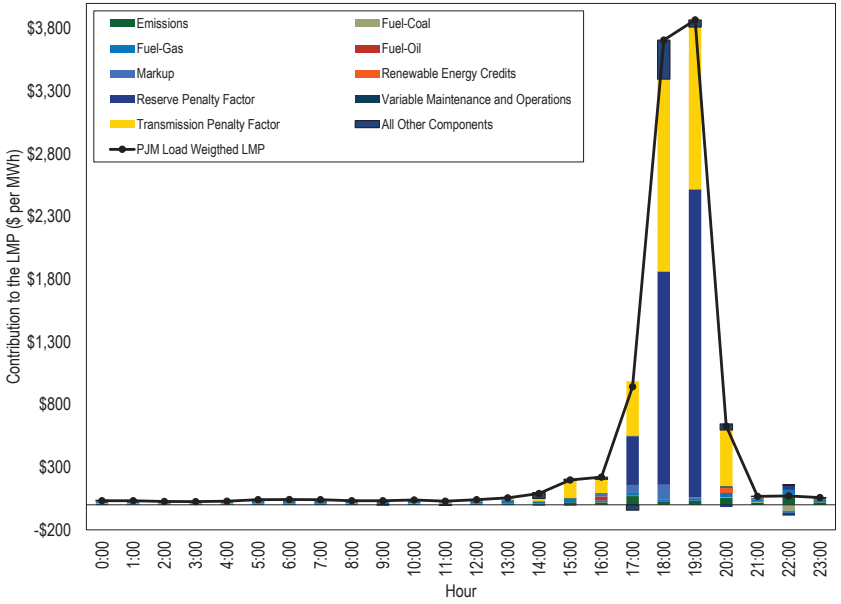


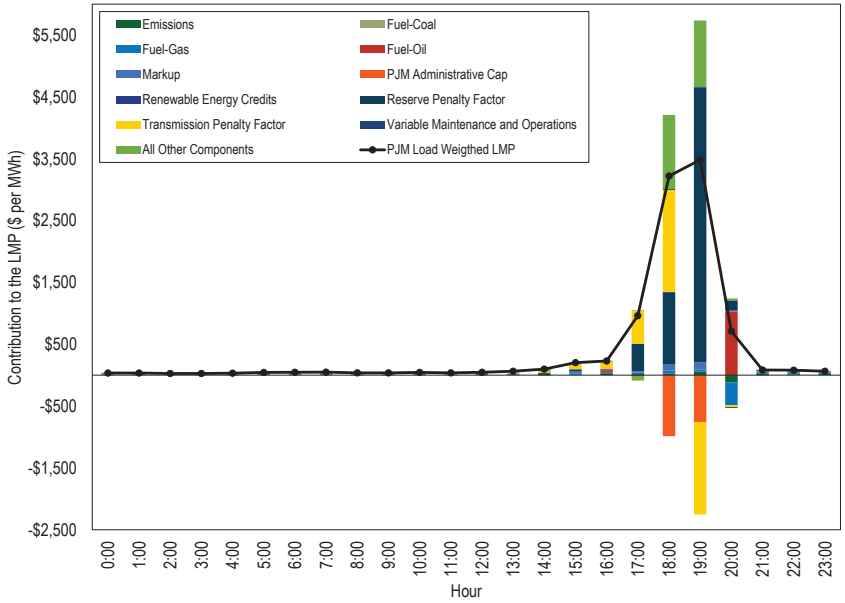
Figure 3-67 Components of real-time (Unadjusted) dispatch run load-weighted average LMP: September 16, 2026



PJM experienced extremely tight conditions on September 16, 2026. The relatively high temperature coupled with a large number of scheduled planned outages in September resulted in substantially high prices with the peak LMP exceeding $3,500 per MWh. Figure 3-67 shows the components of the PJM real-time load-weighted average hourly LMP in the dispatch run for each hour on September 16. Figure 3-68 shows the components of the PJM real-time load-weighted average hourly LMP in the pricing run for each hour on September 16. On September 16, PJM capped the energy LMP in the pricing run at $3,700 per MWh. On September 16, for the hour beginning at 1800, the load-weighted average LMP was reduced by $487.45 per MWh or 13.1 percent from $3,707.90 per MWh to $3,220.46 per MWh.

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Figure 3-68 Components of real-time (Unadjusted) pricing run load-weighted average LMP: September 16, 2026



Competitive Assessment

Market Structure

Market Concentration

The Herfindahl-Hirschman Index (HHI) concentration ratio is the sum of the squares of the market shares of all firms in a market. Hourly PJM energy market HHIs are based on the shares of the real-time energy output of generators, adjusted for scheduled imports. Hourly HHIs for the baseload, intermediate and peaking segments of generation supply are based on hourly energy market shares, unadjusted for imports.

The HHI is not a definitive measure of structural market power. It is possible to have pivotal suppliers even when the HHI level is not in the highly concentrated range. It is possible to have an exercise of market power even when the HHI level is not in the highly concentrated range. The number of pivotal suppliers in the energy market is a more precise measure of both local and aggregate structural market power than the HHI.

The HHI may not accurately capture market power issues in situations where, for example, there is moderate concentration in all on line resources but there is a high level of concentration in resources needed to meet increases in load. A pivotal supplier test is required to accurately measure the ability of incremental resources to exercise market power.

FERC's Merger Policy Statement defines levels of concentration by HHI level. The market is unconcentrated if the market HHI is below 1000, the HHI if there were 10 firms with equal market shares. The market is moderately concentrated if the market HHI is from 1000 to 1800. The market is highly concentrated if the market HHI is greater than 1800, the HHI if there were between five and six firms with equal market shares.[176]

When transmission constraints exist, local markets are created in which ownership 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 the first nine months of 2026, although there are issues with the application of market power mitigation for resources whose owners fail the TPS test that permit local market power to be exercised even when PJM's flawed market power mitigation rules are applied. These issues include the lack of a method for consistently determining the cheaper of the cost and price schedules and the lack of rules requiring that cost-based offers equal short run marginal costs.

PJM HHI Results

Hourly HHIs indicate that by FERC standards, the PJM energy market in the first nine months of 2026 was unconcentrated on average (Table 3-93).[177] The fact that the average HHI and the maximum hourly HHI are in the unconcentrated

176 See *Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement, 77* FERC ¶ 61,263 *mimeo* at 80 (1996).

177 The HHI calculations use actual real time settled generation data for each unit in PJM. Each unit's output is assigned to the owner that is responsible for offering the unit in the energy market.

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range does not mean that the aggregate market was competitive in all hours. It is possible to have pivotal suppliers in the aggregate market even when the HHI level does not indicate a highly concentrated market structure. Given the low responsiveness of consumers to prices (inelastic demand), it is possible to have high markup even when HHI is low. It is possible to have an exercise of market power even when the HHI level does not indicate a highly concentrated market structure.

Table 3-93 Real-time hourly aggregate energy market HHI: January through September, 2025 and 2026

HHI Statistic	Hourly Market HHI (Jan-Sep 2025)	Hourly Market HHI (Jan-Sep 2026)
Average	686	782
Minimum	511	569
Maximum	988	1070
Highest market share (One hour)	24%	26%
Average of the highest hourly market share	17%	19%
# Hours	6,551	6,551
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-94 includes HHI values by supply curve segment, including base, intermediate and peaking plants in the first nine months of 2025 and 2026. On average, ownership in the baseload segment was unconcentrated, in the intermediate segment was moderately concentrated, and in the peaking segment was highly concentrated.[178]

Table 3-94 Real-time hourly energy market HHI by generation segment: January through September, 2025 and 2026

	Jan-Sep 2025			Jan-Sep 2026		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	645	800	1101	643	836	1110
Intermediate	424	912	2746	555	1269	6037
Peak	839	6616	10000	946	6530	10000

178 A unit is classified as base load if it runs for 50 percent of hours or more, as intermediate if it runs for less than 50 percent but greater than or equal to 10 percent of hours, and as peak if it runs for less than 10 percent of hours.

Figure 3-69 shows the total installed capacity (ICAP) MW of units in the baseload, intermediate and peaking segments by fuel source in the first nine months of 2026.[179]

Figure 3-69 Real-time ICAP distribution by fuel and segment: January through September, 2026[180]

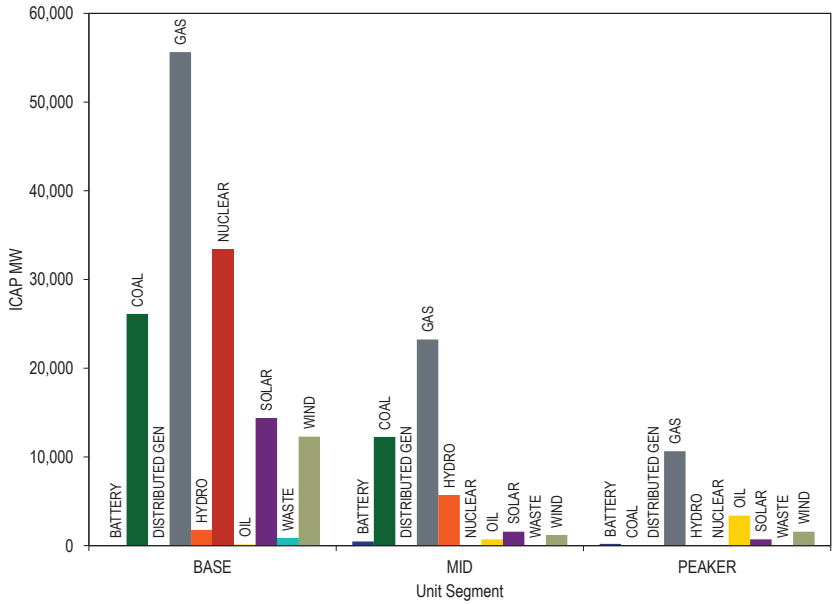


Figure 3-70 shows the ICAP of coal fired and gas fired units in PJM that are classified as baseload, intermediate and peaking in the first nine months of 2014 through 2026. Figure 3-70 shows that the total ICAP of coal fired units in PJM classified as baseload generally decreased from 2014 through 2026, while the total ICAP of gas fired units in PJM classified as baseload generally increased.

179 The installed capacity (ICAP) used for wind and solar units here is their nameplate capacity in MW. In PJM's Capacity Market, the UCAP value of wind and solar units is derated from the ICAP value using ELCC.

180 The units classified as Distributed Gen are buses within Electric Distribution Companies (EDCs) that are modeled as generation buses to accurately reflect net energy injections from distribution level load buses. The modeling change was the outcome of the Net Energy Metering Task Force stakeholder group in July, 2012. See PJM. "Net Energy Metering Senior Task Force (NEMSTF) 1st Read - Final Report and Proposed Manual Revisions," (June 28, 2012).

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Figure 3-70 Real-time annual gas and coal unit segment classification: January through September, 2014 through 2026

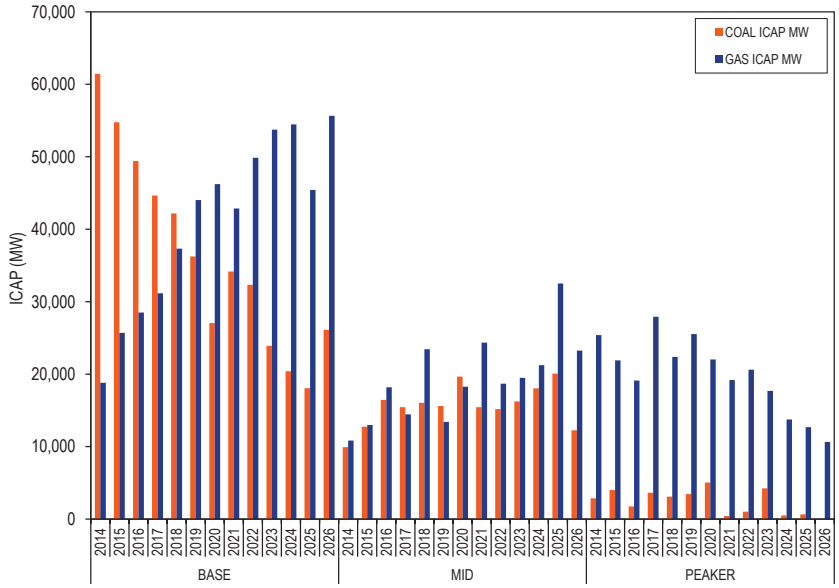
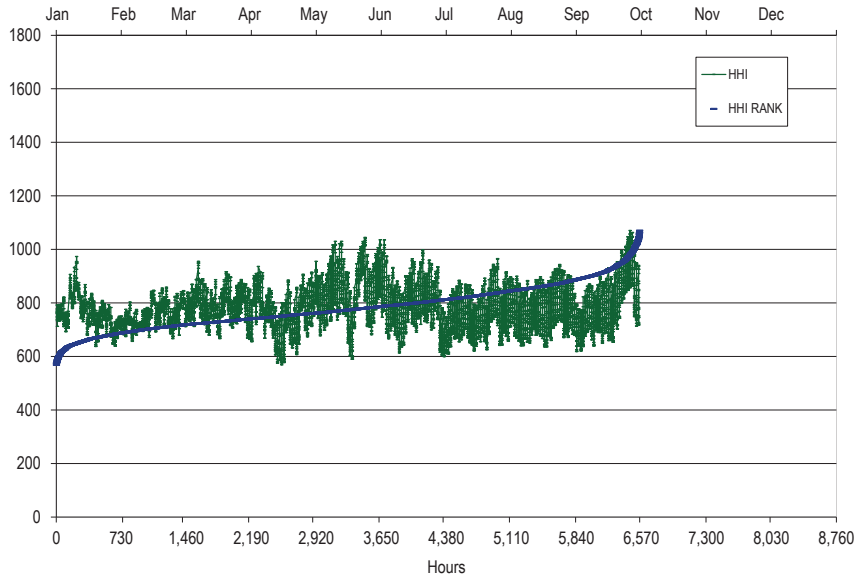


Figure 3-71 presents the hourly HHI values in chronological order and an HHI duration curve for the first nine months of 2026. The HHI duration curve shows the number of hours that HHI was at or below a given value in the first nine months of 2026.

Figure 3-71 Real-time hourly aggregate energy market HHI: January through September, 2026



Market Based Rates

Participation by generators in the PJM market using offers that exceed costs requires market based rate authority approved by FERC.[181] FERC reviews the market based rate authority of PJM market sellers of generation on a triennial schedule to ensure that market sellers do not have market power or that market power is appropriately mitigated. The entire PJM region is included in the Northeast Region for purposes of the triennial review schedule. Triennial filings by utilities with market based rates authorizations must include a market power analysis or a statement that market power has been adequately mitigated under the PJM market rules. Based on Order No. 861, sellers may, in lieu of filing a market power analysis, rely on a rebuttable presumption

181 See *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252 (2007), *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, 123 FERC ¶ 61,055, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No. 697-B, 125 FERC ¶ 61,326 (2008), *order on reh'g*, Order No. 697-C, 127 FERC ¶ 61,284 (2009), *order on reh'g*, Order No. 697-D, 130 FERC ¶ 61,206 (2010), *aff'd sub nom.* Mont. Consumer Counsel v. FERC, 659 F.3d 910 (9th Cir. 2011).

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that market monitoring and market power mitigation are sufficient to ensure competitive market outcomes.[182]

The rules specify a separate filing schedule for transmission owning utilities and nontransmission owning utilities. The rules define a study period for market power analyses including four complete seasons. A study runs from December of one year through November of the following year (i.e., the period includes one complete winter season rather than splitting winter as a calendar year approach would). The study period is not relevant for companies that choose the rebuttable presumption option.

The most recent triennial review filings for nontransmission owning utilities in PJM were filed in June 2026. The applicable study period for the June 2026 filings, ran from December 1, 2023, to November 30, 2024. Triennial review filings for transmission owners in PJM were filed in December 2025. The applicable study period for the December 2025 filings ran from December 1, 2023, to November 30, 2024.

The MMU has recommended since 2015 that changes to the offer capping process for the energy market are needed to ensure effective market power mitigation of units that fail the TPS test. With these results and the supporting evidence, the MMU challenged the rebuttable presumption of sufficient market power mitigation for the June 2020, December 2022, and June 2023 triennial review filings by generating unit owners in PJM. The MMU explained the issues with PJM's offer schedule selection process that allow generators to avoid energy market power mitigation as well as the then overstated capacity market seller offer cap. The MMU recommended that generators not be allowed to rely on PJM's implementation of market power mitigation rules to ensure competitive market outcomes until improvements are made to the offer capping processes in the energy and capacity markets so that suppliers cannot exercise market power.[183] In 2021, FERC issued orders requiring review of the adequacy of the market power mitigation rules and their implementation in the capacity and energy markets.[184] [185] FERC addressed the capacity market Market Seller Offer Cap later in 2021.[186] [187] FERC did not address the energy market power mitigation issues.

Merger Reviews

FERC reviews proposed dispositions, consolidations, acquisitions, and changes in control of jurisdictional generating units and transmission facilities under section 203 of the Federal Power Act to determine whether such transactions are "consistent with the public interest."[188] [189]

FERC applies tests set forth in the 1996 Merger Policy Statement, written prior to the introduction of competitive markets in PJM.[190] [191] The 1996 Merger Policy Statement provides for review of jurisdictional transactions based on "(1) the effect on competition; (2) the effect on rates; and (3) the effect on regulation." FERC adopted the 1992 Department of Justice Guidelines and the Federal Trade Commission Horizontal Merger Guideline (1992 Guidelines) to evaluate the effect on competition. FERC continues to use the 1992 Guidelines even after the Department of Justice modified its guidelines in 2010 and in 2023.[192] [193] Following the 1992 Guidelines, FERC applies a five step framework, which includes: defining the market; analyzing market concentration; analyzing mitigative effects of new entry; assessing efficiency gains; and assessing viability of the parties without a merger. FERC also evaluates the results of a Competitive Analysis Screen measuring HHI changes for markets defined by transmission zones. This approach does not take into account the effect of a transaction on actual PJM LMPs or capacity market prices.

182 *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, Order No. 861, 168 FERC ¶ 61,040 (2019) ("Order No. 861").

183 See Protest of the Independent Market Monitor for PJM, Docket No. ER10-1556 et al. (August 28, 2020); Comments of the Independent Market Monitor for PJM, Docket No. ER10-1618-018 et al. (February 13, 2023); Comments of the Independent Market Monitor for PJM, Docket No. ER23-9-000 et al. (August 28, 2023).

184 See 175 FERC ¶ 61,231 (2021).

185 See 174 FERC ¶ 61,212 (2021).

186 See 176 FERC ¶ 61,137 (2021), ***reh'g denied***, 178 FERC ¶ 61,121 (2022), ***appeal denied***, Vistra Corp. v. FERC, 80 F.4th 302 (2023).

187 *See* Monitoring Analytics, L.L.C., ***2021 Annual State of the Market Report for PJM***, Vol. 2, Section 5: Capacity Market at 311-312.

188 18 U.S.C. § 824b.

189 In February 2019, in response to 2017 amendments to Section 203 of the Federal Power Act, the Commission issued Order No. 855, implementing a $10,000,000 minimum value for transactions requiring the Commission's review. See 166 FERC ¶ 61,120 (2019)

190 See Order No. 592, FERC Stats. & Regs. ¶ 31,044 (1996) (1996 Merger Policy Statement), ***reconsideration denied***, Order No. 592-A, 79 FERC ¶ 61,321 (1997). See also FPA Section 203 Supplemental Policy Statement, FERC Stats. & Regs. ¶ 31,253 (2007), ***order on clarification and reconsideration***, 122 FERC ¶ 61,157 (2008).

191 FERC has an open but inactive docket where the guidelines are under review. See 156 FERC ¶ 61,214 (2016); FERC Docket No. RM16-21-000.

192 See 138 FERC ¶ 61,109 (2012).

193 See U.S. Department of Justice and the Federal Trade Commission, ***Merger Guidelines*** (December 18, 2023), <https://www.justice.gov/d9/2023-12/2023%20Merger%20Guidelines.pdf>.

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The MMU reviews proposed mergers and acquisitions based on analysis of the impact of the merger or acquisition on market power given actual PJM market conditions under the current competitive market design. The analysis includes use of the three pivotal supplier test results in the real-time energy market. The TPS test results, along with the MMU's additional one pivotal supplier analyses, provide a more accurate measure of the ability to exercise market power in the PJM market than the Commission prescribed HHI analysis. The MMU's review ensures that mergers are evaluated based on their impact on local and aggregate market power in the PJM energy market using actual observed market conditions, actual binding constraints and actual congestion results. This is in contrast to the typical merger filing that uses predefined local markets based on historical conditions that no longer exist rather than the actual local markets based on current and potential market conditions. The MMU files comments with FERC including such analyses.[194] The MMU has proposed that FERC adopt this approach when evaluating mergers in PJM.[195] Subsequent to the MMU's arguments about local markets, FERC has required further analysis of local markets from applicants at the transmission zone level.[196] FERC has considered the MMU's analysis in reviewing mergers but continues to apply an analysis that does not accurately account for locational market power in an LMP market.[197]

Neither the MMU's analysis nor the FERC defined analysis is an adequate replacement for effective market power mitigation, because system conditions are dynamic and any owner can become pivotal at any time. FERC routinely approves mergers and acquisitions and grants Market Based Rates authority to PJM market sellers despite known issues in the market power mitigation process that allow market sellers to exercise their market power. For this reason, the MMU recommends that FERC approve mergers and acquisitions conditioned on behavioral commitments by the market sellers that prevent the exercise of market power.

The MMU has also reached agreements to mitigate market power in cases where market power concerns have been identified.[198] [199] Such mitigation is designed to mitigate behavior over the long term, in addition to or instead of structural mitigation in the form of asset divestiture requirements.

