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 2020.

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 every day. The hourly HHI (Herfindahl-Hirschman Index) results indicate that the PJM aggregate energy market in 2020 was unconcentrated by FERC HHI standards. Average HHI was 726 with a minimum of 526 and a maximum of 1080 in 2020. The peaking segment of supply was highly concentrated. The fact that the average HHI is in the unconcentrated range and the maximum hourly HHI is in the moderately concentrated 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. While transmission constraints create the potential for the exercise of local market power, PJM's application of the three pivotal supplier test identified local market power and resulted in offer capping to force 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 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 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 cause concerns. Market design implementation issues, including inaccuracies in modeling of the transmission system and of generator capabilities as well as inefficiencies in real-time dispatch and price formation, undermine market efficiency in the energy market.

- 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.[1] 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. 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.[2] 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. 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.

Overview

Supply and Demand

Market Structure

- **Supply.** The average hourly day-ahead supply was 157,005 for 2020, and 171,443 MW for 2019. The average on-peak hourly offered real-time supply was 135,383 MW for 2020, and 138,779 MW for 2019. In 2020, 2,556.7 MW of new resources were added in the energy market, and 3,255.0 MW of resources and 457.0 MW of pseudo tied resources were retired.

- PJM average hourly real-time cleared generation in 2020 decreased by 2.7 percent from 2019, from 93,434 MWh to 90,946 MWh.

  PJM average hourly day-ahead cleared supply in 2020, including INCs and up to congestion transactions, decreased by 4.9 percent from 2019, from 117,250 MWh to 111,470 MWh.

- **Demand.** The PJM system real-time hourly peak load in 2020 was 141,449 MWh in the HE 1700 on July 20, 2020, which was 6,778 MWh, 4.6 percent,

1 OATT Attachment M (PJM Market Monitoring Plan).

2 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.

lower than the PJM peak load in 2019, which was 148,228 MWh in the HE 1800 on July 19, 2019.

- PJM average hourly real-time load in 2020 decreased by 4.0 percent from 2019, from 88,120 MWh to 84,584 MWh, the largest percent decrease since 2009. Both the weather and COVID-19 contributed to the significant change. Based on the weather normalized demand analysis, 3.4 of the 4.0 percent decrease in load was related to COVID-19.
- PJM average hourly day-ahead demand in 2020, including load, DECs and up to congestion transactions, decreased by 5.7 percent from 2019, from 112,588 MWh to 106,209 MWh.

Market Behavior

- **Supply and Demand: Load and Spot Market.** Companies that serve load in PJM do so using a combination of self supply, bilateral market purchases and spot market purchases. In 2020, 16.1 percent of real-time load was supplied by bilateral contracts, 24.7 percent by spot market purchases and 59.2 percent by self supply. Compared to 2019, reliance on bilateral contracts increased by 0.8 percentage points, reliance on spot market purchases decreased by 0.1 percentage points and reliance on self supply decreased by 0.7 percentage points.
- **Generator Offers.** In day-ahead market offers, generators define the commitment status and the dispatch status of their units. In the day-ahead market in 2020, 21.8 percent of MW were offered as must run, 32.1 percent were offered as economic minimum MW for dispatchable units, 45.0 percent were offered as dispatchable MW, and 1.0 percent were offered as emergency maximum MW.
- **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 increased by 2.7 percent and cleared MW decreased by 16.0 percent in 2020. The hourly average submitted decrement offer MW increased by 24.4 percent and cleared MW increased by 16.6 percent in 2020. The hourly average submitted up to congestion bid MW decreased by 23.8 percent and cleared MW decreased by 12.4 percent in 2020.

Market Performance

- **Generation Fuel Mix.** In 2020, coal units provided 19.3 percent, nuclear units 34.2 percent and natural gas units 39.8 percent of total generation. Compared to 2019, generation from coal units decreased 20.6 percent, generation from natural gas units increased 6.7 percent and generation from nuclear units decreased 0.8 percent. The trend toward more energy from natural gas and less from coal accelerated in 2020.
- **Fuel Diversity.** The fuel diversity of energy generation in 2020, measured by the fuel diversity index for energy (FDI_e), decreased 1.5 percent compared to 2019.
- **Marginal Resources.** In the PJM Real-Time Energy Market in 2020, coal units were 17.5 percent and natural gas units were 72.3 percent of marginal resources. In 2019, coal units were 24.4 percent and natural gas units were 69.4 percent of marginal resources.

  In the PJM Day-Ahead Energy Market in 2020, up to congestion transactions were 51.4 percent, INCs were 13.2 percent, DECs were 18.8 percent, and generation resources were 16.5 percent of marginal resources. In 2019, up to congestion transactions were 57.4 percent, INCs were 12.8 percent, DECs were 17.0 percent, and generation resources were 12.7 percent of marginal resources.
- **Prices.** PJM real-time and day-ahead energy market prices were at the lowest level in the history of PJM markets during 2020. Both the weather and COVID-19 played a role in this significant drop in prices.

  PJM load-weighted, average, real-time LMP in 2020 decreased 20.3 percent from 2019, from $27.32 per MWh to $21.77 per MWh.

  PJM load-weighted, average day-ahead LMP in 2020 decreased 21.4 percent from 2019, from $27.23 per MWh to $21.40 per MWh.
- **Components of LMP.** In the PJM Real-Time Energy Market in 2020, 23.7 percent of the load-weighted LMP was the result of coal costs, 41.5 percent was

the result of gas costs and 1.7 percent was the result of the cost of emission allowances.

In the PJM Day-Ahead Energy Market, in 2020, 24.4 percent of the load-weighted LMP was the result of coal costs, 18.8 percent was the result of gas costs, 15.2 percent was the result of INC offers, 24.0 percent was the result of DEC bids, and 3.0 percent was the result of up to congestion transaction offers.

- **Price Convergence.** Hourly and daily price differences between the day-ahead and real-time energy markets fluctuate continuously and substantially from positive to negative. The difference between the average day-ahead and real-time prices was \$0.33 per MWh in 2020, and -\$0.01 per MWh in 2019. The difference between average day-ahead and real-time prices, by itself, is not a measure of the competitiveness or effectiveness of the day-ahead energy market.

Scarcity

- There were nine intervals with five minute shortage pricing in 2020. There were no emergency actions that resulted in Performance Assessment Intervals in 2020.
- There were 1,819 five minute intervals, or 1.7 percent of all five minute intervals in 2020 for which at least one RT SCED solution showed a shortage of reserves, and 592 five minute intervals, or 0.6 percent of all five minute intervals in 2020 for which more than one RT SCED solution showed a shortage of reserves. PJM triggered shortage pricing for nine five minute intervals.