The MMU also reviews transactions that involve ownership changes of PJM generation resources that are submitted to the Commission pursuant to section 203 of the Federal Power Act. Table 3-95 shows ownership changes in the PJM market that involved entire resources that were completed in the first nine months of 2026, as reported to the Commission. Table 3-96 shows transactions that involved transfers of partial unit ownership that were completed in the first nine months of 2026, as reported to the Commission.[200] [201]

194 See, e.g., Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-141-000 (Nov. 10, 2014); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-96-000 (July 21, 2014) Comments of the Independent Market Monitor for PJM, FERC Docket No. EC11-83-000 (July 21, 2011); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-14 (Dec. 9, 2013); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-112-000 (Sept. 15, 2014); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC20-49 (June 1, 2020).

195 See Comments of the Independent Market Monitor for PJM, Docket No. RM16-21 (Dec. 12, 2016).

196 See, for example, Darby Power, LLC, et al., Response to Second Deficiency Letter, Request for Confidential Treatment, Request for Shortened Comment Period, and Request for Expeditious Action, Docket No. EC24-125 (March 27, 2025).

197 See *Dynegy Inc., et al.*, 150 FERC ¶ 61, 231 (2015); *Exelon Corporation, Constellation Energy Group, Inc.*, 138 FERC ¶ 61,167 (2012); *NRG Energy Holdings, Inc., Edison Mission Energy*, 146 FERC ¶ 61,196 (2014); *see also Analysis of Horizontal Market Power under the Federal Power Act*, 138 FERC ¶ 61,109 (2012).

198 See 138 FERC ¶ 61,167 at P 19 (2012). The Maryland PSC accepted without condition or modification the settlement between Constellation and the MMU at the February 1, 2022, hearing in Case No. 9271. See *In the Matter of the Merger of Exelon Corporation and Constellation Energy Group, Inc.*, Order No. 90084, Order Approving 2021 Settlement Agreement and Denying Request to Require Exelon to Remain In PJM, Case No. 9271 (February 22, 2022). By its terms, the settlement became effective on February 1, 2022.

199 See 192 FERC ¶ 61,074 at 169. FERC accepted Constellation's behavioral commitments agreed to with the MMU and conditioned its approval of the acquisition of Calpine on those commitments.

200 The transaction completion date is based on the notices of consummation submitted to the Commission.

201 For transfers of partial unit ownership, total MW reflects the entire capacity of the transferred asset or assets, as reported to the Commission.

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Table 3-95 Completed transfers of entire resources: January through September, 2026

Generator or Generation Owner Name	Total MW	From	To	Transaction Completion Date	Docket
Calpine Corporation	5,341.0	Bridgepoint Group PLC	Constellation Energy Group	January 7, 2026	EC25-43
Eagle Creek Racine Hydro, LLC and Lake Lynn Generation, LLC	98.6	Ontario Power Generation Inc.	Apollo Global Management, Inc	January 9, 2026	EC26-8
Lightning Power, LLC (Armstrong Power, LLC; Aurora Generation, LLC; Chambersburg Energy, LLC; Doswell Limited Partnership; Gans Energy, LLC; Helix Ironwood, LLC; LSP University Park, LLC; Riverside Genering Company, L.L.LC; Rockford Power, LLC; Rockford Power II, LLC; Springdale Energy, LLC; Troy Energy, LLC; University Park Energy, LLC)	7,821.0	LS Power Group	NRG Energy, Inc.	January 30, 2026	EC25-102
Oregon Clean Energy, LLC	1,061.5	Ares Management Corporation (50%) and I Squared Capital Advisors LLC (50%)	American Electric Power Company, Inc.	March 2, 2026	EC25-84
Hill Top Energy Center, LLC	623.0	Ardian Holding s.a.s.	Blackstone Inc.	March 26, 2026	EC25-148
Conetoe II Solar, LLC	80.0	Brookfield Asset Management Ltd.	BlackRock, Inc.	March 30, 2026	EC26-13
Glover Creek Solar, LLC	50.0	Pine Gate Renewables, LLC	Brookfield Asset Management Ltd.	April 17, 2026	EC26-31
Sugar Maple Wind, LLC	81.0	RWE Clean Energy, LLC	Partners Group Holding AG	April 17, 2026	EC26-62
KMC Thermo, LLC (Brandywine)	288.8	Onward Energy Holdings, LLC	ArcLight Capital Partners, LLC Canada Pension Plan Investment Board and Abu Dhabi Investment Authority	May 12, 2026	EC26-39
Cornerstone Generation Marketing, LLC (Darby Power, LLC; Lawrenceburg Power, LLC; Waterford Power, LLC)	2,545.0	Bridgepoint Group plc	Talen Energy Corporation	June 15, 2026	E26-59
Wolf Hills Energy, LLC	250.0	Avenue Capital Group	American Electric Power Company, Inc.	August 14, 2026	EC26-81
Big Sandy Peaker Plant, LLC	300.0	Avenue Capital Group	American Electric Power Company, Inc.	August 14, 2026	EC26-82
GridFlex Generation, LLC (Tait Electric Generating Station, LLC and Lee County Generating Station, LLC)	1,267.1	Rockland Capital, LP	Hull Street Energy, LLC	August 25, 2026	EC26-83
Dragon Power, LLC (Yankee Stree, LLC; O.H. Hutchings CT, LLC; Monument Generating Station, LLC; and Sidney, LLC)	176.3	Rockland Capital, LP	Ara Partners Group, LLC	September 22, 2026	EC26-126

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Table 3-96 Completed transfers of partial ownership of resources: January through September, 2026

Generator or Generation Owner Name	Total MW	Percent	From	To	Transaction Completion Date	Docket
Clinton Solar LLC and Montpelier Solar, LLC	99.0	50.0%	TotalEnergies SE	KKR & Co. Inc.	January 26, 2026	EC26-12
Heritage Power, LLC (Blossburg Power, LLC; Brunot Island Power, LLC; Gilbert Power, LLC; Hamilton Power, LLC; Hunterstown Power, LLC; Mountain Power, LLC; New Castle Power, LLC; Niles Power, LLC; Lortanna Power, LLC; Portland Power, LLC; Sayreville Power, LLC; Shawnee Power, LLC; Shawville Power, LLC; Titus Power, LLC; Tolna Power, LLC; Warren Generation, LLC)	2,283.8	>10%	Avenue Capital Group	Hudson Bay Capital Management LP	January 21, 2026	EC26-18
Carroll County Energy LLC	832.3	31.6%	JERA, Co., Inc (20.00%) and San Jacinto Carroll Holdings LLC (11.64%)	Strategic Value Partners, LLC	February 12, 2026	EC25-152
Carroll County Energy LLC	832.3	10.6%	Ullico Infrastructure Master Fund, L.P.	ArcLight Capital Partners, LLC	February 6, 2026	EC25-151
Advanced Power US Holdings Inc. (Carroll County Energy LLC [17.76%]) and South Field Energy LLC [15.55%])	1,905.0	100% of controlling entity	Advanced Power AG	ArcLight Capital Partners, LLC	February 12, 2026	EC25-123*
Alpha Generation, LLC (Clean Energy Future - Lordstown, LLC; Parkway Generation Keys Energy Center LLC; Parkway Generation Operating LLC;Parkway Generation Sewaren Urban Renewal Entity LLC)	5,688.0	>10%	ArcLight Capital Partners, LLC	Canada Pension Plan Investment Board	March 9, 2025	EC26-21
CPV Three Rivers, LLC	1,300.0	10.0%	OPC Power Ventures LP	Osaka Gas Co. Ltd (15% ® 25%)	May 12, 2026	EC26-39
CPV Maryland, LLC	775.3	25.0%	Osaka Gas Co. Ltd	OPC Power Ventures LP (75% ® 100%)	May 12, 2026	EC26-39
Birdsboro Power LLC	525.0	66.7%	Tokyo Gas America Ltd. (33.3%), Sojitz Birdsboro LLC (8.3%), Kyushu Electric Power Company Incorporated (8.3%),Toho Gas Co. Ltd. (5.6%), Saibu Gas Co., Ltd. (5.6%), Hiroshima Gas Co., Ltd. (5.6%)	Strategic Value Partners, LLC (33.3% ® 100%)	July 17, 2026	EC26-96
Heritage Power, LLC (Blossburg Power, LLC; Brunot Island Power, LLC; Gilbert Power, LLC; Hamilaton Power, LLC; Hunterstown Power, LLC; Mountain Power, LLC; New Castle Power, LLC; Niles Power, LLC; Ortanna Power, LLC; Portland Power, LLC; Sayreville Power, LLC; Shawnee Power, LLC; Shawville Power, LLC; Titus Power, LLC; Tolna Power, LLC; Warren Generation, LLC)	2,283.8	4.0%	Undisclosed. Existing owners include PGIM, Inc; XYQ Energy LP; Hudson Bay Heritage LLC; and various investors who own <10%	King Street Capital Management GP, L.L.C. (8% ®12%)	July 21, 2026	EC26-80
Keystone Electric Generating Station	1,711.0	12.3%	Talen Energy Corporation	Chief Keystone Power, LLC (44.45% ® 56.79%) [owned by Riverstone Management Group, L.L.C, Man Group plc, and Avenue Capital Group]	September 13, 2026	EC26-125
Invenergy AMPCI Thermal Power LLC (Invenergy Nelson LLC, Invenergy Nelson Expansion LLC, and Lackawanna Energy Center LLC)	2,524.8	50.0%	DigitalBridge Group, Inc.	SoftBank Group Corp.	September 29, 2026	EC26-67
Invenergy AMPCI Thermal Power LLC (Invenergy Nelson LLC, Invenergy Nelson Expansion LLC, and Lackawanna Energy Center LLC)	2,524.8	50.0%	SoftBank Group Corp.	Arclight Capital Partners, LLC	September 29, 2026	EC26-76

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Aggregate Market Pivotal Supplier Results

Notwithstanding the HHI level, a supplier may have the ability to raise energy market prices. If reliably meeting the PJM system load requires energy from a single supplier, that supplier is singly pivotal and has monopoly market power in the aggregate energy market. If reliably meeting the PJM system load requires energy from a small number of suppliers, those suppliers are jointly pivotal and have oligopoly market power in the aggregate energy market. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power. The identification of jointly pivotal suppliers as a source of market power does not require an assumption that the suppliers collude. There are multiple mechanisms that would permit the exercise of market power when there are limited suppliers providing relief to a constraint. FERC Order No. 697 also recognizes this explicitly in the discussion of HHI and pivotal suppliers.[202] FERC's definition of highly concentrated markets, based on an HHI greater than 1800, includes between five and six owners with equal market shares.

The current market power mitigation rules for the PJM energy market rely on the assumption that the aggregate market includes sufficient competing sellers to ensure competitive market outcomes. With sufficient competition, any attempt to economically or physically withhold generation would not result in higher market prices, because another supplier would replace the generation at a similar price. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or without the supply from a small group of suppliers. This assumption is not generally correct, as demonstrated by these results. There are pivotal suppliers in the aggregate energy market.

The existing market power mitigation measures do not address aggregate market power.[203] Aggregate market power should be mitigated in the PJM Day-Ahead and Real-Time Markets when the three pivotal supplier test for the aggregate market is failed.

Day-Ahead Aggregate Energy Market Pivotal Suppliers

To assess the number of pivotal suppliers in the aggregate day-ahead energy market, the MMU determined, for each supplier, the MW available for economic commitment that were already running or were available to start between the close of the day-ahead energy market and the peak load hour of the operating day. The available supply is defined as MW offered at a price less than 150 percent of the applicable LMP because supply available at higher prices is not competing to meet the demand for energy. The offer price for determining available supply includes start up and no load costs for offline units. Generating units, import transactions, economic demand response, and INCs, are included for each supplier.[204] Demand is the total MW required by PJM to meet physical load, cleared load bids, export transactions, and DECs, which is the total cleared supply for the peak hour of the day. A supplier is pivotal if PJM would require some portion of the supplier's available economic capacity in the peak hour of the operating day in order to meet demand. Suppliers are jointly pivotal if PJM would require some portion of the joint suppliers' available economic capacity in the peak hour of the operating day in order to meet demand.

Based on this method, Table 3-97 shows the number of days in 2025 and the first nine months of 2026 with one or multiple singly pivotal suppliers, labelled as one pivotal supplier, with two or more suppliers that were each jointly pivotal with one other supplier, labelled as two pivotal suppliers, and with three or more suppliers that were each jointly pivotal with two other suppliers, labelled as three pivotal suppliers. For 2025, there were three pivotal suppliers for 95.3 percent of days. For the first nine months of 2026, there were three pivotal suppliers for 95.6 percent of days.

202 Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 104–117.

203 One supplier, Exelon Generating Company, LLC, is partially mitigated for aggregate market power through a settlement agreement with the MMU filed December 30, 2021 and approved by the Maryland Public Service Commission as a condition of its merger. *In the Matter of the Merger of Exelon Corporation and Constellation Energy Group, Inc.*, Order No. 90084, Maryland PSC Case No. 9271 (February 22, 2022). Order No. 90084 replaces the original 10 year settlement in this case included as a condition in Order No. 84698, issued February 17, 2012, which approved the merger between Exelon and Constellation Energy Group.

204 Generation, imports, demand response, and virtual transactions are assigned to parent companies based on the ultimate parent company owner of their PJM account.

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Table 3-97 Number of days with day-ahead aggregate pivotal suppliers: January 2025 through September 2026

Year	Month	Days with One Pivotal Suppliers	Percent of Days with One Pivotal	Days with Two Pivotal Suppliers	Percent of Days with Two Pivotal	Days with Three Pivotal Suppliers	Percent of Days with Three Pivotal
2025	Jan	0	0.0%	10	32.3%	28	90.3%
2025	Feb	0	0.0%	15	53.6%	26	92.9%
2025	Mar	0	0.0%	3	9.7%	25	80.6%
2025	Apr	0	0.0%	9	30.0%	27	90.0%
2025	May	0	0.0%	18	58.1%	30	96.8%
2025	Jun	4	13.3%	26	86.7%	30	100.0%
2025	Jul	9	29.0%	31	100.0%	31	100.0%
2025	Aug	0	0.0%	29	93.5%	31	100.0%
2025	Sep	0	0.0%	21	70.0%	29	96.7%
2025	Oct	2	6.5%	11	35.5%	30	96.8%
2025	Nov	0	0.0%	10	33.3%	30	100.0%
2025	Dec	0	0.0%	19	61.3%	31	100.0%
2025	Annual	15	4.1%	202	55.3%	348	95.3%
2026	Jan	2	6.5%	16	51.6%	28	90.3%
2026	Feb	0	0.0%	12	42.9%	28	100.0%
2026	Mar	0	0.0%	10	32.3%	25	80.6%
2026	Apr	4	13.3%	17	56.7%	29	96.7%
2026	May	7	22.6%	21	67.7%	29	93.5%
2026	Jun	3	10.0%	29	96.7%	30	100.0%
2026	Jul	16	51.6%	31	100.0%	31	100.0%
2026	Aug	12	38.7%	31	100.0%	31	100.0%
2026	Sep	13	43.3%	30	100.0%	30	100.0%
2026	Jan-Sep	57	20.9%	197	72.2%	261	95.6%

Figure 3-72 shows the number of days in the first nine months of 2025 and 2026 with one pivotal supplier, two jointly pivotal suppliers, and three jointly pivotal suppliers in the day-ahead aggregate energy market by daily peak load level. It shows that market power, measured by the average number of suppliers that are pivotal, increases with daily peak load. The average number of suppliers in the first nine months of 2026 that were one of three pivotal suppliers (yellow line) was 92.8 on the 51 days with a peak load between 90 and 100 GW (dark gray bar) and was 178.7 suppliers on the 19 days with a peak load between 140 and 150 GW. The number of pivotal suppliers generally increases with load.

The frequency of daily aggregate pivotal suppliers in the day-ahead market increased in in the first nine months of 2026 compared to the first nine months of 2025 at high levels of daily peak load shown in Figure 3-72. The overall frequency of pivotal suppliers rose with an increase in the frequency of days with daily peak load above 130 GW. In the first nine months of both 2025 and 2026, all days with peak load over 130 GW had day-ahead aggregate market pivotal suppliers. There were 38 days with a daily peak load over 130 GW in the first nine months of 2026, compared to 29 in the first nine months of 2025.

Figure 3-72 Average number of pivotal suppliers in the day-ahead energy market by daily peak load level: January through September, 2025 and 2026

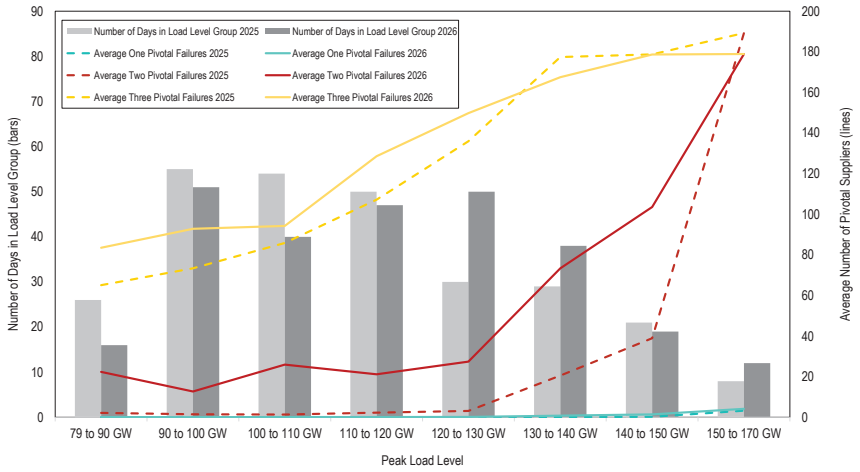


Table 3-98 provides the frequency with which each of the top 10 pivotal suppliers was singly or jointly pivotal for the day-ahead aggregate energy market in the first nine months of 2026. All of the top 10 pivotal suppliers were one of three pivotal suppliers on at least 230 days in the first nine months of 2026 (84.2 percent of the days). All of the top 10 pivotal suppliers were one of two pivotal suppliers on at least 81 days. The top three pivotal suppliers were singly pivotal on at least 24 days.

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Table 3-98 Day-ahead market pivotal supplier frequency: January through September, 2026

Pivotal Supplier Rank	Days Singly Pivotal	Percent of Days	Days Jointly Pivotal with One Other Supplier	Percent of Days	Days Jointly Pivotal with Two Other Suppliers	Percent of Days
1	56	20.5%	197	72.2%	261	95.6%
2	35	12.8%	183	67.0%	259	94.9%
3	24	8.8%	193	70.7%	261	95.6%
4	8	2.9%	137	50.2%	249	91.2%
5	6	2.2%	146	53.5%	257	94.1%
6	6	2.2%	106	38.8%	231	84.6%
7	0	0.0%	113	41.4%	249	91.2%
8	0	0.0%	91	33.3%	236	86.4%
9	0	0.0%	88	32.2%	230	84.2%
10	0	0.0%	81	29.7%	231	84.6%

Market Behavior

Local Market Power

In the PJM energy market, market power mitigation rules currently apply only for local market power. Local market power exists when transmission constraints or reliability issues create local markets that are structurally noncompetitive.[205] If the owners of the units required to solve the constraint or reliability issue are pivotal or jointly pivotal, they have the ability to set the price. Absent market power mitigation, unit owners that submit noncompetitive offers, or offers with inflexible operating parameters, could exercise market power. This could result in LMPs being set at higher than competitive levels, or could result in noncompetitive uplift payments.

The three pivotal supplier (TPS) test is the test for local market power in the energy market.[206] If the TPS test is failed, market power mitigation is applied by offer capping the resources on the high price side of the constraint for the owners who have been identified as having local market power. Offer capping is designed to set offers at competitive levels. Competitive offers are defined to be cost-based energy offers. In the PJM energy market, units are required to submit cost-based energy offers, defined by fuel cost policies, and have the option to submit market-based offers, also called price-based offers. Units are committed and dispatched on price-based offers, if offered, as the default offer. When a unit that submits both cost-based and price-based offers is mitigated to its cost-based offer by PJM, it is considered offer capped. A unit that submits only cost-based offers, or that requests PJM to dispatch it on its cost-based offer, is not considered offer capped.

Local market power mitigation is implemented in both the day-ahead and real-time energy markets. However, the implementation of the TPS test and offer capping differ in the day-ahead and real-time energy markets.

TPS Test Statistics for Local Market Power

The TPS test in the energy market defines whether three suppliers are jointly pivotal in a defined local market. The TPS test is applied when the system solution indicates that a transmission constraint is binding or requires the commitment of additional resources. The TPS test result for a constraint for a specific interval indicates whether a supplier failed or passed the test for that constraint for that interval. A failed test indicates that the resource owner has structural market power.

A metric to describe the number of local markets created by transmission constraints and the applicability of the TPS test is the number of hours that each transmission constraint was binding in the real-time energy market over a period, by zone.

In the first nine months of 2026, in the day-ahead energy market, the 500 kV system, 19 of 21 zones, and PJM/MISO experienced congestion resulting from one or more constraints binding for 75 or more hours, or resulting from a binding interface constraint (Table 3-99).[207] Table 3-99 shows that the 500 kV system, 14 of 21 zones and PJM/MISO experienced congestion resulting from one or more constraints binding for 75 or more hours or resulting from a binding interface constraint in the first nine months of every year from 2017 through 2026. DUKE and one zone did not experience congestion resulting

205 OA Schedule 1, Section 6.4.1.

206 See the MMU Technical Reference for PJM Markets, at "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

207 A constraint is mapped to the 500 kV system if its voltage is 500 kV and it is located in one of the zones including AECO, BGE, DPL, JCPLC, MEC, PECO, PENELEC, PEPCO, PPL and PSEG. All PJM/MISO reciprocally coordinated flowgates (RCF) are mapped to MISO regardless of the location of the flowgates. All PJM/NYISO RCF are mapped to NYISO as location regardless of the location of the flowgates.

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from one or more constraints binding for 75 or more hours or resulting from any binding interface constraint in the first nine months of any year from 2017 through 2026.

Table 3-99 Day-ahead congestion hours resulting from one or more constraints binding for 75 or more hours: January through September, 2017 through 2026

	(Jan - Sep)									
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
500 kV System	6,301	3,681	4,544	4,741	1,896	2,014	971	1,361	1,341	2,515
ACEC	1,686	2,530	4,631	1,955	824	144	1,057	795	608	284
AEP	42,657	13,586	13,085	8,960	4,081	3,024	5,527	4,625	3,123	1,534
APS	9,206	2,382	2,153	3,204	2,442	1,223	1,508	1,855	1,680	3,438
ATSI	3,848	3,186	1,574	184	135	331	1,342	2,278	967	1,758
BGE	7,433	4,561	3,521	4,716	3,159	993	4,000	1,532	1,810	3,459
COMED	46,058	10,796	3,932	2,949	1,515	2,124	3,186	6,525	4,025	4,421
DAY	345	300	76	919	220	0	208	0	0	0
DEOK	5,820	2,393	1,124	218	517	485	583	324	281	448
DLCO	106	198	0	0	0	97	0	0	79	135
DOM	4,755	2,353	727	2,214	1,962	3,646	2,745	3,421	4,806	4,833
DPL	8,991	9,066	6,702	5,006	3,473	2,302	3,591	4,277	2,478	2,847
DUKE	0	0	0	0	0	0	0	0	0	0
DUQ	0	0	0	0	0	0	0	0	0	0
EKPC	1,020	440	0	80	0	0	163	0	218	0
JCPLC	2,112	1,030	286	1,648	0	280	1,722	1,381	138	305
MEC	3,999	3,425	2,378	1,974	1,359	1,986	1,673	2,902	2,471	1,170
NYISO	515	0	0	0	0	0	0	0	0	0
OVEC	440	0	1,170	2,410	80	517	1,537	547	649	549
PE	17,758	7,485	2,739	3,256	681	3,216	3,829	6,373	7,957	7,162
PECO	8,540	2,551	1,218	917	1,231	3,349	4,404	3,201	2,635	1,527
PEPCO	643	116	79	0	0	228	364	354	640	258
PJM/MISO	18,558	14,699	7,450	4,514	4,334	7,949	4,824	3,782	6,941	8,560
PPL	6,618	3,193	7,328	4,142	3,942	4,707	2,252	2,755	3,581	3,853
PSEG	15,199	5,907	2,589	1,271	2,471	3,896	2,078	1,250	2,292	2,318
REC	0	326	1,074	182	1,069	723	895	287	0	0
TVA	0	0	206	75	0	0	0	0	0	125

In the first nine months of 2026, in the real-time energy market, the 500 kV system, 15 of 21 zones, and PJM/MISO experienced congestion resulting from one or more constraints binding for 75 or more hours, or resulting from a binding interface constraint (Table 3-100).[208] Table 3-100 shows that the 500 kV system, six zones, and PJM/MISO experienced congestion resulting from one or more constraints binding for 75 or more hours or resulting from a binding interface constraint in the first nine months of every year from 2017 through 2026. Two zones (DUQ and REC), and DUKE did not experience congestion resulting from one or more constraints binding for 75 or more hours or resulting from any binding interface constraint in the first nine months in any year from 2017 through 2026.[209]

Table 3-100 Real-time congestion hours resulting from one or more constraints binding for 75 or more hours: January through September, 2017 through 2026

	(Jan - Sep)									
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
500 kV System	810	1,009	2,777	2,075	748	869	375	579	460	1,186
ACEC	0	94	97	0	0	0	0	0	0	0
AEP	469	1,170	381	887	976	311	534	1,130	878	922
APS	136	184	0	319	888	82	0	181	345	1,030
ATSI	133	814	0	0	0	78	78	1,015	87	778
BGE	1,297	2,144	533	2,040	1,374	495	1,993	804	856	2,083
COMED	913	522	78	856	762	865	600	2,787	2,093	3,111
DAY	0	0	0	0	181	0	0	0	0	0
DEOK	0	75	0	0	176	0	0	0	132	209
DOM	80	136	91	780	488	1,455	416	664	1,306	2,318
DPL	326	398	0	0	144	0	84	0	158	251
DUKE	0	0	0	0	0	0	0	0	0	0
DUQ	0	0	0	0	0	0	0	0	0	0
EKPC	0	184	0	0	0	0	0	0	0	0
EXT	778	0	0	0	0	0	0	0	0	0
JCPLC	94	0	0	0	0	0	0	0	0	126
MEC	0	553	278	730	302	771	190	587	387	0
NYISO	332	0	0	0	0	0	0	0	0	0
OVEC	0	0	0	0	0	0	0	0	0	496
PE	1,541	1,114	1,013	1,950	586	1,522	2,144	3,818	4,505	3,289
PECO	1,312	537	224	284	612	2,134	2,552	1,468	1,417	995
PEPCO	0	0	0	0	0	0	0	77	83	0
PJM/MISO	3,797	3,060	3,035	2,453	2,458	6,015	3,431	3,494	3,889	4,196
PPL	563	0	748	460	751	1,582	91	96	746	1,642
PSEG	160	211	164	0	759	330	0	0	0	255
REC	0	0	0	0	0	0	0	0	0	0
TVA	0	0	0	0	0	0	0	0	0	89

208 A constraint is mapped to the 500 kV system if its voltage is 500 kV and it is located in one of the zones including AECO, BGE, DPL, JCPLC, MEC, PECO, PENELEC, PEPCO, PPL and PSEG. All PJM/MISO reciprocally coordinated flowgates (RCF) are mapped to MISO regardless of the location of the flowgates. All PJM/NYISO RCF are mapped to NYISO as location regardless of the location of the flowgates.

209 In this report, the MMU used the dispatch run marginal resource and sensitivity factor data, rather than the pricing run data, in the analysis of constraints since 2021 because the PJM pricing run sensitivity factor data for day-ahead LMP was not correct for a small number of hours. The PJM pricing run LMPs are the final settlement LMPs.

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In the PJM Day-Ahead Energy Market, the TPS test is performed in PROBE, as part of the unit commitment process. Table 3-101 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 the TPS test for the interface constraints in the PJM Day-Ahead Energy Market.

Table 3-101 Day-ahead three pivotal supplier test details for internal interface constraints: January through September, 2026

Constraint	Period	Number of Tests	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
AEP - DOM	Peak	19	378	289	21	6	15
	Off Peak	35	505	1,197	34	24	10
AP South	Peak	185	707	1,093	34	15	19
	Off Peak	116	613	1,034	33	13	20
BCPEP	Peak	36	582	334	13	2	11
	Off Peak	20	726	483	17	1	17
Bedington - Black Oak	Peak	80	142	161	26	8	17
	Off Peak	105	154	411	33	21	11
West	Peak	17	1,073	1,574	29	14	15
	Off Peak	0	0	0	0	0	0

Table 3-102 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, whether the TPS test was applied, and the average number of owners passing and failing the TPS test for the 10 constraints that were binding for the most hours in the day-ahead energy market. In the day-ahead energy market, the TPS test evaluates each constraint that was binding for each hour during the operating day after the initial unit commitment run. The set of constraints that are binding in the unit commitment run, for which the TPS test is applied, is not necessarily the same as the set of constraints that bind in the final day-ahead energy market solution. This is because PJM's day-ahead market is solved in three stages, and the initial set of constraints is from the Resource Scheduling and Commitment (RSC) (unit commitment) stage while the final set of binding constraints is from the Scheduling Pricing and Dispatch (SPD) (unit dispatch) stage.[210] The PJM approach fails to apply the TPS test to market sellers that provide relief to constraints in the final dispatch solution, and therefore fails to mitigate such sellers for market power.

The MMU recommends that PJM modify the process for applying the TPS test in the day-ahead energy market to ensure that all local markets created by binding constraints are tested for market power and to ensure that market sellers with market power are appropriately mitigated to their competitive offers.

Table 3-102 Day-ahead three pivotal supplier test details for top 10 congested constraints: January through September, 2026

Constraint	Period	Number of Tests	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Graceton - Manor	Peak	1,351	470	578	34	13	21
	Off Peak	1,610	325	591	30	16	15
East Towanda - Hillside	Peak	381	151	125	9	1	8
	Off Peak	500	143	156	10	1	9
Haumesser Road - Steward	Peak	851	165	114	6	0	6
	Off Peak	864	168	93	6	0	6
Chicago Ave - Praxair	Peak	36	48	55	10	5	6
	Off Peak	179	59	18	6	0	6
Burnham - Munster	Peak	592	420	711	40	18	22
	Off Peak	1,091	544	1,425	41	28	13
Lenox - Macnew Tap	Peak	6	53	14	7	0	7
	Off Peak	49	61	45	11	1	10
Elimsport - Sunbury	Peak	274	87	166	3	0	3
	Off Peak	623	119	264	3	0	3
Nottingham	Peak	635	651	907	38	19	19
	Off Peak	557	453	765	33	19	14
Fremont - Fremont Center	Peak	409	42	88	7	1	7
	Off Peak	156	57	109	9	1	8
Kewanee	Peak	223	79	61	4	0	3
	Off Peak	206	79	54	3	0	3

The local market structure in the real-time energy market associated with each of the frequently binding constraints was analyzed using the three pivotal

210 *See* PJM. "Manual 11: Energy & Ancillary Services Market Operations," Section 5.2.6, Rev. 136 (Oct. 1, 2025).

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supplier results for the first nine months of 2026.[211] While the real-time constraint hours include constraints that were binding in the five minute real-time dispatch solution (RT SCED), IT SCED, the software that performs the TPS test, may contain different binding constraints because IT SCED looks ahead to target times that are in the near future to solve for constraints that could be binding, using the load forecast for those times.[212] IT SCED solves for target times that occur at 15 minute time increments, unlike RT SCED that solves for every five minute time increment. The TPS statistics shown in this section present the data from the IT SCED TPS solution. Some IT SCED TPS solutions are used to commit units, while others are not. PJM operators have discretion in choosing which units to commit and which IT SCED results to use as the basis for the commitment and therefore which units are tested for market power using the TPS test. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that did result in offer capping.

Table 3-103 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 interface constraints in the PJM Real-Time Energy Market. Table 3-104 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 10 constraints that were binding for the most hours in the PJM Real-Time Energy Market. Table 3-103 and Table 3-104 include analysis of all the tests for every target time where IT SCED determined that constraint relief was needed for each of the constraints shown. The same target time can be evaluated by multiple IT SCED cases at different look ahead times. Each 15 minute target time is solved by 12 different IT SCED cases at different look ahead times. The set of binding constraints for a target time may be different in 12 look ahead IT SCED solutions.

211 See the *MMU Technical Reference for PJM Markets*, p. 38 "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

212 Prior to September 1, 2021, the real-time binding constraints were identical in the dispatch (RT SCED) and pricing (LPC) solutions. Beginning September 1, 2021, with implementation of fast start pricing, the set of binding constraints can differ between RT SCED and LPC pricing solutions. The set of constraints reported here are based on the binding constraints in RT SCED. This is because PJM commits and mitigates units based on a dispatch solution in IT SCED without fast start pricing.

Table 3-103 Real-time three pivotal supplier test details for internal interface constraints: January through September, 2026

Constraint	Period	Number of Tests	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Bedington - Black Oak	Peak	3,383	245	158	11	1	10
	Off Peak	3,816	279	146	11	1	10
AEP - DOM	Peak	387	574	371	11	0	11
	Off Peak	2,409	665	399	12	0	12
AP South	Peak	2,598	542	686	15	5	10
	Off Peak	1,605	496	592	13	2	11

Table 3-104 Real-time three pivotal supplier test details for top 10 congested constraints: January through September, 2026

Constraint	Period	Number of Tests	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Graceton - Manor	Peak	31,069	167	216	14	4	10
	Off Peak	42,144	140	205	12	3	9
East Towanda - Hillside	Peak	21,053	85	112	3	0	3
	Off Peak	30,677	77	110	2	0	2
Chicago Ave - Praxair	Peak	3,887	37	18	3	0	3
	Off Peak	11,673	33	19	3	0	3
Lenox - Macnew Tap	Peak	15,545	26	28	3	0	3
	Off Peak	19,572	24	26	2	0	2
Haumesser Road - Steward	Peak	12,541	52	90	2	0	2
	Off Peak	13,277	36	70	2	0	2
Nottingham	Peak	20,529	227	256	14	2	12
	Off Peak	15,564	199	221	13	1	11
Burnham - Munster	Peak	10,443	238	209	11	1	10
	Off Peak	17,485	209	181	10	1	9
Elimsport - Sunbury	Peak	4,170	24	153	1	0	1
	Off Peak	13,327	33	144	1	0	1
Kewanee	Peak	3,346	23	87	1	0	1
	Off Peak	4,011	15	68	1	0	1
State Line - Roxana	Peak	2,477	62	20	3	0	3
	Off Peak	7,922	54	21	2	0	2

The three pivotal supplier test is applied every time the IT SCED solution indicates that incremental relief is needed to relieve a transmission constraint.

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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 offer capping. Steam unit offers that are offer capped in the day-ahead energy market continue to be offer capped in the real-time energy market regardless of their inclusion in the TPS test in real time or the outcome of the TPS test in real time. Steam unit offers that are not offer capped in the day-ahead energy market continue to not be offer capped in the real-time energy market regardless of their inclusion in the TPS test in real time or the outcome of the TPS test in real time.[213] Offline units that are committed to provide relief for a transmission constraint, whose owners fail the TPS test, are committed on the cheaper of their cost or price-based offers. Beginning November 1, 2017, with the introduction of hourly offers and intraday offer updates, online units whose commitment is extended beyond the day-ahead or real-time commitment, and whose owners fail the TPS test, are also switched to the cost-based offer if it is cheaper than the price-based offer.

Units committed in the day-ahead market often fail the TPS test in the real-time market when they are redispatched to provide relief to transmission constraints, even though they did not fail the TPS test in the day-ahead market. Day-ahead committed units are not evaluated for offer capping in real-time unless they update their cost-based offer. These units are able to set prices with a positive markup in the real-time market. Units that cleared the day-ahead market on their price based schedule were evaluated to identify the units whose offers were mitigated in real-time and the units that cleared on price offers in real-time despite failing the real-time TPS test. Table 3-105 shows that, in the first nine months of 2026, 5.5 percent of unit hours that cleared the day-ahead market on their price based offer were switched to cost in real-time. Table 3-105 shows that 11.5 percent of unit hours that cleared the day-ahead market on their price based offer cleared on their price based offer in real-time despite failing the real-time TPS test.

Table 3-105 Day-ahead units committed on price-based offers that cleared real-time: January through September, 2025 and 2026

Year (Jan-Sep)	Day Ahead Price Based Unit Hours That Cleared Real-Time			Percent Day Ahead Price Based Unit Hours That Cleared Real-Time	
	On Cost	On Price	On Price and Failed TPS Test	On Cost	On Price and Failed TPS Test
2025	106,325	2,431,227	191,273	4.6%	7.8%
2026	139,675	2,553,165	293,737	5.5%	11.5%

The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the real-time market that were not offer capped at the time of commitment in the day-ahead market or at a prior time in the real-time market.

Table 3-106 and Table 3-107 provide, for the identified constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping in the real-time energy market. Tests where there was at least one offline unit or an online unit eligible for offer capping by the online TPS test are considered tests that could have resulted in offer capping. A relatively small number of these tests result in offer capping because the offline or online units eligible for offer capping by the online TPS test may not fail the TPS test, may not be on the high price side of the constraint, or may have offers which, under current PJM rules, result in the unit's price-based offer being determined the least-cost offer. PJM operators also manually commit units for reliability reasons other than providing relief to a binding constraint. Manual commitments are offer capped along with resources that fail the TPS test.

213 If a steam unit were to lower its cost-based offer in real time, it would become eligible for offer capping based on the online TPS test.

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Table 3-106 Summary of real-time three pivotal supplier tests applied for internal interface constraints: January through September, 2026

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
Bedington - Black Oak	Peak	3,383	3,383	100%	81	2%	2%
	Off Peak	3,816	3,767	99%	134	4%	4%
AEP - DOM	Peak	387	387	100%	21	5%	5%
	Off Peak	2,409	2,409	100%	68	3%	3%
AP South	Peak	2,598	2,598	100%	111	4%	4%
	Off Peak	1,605	1,605	100%	102	6%	6%

Table 3-107 Summary of real-time three pivotal supplier tests applied for top 10 congested constraints: January through June, 2026

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
Graceton - Manor	Peak	31,069	30,990	100%	504	2%	2%
	Off Peak	42,144	42,047	100%	363	1%	1%
East Towanda - Hillside	Peak	21,053	10,665	51%	0	0%	0%
	Off Peak	30,677	12,628	41%	20	0%	0%
Chicago Ave - Praxair	Peak	3,887	900	23%	0	0%	0%
	Off Peak	11,673	2,126	18%	2	0%	0%
Lenox - Macnew Tap	Peak	15,545	8,771	56%	4	0%	0%
	Off Peak	19,572	6,707	34%	14	0%	0%
Haumesser Road - Steward	Peak	12,541	1,902	15%	0	0%	0%
	Off Peak	13,277	1,580	12%	0	0%	0%
Nottingham	Peak	20,529	20,522	100%	243	1%	1%
	Off Peak	15,564	15,552	100%	137	1%	1%
Burnham - Munster	Peak	10,443	8,960	86%	146	1%	2%
	Off Peak	17,485	14,994	86%	125	1%	1%
Elimsport - Sunbury	Peak	4,170	60	1%	0	0%	0%
	Off Peak	13,327	205	2%	0	0%	0%
Kewanee	Peak	3,346	3	0%	0	0%	0%
	Off Peak	4,011	29	1%	0	0%	0%
State Line - Roxana	Peak	2,477	546	22%	1	0%	0%
	Off Peak	7,922	1,239	16%	4	0%	0%

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, like voltage support and N-2 contingencies, for providing black start and for providing 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.

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There are some issues with the application of mitigation in the day-ahead energy market and the real-time energy market when market sellers fail the TPS test. There are also issues with the absence of a TPS test under some conditions. There is no tariff or manual language that defines in detail the application of the TPS test and offer capping in the day-ahead energy market and the real-time energy market. There is no tariff or manual language that defines the PJM process for evaluating units for multi-day commitments in the day-ahead energy market.

In both the day-ahead and real-time energy markets, generators with market power have the ability to evade mitigation by using varying markups in their price-based offers, offering different operating parameters in their price-based and cost-based offers, and using different fuels in their price-based and cost-based offers. These issues can be resolved by simple rule changes.

When an owner fails the TPS test, the units offered by the owner that are committed to provide relief are committed on the cheaper of cost-based or price-based offers. In the day-ahead energy market, PJM commits a unit on the schedule that results in the lower overall system production cost. The day-ahead energy market selects which schedule to use for a resource that failed the TPS test based on its objective of clearing resources to meet the total demand at the lowest bid production cost for the system over the 24 hour period.

In the real-time energy market, PJM uses a dispatch cost formula to compare price-based offers and cost-based offers to select the cheaper offer.[214]

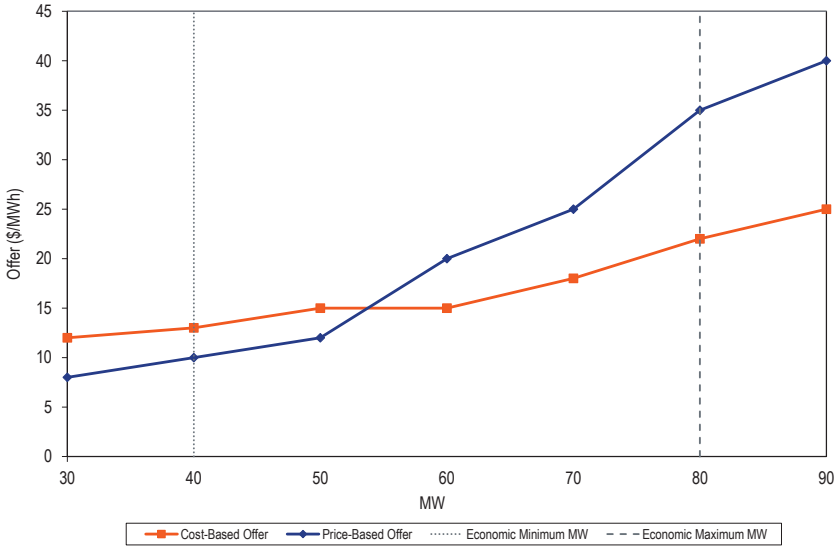
$$\text{Total Dispatch Cost} = \text{Startup Cost} + \sum_{\text{Min Run}} \text{Hourly Dispatch Cost}$$

where the hourly dispatch cost is calculated for each hour using the offers applicable for that hour as:

$$\text{Hourly Dispatch Cost} = (\text{Incremental Energy Offer@EcoMin} \times \text{EcoMin MW}) + \text{NoLoad Cost}$$

The hourly dispatch cost is calculated only at the economic minimum level and not at higher output levels. Given the ability to submit offer curves with different markups at different output levels in the price-based offer, unit owners with market power can evade mitigation by using a low markup at low output levels and a high markup at higher output levels. This strategy is called crossing curves, or markup switching. Figure 3-73 shows an example of offers from a unit that has a negative markup at the economic minimum MW level and a positive markup at the economic maximum MW level. The result would be that a unit that failed the TPS test would be committed on its price-based offer that has a lower dispatch cost, even though the price-based offer is higher than cost-based offer at higher output levels and includes positive markups, inconsistent with the explicit goal of local market power mitigation.