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.
- **Local Market Power.** For six out of the top 10 congested facilities (by real-time binding hours) in 2020, the average number of suppliers providing constraint relief was three or less. There is 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 is 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 1.3 percent in 2019 to 1.6 percent in 2020. In the real-time energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 1.7 percent in 2019 to 1.0 percent in 2020. 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.

  In 2020, 10 control zones experienced congestion resulting from one or more constraints binding for 100 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working 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.

- **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 remained at 0.0 percent in 2019 and 2020. In the real-time energy market, for units committed for reliability reasons, offer-capped unit hours remained at 0.0 percent in 2019 and 2020.
- **Frequently Mitigated Units (FMU) and Associated Units (AU).** 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.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In 2020, in the PJM Real-Time Energy Market, 98.2 percent of marginal units had offer prices less than $50 per MWh. While markups in the real-time market were generally low, some marginal units did have substantial markups. The highest markup for any marginal unit in 2020 was more than $450 per MWh when using unadjusted cost-based offers.

  In 2020, in the PJM Day-Ahead Energy Market, 99.2 percent of marginal generating units had offer prices less than $50 per MWh. Markups in the day-ahead market were generally low. The highest markup for any marginal unit in the day-ahead market in 2020 was more than $70 per MWh when using unadjusted cost-based offers.

- **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 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. Markup for coal and gas fired units decreased in 2020.

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 2020, the unadjusted markup component of LMP was $0.50 per MWh or 2.3 percent of the PJM load-weighted, average LMP. August had the highest unadjusted peak markup component, $2.88 per MWh, or 9.7 percent of the real-time, peak hour load-weighted, average LMP. There were 35 hours in 2020 where the positive markup contribution to the PJM system wide, load-weighted, average LMP exceeded the 99^{th} percentile of the hourly markup contribution or $30.70 per MWh.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In 2020, the unadjusted markup component of LMP resulting from generation resources was -$0.11 per MWh or -0.5 percent of the PJM day-ahead load-weighted, average LMP. August had the highest unadjusted peak markup component, $0.70 per MWh.

  Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the day-ahead and real-time energy markets, although the behavior of some participants represents economic withholding.

- **Markup and Local Market Power.** Comparison of the markup behavior of marginal units with TPS test results shows that for 5.2 percent of marginal unit intervals in 2020 the marginal unit had local market power as determined by the TPS test and a positive markup, compared to 10.0 percent of marginal unit intervals in 2019. The fact that units with market power had a positive markup 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.

- **Markup and Aggregate Market Power.** In the summer of 2020, pivotal suppliers in the aggregate market set prices with high markups for some real-time market intervals.

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. The short run marginal cost should reflect opportunity cost when and where appropriate. The MMU recommends that the level of incremental costs includable in cost-based offers 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 tariff be changed to allow units to have fuel cost policies that do not include fuel procurement practices, including fuel contracts. Fuel procurement practices, including fuel contracts, may be used as the basis for fuel cost policies but should not be required. (Priority: Low. First reported 2018. Status: Adopted 2020.)
- The MMU recommends that PJM change the fuel cost policy requirement to apply only to units that will be offered with non-zero cost-based offers. The PJM market rules should require that the cost-based offers of units without an approved fuel cost policy be set to zero. (Priority: Low. First reported 2018. Status: Adopted 2020.)
- 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 Q3, 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 Q3, 2020. Status: Not adopted.)

Cost-Based Offers

- The MMU recommends that Manual 15 (Cost Development Guidelines) be replaced 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. (Priority: Medium. First reported 2016. Status: Not adopted.)
- 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 labor costs 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 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. (Priority: Medium. First reported Q3, 2020. 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 Q3, 2020. Status: Not adopted.)
- 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: 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.)
- 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.)
- The MMU recommends revisions to the calculation of energy market opportunity costs to incorporate all time based offer parameters and all limitations that impact the opportunity cost of generating unit

output. (Priority: Medium. First reported 2016. Status: Adopted 2020.)

- The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2. (Priority: Medium. 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.)
- 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 constant 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 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 Q3, 2020. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, and during high load conditions such as cold and hot weather alerts or more severe emergencies, that the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available price-based non-PLS offer, and that the price-MW pairs in the price-based PLS offer be exactly equal to the price-based non-PLS offer. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation, that PJM always enforce parameter limited values by committing units only on parameter limited schedules, when the TPS test is failed or during high load conditions such as cold and hot weather alerts or more severe emergencies. (Priority: High. First reported 2019. 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.)

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. New recommendation. Status: Not adopted.)
- The MMU recommends that storage and intermittent resources be subject to an enforceable ICAP must offer rule that reflects the limitations of these resources. (Priority: Medium. New recommendation. 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.)

Capacity Performance Resources

- The MMU recommends that capacity performance 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 performance construct. 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 performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs) in the capacity market default offer cap, and only include those events that trigger emergencies at a defined zonal or higher level. (Priority: Medium. First reported 2018. Status: Not adopted.)
- 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 performance capacity resources. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM institute rules to assess a penalty for resources that choose to submit real-time values that are less flexible than their unit specific parameter limits or approved parameter limit exceptions based on tariff defined reasons. (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 routinely enforced, and based on inferior transportation service procured by the generator. (Priority: Medium. First reported 2019. Status: Not adopted.)

Accurate System Modeling

- The MMU recommends that PJM approve one RT SCED case for each five minute interval to dispatch resources during that interval using a five minute ramp time, and that PJM calculate prices using LPC for that five minute interval using the same approved RT SCED case. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including: the level of the penalty factors; the triggers for the use of the penalty factors; the appropriate line ratings to trigger the use of penalty factors; the allowed duration of the violation; the use of constraint relaxation logic; and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. First reported 2015. Status: Partially adopted 2020.)
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Partially 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 scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not use CT price setting logic to modify transmission line limits to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that if PJM believes it appropriate to implement CT price setting logic, PJM first initiate a stakeholder process to determine whether such modification is appropriate. PJM should file any proposed changes with FERC

to ensure review. Any such changes should be incorporated in the PJM tariff. (Priority: Medium. First reported 2016. Status: Partially adopted.)

- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability, and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that 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.[3] [4] (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.)
- 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 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 Q1, 2020. Status: Not adopted.)