Figure 3-73 Offers with varying markups at different MW output levels



214 See OA Schedule 1 § 6.4.1(g).

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Table 3-108 shows the number and percent of unit schedule hours, by month, when unit offers included crossing curves (markup switch) in the PJM Day-Ahead and Real-Time Energy Markets in the first nine months of 2026. The analysis includes only units that offer both price-based and cost-based offers. Units in PJM are required to submit cost-based offers, but most elect to submit price-based offers.

Table 3-108 Units offered with crossing curves (markup switch): January through Setember, 2026

	Day-Ahead			Real-Time		
2026	Number of Schedule Hours with Crossing Curves	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Crossing Curves	Number of Schedule Hours with Crossing Curves	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Crossing Curves
Jan	71,460	903,312	7.9%	60,246	850,012	7.1%
Feb	63,354	814,296	7.8%	52,191	735,377	7.1%
Mar	73,320	923,695	7.9%	53,035	779,829	6.8%
Apr	72,100	896,976	8.0%	48,717	718,785	6.8%
May	71,131	926,712	7.7%	51,019	770,325	6.6%
Jun	76,643	903,000	8.5%	65,063	835,604	7.8%
Jul	92,101	935,640	9.8%	78,419	864,015	9.1%
Aug	93,609	938,328	10.0%	79,598	870,654	9.1%
Sep	81,985	916,176	8.9%	70,866	807,798	8.8%
Total	695,703	8,158,135	8.5%	559,154	7,232,399	7.7%

Table 3-109 shows the percent of unit schedule hours offered with crossing curves (markup switch), their average markup, their MW output weighted markup, and their average marginal unit LMP and markup contribution, when units failed the three pivotal supplier test in the PJM Day-Ahead Market and were marginal in the Real-Time Energy Market in the first nine months of 2022 through 2026. The analysis only includes units that offer both price-based and cost-based offers.

Table 3-109 Marginal units offered with crossing curves (markup switch) and local market power: January through September, 2022 through 2026

Unit hours with Crossing Curves Committed on Price Offer and Eligible for Offer-Capping DA and Marginal in Real-Time							
Year (Jan-Sep)	Percent of Unit hours with Crossing Curves	Average Markup Day-Ahead	Average Markup Real-Time	Load-Weighted Average Markup Day-Ahead	Load-Weighted Average Markup Real-Time	Average Marginal Unit LMP Contribution	Average Marginal Unit Markup Contribution
2022	12.7%	$14.40	$8.26	$17.21	$12.60	$3.45	$0.47
2023	12.1%	$10.24	$3.23	$11.71	$5.25	$1.37	$0.17
2024	12.3%	$9.27	$3.34	$10.61	$5.54	$1.32	$0.14
2025	18.2%	$11.46	$9.17	$14.46	$13.66	$1.68	$0.27
2026	12.0%	$33.62	$16.98	$45.98	$33.54	$2.16	$0.12

Table 3-110 shows the percent of unit schedule hours offered with crossing curves (markup switch), their average markup, their MW output weighted markup, and their average marginal unit LMP and markup contribution, when units failed the three pivotal supplier test in the PJM Day-Ahead Market, were marginal in the Real-Time Energy Market and had a negative markup in the PJM Day-Ahead Market in the first nine months of 2022 through 2026. The analysis only includes units that offer both price-based and cost-based offers.

Table 3-110 Marginal units offered with crossing curves (markup switch), local market power and negative markup day-ahead: January through September, 2022 through 2026

Unit hours with Crossing Curves Committed on Price Offer with Negative Markup and Eligible for Offer-Capping DA and Marginal with Positive Markup in Real-Time							
Year (Jan-Sep)	Percent of Unit hours with Crossing Curves	Average Markup Day-Ahead	Average Markup Real-Time	Load-Weighted Average Markup Day-Ahead	Load-Weighted Average Markup Real-Time	Average Marginal Unit LMP Contribution	Average Marginal Unit Markup Contribution
2022	2.0%	($8.20)	$20.83	($7.89)	$25.20	$3.73	$0.77
2023	2.7%	($3.16)	$10.54	($2.90)	$12.19	$1.22	$0.24
2024	2.6%	($3.48)	$11.37	($3.03)	$13.04	$1.47	$0.42
2025	3.7%	($3.98)	$23.24	($2.74)	$30.97	$1.69	$0.38
2026	2.5%	($5.10)	$25.79	($3.69)	$34.20	$2.39	$0.62

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Offering a different economic minimum MW level, different minimum run times, or different start up and notification times in the cost-based and price-based offers can also be used to evade mitigation. For example, a unit may have a price-based offer with a positive markup, but have a shorter minimum run time (MRT) in the price-based offer resulting in a lower dispatch cost for the price-based offer but setting prices at a level that includes a positive markup. Table 3-111 shows the number and percent of unit schedule hours when units offered lower minimum run times in price-based offers than in cost-based offers while having a positive markup in the price-based offer.

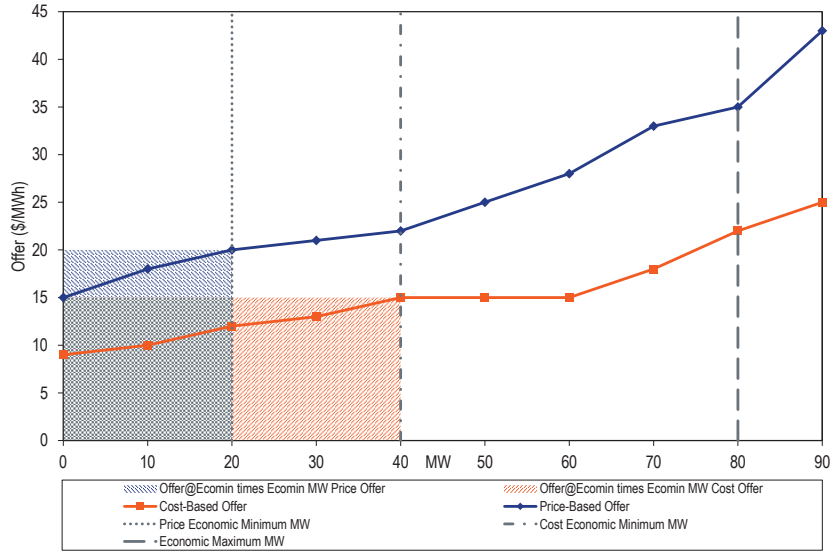
Table 3-111 Units offered with lower minimum run time on price compared to cost and with positive markup: January through September, 2026

	Day-Ahead			Real-Time		
2026	Number of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Number of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Min Run Time in Price Compared to Cost
Jan	3,274	903,312	0.4%	2,981	850,012	0.4%
Feb	3,212	814,296	0.4%	2,251	735,377	0.3%
Mar	3,214	923,695	0.3%	2,099	779,829	0.3%
Apr	2,968	896,976	0.3%	1,803	718,785	0.3%
May	3,144	926,712	0.3%	2,098	770,325	0.3%
Jun	3,405	903,000	0.4%	3,337	835,604	0.4%
Jul	2,717	935,640	0.3%	2,091	864,015	0.2%
Aug	2,740	938,328	0.3%	1,239	870,654	0.1%
Sep	2,662	916,176	0.3%	1,222	807,798	0.2%
Total	27,336	8,158,135	0.3%	19,121	7,232,399	0.3%

A unit may offer a lower economic minimum MW level on the price-based offer than the cost-based offer. Such a unit may appear to be cheaper to commit on the price-based offer even with a positive markup. A unit with a positive markup can have lower dispatch cost with the price-based offer with a lower economic minimum level compared to the cost-based offer. Figure 3-74 shows an example of offers from a unit that has a positive markup and a price-based offer with a lower economic minimum MW than the cost-based offer. Keeping the startup cost, Minimum Run Time and no load cost constant between the price-based offer and cost-based offer, the dispatch cost for this unit is lower on the price-based offer than on the cost-based offer solely as a result of the lower economic minimum MW. However, the price-based offer includes a positive markup and could result in setting the market price at a noncompetitive level even after the resource owner fails the TPS test.

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Figure 3-74 Offers with a positive markup but different economic minimum MW



The behavior in which units offered lower economic minimum MW in price-based offers than in cost-based offers while having a positive markup in the price-based offer is limited to a number of units that does not permit data to be provided under the PJM confidentiality rules in both the day-ahead and real-time energy markets.

In the case of dual fuel units, if the price-based offer uses a cheaper fuel and the cost-based offer uses a more expensive fuel, the price-based offer will appear to be cheaper even when it includes a markup. Figure 3-75 shows an example of offers by a dual fuel unit, where the active cost-based offer uses a more expensive fuel and the price-based offer uses a cheaper fuel and includes a markup. Table 3-112 shows the number and percent of dual fuel unit hours where the price-based offer does not have a comparable cost-based offer with a matching fuel, and the cost-based offer exceeds the price-based offer. The analysis includes only those units that offered multiple offers (cost or price) with different fuels in the first nine months of 2026.

Figure 3-75 Dual fuel unit offers

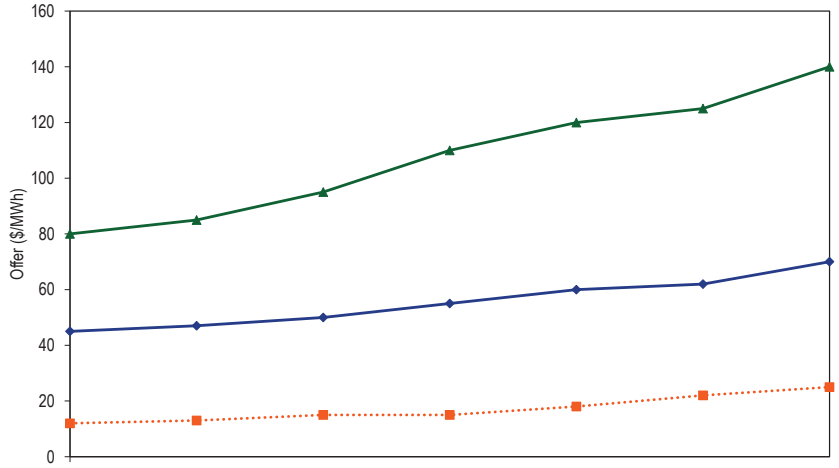


Table 3-112 Dual fuel unit offers with cost-based offers exceeding price-based offers (negative markup) but different fuel: January through September, 2026

	Day-Ahead			Real-Time		
2026	Number of Unit Hours With Negative Markup And No Matching Fuel on Cost	Total Number of Unit Hours By Units With Multiple Fuels	Percent Unit Hours With Negative Markup And No Matching Fuel on Cost	Number of Unit Hours With Negative Markup And No Matching Fuel on Cost	Total Number of Unit Hours By Units With Multiple Fuels	Percent Unit Hours With Negative Markup And No Matching Fuel on Cost
Jan	9,866	195,216	5.1%	9,866	190,925	5.2%
Feb	11,986	179,688	6.7%	11,986	167,397	7.2%
Mar	13,944	212,310	6.6%	13,944	182,450	7.6%
Apr	18,102	207,408	8.7%	18,102	161,071	11.2%
May	25,388	220,104	11.5%	25,388	191,932	13.2%
Jun	26,967	219,120	12.3%	26,967	209,303	12.9%
Jul	26,597	221,928	12.0%	26,597	209,386	12.7%
Aug	23,805	226,872	10.5%	23,805	216,534	11.0%
Sep	24,281	218,016	11.1%	24,281	201,368	12.1%
Total	180,936	1,900,662	9.5%	180,936	1,730,366	10.5%

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These issues can be solved by simple rule changes.[215] The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be consistently positive or negative across the full MWh range of price and cost-based offers. This means that the cost-based and price-based offer curves never cross.[216]

PJM filed and, on October 25, 2024, FERC accepted a revised proposal that would require that sellers that fail the TPS test will be offer capped at their cost-based offers and that operating parameters will be mitigated. However, PJM has no plans to implement the improved rules, so the flawed rules remain in place. PJM's proposal also uses the flawed formula rejected by FERC to select among cost-based offers. This will result in the illogical selection of cost-based offers in some circumstances, particularly if a dual fuel unit submits offers for both oil and gas on a day when the economics change between the two fuels midday. PJM should modify its implementation to address that issue. The result would allow market sellers to select the correct cost-based fuel schedule. There is no reason to delay implementation until PJM addresses combined cycle modelling. The changes would decrease the solution time for the day-ahead market and enhance market efficiency. The new approach should be implemented as soon as possible to help ensure effective market power mitigation.

The issues with offer capping will continue to allow the exercise of market power to affect prices until PJM implements the new approach. Currently, there is no implementation date. The simplified schedule selection process would shorten the time required to reach the day-ahead market solution, which is a market efficiency gain regardless of whether PJM implements combined cycle modelling. The MMU recommends that PJM commit all resources that fail the TPS test on their cost-based offers and that PJM implement that solution as soon as possible. [217]

Levels of offer capping have historically been low in PJM, as shown in Table 3-114. But offer capping remains a critical element of PJM market rules because it is designed to prevent the exercise of local market power. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have a significant impact on prices in the absence of local market power mitigation. Until November 1, 2017, only uncommitted resources, started to relieve a transmission constraint, were subject to offer capping. Beginning November 1, 2017, under certain circumstances, online resources that are committed beyond their original commitment (day-ahead or real-time) can be offer capped if the owner fails the TPS test, and the latest available cost-based offer is determined to be lower than the price-based offer.[218] Units running in real time as part of their original commitment on the price-based offer on economics, and that can provide incremental relief to a constraint, cannot be switched to their cost-based offer by PJM.

The offer capping percentages shown in Table 3-113 include units that are committed to provide constraint relief whose owners failed the TPS test in the energy market or were committed to provide constraint relief in advance of the day-ahead market, but excluding units that were committed for reliability reasons, providing black start or providing reactive support. Offer capped unit run hours and offer capped generation (in MWh) are shown as a percentage of the total run hours and the total generation (MWh) from all the units in the PJM energy market.[219] Beginning November 1, 2017, with the introduction of hourly offers, certain online units, whose owners fail the TPS test in the real-time energy market for providing constraint relief, can be offer capped and dispatched on their cost-based offer subsequent to a real-time hourly offer update.

215 The MMU proposed these offer rule changes as part of a broader reform to address generator offer flexibility and associated impact on market power mitigation rules in the Generator Offer Flexibility Senior Task Force (GOFSTF) and subsequently in the MMU's protest in the hourly offers proceeding in Docket No. ER16-372-000, filed December 14, 2015.

216 See related recommendations about mitigation of operating parameters and financial offer parameters.

217 See Monitoring Analytics, LLC, "Schedule Selection: IMM Package," Market Implementation Committee (September 6, 2023), <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Schedule_Selection_IMM_Package_20230906.pdf>.

218 See OA Schedule 1 § 6.4.1.

219 Prior to the *2018 Quarterly State of the Market Report for PJM: January through June*, these tables presented the offer cap percentages based on total bid unit hours and total load MWh. Beginning with the quarterly report for January through June, 2018, the statistics have been updated with percentages based on run hours and total generation MWh from units modeled in the energy market.

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Table 3-113 Offer capping statistics for units committed for constraints: January through September, 2018 to 2026

	Real-Time		Day-Ahead	
Year (Jan - Sep)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2018	1.1%	0.5%	0.1%	0.2%
2019	1.6%	1.1%	1.2%	0.8%
2020	1.0%	1.2%	1.6%	1.4%
2021	1.3%	1.0%	1.4%	0.8%
2022	1.4%	1.1%	1.4%	1.0%
2023	1.3%	1.0%	1.6%	0.7%
2024	1.5%	1.0%	2.0%	1.0%
2025	1.4%	1.1%	1.9%	1.0%
2026	1.7%	1.1%	3.7%	1.3%

Table 3-114 Offer capping statistics for units committed for constraints or for reliability: January through September, 2018 to 2026

	Real-Time		Day-Ahead	
Year (Jan - Sep)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2018	1.2%	0.8%	0.2%	0.4%
2019	1.6%	1.1%	1.2%	0.8%
2020	1.0%	1.2%	1.6%	1.4%
2021	1.3%	1.0%	1.4%	0.8%
2022	1.5%	1.4%	1.5%	1.1%
2023	1.4%	1.2%	1.8%	1.0%
2024	1.7%	1.4%	2.2%	1.4%
2025	1.5%	1.3%	2.1%	1.2%
2026	2.2%	1.7%	4.0%	1.7%

Table 3-114 shows the offer capping percentages including both units committed to provide constraint relief and units committed for reliability reasons, including units that were committed in advance of the day-ahead market for conservative operations. Reliability reasons also include black start and reactive support.

PJM creates closed loop interfaces to, in some cases, model reactive constraints. The closed loop interface creates demand for the output of the resource needed to provide reactive power. The resulting higher LMPs in the closed loop interfaces increased economic dispatch, which contributed to the reduction in units offer capped for reactive support over time in Table 3-115. In instances where units are committed and offer capped for the modeled closed loop interface constraints, they are considered offer capped for providing constraint relief, and not for reliability. They are included in the offer capping percentages in Table 3-113. Prior to closed loop interfaces, these units were considered as committed for reactive support and were included in the offer capping statistics for reliability in Table 3-115.

Table 3-115 shows the offer capping percentages only for units committed for reliability reasons, black start or reactive support. The low offer capping percentages do not mean that units manually committed for reliability reasons do not have market power. All units manually committed for reliability have market power, and all are treated consistent with that fact.[220]

Table 3-115 Offer capping statistics for units committed for reliability: January through September, 2018 to 2026

	Real-Time		Day-Ahead	
Year (Jan - Sep)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2018	0.14%	0.29%	0.12%	0.23%
2019	0.01%	0.02%	0.01%	0.01%
2020	0.00%	0.01%	0.00%	0.00%
2021	0.02%	0.04%	0.02%	0.02%
2022	0.15%	0.27%	0.06%	0.12%
2023	0.13%	0.23%	0.17%	0.27%
2024	0.18%	0.38%	0.23%	0.42%
2025	0.10%	0.23%	0.12%	0.24%
2026	0.53%	0.61%	0.26%	0.36%

220 OA Schedule 1, Section 6.4.1.

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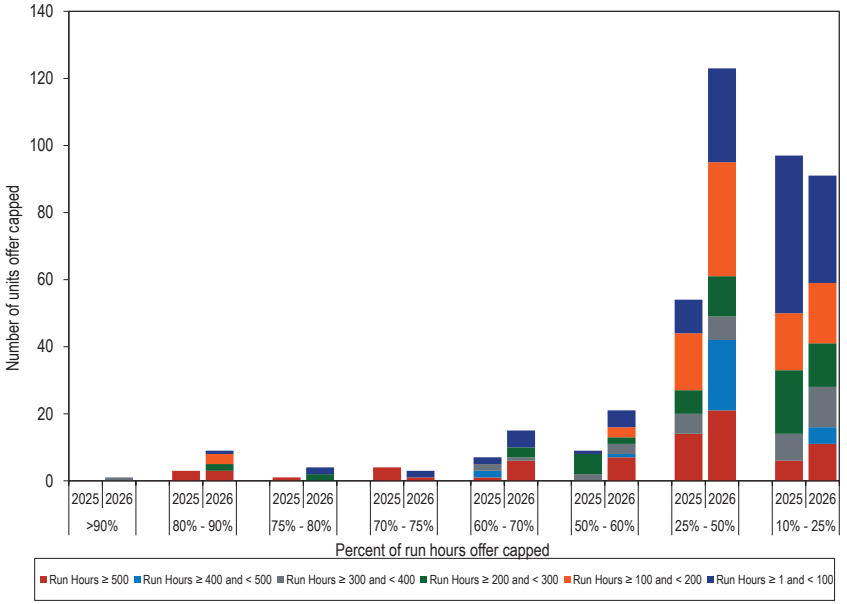
Table 3-116 presents data on the frequency with which units were offer capped in the first nine months of 2025 and 2026 as a result of failing the TPS test to provide energy for constraint relief in the real-time energy market, or for reliability reasons.

Table 3-116 Real-time offer capped unit statistics: January through September, 2025 and 2026

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Jan - Sep	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2025	0	0	0	0	0	0
	2026	0	0	1	0	0	0
80% and < 90%	2025	3	0	0	0	0	0
	2026	3	0	0	2	3	1
75% and < 80%	2025	1	0	0	0	0	0
	2026	0	0	0	2	0	2
70% and < 75%	2025	4	0	0	0	0	0
	2026	1	0	0	0	0	2
60% and < 70%	2025	1	2	2	0	0	2
	2026	6	0	1	3	0	5
50% and < 60%	2025	0	0	2	6	0	1
	2026	7	1	3	2	3	5
25% and < 50%	2025	14	0	6	7	17	10
	2026	21	21	7	12	34	28
10% and < 25%	2025	6	0	8	19	17	47
	2026	11	5	12	13	18	32

Figure 3-76 shows the frequency with which units were offer capped in the first nine months of 2025 and 2026 for failing the TPS test to provide energy for constraint relief in the real-time energy market or for reliability reasons.

Figure 3-76 Real-time offer capped unit statistics: January through September, 2025 and 2026



In response to FERC's request for Common Metrics for 2019 through 2022, which were published in FERC's 2023 Common Metrics Staff report, PJM filed a report stating that between 2019 and 2022 the percent of unit hours in the day-ahead energy market with active market power mitigation was between 78.8 and 100 percent, while the actual results were between 1.4 and 1.6 percent.[221] [222] PJM also reported that between 2019 and 2022, the percent of unit intervals in the real-time energy market with active market power mitigation was between 43.3 and 53.3 percent, while the actual results were

221 See Common Performance Metrics, Docket No. AD19-16-000, PJM Compliance Filing, PJM Metrics Spreadsheet 2023 (April 17, 2023).
222 See 2023 Common Metrics: Performance Metrics for ISOs, RTOs, and Regions Outside ISOs and RTOs for the Reporting Period 2019 to 2022, FERC Staff Report (January 31, 2024), <https://elibrary.ferc.gov/eLibrary/filelist?accession_num=20240131-4000>.