Transparency

- The MMU recommends that PJM market rules require the fuel type be identified for every price and cost schedule and PJM market rules remove nonspecific fuel types such as other or co-fire other from the list of fuel types available for market participants to identify the fuel type associated with their price and cost schedules. (Priority: Medium. First reported 2015. Status: Adopted 2019.)
- 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.)
- The MMU recommends that PJM continue to enhance its posting of market data to promote market efficiency. (Priority: Medium. First reported 2005. Status: Partially adopted.)

3 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.

4 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>.

- The MMU recommends that PJM clearly define the criteria for operator approval of RT SCED cases used to send dispatch signals to resources and for pricing, to minimize operator discretion and implement a rule based, scheduled approach. (Priority: High. First reported 2018. Status: Not adopted.)

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 Q3, 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 Q3, 2020. Status: Not adopted.)

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in 2020, including aggregate supply and demand, concentration ratios, aggregate pivotal supplier results, local three pivotal supplier test results, offer capping, markup, marginal units, participation in demand response programs, virtual bids and offers, loads and prices.

PJM average hourly real-time load in 2020 decreased by 4.0 percent from 2019, from 88,120 MWh to 84,584 MWh, the largest percent decrease since 2009. Both the weather and COVID-19 contributed to the significant change. Based on the weather normalized demand analysis, 3.4 of the 4.0 percent decrease in load was related to COVID-19. The relationship between supply and demand, regardless of the specific market, along with market concentration and the extent of pivotal suppliers, is referred to as the supply-demand fundamentals or economic fundamentals or market structure. The market structure of the PJM aggregate energy market is 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. 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 correct. There are pivotal suppliers in the aggregate energy market at times. High markups for some units demonstrate the potential to exercise market power both routinely and during high demand conditions. 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.[5] However, there are some 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. Many of these issues can be resolved by simple rule changes.

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, some unit owners include costs that are not short run marginal costs in offers, especially fixed maintenance costs. This issue can be resolved by simple rule changes to incorporate a clear and accurate definition of short run marginal costs.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is

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

an indicator of the level of competition in a market. In a competitive market, prices are directly related to the marginal cost to serve load at a given time. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of the impact of the price elasticity of demand on prices. Energy market results in 2020 generally reflected supply-demand fundamentals, although the behavior of some participants both routinely and during high demand periods represents economic withholding. Economic withholding is the ability to substantially increase markups in energy offers in tight market conditions. There are additional issues in the energy market including the uncertainties about the pricing and availability of natural gas, the way that generation owners incorporate natural gas costs in offers, and the lack of adequate incentives for unit owners to take all necessary actions to acquire fuel and operate rather than economically withhold or physically withhold.

Prices in PJM are not too low. Prices in PJM are the result of input prices, consistent with a competitive market. Low natural gas prices have been a primary cause of low PJM energy market prices. There is no evidence to support the need for a significant change to the calculation of LMP, such as fast start pricing or the extended ORDC. The underlying problem that fast start pricing and PJM's reserve pricing approach are attempting to address is actually scarcity pricing, including the impact of operator actions on the definition of scarcity. Prices do not reflect market conditions when the market is tight, because PJM is not implementing scarcity pricing when there is scarcity. Rather than undercutting the basic LMP logic that is core to market efficiency, it would make more sense to directly address the design of RT SCED/LPC, scarcity pricing, operator actions and the design of reserve markets. Implementing scarcity pricing when there is scarcity is a basic first step. Targeted increases to the demand for reserves when the market is tight would address price formation in the energy market.

When the real-time security constrained economic dispatch (RT SCED) solution indicates a shortage of reserves, it should be used in calculating real-time prices and those prices should be applied to the market interval for which RT SCED calculated the shortage and during which resources followed associated dispatch instructions. There are significant issues with operator discretion and reluctance to approve RT SCED cases indicating shortage of reserves, and in using these cases to calculate prices. While it is appropriate for operators to ensure that cases that use erroneous inputs are not approved and not allowed to set prices, 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. There are also issues with the alignment of RT SCED cases used for resource dispatch and the RT SCED cases used to calculate real-time prices. Alignment of resource dispatch with pricing and settlements requires reducing the RT SCED ramp time to five minutes to match the five minute settlement interval. PJM should fix its current operating practices and ensure consistency and transparency regarding approval of RT SCED cases for resource dispatch and pricing so that market participants can have confidence in the market design to produce accurate and efficient price signals. PJM has a plan to make these changes, and PJM should prioritize implementing it. These issues are even more critical now that PJM settles real-time energy transactions on a five minute basis and will soon implement fast start pricing.

The PJM defined inputs to the dispatch tools, particularly the RT SCED, have substantial effects on energy market outcomes. Transmission line ratings, transmission penalty factors, load forecast bias, hydro resource schedules, and unit ramp rate adjustments change the dispatch of the system, affect prices, and can create significant price increases through transmission line limit violations or restrictions on the resources available to resolve constraints. The automated adjustment of ramp rates by PJM, called Degree of Generator Performance (DGP), modifies the values offered by generators and limits the MW available to the RT SCED. Rather than sending dispatch signals consistent with resource offers and holding resources accountable when they fail to follow them, DGP accommodates resources that do not follow dispatch. PJM should evaluate its interventions in the market, consider whether the interventions are appropriate, and provide greater transparency to enhance market efficiency.

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 prioritizes minimizing uplift over minimizing production costs. 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. This tradeoff will be created by PJM's fast start pricing proposal as approved by FERC and would be created in a much more extensive form by PJM's convex hull pricing proposal and reserve pricing proposal.

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 will distort the incentive for market participants to behave competitively and to follow PJM's dispatch instructions. PJM will pay new forms of uplift in an attempt to counter the distorted incentives. The magnitude of the new payments and their effects on behavior are not well understood.

The fast start pricing and convex hull solutions would undercut LMP logic rather than directly addressing the underlying issues. The solution is not to accept that the inflexible CT should be paid or set price based on its commitment costs rather than its short run marginal costs. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? The question of why the unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question of how to provide market incentives for investment in flexible units and for investment in increased flexibility of existing units should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying excess uplift to inflexible units would create incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy, as in PJM's ORDC proposal, is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers based on measured reserve levels and transparent prices, that scarcity pricing only occurs when scarcity exists, and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. Administrative scarcity pricing that establishes scarcity pricing in about 85 percent of hours, as PJM's ORDC proposal would, is not scarcity pricing but simply a revenue enhancement mechanism. When combined with PJM's failure to address the energy and ancillary services offset in the capacity market, PJM's ORDC filing is not consistent with efficient market design and is even more clearly just a revenue enhancement mechanism.