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between 1.0 and 1.7 percent. PJM's reported results were incorrect because PJM provided hours of mitigation instead of unit hours or unit intervals mitigated. In the day-ahead market, a mitigated unit hour is one unit mitigated for one hour. The denominator is all cleared units cleared for all hours. In the real-time market, a mitigated unit interval is one unit mitigated for one interval. The denominator is all cleared units for all intervals. For example, if there were 10 units running in a given hour in the day-ahead market, if one unit was mitigated for that hour, then the percent of unit hours mitigated would be 10 percent, but PJM defined the percent mitigated as 100 percent of the hour. The PJM filed report dramatically overstated the frequency of market power mitigation in the PJM energy market. The MMU has correctly reported this metric in the State of the Market Reports for 2002 and subsequent years. The MMU also reports the MWh subject to market power mitigation, which reflects the relative size of the units subject to market power mitigation.

Markup Index

Markup is a summary measure of the degree to which a participant's offer behavior or conduct for individual units is competitive. When a seller makes a competitive offer, markup is zero. When a seller exercises market power in its offer, markup is positive. The degree of markup increases with the degree of market power. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[223] The markup index is normalized and can vary from -1.00 when the offer price is less than the cost-based offer price, to 1.00 when the offer price is higher than the cost-based offer price. The markup index does not measure the impact of unit markup on total LMP. The dollar markup for a unit is the difference between price and cost.

Real-Time Markup Index

Table 3-117 shows the average markup index of marginal units in the real-time energy market, by offer price category using unadjusted cost-based offers.

Table 3-117 Real-time average marginal unit markup index (By offer price category unadjusted): January through September, 2025 and 2026

	2025 (Jan - Sep)			2026 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	(0.28)	($5.17)	17.0%	0.05	($3.42)	19.8%
$10 to $15	(0.13)	($2.32)	6.4%	(0.12)	($2.14)	9.6%
$15 to $20	(0.09)	($2.14)	13.8%	(0.10)	($2.46)	16.0%
$20 to $25	(0.07)	($2.11)	16.1%	(0.09)	($3.44)	10.2%
$25 to $50	(0.03)	($2.49)	34.2%	(0.04)	($3.13)	30.4%
$50 to $75	0.05	$0.30	6.6%	0.04	($2.61)	5.9%
$75 to $100	0.14	$11.09	1.7%	0.10	$5.23	2.3%
$100 to $125	0.19	$19.92	0.7%	0.13	$9.11	0.9%
$125 to $150	0.16	$20.36	0.5%	0.16	$17.25	0.6%
>= $150	0.07	$17.99	2.9%	0.10	$23.89	4.1%
All Offers	(0.07)	($1.53)	100.0%	(0.03)	($1.43)	100.0%

Table 3-118 shows the average markup index of marginal units in the real-time energy market, by offer price category using adjusted cost-based offers. The unadjusted markup is the difference between the price-based offer and the cost-based offer including the 10 percent adder in the cost-based offer at the dispatch point on the offer curves. The adjusted markup is the difference between the price-based offer and the cost-based offer excluding the 10 percent adder from the cost-based offer. The adjusted markup is calculated for coal, gas and oil units because these units have consistently had price-based offers less than cost-based offers.[224] The markup is negative if the cost-based offer of the marginal unit is greater than its price-based offer at its operating point.

All generating units are allowed to add an additional 10 percent to their cost-based offer. The 10 percent adder was included 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. The owners of coal units, facing competition, typically exclude the additional 10 percent from their actual offers. The owners of many gas fired and oil fired units also exclude the 10 percent adder. The introduction of hourly offers and intraday offer updates in November 2017 allows gas and oil generators to directly

223 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00) for comparison across both low and high cost units, the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost.

224 The MMU will calculate adjusted markup for gas units also in future reports because gas units also more consistently have price-based offers less than cost-based offers.

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incorporate the impact of ambient temperature changes in fuel consumption in offers.

Table 3-118 Real-time average marginal unit markup index (By offer price category adjusted): January through September, 2025 and 2026

	2025 (Jan - Sep)			2026 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	(0.28)	($4.79)	17.0%	0.07	($3.23)	19.8%
$10 to $15	(0.06)	($1.14)	6.4%	(0.05)	($0.93)	9.6%
$15 to $20	(0.02)	($0.54)	13.8%	(0.02)	($0.90)	16.0%
$20 to $25	0.00	($0.16)	16.1%	(0.02)	($1.41)	10.2%
$25 to $50	0.04	$0.38	34.2%	0.03	($0.39)	30.4%
$50 to $75	0.11	$4.60	6.6%	0.10	$1.75	5.9%
$75 to $100	0.20	$16.11	1.7%	0.17	$11.21	2.3%
$100 to $125	0.24	$25.40	0.7%	0.18	$15.56	0.9%
$125 to $150	0.21	$27.37	0.5%	0.21	$24.77	0.6%
>= $150	0.14	$37.34	2.9%	0.16	$42.93	4.1%
All Offers	(0.01)	$1.14	100.0%	0.03	$1.30	100.0%

PJM implemented Fast Start Pricing on September 1, 2021. For all the fast start marginal units beginning on September 1, 2021, the markup includes markup in the incremental offer, markup in the amortized start up offer, and markup in the amortized no load offer.

Even the adjusted markup overestimates the negative markup because units facing increased competitive pressure have excluded both the 10 percent and components of operating and maintenance costs that are not short run marginal costs. The PJM Market rules permit the 10 percent adder and maintenance costs, which are not short run marginal costs, under the definition of cost-based offers. Actual market behavior reflects the fact that neither is part of a competitive offer and neither is a short run marginal cost.[225]

In the first nine months of 2026, the average dollar markup of units with offer prices less than $10 was negative (-$3.42 per MWh) when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $10 and $15 was negative (-$2.14 per MWh) when using unadjusted cost-based offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, revealing a short run marginal cost that is less than the maximum allowable cost-based offer under the PJM Market Rules.

Some marginal units did have substantial markups. Among the units that were marginal in the first nine months of 2026, 4.1 percent had offer prices above $150 per MWh. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the first nine months of 2026 was more than $1,000, and the highest markup in the first six months of 2025 was more than $900.

Table 3-119 shows the percentage of marginal units that had markups, calculated using unadjusted cost-based offers, below, above and equal to zero for coal, gas and oil fuel types.[226]

Table 3-119 Percent of marginal units with markup below, above and equal to zero (By fuel type with unadjusted offers): January through September, 2025 and 2026

	2025 (Jan - Sep)			2026 (Jan - Sep)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	47.9%	32.0%	20.1%	55.0%	33.4%	11.6%
Gas	65.5%	18.4%	16.1%	59.4%	23.7%	16.9%
Oil	16.4%	80.8%	2.8%	13.8%	84.6%	1.7%
Wind	27.1%	64.1%	8.9%	24.9%	61.6%	13.4%

Table 3-120 shows the percentage of marginal units that had markups, calculated using adjusted cost-based offers, below, above and equal to zero for coal, gas and oil fuel types and wind resources. In the first nine months of 2026, using unadjusted cost-based offers for coal units, 55.0 percent of marginal coal units had negative markups. In the first nine months of 2026, using adjusted cost-based offers for coal units, 42.4 percent of marginal coal units had negative markups. The share of marginal coal units with negative markups at the dispatch point on their offer curve increased from 47.9 percent in the first nine months of 2025 to 55.0 percent in the first nine months of 2026 when using unadjusted cost-based offers.

225 See PJM. "Manual 15: Cost Development Guidelines," Rev. 48 (July 15, 2026).

226 Other fuel types were excluded based on data confidentiality rules.

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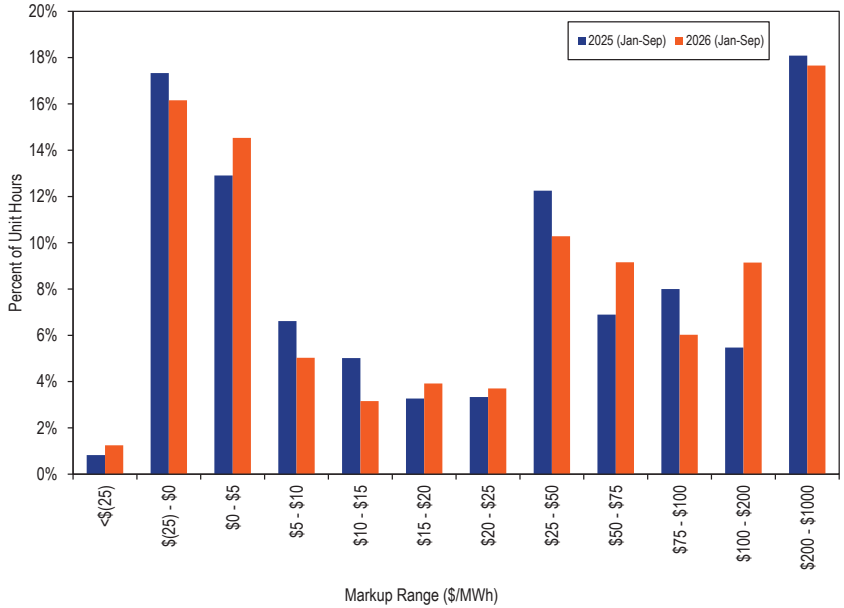
In the first nine months of 2026, using adjusted cost-based offers for coal units, 42.4 percent of marginal coal units had negative markups.

Table 3-120 Percent of marginal units with markup below, above and equal to zero (By fuel type with adjusted offers): January through September, 2025 and 2026

	2025 (Jan - Sep)			2026 (Jan - Sep)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	33.8%	8.8%	57.4%	42.4%	14.3%	43.3%
Gas	33.2%	11.1%	55.7%	34.1%	14.8%	51.1%
Oil	15.5%	79.6%	4.9%	13.7%	83.3%	3.0%
Wind	27.1%	64.1%	8.9%	24.9%	61.6%	13.4%

Figure 3-77 shows the frequency distribution of hourly markups for all gas units offered in the first nine months of 2025 and 2026 using unadjusted cost-based offers. The highest markup within the economic operating range of the unit's offer curve was used in the frequency distributions.[227] Of the gas units offered in the PJM market in the first nine months of 2026, 17.4 percent of gas unit hours had a maximum markup that was negative and 26.8 percent of gas fired unit hours had a maximum markup above $100 per MWh. The share of offered gas units with maximum markup that was negative and the share of marginal gas units with negative markups at the dispatch point decreased in the first nine months of 2026 compared to the first nine months of 2025.

Figure 3-77 Frequency distribution of highest markup of gas units offered using unadjusted cost offers: January through September, 2025 and 2026



227 The categories in the frequency distribution were chosen so as to maintain data confidentiality.

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Figure 3-78 shows the frequency distribution of hourly markups for all coal units offered in the first nine months of 2025 and the first nine months of 2026 using unadjusted cost-based offers. Of the coal units offered in the PJM market in the first nine months of 2026, 37.4 percent of coal unit hours had a maximum markup that was negative or equal to zero, increasing from 36.3 percent in the first nine months of 2025. The share of offered coal units with maximum markup that was negative and the share of marginal coal units with negative markups at the dispatch point increased in the first nine months of 2026 compared to the first nine months of 2025.

Figure 3-78 Frequency distribution of highest markup of coal units offered using unadjusted cost offers: January through September, 2025 and 2026

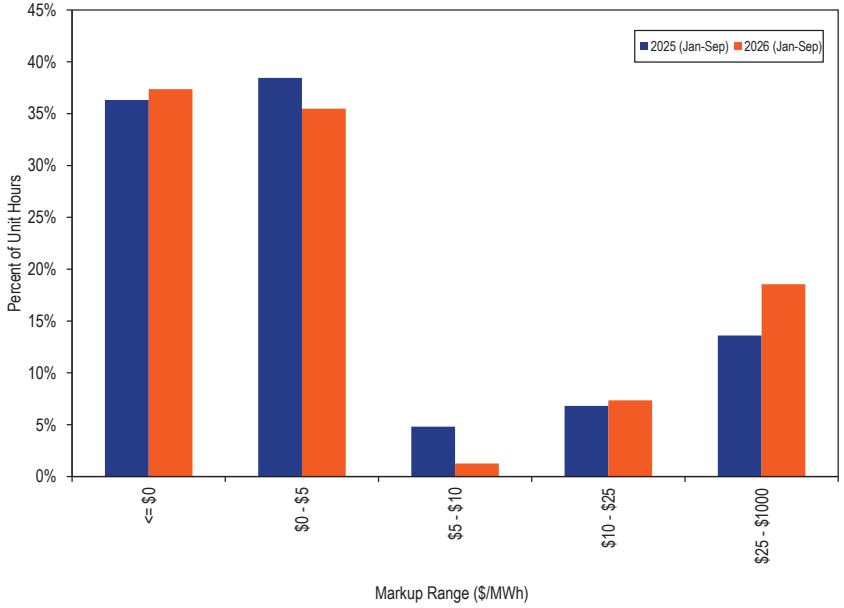
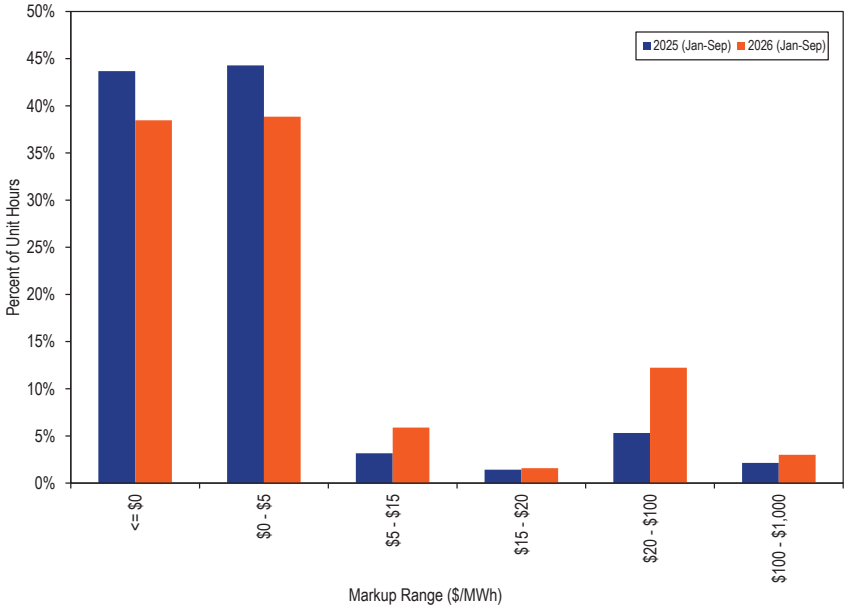


Figure 3-79 shows the frequency distribution of hourly markups for all offered oil units in the first nine months of 2025 and the first nine months of 2026 using unadjusted cost-based offers. Of the oil units offered in the PJM market in the first nine months of 2026, 38.5 percent of oil unit hours had a maximum markup that was negative or equal to zero and 3.0 percent of oil fired unit hours had a maximum markup above $100 per MWh.

Figure 3-79 Frequency distribution of highest markup of oil units offered using unadjusted cost offers: January through September, 2025 and 2026



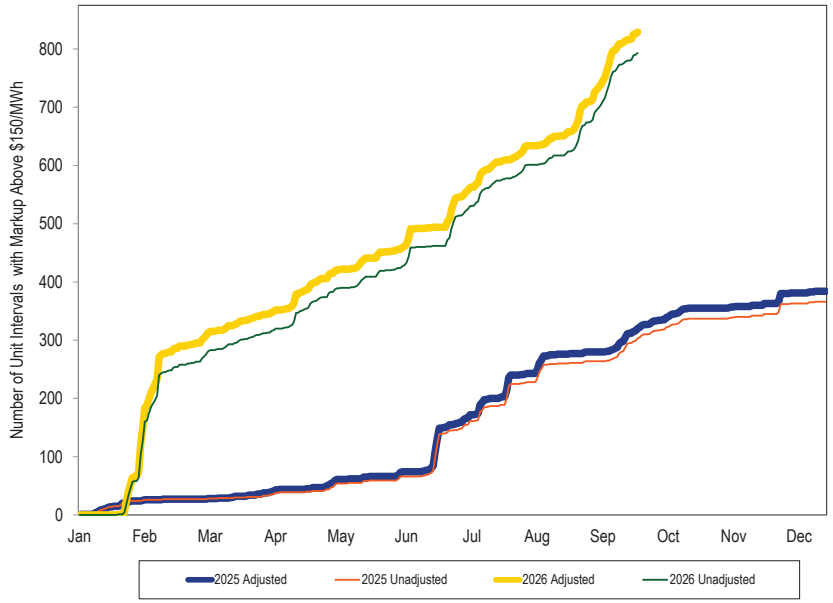
The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion of costs in cost-based offers that are not short run marginal costs.

The markup behavior shown in the markup frequency distributions also shows that a substantial number of units were offered with high markups, consistent with the exercise of market power.

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Figure 3-80 shows the number of marginal unit intervals in the first nine months of 2026 and the first nine months of 2025 with markup above $150 per MWh.

Figure 3-80 Cumulative number of marginal unit intervals with markups above $150 per MWh: January 2025 through September 2026



Day-Ahead Markup Index

Table 3-121 shows the average markup index of marginal generating units in the day-ahead energy market, by offer price category using unadjusted cost-based offers.[228]

In the first nine months of 2026, the average dollar markup of units with offer prices less than $10 was positive ($14.04 per MWh) when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $10 and $15 was positive ($1.80 per MWh) when using unadjusted cost-based offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, revealing a short run marginal cost that is less than the maximum allowable cost-based offer under the PJM Market Rules.

Some marginal units did have substantial markups. Among the units that were marginal in the first nine months of 2026, 3.0 percent had offer prices above $150 per MWh when using unadjusted cost-based offers. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the first nine months of 2026 was more than $900 per MWh.

Table 3-121 Average day-ahead marginal unit markup index (By offer price category, unadjusted): January through September, 2026

	2026 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency
< $10	7.79	$14.04	13.3%
$10 to $15	0.21	$1.80	8.0%
$15 to $20	0.09	$0.25	15.0%
$20 to $25	0.01	($1.34)	12.2%
$25 to $50	0.04	$0.70	38.7%
$50 to $75	0.21	$11.61	6.2%
$75 to $100	0.17	$15.04	2.2%
$100 to $125	0.25	$27.23	0.9%
$125 to $150	0.23	$29.93	0.5%
>= $150	0.14	$39.13	3.0%
All Offers	0.54	$4.79	100.0%

228 The MMU identified an error in the marginal resource identification algorithm within the day ahead clearing optimization in April 2024. The calculation of generator sensitivity factors and markup index require accurate identification of marginal resources. The error was fixed by the PJM software vendor in March 2025. The MMU was unable to calculate markup index for 2024 and the first quarter of 2025 due to the inaccurate identification of marginal resources.

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Table 3-122 shows the average markup index of marginal generating units in the day-ahead energy market, by offer price category using adjusted cost-based offers.

Table 3-122 Average day-ahead marginal unit markup index (By offer price category, adjusted): January through September, 2026

	2026 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency
< $10	7.82	$14.15	13.3%
$10 to $15	0.28	$2.85	8.0%
$15 to $20	0.15	$1.69	15.0%
$20 to $25	0.08	$0.57	12.2%
$25 to $50	0.11	$3.22	38.7%
$50 to $75	0.26	$14.88	6.2%
$75 to $100	0.23	$20.32	2.2%
$100 to $125	0.30	$33.36	0.9%
$125 to $150	0.26	$35.09	0.5%
>= $150	0.20	$57.67	3.0%
All Offers	0.60	$7.27	100.0%

No Load and Start Cost Markup

Generator energy offers in PJM are comprised of three parts, an incremental energy offer curve, no load cost and start cost. In cost-based offers, all three parts are capped at the level allowed by Schedule 2 of the Operating Agreement, the Cost Development Guidelines (Manual 15) and fuel cost policies approved by PJM. In price-based offers, the incremental energy offer curve is capped at $1,000 per MWh (unless the verified cost-based offer exceeds $1,000 per MWh, but cannot exceed $2,000 per MWh). Generators are allowed to choose whether to use price-based or cost-based no load cost and start costs twice a year. If price-based is selected, the no load and start costs do not have a cap, but the offers cannot be changed for six months (April through September and October through March). If cost-based is selected, the cap is the same as the cap of the no load and start costs in the cost-based offers, and the offers can be updated daily or hourly based on changes in costs. Table 3-123 shows the caps on the three parts of cost-based and price-based offers.

Table 3-123 Cost-based and price-based offer caps

Offer Type	No Load and Start Cost Option	Incremental Offer Curve Cap	No Load Cost Cap	Start Cost Cap
Cost-Based	Cost-Based	Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies		
Price-Based	Cost-Based	$1,000/MWh or based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies if verified cost-based offer exceeds $1,000/MWh but no more than $2,000/MWh.	Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies	Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies
	Price-Based		No cap but can only be changed twice a year.	No cap but can only be changed twice a year.

Table 3-124 shows the number of units that chose the cost-based option and the price-based option. In the first nine months of 2026, 95 percent of all generators that submitted no load or start costs chose to have cost-based no load and start costs in their price-based offers, 5.0 percentage points higher than in the first nine months of 2025.