The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. However, the explicit balancing mechanism that included net revenues directly in unit offers in the prior capacity market design is not present in the Capacity Performance design. The nature of a direct and explicit energy pricing net revenue true up mechanism in the capacity market should be addressed if energy revenues are expected to increase as a result of scarcity events, as a result of increased demand for reserves, or as a result of PJM's inappropriate proposals related to fast start pricing and the inclusion of maintenance expenses as short run marginal costs. The true up mechanism must address both cleared auctions and subsequent auctions. There are also significant issues with PJM's scarcity pricing rules, including the absence of a clear trigger based on measured reserve levels (the current triggers are based on estimated reserves) and the lack of adequate locational scarcity pricing options.

The overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units operating at, or close to, their marginal costs, although this was not always the case in 2020 or prior years. In 2020, marginal units were predominantly combined cycle gas generators with low fuel costs. The frequency of combined cycle gas units as the marginal unit type has risen rapidly, from 31.2 percent in 2016 to 64.3 percent in 2020. Overdue improvements in generator modeling in the energy market would allow PJM to more efficiently commit and dispatch combined cycle plants and to fully reflect the flexibility of these units. New combined cycle units placed competitive pressure on less efficient generators, and the market reliably served load with less congestion, less uplift, and less markup in marginal offers than in 2019. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants represents economic withholding. Given the structure of the energy market which can permit the exercise of aggregate and local market power, the change in some participants' behavior is a source of concern in the energy market and provides a reason to use correctly defined short run marginal cost as the sole basis for cost-based offers and a reason for implementing an aggregate market power test and correcting the offer capping process for resources with local market power. The MMU concludes that the PJM energy market results were competitive in 2020.

Supply and Demand

Market Structure

Supply

Supply includes physical generation, imports and virtual transactions.

In 2020, 2,556.7 MW of new resources were added in the energy market, and 3,255.0 MW of resources and 457 MW of pseudo tied resources were retired. Figure 3-1 shows the average real-time and day-ahead supply curves in 2019 and 2020.[6][7][8] The real-time supply curve shows the average of on peak hourly offers. The real-time supply curve includes available MW from units that are online or offline and available to generate power in one hour or less. The day-ahead supply curve shows the average of all hourly offers.

Figure 3-2 shows the typical dispatch range.

Figure 3-1 Hourly real-time and aggregate day-ahead supply curve comparison: 2019 and 2020

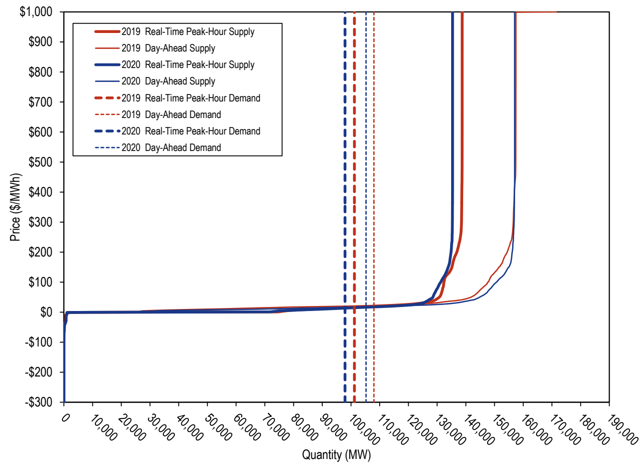
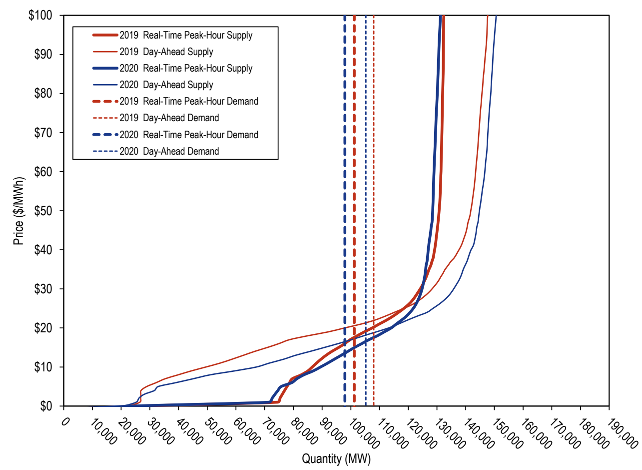


Figure 3-2 Typical dispatch range of supply curves



6 Real-time generation offers and real-time import MWh are included.
7 Real-time load and export MWh are included.
8 The supply curve period is from January 1 to December 31.

Table 3-2 shows the price elasticity of the real-time supply curve for the on peak hours in 2019 and 2020 by load level.

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

$$\text{Elasticity of Supply} = \frac{\text{Percent change in quantity supplied}}{\text{Percent change in price}}$$

The supply curve is elastic when elasticity is greater than 1.0. The supply curve 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 calculated elasticity is low throughout.

Table 3-2 Price elasticity of the supply curve

	Elasticity of Supply	
GW	2019	2020
Min - 75	0.021	0.022
75 - 95	0.388	0.188
95 - 115	0.025	0.325
115 - Max	0.004	0.004

Real-Time Supply

The maximum average on-peak hourly offered real-time supply was 135,383 MW for 2020 and 138,779 MW for 2019. The available supply at a defined time is less than the total capacity of the PJM system because real-time supply at a defined time is limited by unit ramp rates and start times.

PJM average hourly real-time cleared generation in 2020 decreased by 2.7 percent from 2019, from 93,434 MWh to 90,946 MWh.[9]

PJM average hourly real-time cleared supply including imports in 2020 decreased by 3.1 percent from 2019, from 94,618 MWh to 91,681 MWh.

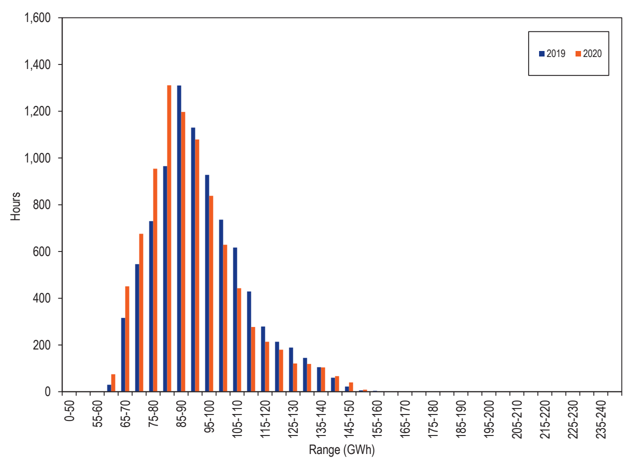
In the PJM Real-Time Energy Market, there are three types of supply offers:

- **Self Scheduled Generation Offer.** Offer to supply a fixed block of 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 specific unit.
- **Import.** An import is an external energy transaction scheduled to PJM from another balancing authority. A real-time import must have a valid OASIS reservation when offered, must have available ramp room to support the import, must be accompanied by a NERC Tag, and must pass the neighboring balancing authority checkout process.

PJM Real-Time Supply Frequency

Figure 3-3 shows the hourly distribution of PJM real-time generation plus imports in 2019 and 2020. The hours of generation less than 85 GWh increased significantly, while the hours of generation more than 85 GWh decreased in 2020.

Figure 3-3 Distribution of real-time generation plus imports: 2019 and 2020[10]



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

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

PJM Real-Time, Average Supply

Table 3-3 shows real-time hourly supply summary statistics for 20 year period from 2001 through 2020.

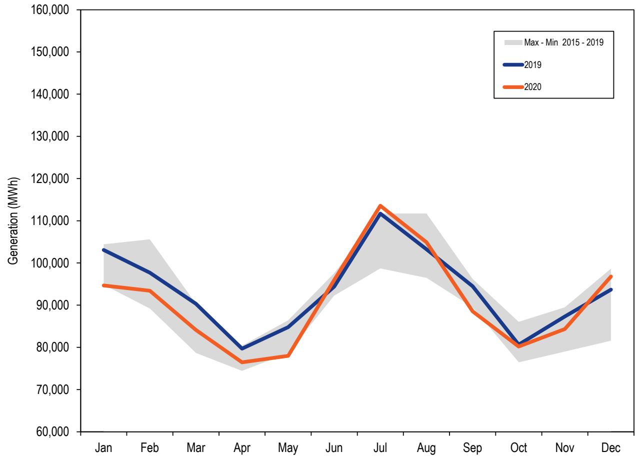
Table 3-3 Average hourly real-time generation and real-time generation plus imports: 2001 through 2020

	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2001	29,553	4,937	32,552	5,285	NA	NA	NA	NA
2002	34,928	7,535	38,535	7,751	18.2%	52.6%	18.4%	46.7%
2003	36,628	6,165	40,205	6,162	4.9%	(18.2%)	4.3%	(20.5%)
2004	51,068	13,790	55,781	14,652	39.4%	123.7%	38.7%	137.8%
2005	81,127	15,452	86,353	15,981	58.9%	12.0%	54.8%	9.1%
2006	82,780	13,709	86,978	14,402	2.0%	(11.3%)	0.7%	(9.9%)
2007	85,860	14,018	90,351	14,763	3.7%	2.3%	3.9%	2.5%
2008	83,476	13,787	88,899	14,256	(2.8%)	(1.7%)	(1.6%)	(3.4%)
2009	78,026	13,647	83,058	14,140	(6.5%)	(1.0%)	(6.6%)	(0.8%)
2010	82,585	15,556	87,386	16,227	5.8%	14.0%	5.2%	14.8%
2011	85,775	15,932	90,511	16,759	3.9%	2.4%	3.6%	3.3%
2012	88,708	15,701	94,083	16,505	3.4%	(1.4%)	3.9%	(1.5%)
2013	89,769	15,012	94,833	15,878	1.2%	(4.4%)	0.8%	(3.8%)
2014	90,894	15,151	96,295	16,199	1.3%	0.9%	1.5%	2.0%
2015	88,628	16,118	94,330	17,313	(2.5%)	6.4%	(2.0%)	6.9%
2016	91,304	17,731	95,054	17,980	3.0%	10.0%	0.8%	3.9%
2017	90,945	15,194	92,721	15,493	(0.4%)	(14.3%)	(2.5%)	(13.8%)
2018	94,236	16,326	96,109	16,595	3.6%	7.5%	3.7%	7.1%
2019	93,434	16,357	94,618	16,515	(0.9%)	0.2%	(1.6%)	(0.5%)
2020	90,946	16,528	91,681	16,629	(2.7%)	1.1%	(3.1%)	0.7%

PJM Real-Time, Monthly Average Generation

Figure 3-4 compares the real-time, monthly average hourly generation in 2019 and 2020 with the five year range. As a result of weather and COVID-19, the monthly average hourly generation was lower than the minimum of the past five years in January, May and September, but was higher than the maximum of the past five years in July as a result of weather.

Figure 3-4 Real-time monthly average hourly generation: 2019 through 2020



Day-Ahead Supply

PJM average hourly day-ahead cleared supply in 2020, including INCs and up to congestion transactions, decreased by 4.9 percent from 2019, from 117,250 MWh to 111,470 MWh. When imports are added, PJM average hourly, day-ahead cleared supply in 2020 decreased by 5.1 percent from 2019, from 117,622 MWh to 111,636 MWh.

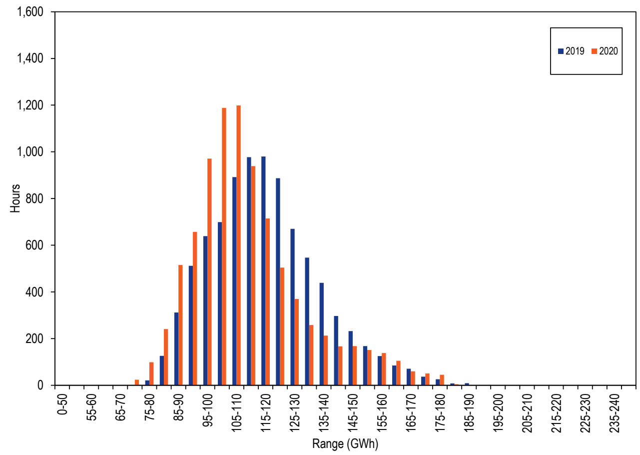
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

- **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.

PJM Day-Ahead Supply Duration

Figure 3-5 shows the hourly distribution of PJM day-ahead cleared supply, including increment offers, up to congestion transactions, and imports in 2019 and 2020.

Figure 3-5 Distribution of day-ahead cleared supply plus imports: 2019 and 2020[11]



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

PJM Day-Ahead, Average Supply

Table 3-4 presents day-ahead hourly cleared supply summary statistics for the 20 year period from 2001 through 2020.