Table 3-124 Number of units selecting cost-based and price-based no load and start costs: January through September, 2025 and 2026

No Load and Start Cost Option	2025 (Jan -Sep)		2026 (Jan -Sep)	
	Number of units	Percent	Number of units	Percent
Cost-Based	468	90%	486	95%
Price-Based	50	10%	27	5%
Total	518	100%	513	100%

Generators can have positive or negative markups in their no load and start costs under the price-based option. Generators cannot have positive markups in no load and start costs when they select the cost-based option. Table 3-125 shows the average markup in the no load and start costs in the first nine months of 2025 and 2026. Generators that selected the cost-based start and no load option offered on average with a negative markup on the no load cost and a negative markup on the start costs, meaning that the price-based offers were lower than the cost-based offers. In the first nine months of 2026, generators that selected the price-based start and no load option offered on

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average with a negative markup on the no load cost and with very large positive markups on the start costs.

Table 3-125 No load and start cost markup: January through September, 2025 and 2026

Period	No Load and Start Cost Option	No Load Cost	Cold Start Cost	Intermediate Start Cost	Hot Start Cost
2025 (Jan -Sep)	Cost-Based	(12%)	(5%)	(6%)	(6%)
	Price-Based	(28%)	85%	73%	73%
2026 (Jan -Sep)	Cost-Based	(12%)	(5%)	(6%)	(6%)
	Price-Based	(41%)	113%	94%	96%

Energy Market Cost-Based Offers

The application of market power mitigation rules in the day-ahead energy market and the real-time energy market helps ensure competitive market outcomes even in the presence of structural market power.

Cost-based offers in PJM affect all aspects of the PJM energy market. Cost-based offers affect prices when units are committed and dispatched on their cost-based offers. In the first nine months of 2026, 14.0 percent of the marginal units set market prices based on cost-based offers, 4.2 percentage points higher than in the first nine months of 2025.

The efficacy of market power mitigation rules depends on the definition of a competitive offer. A competitive offer is equal to short run marginal costs. The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer in the PJM market rules is not correct. Some unit owners include costs that are not short run marginal costs in offers, including maintenance costs. The market rules allow these overstated cost-based offers. This issue can be resolved by simple changes to the PJM market rules to incorporate a clear and accurate definition of short run marginal costs.

The efficacy of market power mitigation rules also depends on the accuracy of cost-based offers. Some unit owners use fuel cost policies that are not algorithmic, verifiable, and systematic. These inadequate fuel cost policies permit overstated fuel costs in cost-based offers.

When market power mitigation is not effective due to inaccurate cost-based offers that exceed short run marginal costs, market power causes increases in market prices above the competitive level.

Short Run Marginal Costs

Short run marginal costs are the only costs relevant to competitive offers in the energy market. Specifically, the competitive energy offer level is the short run marginal cost of production. The current PJM market rules distinguish costs includable in cost-based energy offers from costs includable in cost-based capacity market offers based on whether costs are "directly related to energy production." The rules do not provide a clear standard. Energy production is the sole purpose of a power plant. Therefore, all costs, including the sunk costs, are directly related to energy production. This current ambiguous criterion is incorrect and allows for multiple interpretations, which could lead to tariff violations. The incorrect rules lead to higher energy market prices and higher uplift.

There are three types of costs identified in PJM rules as of April 15, 2019: variable costs, avoidable costs, and fixed costs. The criterion for whether a generator may include a cost in an energy market cost-based offer, a variable cost, is that the cost is "directly related to electric production."[229]

Variable costs, as defined in the PJM rules, are comprised of short run marginal costs and avoidable costs that are directly related to electric production. Short run marginal costs are the cost of inputs consumed or converted to produce energy, and the costs associated with byproducts that result from consuming or converting materials to produce energy, net of any revenues from the sale of those byproducts. The categories of short run marginal costs are fuel costs,

229 See 167 FERC ¶ 61,030 (2019).

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emission allowance costs, operating costs, and energy market opportunity costs.[230]

Avoidable costs are annual costs that would be avoided if energy were not produced over an annual period. The PJM rules divide avoidable costs into those that are directly related to electric production and those not directly related to electric production. The distinction is ambiguous at best. PJM includes overhaul and maintenance costs, replacement of obsolete equipment, and overtime staffing costs in costs related to electric production. PJM includes taxes, preventative maintenance to auxiliary equipment, improvement of working equipment, maintenance expenses triggered by a time milestone (e.g. annual, weekly) and pipeline reservation charges in costs not related to electric production.

Fixed costs are costs associated with an investment in a facility including the return on and of capital.

The MMU recommends that PJM require that the level of costs includable in cost-based offers in the energy market not exceed the unit's short run marginal cost.

Fuel Cost Policies

Fuel cost policies (FCP) document the process by which market sellers calculate the fuel cost component of their cost-based offers. Short run marginal fuel costs include commodity costs, transportation costs, fees, and taxes for the purchase of fuel.

Fuel Cost Policy Review

Table 3-126 shows the status of all fuel cost policies (FCP). As of September 30, 2026, 730 units (91 percent) had an FCP passed by the MMU and 69 units (nine percent) had an FCP failed by the MMU. The units with fuel cost policies failed by the MMU represented 14,716 MW. All units' FCPs were approved by PJM. As of September 30, 2026, 631 units did not have FCPs. Units without FCPs cannot submit nonzero cost-based offers, unless they use the temporary cost method.[231]

Table 3-126 FCP Status for PJM generating units: September 30, 2026

	MMU Status				Units without
PJM Status	Pass	Submitted	Fail	Total	FCPs
Approved	730	0	69	799	
Rejected	0	0	0	0	
Under Review	0	0	0	0	
Customer Input Required	0	0	0	0	
Submitted	0	0	0	0	
Total	730	0	69	799	631

The MMU performed a detailed review of every FCP. PJM approved the FCPs that the MMU passed. PJM approved every FCP failed by the MMU.

The standards for the MMU's market power evaluation are that FCPs be algorithmic, verifiable and systematic, accurately reflecting the short run marginal cost of producing energy. In its filings with FERC, PJM agreed with the MMU that FCPs should be verifiable and systematic.[232] Verifiable means that the FCP requires a market seller to provide a fuel price that can be calculated by the MMU after the fact with the same data available to the market seller at the time the decision was made, and documentation for that data from a public or a private source. Systematic means that the FCP must document a clearly defined quantitative method or methods for calculating fuel costs, including objective triggers for each method.[233] PJM and FERC did not agree that fuel cost policies should be algorithmic, although PJM's standard effectively requires algorithmic fuel cost policies by describing the requirements.[234] Algorithmic means that the FCP must use a set of defined, logical steps, analogous to a recipe, to calculate the fuel costs. These steps may be as simple as a single number from a contract, a simple average of broker quotes, a simple average of bilateral offers, or the weighted average index price posted on the Intercontinental Exchange trading platform ('ICE').[235]

230 See OA Schedule 2 § 1.1(a).

231 See OA Schedule 2 § 2.1.

232 Answer of PJM Interconnection, L.L.C. to Protests and Comments, Docket No. ER16-372-002 (October 7, 2016) at P 11 ("October 7th Filing").

233 Protest of the Independent Market Monitor for PJM, Docket No. ER16-372-002 (September 16, 2016) at P 8 ("September 16th Filing").

234 October 7th Filing at P12; 158 FERC ¶ 61,133 at P 57 (2017).

235 September 16th Filing at P 8.

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FCPs are not verifiable and systematic if they are not algorithmic. The natural gas FCPs failed by the MMU and approved by PJM are not verifiable and systematic.

Not all FCPs approved by PJM met the standard of the PJM tariff. The tariff standards that some fuel cost policies did not meet are: accuracy (reflect applicable costs accurately); and fuel contracts (reflect the market seller's applicable commodity and/or transportation contracts where it holds such contracts). [236]

The MMU failed FCPs not related to natural gas submitted by some market sellers because they do not accurately describe the short run marginal cost of fuel. Some policies include contractual terms (in dollars per MWh or in dollars per MMBtu) that do not reflect the actual cost of fuel. The MMU determined that the terms used in these policies do not reflect the cost of fuel based on the information provided by the market sellers and information gathered by the MMU for similar units.

The MMU failed the remaining FCPs because they do not accurately reflect the cost of natural gas. The main issues identified by the MMU in the natural gas policies were the use of available market information that results in inaccurate and overstated expected costs. Overstated costs permit the exercise of market power.

Some of the failed fuel cost policies include the use of available market information that results in inaccurate expected costs because the information does not represent a cleared market price. Some market sellers include the use of offers to sell natural gas on ICE as the sole basis for the cost of natural gas. An offer to sell is not a market clearing price and is not an accurate indication of the expected fuel cost. The price of uncleared offers on the exchange generally exceeds the price of cleared transactions, often by a wide margin. Use of sell offers alone is equivalent to using the supply curve alone to determine the market price of a good without considering the demand curve. It is clearly incorrect.

The FCPs that failed the MMU's evaluation also fail to meet the standards defined in the PJM tariff. PJM should not have approved noncompliant fuel cost policies. The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic.

Units are required to have an approved fuel cost policy before they can submit nonzero cost-based offers or request from PJM the use of a temporary cost method. The temporary cost offer method allows units to submit nonzero cost-based offers without an approved fuel cost policy if they follow the temporary cost offer method. The use of the method results in cost-based offers that do not follow the fuel cost policy rules. The approach significantly weakens market power mitigation by allowing market sellers to make offers without an approved fuel cost policy, allowing the use of an inaccurate and unsupported fuel cost calculation in place of an accurate fuel cost policy.

The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved fuel cost policy.

Cost-Based Offer Penalties

Market sellers are assessed penalties when they submit cost-based offers that do not comply with Schedule 2 of the PJM Operating Agreement and PJM Manual 15.[237] Penalties are assessed when both PJM and the MMU are in agreement.

In the first nine months of 2026, 58 penalty cases were identified, 53 have been assessed cost-based offer penalties and five remain pending. These cases were for 46 units owned by 11 different companies. Table 3-127 shows the penalties by the year in which participants were notified.

236 See PJM Operating Agreement Schedule 2 § 2.3 (a).

237 See OA Schedule 2 § 6.

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Table 3-127 Cost-based offer penalty cases by year notified: May 2017 through September 2026

Year notified	Cases	Assessed penalties	Self Identified	MMU and PJM Disagreement	Pending cases	Number of units impacted	Number of companies impacted
2017	57	56	0	1	0	55	16
2018	187	161	0	26	0	138	35
2019	57	57	0	0	0	57	19
2020	142	137	24	5	0	124	25
2021	129	124	42	5	0	124	21
2022	116	116	51	0	0	110	20
2023	65	65	13	0	0	61	18
2024	77	77	39	0	0	67	21
2025	41	41	13	0	0	41	19
2026	58	53	20	0	5	46	11
Total	929	887	202	37	5	530	89

Table 3-128 Cost-based offer penalties by year: May 2017 through September 2026

Year	Number of units	Number of companies	Penalties	Average Available Capacity Charged (MW)	Average Penalty ($/MW)
2017	92	21	$556,826	16,930	$1.56
2018	127	34	$1,242,102	25,743	$2.28
2019	73	23	$378,245	15,073	$1.14
2020	140	28	$407,283	21,908	$0.85
2021	125	27	$753,463	24,808	$1.31
2022	123	21	$1,613,621	24,385	$2.76
2023	61	15	$333,948	10,383	$1.33
2024	79	21	$549,736	21,900	$1.05
2025	41	19	$216,648	7,854	$1.18
2026	45	10	$1,709,024	12,663	$5.72
Total	906	78	$7,760,896	181,646	$1.88

Since 2017 through September 2026, of the 929 penalty cases, 887 resulted in assessed cost-based offer penalties, 37 resulted in disagreement between the MMU and PJM and five remain pending. A total of 202 were self identified by market sellers. The 887 cases were from 530 units owned by 89 different companies. The total penalties were $7.8 million, charged to units that totaled 181,646 available MW. The average penalty was $1.88 per available MW. This means that a 100 MW unit would have paid a penalty of $4,512.[238] There is no link between the increased costs to the market that result from a penalized fuel cost policy and the amount of the penalty. The increased costs to the market can exceed the penalty payment and the reverse can also be true. Table 3-128 shows the total cost-based offer penalties since 2017 by year. The increase in the average penalty in the first nine months of 2026 was the result of violations that occurred during Winter Storm Fern, a period with high LMPs. Cost-based offer penalties are a function of real-time LMPs.

The incorrect cost-based offers resulted from incorrect application of fuel cost policies, lack of approved fuel cost policies, fuel cost policy violations, miscalculation of no load costs, inclusion of prohibited maintenance costs, use of incorrect incremental heat rates, use of incorrect start cost, and use of incorrect emission costs.

Penalties do not apply when PJM determines that an unforeseen event hindered the market seller's ability to submit a compliant cost-based offer. This allows market sellers to not follow their fuel cost policy, submit cost-based offers that are not verifiable or systematic and not face any penalties for doing so. This practice is inappropriate and should stop.

The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to follow their approved fuel cost policy.

238 Cost-based offer penalties are assessed by hour. Therefore, a $1 per available MW penalty results in a total of $24 for a 1 MW unit if the violation is for the entire day.

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Cost Development Guidelines

The Cost Development Guidelines contained in PJM Manual 15 do not clearly or accurately describe the short run marginal cost of generation. The MMU recommends that PJM Manual 15 be replaced or updated with a straightforward description of the components of cost-based offers based on short run marginal costs and the correct calculation of cost-based offers for thermal resources. In 2022, PJM made updates recommended by the MMU to Manual 15 to add straightforward descriptions for some of the most essential cost offer calculations.[239]

Variable Operating and Maintenance Costs

PJM Manual 15 and the PJM Operating Agreement Schedule 2 include rules related to VOM costs. On October 29, 2018, PJM filed tariff revisions changing the rules related to VOM costs.[240] The changes proposed by PJM attempted but failed to clarify the rules. The proposed rules defined all costs directly related to electricity production as includable in cost-based offers. This also included the long term maintenance costs of combined cycles and combustion turbines, which had been explicitly excluded in PJM Manual 15.

On April 15, 2019, FERC accepted PJM's filing, subject to revisions requested by FERC.[241] On October 28, 2019, FERC issued a final order accepting PJM's compliance filing.[242] Regardless of the changes, the rules remain unclear and are now inconsistent with economic theory and effective market power mitigation and competitive market results.

Maintenance costs are not short run marginal costs. Generators perform maintenance during outages. Generators do not perform maintenance in the short run, while operating the generating unit. Generators do not perform maintenance in real time to increase the output of a unit. Some maintenance costs are correlated with the historic operation of a generator. Correlation between operating hours or starts and maintenance expenditures over a long run, multiyear time frame does not indicate the necessity of any specific maintenance expenditure to produce power in the short run.

A generating unit does not consume a defined amount of maintenance parts and labor in order to start. A generating unit does not consume a defined amount of maintenance parts and labor in order to produce an additional MWh. Maintenance events do not occur in the short run. The company cannot optimize its maintenance costs in the short run.

PJM allows for the calculation of VOM costs in dollars per MWh, dollars per MMBtu, dollars per run hour, dollars per equivalent operating hour (EOH) and dollars per start. The MMU converted all VOM costs into dollars per MWh using the units' heat rates, the average economic maximum and average minimum run time of the units in 2024.

Table 3-129 shows the average VOM by unit type. The VOM equals the sum of variable operating cost, major maintenance adder and minor maintenance adder as submitted by market participants.[243]

Table 3-129 Effective VOM costs in dollars per MWh: 2025

Unit Type	VOM ($/MWh)
Combined Cycles	$3.18
Combustion Turbines and RICE	$21.98
Gas/Oil Steam Turbines	$11.51
Coal	$6.67

The level of costs accepted by PJM for inclusion in VOM depends on PJM's interpretation of the maintenance activities or expenses directly related to electricity production and the level of detailed support provided by market sellers to PJM.

PJM's VOM review is not adequate to determine whether all costs included in VOM are compliant. PJM's VOM review focuses only on the expenses submitted for the last year of up to 20 years of data. For example, a market seller can provide data from ten years ago without any supporting documentation as

239 See PJM Manual 15: Cost Development Guidelines, Revision 48 (July 15, 2026).
240 See PJM Interconnection Maintenance Adder Revisions to the Amended and Restated Operating Agreement, L.L.C., Docket No. EL19-8-000.
241 167 FERC ¶ 61,030 (2019).
242 168 FERC ¶ 61,134 (2019).
243 PJM reviews and approved VOM adders yearly. The effective VOM costs in dollars per MWh reflect the latest approved VOM adders. The values are updated once PJM finishes its annual VOM review process.

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long as the data from the current year has documentation. PJM's review is dependent on the level of detail provided by the market seller. As a result of questions raised by the MMU, PJM now requires more details from market sellers, which has led to the appropriate exclusion of expenses that were previously included.[244]

The flaws in PJM's review process for VOM are compounded by the ambiguity in the criteria used to determine if costs are includable. PJM's definition of allowable costs for cost-based offers, "costs resulting from electric production," is so broad as to be meaningless. Most costs incurred at a generating station result from electric production in one way or another. The generator itself would not exist but for the need for electric production. PJM's broad definition cannot identify which costs associated with electric production are includable in cost-based offers. The definition is not verifiable or systematic and permits wide discretion by PJM and generators.

On February 17, 2023, PJM filed tariff revisions changing the rules related to VOM costs. The changes included separating maintenance expenses into major and minor maintenance, allowing the use of default adders for minor maintenance and operating costs and eliminating the annual review requirement for units that choose to use default adders. The proposal, that included the tariff changes, also included Manual 15 changes that introduced additional documentation requirements. Regarding maintenance expenses, market participants will be required to provide all supporting documentation for all expenses submitted, regardless of year. Regarding operating expenses, market participants will be required to provide the amount of consumables used during operation and the cost per unit of each consumable.[245] On April 18, 2023, FERC accepted PJM's filing. Table 3-130 shows the default adders for operating cost and minor maintenance.

Table 3-130 Default operating cost and minor maintenance adder: 2025

Unit Type	Operating Cost ($/MWh)	Minor Maintenance Cost ($/MWh)
Combined Cycle	0.49	1.21
Combustion Turbine	0.92	4.43
Reciprocating Engine	2.00	4.97
Steam Turbine	3.54	2.11

The MMU recommended that market participants be required to document the amount and cost of consumables used when operating in order to verify that the total operating cost is consistent with the total quantity used and the unit characteristics. The revisions to Manual 15 based on the February 17, 2023, filing included this requirement.

The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced. The revisions to Manual 15 based on the February 17, 2023, filing partially included this requirement. Even though Manual 15 requires maintenance expenses to be the result of operating hours, starts or a combination of the two, the expenses are not tied to a maintenance cycle. Therefore, it is not possible to distinguish between maintenance that resulted from operating the resource versus maintenance from normal wear and tear.

The MMU understands that companies have different document retention policies but in order to be allowed to include maintenance costs, such costs must be verified, and they cannot be verified without documentation. Supporting documentation includes internal financial records, maintenance project documents, invoices, and contracts. Market participants should be required to provide the operational data (e.g. run hours, MWh, MMBtu) that supports the maintenance cycle of the equipment being serviced/replaced. For example, if equipment is serviced every 5,000 run hours, the market

244 See PJM "Maintenance Adder & Operating Cost Submission Process," 55-57 , Tech Change Forum. (April 21, 2020) <https://pjm.com/-/media/committees-groups/forums/tech-change/2020/20200421-special/20200421-item-01-maintenance-adder-and-operating-cost-submission-process.ashx>.

245 See PJM "Maintenance Adder & Operating Cost Submission Process," 55-57. Tech Change Forum. (April 21, 2020) <https://pjm.com/-/media/committees-groups/forums/tech-change/2020/20200421-special/20200421-item-01-maintenance-adder-and-operating-cost-submission-process.ashx>.

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participant must include at least 5,000 run hours of historical operation in its maintenance cost history.

FERC System of Accounts

PJM Manual 15 relies on the FERC System of Accounts, which predates markets and does not define costs consistent with market economics. Market sellers should not rely solely on the FERC System of Accounts for the calculation of their variable operating and maintenance costs. The FERC System of Accounts does not differentiate between short run marginal costs and avoidable costs. The FERC System of Accounts does not differentiate between costs directly related to energy production and costs not directly related to energy production. Reliance on the FERC System of Accounts for the calculation of variable operating and maintenance costs is likely to lead to incorrect, overstated costs.

The MMU recommends removal of all references to and reliance on the FERC System of Accounts in PJM Manual 15.

Cyclic Starting and Peaking Factors

The use of cyclic starting and peaking factors for calculating VOM costs for combined cycles and combustion turbines is designed to allocate a greater proportion of long term maintenance costs to starts and the tail block of the incremental offer curve. The use of such factors is not appropriate given that long term maintenance costs are not short run marginal costs and should not be included in cost offers. PJM Manual 15 allows for a peaking cyclic factor of three, which means that a unit with a $300 per hour (EOH) VOM cost can add $180 per MWh to a 5 MW peak segment.[246]

The MMU recommends the removal of all cyclic starting and peaking factors from PJM Manual 15.

Labor Costs

PJM Manual 15 allows for the inclusion of plant staffing costs in energy market cost offers. This is inappropriate given that labor costs are not short run marginal costs.

The MMU recommends the removal of all labor costs from the PJM Manual 15. On December 2, 2022, PJM filed tariff changes removing labor costs from cost-based offers. The changes were approved by the Commission on January 10, 2023 and became effective on June 1, 2023.[247]

Combined Cycle Start Heat Input Definition

PJM Manual 15 defines the start heat input of combined cycles as the amount of fuel used from the firing of the first combustion turbine to the close of the steam turbine breaker plus any fuel used by other combustion turbines in the combined cycle from firing to the point at which the HRSG steam pressure matches the steam turbine steam pressure. This definition is inappropriate given that after each combustion turbine is synchronized, some of the fuel is used to produce energy for which the unit is compensated in the energy market. To account for this, PJM Manual 15 requires reducing the station service MWh used during the start sequence by the output in MWh produced by each combustion turbine after synchronization and before the HRSG steam pressure matches the steam turbine steam pressure. The formula and the language in this definition are not appropriate and are unclear.

The MMU recommended changing the definition of the start heat input for combined cycles to include only the amount of fuel used from firing each combustion turbine in the combined cycle to the breaker close of each combustion turbine. This change will make the treatment of combined cycles consistent with steam turbines. Exceptions to this definition should be granted when the amount of fuel used from synchronization to steam turbine breaker close is greater than the no load heat plus the output during this period times the incremental heat rate.

In 2022, the MMU and PJM proposed changing the start cost definition of units with a steam process to include the costs from the beginning of the start sequence to dispatchable.[248] The new definition included what is commonly consider soak costs in the start cost. The new definition was combined with the elimination of make whole payments to units with a steam process for MW

246 The peak adder is equal to $300 times three divided by 5 MW.

247 *See* Federal Energy Regulatory Commission, Docket No. ER23-557-000 (January 10, 2023) at 1.

248 *See* Monitoring Analytics, LLC. "Start Cost Alternate Proposal," Cost Development Subcommittee. (December 2, 2021) <20211202-item-06-start-cost-alternate-proposal.ashx>.

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produced before the unit becomes dispatchable. The proposal was approved by the Commission on January 10, 2023 and became effective on June 1, 2023.[249]

Even though the MMU developed and supported the new definition, it is important to recognize that this approach should be temporary until PJM implements an approach that reflects soak time, soak costs and soak energy output. The main shortcoming of the new definition is that PJM models do not properly value the energy produced during the soak process (soak energy output). Instead, the proposal simply assumes that such MWh are valued at PJM's station service rate. The ideal solution is to model start costs and soak costs separately since there are revenues associated with the MWh produced during soaking, while during the start process there are no MWh being injected into the grid.

The MMU recommends that soak costs, soak time and the MWh produced during soaking be modeled separately. This will ensure that the time required for units to reach a dispatchable level is known and used in the unit commitment process instead of only being communicated verbally between dispatchers and generators. Separating soak costs from start costs and modeling the MWh produced during soaking allows for a better representation of the costs because it eliminates the need to simply assume the price paid for those MWh.

Nuclear Costs

The fuel costs for nuclear plants are fixed in the short run and amortized over the period between refueling outages. The short run marginal cost of fuel for nuclear plants is zero. Operations and maintenance costs for nuclear power plants consist primarily of labor and maintenance costs incurred during outages, which are also fixed in the short run.

The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the PJM Manual 15.

Pumped Hydro Costs

The calculation of pumped hydro costs for energy storage in Section 7.3 of PJM Manual 15 is inaccurate. The mathematical formulation does not take into account the purchase of power for pumping in the day-ahead market.

The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases.

Gas Pipeline Penalties

Section 2.2.2 of PJM Manual 15 states that gas pipeline penalties are not includable in cost-based offers. Penalties can be incurred by units for many reasons, for example, withdrawing gas not nominated and deviating from an imposed threshold during an operational flow order. Any unit with cost-based offers that include gas pipeline penalties will be subject to penalties per Schedule 2 of the PJM Operating Agreement.

Many Market Sellers rely on independent third party quotes to estimate or determine the gas spot price. The quotes received from these third parties should not be based on incurring gas pipeline penalties. It is recommended that Market Sellers confirm with their third parties that gas is available to them without the need to incur gas pipeline penalties. If that is not possible, the units should be unavailable until the third party can confirm that gas is available without incurring penalties.

Frequently Mitigated Units (FMU) and Associated Units (AU)

The rules for determining the qualification of a unit as an FMU or AU became effective November 1, 2014. 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 units eligible for an FMU or AU adder for the period between December 2014 and August 2019.[250] One unit qualified for an FMU adder for the months of September and October, 2019. In 2020, five units qualified for an FMU adder in at least one month. In 2021, one unit qualified for an FMU adder in January. In 2022, 2023, 2024 and 2025 no units qualified for an FMU adder. In the first nine months of 2026, no units qualified for an FMU adder

249 *See* Federal Energy Regulatory Commission, Docket No. ER23-557-000 (January 10, 2023) at 1.

250 For a definition of FMUs and AUs, and for historical FMU/AU results, see the *2018 Annual State of the Market Report for PJM*, Volume 2, Section 3, Energy Market, at Frequently Mitigated Units (FMU) and Associated Units (AU).

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Table 3-131 shows, by month, the number of FMUs and AUs from January 2021 through September 2026. For example, in January 2021, there were zero units that qualified as an FMU or AU in Tier 1, one unit qualified as an FMU or AU in Tier 2, and zero units qualified as an FMU or AU in Tier 3.

Table 3-131 Number of frequently mitigated units and associated units (By month): January 2021 through September 2026

	2021				2022				2023				2024				2025				2026			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
February	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
March	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
April	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
June	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
July	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
August	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
September	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
October	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
November	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
December	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				

The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.

Market Performance

Ownership of Marginal Resources

Table 3-132 shows the contribution to real-time, load-weighted LMP by individual marginal resource owners.[251] The contribution of each marginal resource to price at each load bus is calculated for each five minute interval of first nine months of 2026, and summed by the parent company that offers the marginal resource into the real-time energy market. In the first nine months of 2026, the offers of one company resulted in 8.3 percent of the real-time load-weighted PJM system LMP and the offers of the top four companies resulted in 30.3 percent of the real-time load-weighted average PJM system LMP. In the first nine months of 2026, the offers of one company resulted in 9.1 percent of the peak hour real-time load-weighted PJM system LMP.

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

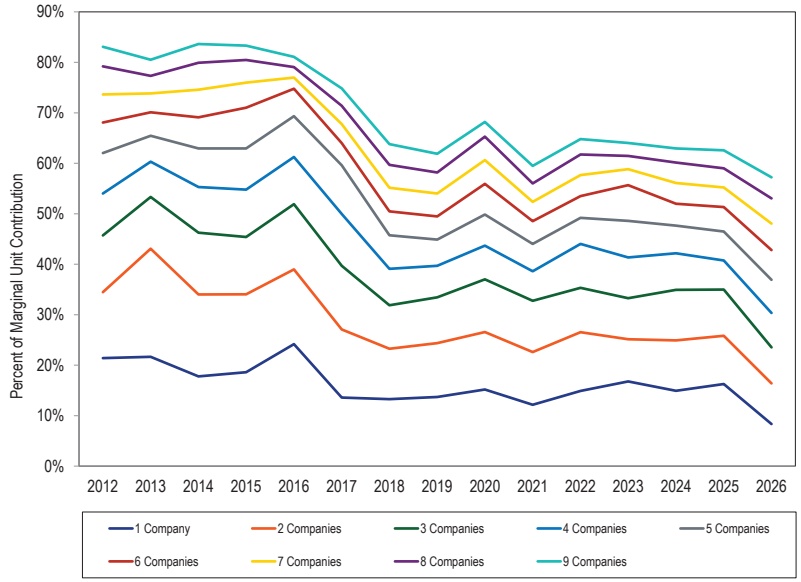
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Table 3-132 Marginal unit contribution to real-time load-weighted LMP (By parent company): January through September, 2025 and 2026

2025 (Jan - Sep)						2026 (Jan - Sep)					
All Hours			Peak Hours			All Hours			Peak Hours		
Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent
1	16.3%	16.3%	1	15.0%	15.0%	1	8.3%	8.3%	1	9.1%	9.1%
2	9.6%	25.8%	2	10.1%	25.1%	2	8.0%	16.4%	2	8.1%	17.2%
3	9.2%	35.0%	3	7.3%	32.5%	3	7.1%	23.5%	3	7.2%	24.4%
4	5.8%	40.7%	4	5.2%	37.6%	4	6.8%	30.3%	4	6.5%	30.9%
5	5.7%	46.5%	5	5.1%	42.8%	5	6.6%	36.9%	5	5.2%	36.2%
6	4.8%	51.3%	6	4.9%	47.7%	6	5.9%	42.8%	6	5.1%	41.2%
7	3.9%	55.2%	7	4.8%	52.5%	7	5.2%	48.0%	7	4.9%	46.1%
8	3.8%	59.0%	8	4.6%	57.1%	8	5.0%	53.0%	8	4.4%	50.5%
9	3.6%	62.6%	9	4.3%	61.4%	9	4.2%	57.2%	9	3.8%	54.3%
Other (104 companies)	37.4%	100.0%	Other (100 companies)	38.6%	100.0%	Other (99 companies)	42.8%	100.0%	Other (99 companies)	45.7%	100.0%

Figure 3-81 shows the marginal unit contribution to the real-time load-weighted PJM system LMP summed by parent companies for the first nine months of every year since 2012.

Figure 3-81 Marginal unit contribution to real-time load-weighted LMP (By parent company): January through September, 2012 through 2026



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Markup

The markup index is a measure of the competitiveness of participant behavior for individual units. The markup in dollars is a measure of the impact of participant behavior on the generator bus market price when a unit is marginal. 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 index 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 have different impacts on total system price. Markup can also affect prices when units with markups are not marginal by altering the economic dispatch order of supply.

The MMU calculates an explicit measure of the impact of marginal unit incremental energy offer markups on LMP using the mathematical relationships among LMPs in the market solution.[252] The markup impact calculation sums, over all marginal units, the product of the dollar markup of the unit and the marginal impact of the unit's offer on the system load-weighted LMP. The markup impact includes the impact of the identified markup behavior of all marginal units. Positive and negative markup impacts may offset one another. The markup analysis is a direct measure of market performance. It does not take into account whether or not marginal units have either locational or aggregate structural market power.

The markup calculation is not based on a counterfactual 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 short run marginal cost. 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 short run marginal cost and actual dispatch. It is possible that the unit specific markup, based on a redispatch analysis, would be lower than the markup component of price if the reference point were an inframarginal unit with a lower price and a higher cost than the actual marginal unit. If the actual marginal unit has short run 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.

252 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 LMP based on a comparison between the price-based incremental energy offer and the cost-based incremental energy offer of each actual marginal unit on the system. This is the same method used to calculate the fuel cost adjusted LMP and the components of LMP. *See* Calculation and Use of Generator Sensitivity/Unit Participation Factors, 2010 State of the Market Report for PJM: Technical Reference for PJM Markets.

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.

PJM implemented fast start pricing on September 1, 2021. Under the fast start pricing rules, the LMPs are calculated in the pricing run, where the offer price of a marginal fast start unit includes amortized commitment costs. For all the fast start marginal units starting from September 1, 2021, the markup includes markup in the incremental offer, markup in the amortized start up offer and markup in the amortized no load offer.

Table 3-133 shows the impact (markup component of LMP) of the marginal unit markup behavior by fuel type and unit type on the real-time load-weighted average system LMP using unadjusted and adjusted offers. The adjusted markup component of LMP increased from $2.95 per MWh in the first nine months of 2025 to $4.34 per MWh in the first nine months of 2026. The adjusted markup contribution of coal units in the first nine months of 2026 was $1.19 per MWh, an increase of $0.54 per MWh from the first nine months of 2025. The adjusted markup component of gas fired units in the first nine months of 2026 was $3.84 per MWh, an increase of $0.92 per MWh from the first nine months of 2025. The markup component of wind units was $0.24 per MWh. If a price-based offer is negative, but less negative than a cost-based offer, the markup is positive. In the first nine months of 2026,

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among the wind units that were marginal, 74.3 percent had negative offer prices.

Table 3-133 Markup component of real-time load-weighted average LMP by primary fuel type and unit type: January through September, 2025 and 2026[253]

		2025 (Jan - Sep)		2026 (Jan - Sep)	
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	$0.23	$0.64	$0.64	$1.19
Gas	CC	$0.54	$2.00	$0.53	$2.22
Gas	CT	$0.12	$0.91	$0.62	$1.52
Gas	RICE	$0.03	$0.05	($0.03)	$0.01
Gas	Steam	($0.15)	($0.04)	($0.03)	$0.10
Municipal Waste	RICE	$0.02	$0.02	$0.01	$0.01
Oil	CC	($0.00)	$0.01	$0.00	$0.01
Oil	CT	($0.91)	($0.72)	($1.50)	($1.12)
Oil	RICE	$0.00	$0.01	($0.00)	$0.00
Oil	Steam	($0.07)	($0.04)	($0.05)	($0.02)
Other	Battery	$0.01	$0.01	$0.12	$0.12
Other	Solar	$0.00	$0.00	$0.10	$0.05
Other	Solar Battery Hybrid	$0.00	$0.00	$0.02	$0.02
Other	Steam	$0.01	$0.02	$0.01	$0.01
Wind	Wind	$0.01	$0.01	$0.24	$0.24
Total		($0.10)	$2.95	$0.65	$4.34

Markup Component of Real-Time Price

Table 3-134 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on peak and off peak prices. Table 3-135 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on peak and off peak prices. In the first nine months of 2026, when using unadjusted cost-based offers, $0.65 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost-based offers, $4.34 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In the first nine months of 2026, the peak markup component was highest in September, $6.25 per MWh using unadjusted cost-based offers and $9.64 per MWh using adjusted cost-based offers. This corresponds to 5.3 percent and 8.2 percent of the real-time peak load weighted average LMP in September.

253 The unit type RICE refers to Reciprocating Internal Combustion Engines.

Table 3-134 Monthly markup components of real-time load-weighted LMP (Unadjusted): January 2025 through September 2026

	2025			2026		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	($2.00)	($1.17)	($2.83)	($3.80)	($6.96)	($1.03)
Feb	($0.22)	($0.59)	$0.15	$5.04	$4.16	$5.88
Mar	($0.37)	($1.02)	$0.22	$1.11	$0.73	$1.50
Apr	$0.68	$0.32	$1.07	$0.78	$0.09	$1.55
May	($0.54)	($0.29)	($0.79)	$0.86	$2.26	($0.38)
Jun	$0.29	($0.08)	$0.69	($0.19)	$1.52	($2.15)
Jul	$0.55	$2.74	($1.87)	$0.35	$2.77	($2.55)
Aug	($0.91)	($0.94)	($0.87)	($1.11)	($1.85)	($0.38)
Sep	$1.52	$1.48	$1.56	$4.09	$6.25	$1.81
Oct	$1.69	$2.28	$1.04			
Nov	($1.06)	($2.04)	($0.26)			
Dec	($1.40)	($1.31)	($1.49)			
Total	($0.16)	$0.01	($0.40)	$0.65	$0.95	$0.39

Table 3-135 Monthly markup components of real-time load-weighted LMP (Adjusted): January 2025 through September 2026

	2025			2026		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$2.16	$3.38	$0.95	$3.32	($0.24)	$6.45
Feb	$3.21	$3.08	$3.35	$9.50	$8.25	$10.70
Mar	$2.40	$1.79	$2.94	$3.59	$3.41	$3.77
Apr	$3.53	$3.24	$3.85	$3.25	$2.79	$3.76
May	$1.68	$2.16	$1.20	$3.30	$4.97	$1.81
Jun	$3.34	$3.47	$3.21	$2.64	$4.74	$0.23
Jul	$4.01	$6.66	$1.08	$4.57	$7.89	$0.60
Aug	$1.72	$2.08	$1.37	$2.08	$1.86	$2.30
Sep	$3.86	$4.05	$3.66	$7.13	$9.64	$4.49
Oct	$4.56	$5.42	$3.59			
Nov	$2.13	$1.50	$2.64			
Dec	$2.23	$2.49	$1.96			
Total	$2.93	$3.39	$2.40	$4.34	$4.86	$3.85

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Hourly Markup Component of Real-Time Prices

Figure 3-82 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers in 2025 and the first nine months of 2026. Figure 3-83 shows the markup contribution to the hourly load-weighted LMP using adjusted cost-based offers in 2025 and the first nine months of 2026.

Figure 3-82 Markup contribution to real-time hourly load-weighted LMP (Unadjusted): January 2025 through September 2026

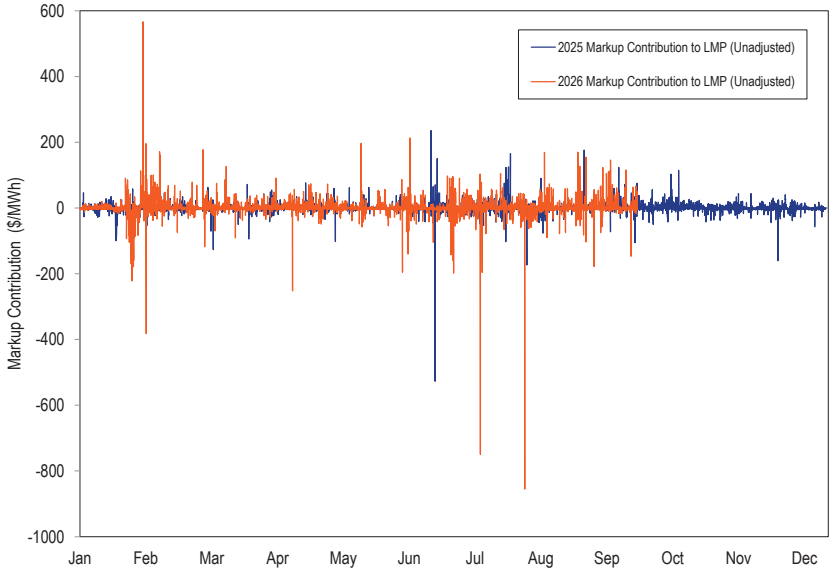
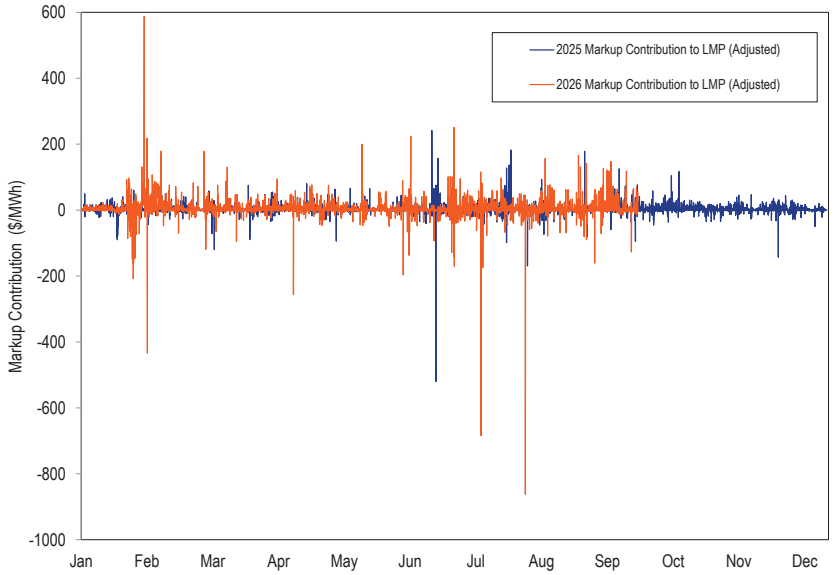


Figure 3-83 Markup contribution to real-time hourly load-weighted LMP (Adjusted): January 2025 through September 2026



Markup Component of Real-Time Zonal Prices

The unit markup component of average real-time price using unadjusted offers is shown for each zone in the first nine months of 2025 and 2026 in Table 3-136 and for adjusted offers in Table 3-137.[254] The smallest zonal all hours average markup component using unadjusted offers in the first nine months of 2026, was in the DPL Zone, -$2.88 per MWh, while the highest was in the BGE Zone, $2.61 per MWh. The smallest zonal on peak average markup component using unadjusted offers in the first nine months of 2026, was in the DPL Zone, -$4.69 per MWh, while the highest was in the BGE Zone, $3.77 per MWh.

254 A marginal unit's offer price affects LMPs in the entire PJM market. The markup component of average zonal real-time price is based on offers of units located within the zone and units located outside the transmission zone.