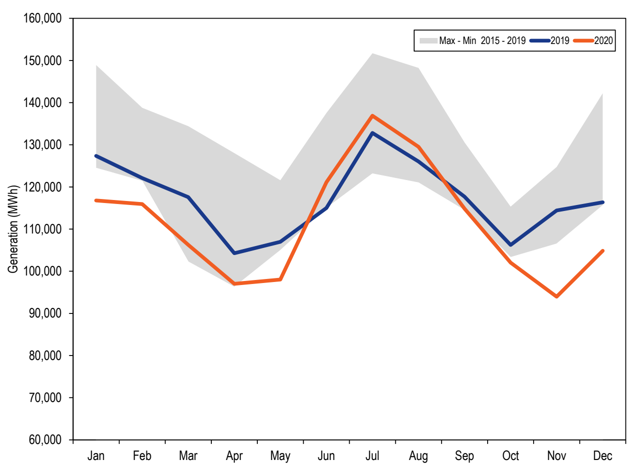
Table 3-4 Average hourly day-ahead cleared supply and day-ahead cleared supply plus imports: 2001 through 2020

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2001	26,762	4,595	27,497	4,664	NA	NA	NA	NA
2002	31,434	10,007	31,982	10,015	17.5%	117.8%	16.3%	114.7%
2003	40,642	8,292	41,183	8,287	29.3%	(17.1%)	28.8%	(17.3%)
2004	62,755	17,141	63,654	17,362	54.4%	106.7%	54.6%	109.5%
2005	94,438	17,204	96,449	17,462	50.5%	0.4%	51.5%	0.6%
2006	100,056	16,543	102,164	16,559	5.9%	(3.8%)	5.9%	(5.2%)
2007	108,707	16,549	111,023	16,729	8.6%	0.0%	8.7%	1.0%
2008	105,485	15,994	107,885	16,136	(3.0%)	(3.4%)	(2.8%)	(3.5%)
2009	97,388	16,364	100,022	16,397	(7.7%)	2.3%	(7.3%)	1.6%
2010	107,307	21,655	110,026	21,837	10.2%	32.3%	10.0%	33.2%
2011	117,130	20,977	119,501	21,259	9.2%	(3.1%)	8.6%	(2.6%)
2012	134,479	17,905	136,903	18,080	14.8%	(14.6%)	14.6%	(15.0%)
2013	148,323	18,783	150,595	18,978	10.3%	4.9%	10.0%	5.0%
2014	146,672	33,145	148,906	33,346	(1.1%)	76.5%	(1.1%)	75.7%
2015	114,890	19,165	117,147	19,406	(21.7%)	(42.2%)	(21.3%)	(41.8%)
2016	131,618	22,329	133,246	22,368	14.6%	16.5%	13.7%	15.3%
2017	130,603	20,035	131,142	20,153	(0.8%)	(10.3%)	(1.6%)	(9.9%)
2018	114,556	20,239	114,967	20,224	(12.3%)	1.0%	(12.3%)	0.4%
2019	117,250	18,909	117,622	18,881	2.4%	(6.6%)	2.3%	(6.6%)
2020	111,470	19,749	111,636	19,729	(4.9%)	4.4%	(5.1%)	4.5%

PJM Day-Ahead, Monthly Average Cleared Supply

Figure 3-6 compares the day-ahead, monthly average hourly cleared supply, including increment offers and up to congestion transactions in 2019 and 2020 with the historic five year range.

Figure 3-6 Day-ahead monthly average cleared hourly supply: 2019 through 2020



Real-Time and Day-Ahead Supply

Table 3-5 presents summary statistics for 2019 and 2020, for day-ahead cleared supply and real-time supply, which is generation plus imports. The last two columns of Table 3-5 are the day-ahead supply minus the real-time supply. The first of these columns is the total physical day-ahead generation less the total physical real-time generation and the second of these columns is the total day-ahead supply less the total real-time supply.

Table 3-5 Day-ahead and real-time supply (MWh): 2019 and 2020

		Day-Ahead					Real-Time		Day-Ahead Less Real-Time	
		Generation	INC Offers	Up to Congestion	Imports	Total Supply	Generation	Total Supply	Generation	Supply
Average	2019	93,498	2,889	20,862	373	117,622	93,434	94,618	64	23,005
	2020	90,786	2,427	18,257	166	111,636	90,946	91,681	(159)	19,955
Median	2019	91,096	2,753	20,664	340	115,949	91,006	92,159	90	23,790
	2020	87,852	2,364	19,196	125	107,798	88,107	88,830	(254)	18,969
Standard Deviation	2019	16,925	1,018	4,732	233	18,881	16,357	16,515	568	2,366
	2020	17,343	852	5,908	166	19,729	16,528	16,629	814	3,100
Peak Average	2019	102,570	3,389	22,303	330	128,592	101,815	103,078	755	25,515
	2020	99,578	2,758	18,960	152	121,448	98,949	99,724	630	21,724
Peak Median	2019	99,921	3,313	22,120	287	125,612	99,190	100,352	731	25,260
	2020	96,111	2,713	19,883	100	116,084	95,567	96,441	543	19,642
Peak Standard Deviation	2019	15,023	1,012	4,506	237	16,065	14,968	15,095	56	970
	2020	16,544	868	5,866	155	19,322	16,028	16,151	517	3,171
Off-Peak Average	2019	85,587	2,454	19,606	410	108,057	86,126	87,241	(539)	20,815
	2020	83,048	2,135	17,639	179	103,000	83,902	84,603	(854)	18,397
Off-Peak Median	2019	83,416	2,366	19,274	390	105,987	83,939	84,926	(524)	21,061
	2020	80,536	2,076	18,490	145	100,743	81,652	82,365	(1,116)	18,378
Off-Peak Standard Deviation	2019	14,321	800	4,565	222	15,680	13,815	13,968	506	1,713
	2020	14,025	721	5,877	174	15,618	13,476	13,539	549	2,079

Figure 3-7 shows the average cleared volumes of day-ahead supply and real-time supply by hour of the day in 2020. The day-ahead supply consists of cleared MW of physical generation, imports, increment offers and up to congestion transactions. The real-time supply consists of cleared MW of physical generation and imports.

Figure 3-7 Day-ahead and real-time supply (Average volumes by hour of the day): 2020

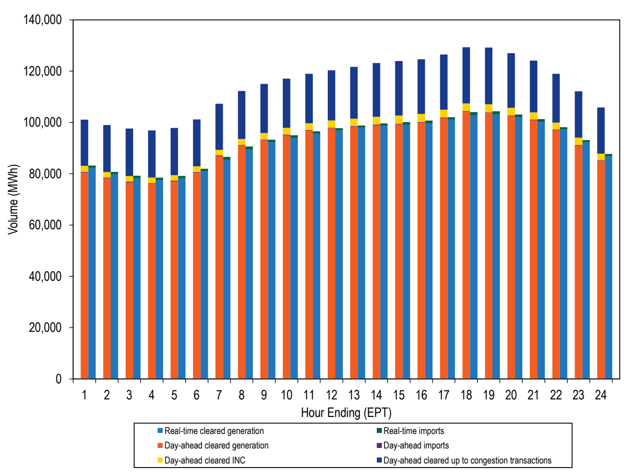
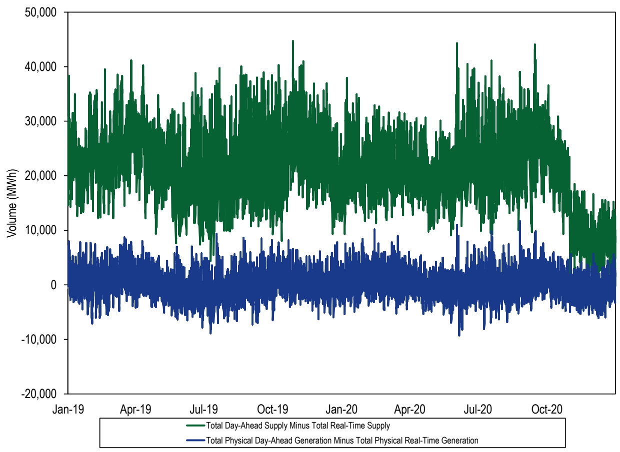


Figure 3-8 shows the difference between the day-ahead and real-time average daily supply in 2019 and 2020.

Figure 3-8 Difference between cleared day-ahead and real-time supply (Average daily volumes): 2019 through 2020



Demand

Demand includes physical load and exports and virtual transactions.

Peak Demand

In this section, demand refers to accounting load and exports and, in the day-ahead energy market, includes virtual transactions.[12]

The PJM system real-time hourly peak load in 2020 was 141,449 MWh in the HE 1700 on July 20, 2020, which was 6,778 MWh, or 4.6 percent, less than the peak load in 2019, 148,228 MWh in the HE 1800 on July 31, 2019.

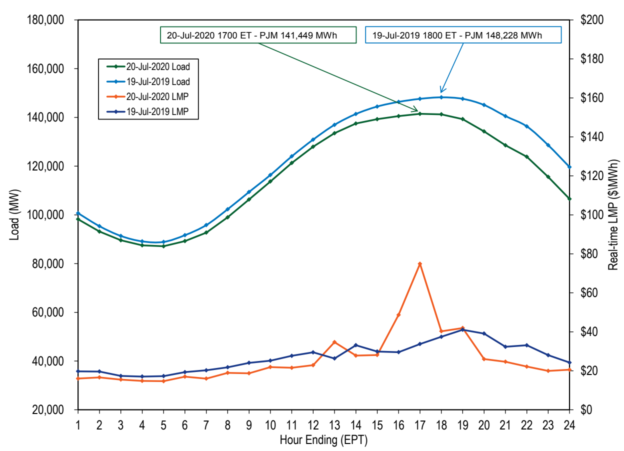
Table 3-6 shows the peak loads for 1999 through 2020.

Table 3-6 Actual footprint peak loads: 1999 through 2020[13 14]

	Date	Hour Ending (EPT)	PJM Load (MWh)	Annual Change (MW)	Annual Change (%)
1999	Tue, July 06	17	51,714	NA	NA
2000	Wed, August 09	17	49,462	(2,252)	(4.4%)
2001	Thu, August 09	15	54,030	4,568	9.2%
2002	Wed, August 14	16	64,126	10,096	18.7%
2003	Fri, August 22	16	61,670	(2,456)	(3.8%)
2004	Mon, December 20	19	96,838	35,168	57.0%
2005	Tue, July 26	16	134,017	37,179	38.4%
2006	Wed, August 02	17	144,904	10,887	8.1%
2007	Wed, August 08	16	136,368	(8,535)	(5.9%)
2008	Mon, June 09	17	127,216	(9,153)	(6.7%)
2009	Mon, August 10	17	123,900	(3,315)	(2.6%)
2010	Tue, July 06	17	133,297	9,397	7.6%
2011	Thu, July 21	17	154,095	20,798	15.6%
2012	Tue, July 17	17	150,879	(3,216)	(2.1%)
2013	Thu, July 18	17	153,790	2,911	1.9%
2014	Tue, June 17	18	138,448	(15,341)	(10.0%)
2015	Tue, July 28	17	140,266	1,818	1.3%
2016	Thu, August 11	16	148,577	8,311	5.9%
2017	Wed, July 19	18	142,387	(6,190)	(4.2%)
2018	Tue, August 28	17	147,042	4,656	3.3%
2019	Fri, July 19	18	148,228	1,185	0.8%
2020	Mon, July 20	17	141,449	(6,778)	(4.6%)

Figure 3-9 compares prices and load on the peak load days in 2019 and 2020. The average, real-time LMP for the July 20, 2020, peak load hour was $74.91 and for the July 19, 2019 peak load hour it was $37.47.

Figure 3-9 Peak load day comparison: Friday, July 19, 2019 and Monday, July 20, 2020



12 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.

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

14 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.

Real-Time Demand

PJM average hourly real-time demand in 2020 decreased by 4.0 percent from 2019, from 88,120 MWh to 84,584 MWh.[15] PJM average hourly real-time demand including exports in 2020 decreased by 3.1 percent from 2019, from 92,920 MWh to 90,059 MWh. Both the weather and COVID-19 played a role in this significant drop in demand.

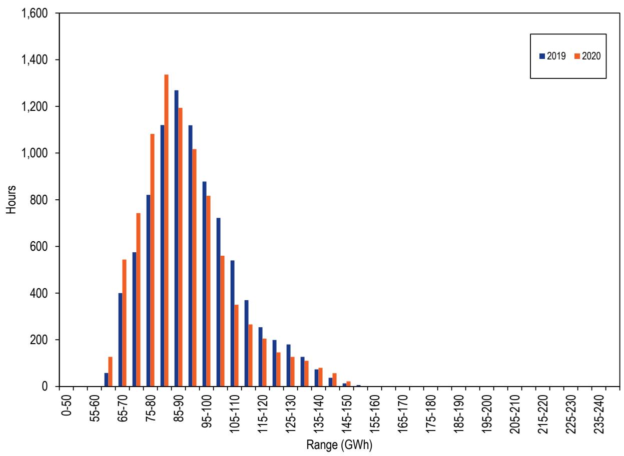
In the PJM Real-Time Energy Market, there are two types of demand:

- **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.