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Table 3-136 Real-time average zonal markup component (Unadjusted): January through September, 2025 and 2026

	2025 (Jan - Sep)			2026 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	($1.61)	($2.12)	($1.09)	($2.08)	($3.13)	($1.00)
AEP	$0.17	$0.72	($0.39)	$1.16	$1.96	$0.35
APS	$0.14	$0.54	($0.26)	$1.24	$1.96	$0.51
ATSI	$0.05	$0.56	($0.46)	$0.64	$1.14	$0.12
BGE	$0.71	$0.78	$0.64	$2.61	$3.77	$1.42
COMED	$0.22	$0.80	($0.35)	$1.04	$1.46	$0.60
DAY	$0.01	$0.46	($0.44)	$1.41	$2.27	$0.53
DOM	($0.07)	$0.09	($0.22)	$1.97	$2.24	$1.70
DPL	($2.08)	($2.88)	($1.29)	($2.88)	($4.69)	($1.04)
DUKE	($0.01)	$0.41	($0.44)	$1.37	$2.28	$0.45
DUQ	$0.00	$0.55	($0.55)	$0.61	$1.38	($0.17)
EKPC	($0.09)	$0.16	($0.34)	$1.14	$1.80	$0.46
JCPLC	($0.76)	($0.52)	($0.99)	($1.81)	($2.76)	($0.85)
MEC	($0.74)	($0.36)	($1.11)	($0.48)	$0.18	($1.16)
OVEC	$0.15	$0.76	($0.46)	$1.08	$1.67	$0.47
PE	$0.61	$1.23	($0.00)	($0.08)	$0.79	($0.96)
PECO	($1.69)	($2.25)	($1.12)	($2.63)	($4.09)	($1.15)
PEPCO	$0.40	$0.19	$0.61	$2.45	$3.19	$1.70
PPL	($1.15)	($0.78)	($1.51)	($1.23)	($0.92)	($1.54)
PSEG	($0.63)	($0.43)	($0.83)	($1.49)	($2.43)	($0.53)
REC	$0.17	$0.27	$0.07	($0.03)	($0.54)	$0.49

Table 3-137 Real-time average zonal markup component (Adjusted): January through September, 2025 and 2026

	2025 (Jan - Sep)			2026 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$1.27	$1.07	$1.48	$1.42	$0.58	$2.27
AEP	$3.28	$4.15	$2.41	$4.64	$5.65	$3.60
APS	$3.33	$4.07	$2.58	$5.10	$6.04	$4.15
ATSI	$3.15	$3.99	$2.30	$4.07	$4.87	$3.26
BGE	$4.23	$4.69	$3.77	$7.25	$8.71	$5.76
COMED	$2.98	$3.93	$2.04	$3.91	$4.61	$3.20
DAY	$3.13	$3.89	$2.36	$4.94	$6.05	$3.81
DOM	$3.41	$3.99	$2.83	$6.38	$6.80	$5.94
DPL	$0.98	$0.61	$1.34	$0.87	($0.76)	$2.52
DUKE	$3.02	$3.75	$2.29	$4.89	$6.09	$3.68
DUQ	$3.06	$3.96	$2.17	$4.00	$5.03	$2.95
EKPC	$2.98	$3.54	$2.42	$4.58	$5.46	$3.68
JCPLC	$2.14	$2.67	$1.61	$1.73	$1.04	$2.42
MEC	$2.22	$2.96	$1.47	$2.89	$3.71	$2.05
OVEC	$3.09	$4.01	$2.19	$4.46	$5.29	$3.61
PE	$3.76	$4.71	$2.82	$3.41	$4.54	$2.25
PECO	$1.12	$0.85	$1.39	$0.83	($0.40)	$2.08
PEPCO	$3.84	$4.01	$3.67	$7.03	$8.05	$5.98
PPL	$1.69	$2.39	$1.00	$2.08	$2.59	$1.56
PSEG	$2.29	$2.80	$1.79	$2.06	$1.40	$2.74
REC	$3.24	$3.64	$2.83	$3.51	$3.31	$3.73

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Markup by Real-Time Price Levels

Table 3-138 shows the markup contribution to the LMP, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system wide load-weighted average LMP was in the identified price range.

Table 3-138 Real-time markup contribution (By load-weighted LMP category, unadjusted): January through September, 2025 and 2026

	2025 (Jan - Sep)		2026 (Jan - Sep)	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $10	($3.99)	0.1%	($2.86)	0.3%
$10 to $15	($2.43)	1.1%	($1.42)	1.8%
$15 to $20	($1.82)	7.8%	($1.79)	6.9%
$20 to $25	($1.91)	12.0%	($2.59)	11.4%
$25 to $50	($1.65)	53.3%	($1.69)	47.8%
$50 to $75	$0.71	15.5%	($0.10)	13.1%
$75 to $100	$3.58	4.8%	$4.50	5.1%
$100 to $125	$10.08	2.2%	$10.04	3.3%
$125 to $150	$9.12	1.1%	$7.35	2.3%
>= $150	$11.76	2.0%	$10.42	7.8%

Table 3-139 Real-time markup contribution (By load-weighted LMP category, adjusted): January through September, 2025 and 2026

	2025 (Jan - Sep)		2026 (Jan - Sep)	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $10	($2.84)	0.1%	($1.79)	0.3%
$10 to $15	($1.13)	1.1%	($0.16)	1.8%
$15 to $20	($0.31)	7.8%	($0.26)	6.9%
$20 to $25	($0.07)	12.0%	($0.63)	11.4%
$25 to $50	$1.07	53.3%	$1.00	47.8%
$50 to $75	$4.43	15.5%	$3.71	13.1%
$75 to $100	$7.90	4.8%	$8.65	5.1%
$100 to $125	$14.63	2.2%	$14.59	3.3%
$125 to $150	$15.15	1.1%	$12.62	2.3%
>= $150	$19.23	2.0%	$20.93	7.8%

Markup by Company

Table 3-140 shows the markup contribution based on the unadjusted cost-based offers and adjusted cost-based offers to real-time load-weighted average LMP by individual marginal resource owners. The markup contribution of each marginal resource to price at each load bus is calculated for each five-minute interval, and summed by the parent company that offers the marginal resource into the real-time energy market. In the first nine months of 2026, when using unadjusted cost-based offers, the markup of one company accounted for 0.8 percent of the load-weighted average LMP, the markup of the top five companies accounted for 2.3 percent of the load-weighted average LMP, and the markup of all companies accounted for 0.9 percent of the load-weighted average LMP. The share of top five companies' markup contribution to the load-weighted average LMP and the dollar values of their markup increased in the first nine months of 2026. The markup contribution to the load-weighted average LMP and share of the markup contribution to the load-weighted average LMP increased in the first nine months of 2026. The markup contribution of a unit to the real-time load-weighted average LMP can be positive or negative.

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Table 3-140 Markup component of real-time load-weighted average LMP by Company: January through September, 2025 and 2026

	2025 (Jan - Sep)				2026 (Jan - Sep)			
	Markup Component of LMP (Unadjusted)		Markup Component of LMP (Adjusted)		Markup Component of LMP (Unadjusted)		Markup Component of LMP (Adjusted)	
	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP
Top 1 Company	$0.37	0.7%	$0.60	1.2%	$0.62	0.8%	$0.87	1.2%
Top 2 Companies	$0.62	1.2%	$1.17	2.3%	$0.97	1.3%	$1.56	2.1%
Top 3 Companies	$0.76	1.5%	$1.45	2.9%	$1.23	1.6%	$2.15	2.9%
Top 4 Companies	$0.89	1.8%	$1.71	3.4%	$1.47	2.0%	$2.48	3.3%
Top 5 Companies	$1.02	2.0%	$1.94	3.9%	$1.71	2.3%	$2.78	3.7%
All Companies	($0.16)	(0.3%)	$2.89	5.7%	$0.65	0.9%	$4.38	5.8%

Day-Ahead Markup[255]

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 3-141. INC, DEC and up to congestion transactions (UTC) have zero markups. The adjusted markup of coal, gas and oil units is calculated as the difference between the price-based offer and the cost-based offer excluding the 10 percent adder.

Table 3-141 shows the markup component of LMP for marginal generating resources. The adjusted markup component of LMP for coal fired units was $0.68 per MWh in the first nine months of 2026. The adjusted markup component of LMP for gas fired CC units was $2.53 per MWh in the first nine months of 2026.

Table 3-141 Markup component of day-ahead load-weighted average LMP by primary fuel type and technology type: January through September, 2026

		2026 (Jan - Sep)	
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	$0.14	$0.68
Gas	CC	$1.36	$2.53
Gas	CT	$0.54	$0.67
Gas	RICE	$0.02	$0.00
Gas	Steam	$0.06	$0.21
Municipal Waste	RICE	($0.00)	($0.00)
Oil	CT	($0.04)	$0.04
Oil	RICE	$0.00	$0.01
Oil	Steam	($0.14)	($0.13)
Other	Solar	$0.33	$0.33
Other	Steam	($0.00)	($0.00)
Wind		$0.69	$0.69
Total		$2.95	$5.01

255 The MMU identified an error in the marginal resource identification algorithm within the day ahead clearing optimization in April 2024. The calculation of generator sensitivity factors and markup index require accurate identification of marginal resources. The error was fixed by the PJM software vendor in March 2025. The MMU was unable to calculate markup index for 2024 and the first quarter of 2025 due to the inaccurate identification of marginal resources.

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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 3-142 shows the markup component of average prices and of average monthly on peak and off peak prices using unadjusted cost-based offers. Table 3-143 shows the markup component of average prices and of average monthly on peak and off peak prices using adjusted cost-based offers. In the first nine months of 2026, when using unadjusted cost-based offers, $2.95 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. Using adjusted cost-based offers, $5.01 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In the first nine months of 2026, the peak markup component was highest in August, $16.62 per MWh using unadjusted cost-based offers and $18.26 per MWh using adjusted cost-based offers. This corresponds to 26.6 percent and 28.7 percent of the day-ahead peak load weighted average LMP in August.

Table 3-142 Monthly markup components of day-ahead (Unadjusted) load-weighted LMP: January 2026 through September 2026

	2026		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$3.39	$5.37	$1.64
Feb	$1.30	$0.02	$2.54
Mar	($0.98)	$2.28	($4.31)
Apr	($2.58)	($3.89)	($1.13)
May	$1.60	$0.77	$2.34
Jun	$4.17	$9.17	($1.67)
Jul	$5.72	$9.84	$0.67
Aug	$9.00	$16.62	$1.30
Sep	$2.41	$2.12	$2.71
Total	$2.95	$5.26	$0.56

Table 3-143 Monthly markup components of day-ahead (Adjusted) load-weighted LMP: January 2026 through September 2026

	2026		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$7.73	$9.33	$6.31
Feb	$3.51	$2.01	$4.95
Mar	$0.76	$3.49	($2.03)
Apr	($0.56)	($1.83)	$0.86
May	$3.09	$2.22	$3.87
Jun	$6.31	$11.74	($0.04)
Jul	$7.32	$12.07	$1.50
Aug	$10.47	$18.26	$2.60
Sep	$3.70	$3.23	$4.20
Total	$5.01	$7.32	$2.63

Markup Component of Day-Ahead Zonal Prices

Table 3-144 shows the markup component of annual average day-ahead price using unadjusted cost-based offers for each zone and for adjusted offers in Table 3-145.

The smallest zonal all hours average markup component using unadjusted cost-based offers for the first nine months of 2026 was in MEC, -1.32 per MWh, while the highest was in DUQ, $5.79 per MWh. The smallest zonal on peak average markup using unadjusted cost-based offers was in PPL, $2.18 per MWh, while the highest was in EKPC, $10.68 per MWh.

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Table 3-144 Day-ahead average zonal markup component (Unadjusted): January through September, 2026

	2026 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$0.87	$3.62	($1.88)
AEP	$5.33	$9.23	$1.45
APS	$4.81	$8.38	$1.26
ATSI	$5.48	$7.18	$3.78
BGE	$4.11	$5.94	$2.28
COMED	$0.79	$3.01	($1.42)
DAY	$4.96	$9.29	$0.66
DOM	$3.40	$4.54	$2.26
DPL	($0.25)	$0.92	($1.41)
DUKE	$3.82	$6.20	$1.46
DUQ	$5.79	$8.30	$3.28
EKPC	$5.28	$8.56	$2.01
JCPLC	$0.18	$1.79	($1.43)
MEC	($1.32)	($0.27)	($2.36)
OVEC	$4.33	$7.12	$1.09
PE	$2.65	$3.86	$1.45
PECO	$0.73	$4.42	($2.93)
PEPCO	$3.60	$6.39	$0.83
PPL	($1.25)	($0.79)	($1.71)
PSEG	($0.23)	$0.78	($1.23)
REC	$1.29	$2.51	$0.08

Table 3-145 Day-ahead average zonal markup component (Adjusted): January through September, 2026

	2026 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$3.23	$5.88	$0.59
AEP	$7.21	$10.67	$3.76
APS	$7.12	$10.38	$3.87
ATSI	$7.47	$8.65	$6.30
BGE	$6.68	$8.65	$4.72
COMED	$2.51	$4.89	$0.13
DAY	$6.99	$10.27	$3.72
DOM	$6.04	$7.47	$4.62
DPL	$2.38	$3.53	$1.23
DUKE	$6.53	$8.23	$4.84
DUQ	$7.69	$9.88	$5.50
EKPC	$7.91	$10.68	$5.15
JCPLC	$2.65	$4.30	$1.01
MEC	$1.28	$2.39	$0.17
OVEC	$7.13	$10.42	$3.32
PE	$4.95	$5.87	$4.04
PECO	$3.13	$6.75	($0.48)
PEPCO	$6.15	$9.17	$3.14
PPL	$1.36	$2.18	$0.55
PSEG	$2.34	$3.37	$1.32
REC	$3.64	$4.86	$2.44

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Markup by Day-Ahead Price Levels

Table 3-146 and Table 3-147 show the average markup component of LMP, 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 3-146 Day-ahead average markup component (By LMP category, unadjusted): January through September, 2026

	2026 (Jan - Sep)	
LMP Category	Markup Component	Frequency
$10 to $15	($0.08)	0.1%
$15 to $20	($0.68)	2.7%
$20 to $25	($1.07)	9.2%
$25 to $50	($0.62)	55.5%
$50 to $75	$3.58	15.9%
$75 to $100	$12.78	5.5%
$100 to $125	$1.53	2.4%
$125 to $150	$9.06	1.8%
>= $150	$18.82	6.8%

Table 3-147 Day-ahead average markup component (By LMP category, adjusted): January through September, 2026

	2026 (Jan - Sep)	
LMP Category	Markup Component	Frequency
$10 to $15	$0.69	0.1%
$15 to $20	$0.28	2.7%
$20 to $25	$0.27	9.2%
$25 to $50	$1.17	55.5%
$50 to $75	$5.06	15.9%
$75 to $100	$14.17	5.5%
$100 to $125	$2.33	2.4%
$125 to $150	$12.05	1.8%
>= $150	$25.25	6.8%

Market Structure, Participant Behavior, and Market Performance

The goal of regulation through competition is to achieve competitive market outcomes even in the presence of market power. Market structure in the PJM energy market is not competitive in local markets created by transmission constraints. At times, market structure is not competitive in the aggregate energy market. Market sellers pursuing their financial interests may choose behavior that benefits from structural market power in the absence of an effective market power mitigation program. The overall competitive assessment evaluates the extent to which participant behavior results in competitive or above competitive pricing. The competitive assessment brings together the structural measures of market power, HHI and pivotal suppliers, with participant behavior, specifically markup, and pricing outcomes.

HHI and Markup

In theory, the HHI provides insight into the relationship between market structure, behavior, and performance. In the case where participants compete by producing output at constant, but potentially different, marginal costs, the HHI is directly proportional to the expected average price cost markup in the market:[256]

$$\frac{HHI}{\varepsilon} = \frac{P - MC}{P}$$

where ε is the absolute value of the price elasticity of demand, P is the market price, and MC is the average marginal cost of production. This is called the Lerner Index. The left side of the equation quantifies market structure, and the right side of the equation measures market performance. The assumed participant behavior is profit maximization. As HHI decreases, implying a more competitive market, prices converge to marginal cost, the competitive market outcome. But even a low HHI may result in substantial markup with a low price elasticity of demand. If HHI is very high, meaning competition is lacking, prices can reach the monopoly level. Price elasticity of demand

256 *See* Tirole, Jean. *The Theory of Industrial Organization*, MIT (1988), Chapter 5: Short-Run Price Competition.

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(ε) determines the degree to which suppliers with market power can impose higher prices on customers. The Lerner Index is a measure of market power that connects market structure (HHI and demand elasticity) to market performance (markup).

The PJM energy market HHIs and application of the FERC concentration categories understate the degree of market power because, in the absence of aggregate market power mitigation, even the unconcentrated HHI level implies substantial markups due to the low short run price elasticity of demand. For example, research estimates find short run electricity demand elasticity ranging from -0.2 to -0.4.[257] Using the Lerner Index, the elasticity of -0.2 implies, for example, an average markup ranging from 25 to 50 percent at the low end of the moderately concentrated threshold HHI of 1000:[258]

$$\frac{HHI}{\varepsilon} = \frac{0.1}{0.2} = \frac{P - MC}{P} = 0.5$$

With knowledge of HHI, elasticity, and marginal cost, one can solve for the price level theoretically indicated by the Lerner Index, based on profit maximizing behavior including the exercise of market power. With marginal costs of $74.33 per MWh and an average HHI of 782 in the first nine months of 2026, average PJM prices would theoretically range from $92 to $122 per MWh, an implied markup of 19.6 to 39.1 percent, using the elasticity range of -0.2 to -0.4. Given the elasticity estimates, the theoretical prices exceed marginal costs because the exercise of market power is profit maximizing. In the PJM market, market power mitigation limits the exercise of market power, so prices cannot reach the higher theoretical level. Actual prices, averaging $74.98 per MWh with markups at 0.9 percent, are lower than the theoretical range, supporting the MMU's competitive assessment of the market. However, markup is not zero. In some market intervals, markup and prices reach levels that reflect the exercise of market power.

Aggregate Market Power and Markup

The HHI is not the only test for market power in the aggregate market. The pivotal supplier test is a better measure than HHI of whether a resource has market power in the PJM aggregate energy market. The Day-Ahead Market columns in Table 3-148 compare the markup behavior of companies that failed the aggregate market TPS test (TPS Aggregate) in the day-ahead market to marginal resources that did not fail the TPS test (Not TPS Aggregate), in both the day-ahead energy market and in the real-time energy market. The day-ahead results show that on days when a company is one of three pivotal suppliers in the day-ahead energy market, it is more likely to set price with a positive markup (22.7 percent) than a company that is not one of three pivotal suppliers (4.8 percent). Of the companies that were pivotal in the aggregate day-ahead energy market, 113 marginal unit hours and 79 marginal unit hours in the real-time market had markups over $100 per MWh in the day-ahead market. The Real-Time Market columns in Table 3-148 results compare the markup behavior in the real-time energy market of companies that failed the aggregate market TPS test (TPS Aggregate) in the day-ahead market to marginal resources that did not fail the TPS test (Not TPS Aggregate) in the day-ahead energy market.

257 See Patrick, Robert H. and Frank A. Wolak (1997), "Estimating the Customer-Level Demand for Electricity Under Real-Time Market Prices," <https://www.nber.org/system/files/working_papers/w8213/w8213.pdf>, last accessed July 30, 2026 and Fan, Shu and Rob Hyndman (2010), "The price elasticity of electricity demand in South Australia," <https://robjhyndman.com/papers/Elasticity2010.pdf>, last accessed July 30, 2026.

258 The HHI used in the equation is based on market shares. For the FERC HHI thresholds and standard HHI reporting, market shares are multiplied by 100 prior to squaring the market shares.

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Table 3-148 Percent of marginal unit intervals with markup and aggregate market power: January through September, 2026

	Day-ahead Market			Real-time Market		
Markup Category	Not TPS Aggregate	TPS Aggregate	Percent in Category	Not TPS Aggregate	TPS Aggregate	Percent in Category
Negative Markup	10.2%	38.7%	48.9%	8.7%	43.2%	51.9%
Zero Markup	1.9%	21.7%	23.6%	4.2%	28.9%	33.1%
$0 to $5	2.1%	11.9%	13.9%	1.5%	6.1%	7.5%
$5 to $10	0.4%	2.7%	3.1%	0.3%	1.6%	1.9%
$10 to $15	0.1%	1.6%	1.7%	0.2%	0.9%	1.1%
$15 to $20	0.2%	1.0%	1.2%	0.0%	0.7%	0.7%
$20 to $25	0.2%	0.9%	1.1%	0.1%	0.5%	0.6%
$25 to $50	1.2%	2.6%	3.8%	0.5%	1.5%	2.0%
$50 to $75	0.5%	1.1%	1.5%	0.1%	0.4%	0.5%
$75 to $100	0.1%	0.5%	0.6%	0.0%	0.2%	0.2%
Above $100	0.1%	0.5%	0.5%	0.0%	0.4%	0.5%
Total Positive Markup	4.8%	22.7%	27.5%	2.7%	12.3%	15.0%
Total	16.9%	83.1%	100.0%	15.6%	84.4%	100.0%

Table 3-149 Percent of marginal unit intervals with markup and local market power: January through September, 2026

	Day-ahead Market			Real-time Market		
Markup Category	Not Failing TPS Test	Failing TPS Test	Percent in Category	Not Failing TPS Test	Failing TPS Test	Percent in Category
Negative Markup	42.8%	6.1%	48.9%	42.6%	9.3%	51.9%
Zero Markup	17.8%	5.8%	23.6%	20.5%	12.6%	33.1%
$0 to $5	12.5%	1.4%	13.9%	5.8%	1.7%	7.5%
$5 to $10	2.7%	0.5%	3.1%	1.4%	0.5%	1.9%
$10 to $15	1.3%	0.4%	1.7%	0.9%	0.2%	1.1%
$15 to $20	1.0%	0.2%	1.2%	0.6%	0.2%	0.7%
$20 to $25	1.0%	0.2%	1.1%	0.5%	0.1%	0.6%
$25 to $50	3.4%	0.4%	3.8%	1.7%	0.3%	2.0%
$50 to $75	1.4%	0.2%	1.5%	0.4%	0.2%	0.5%
$75 to $100	0.5%	0.1%	0.6%	0.1%	0.1%	0.2%
Above $100	0.4%	0.1%	0.5%	0.2%	0.3%	0.5%
Total Positive Markup	24.1%	3.4%	27.5%	11.5%	3.6%	15.0%
Total	84.7%	15.3%	100.0%	74.6%	25.4%	100.0%

Market Power Mitigation and Markup

Fully effective local market power mitigation would not allow a seller that fails the structural market power test (the TPS test) to set prices with a positive markup. With the flaws in PJM's implementation of the TPS test, resources can and do set prices with a positive markup while failing the TPS test.

Table 3-149 categorizes day-ahead and real-time marginal unit intervals by markup level and TPS test status. In the first nine months of 2026, 3.6 percent of real-time marginal unit intervals and 3.4 percent of day-ahead marginal unit hours included a positive markup even though the resource failed the TPS test for local market power. Unmitigated local market power affects PJM market prices. Zero markup with a TPS test failure indicates the mitigation of a marginal unit.

The markup of marginal units was zero or negative in 85.0 percent of real-time marginal unit intervals and 72.5 percent of day-ahead marginal unit intervals in the first nine months of 2026. Zero and negative markup are the expected results in a competitive market. Allowing positive markups to affect prices in the presence of market power permits the exercise of market power and has a negative impact on the competitiveness of the PJM energy market. This problem can and should be addressed.

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