PJM Real-Time Demand Duration

Figure 3-10 shows the distribution of hourly PJM real-time load plus exports in 2019 and 2020.[16]

Figure 3-10 Distribution of real-time accounting load plus exports: 2019 and 2020[17]



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

16 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>.

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

PJM Real-Time, Average Load

Table 3-7 presents real-time hourly demand summary statistics for 2001 through 2020.[18] Real-time annual load in 2020 reached its lowest level since 2011.

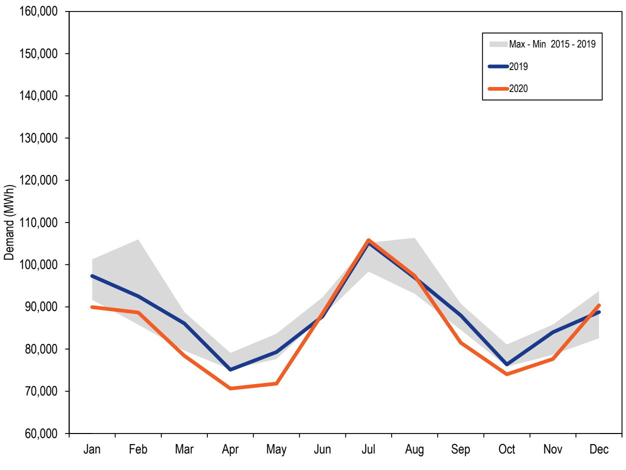
Table 3-7 Real-time load and real-time load plus exports: 2001 through 2020

	PJM Real-Time Demand (MWh)				Year to Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
2001	30,297	5,873	32,165	5,564	NA	NA	NA	NA
2002	35,776	7,976	37,676	8,145	18.1%	35.8%	17.1%	46.4%
2003	37,395	6,834	39,380	6,716	4.5%	(14.3%)	4.5%	(17.5%)
2004	49,963	13,004	54,953	14,947	33.6%	90.3%	39.5%	122.6%
2005	78,150	16,296	85,301	16,546	56.4%	25.3%	55.2%	10.7%
2006	79,471	14,534	85,696	15,133	1.7%	(10.8%)	0.5%	(8.5%)
2007	81,681	14,618	87,897	15,199	2.8%	0.6%	2.6%	0.4%
2008	79,515	13,758	86,306	14,322	(2.7%)	(5.9%)	(1.8%)	(5.8%)
2009	76,034	13,260	81,227	13,792	(4.4%)	(3.6%)	(5.9%)	(3.7%)
2010	79,611	15,504	85,518	15,904	4.7%	16.9%	5.3%	15.3%
2011	82,541	16,156	88,466	16,313	3.7%	4.2%	3.4%	2.6%
2012	87,011	16,212	92,135	16,052	5.4%	0.3%	4.1%	(1.6%)
2013	88,332	15,489	92,879	15,418	1.5%	(4.5%)	0.8%	(3.9%)
2014	89,099	15,763	94,471	15,677	0.9%	1.8%	1.7%	1.7%
2015	88,594	16,663	92,665	16,784	(0.6%)	5.7%	(1.9%)	7.1%
2016	88,601	17,229	93,551	17,498	0.0%	3.4%	1.0%	4.3%
2017	86,618	15,170	91,015	15,083	(2.2%)	(11.9%)	(2.7%)	(13.8%)
2018	90,308	15,982	94,351	16,142	4.3%	5.4%	3.7%	7.0%
2019	88,120	15,867	92,920	16,085	(2.4%)	(0.7%)	(1.5%)	(0.4%)
2020	84,584	16,016	90,059	16,233	(4.0%)	0.9%	(3.1%)	0.9%

PJM Real-Time, Monthly Average Load

Figure 3-11 compares the real-time, monthly average loads in 2019 and 2020, with the historic five year range. The monthly average loads in 2020, were lower than the minimum of the past five years in January, March, April, May , September, October, and November but higher than the maximum of the past five years in July.

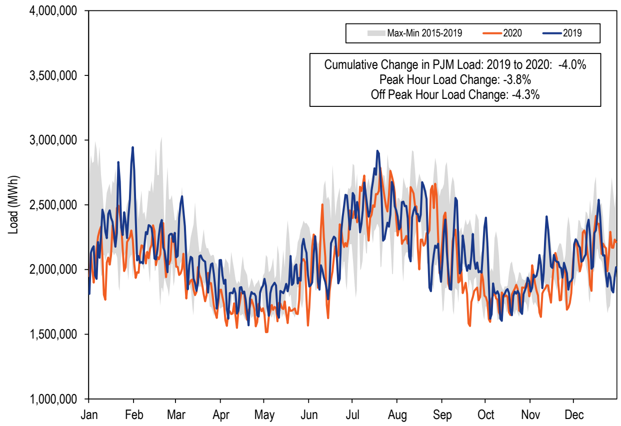
Figure 3-11 Real-time monthly average hourly load: 2019 through 2020



18 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.

Figure 3-12 compares the real-time, average daily loads in 2019 and 2020, with the historic five year range.

Figure 3-12 Real-time daily load: 2019 and 2020



PJM real-time load is significantly affected by weather conditions. Table 3-8 compares the PJM monthly heating and cooling degree days in 2019 and 2020.[19] Heating degree days decreased 11.3 percent compared to 2019. Cooling degree days decreased 2.2 percent compared to 2019.

Table 3-8 Heating and cooling degree days: 2019 through 2020

	2019		2020		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	909	0	698	0	(23.3%)	0.0%
Feb	688	0	652	0	(5.2%)	0.0%
Mar	607	0	385	0	(36.6%)	0.0%
Apr	145	0	279	0	92.1%	0.0%
May	23	90	105	59	363.0%	(33.9%)
Jun	0	210	0	262	0.0%	24.9%
Jul	0	423	0	464	0.0%	9.7%
Aug	0	312	0	342	0.0%	9.7%
Sep	0	211	13	120	0.0%	(43.3%)
Oct	100	31	139	1	38.5%	(95.3%)
Nov	576	0	313	0	(45.7%)	0.0%
Dec	675	0	719	0	6.6%	0.0%
Total	3,723	1,277	3,302	1,249	(11.3%)	(2.2%)

Figure 3-13 and Figure 3-14 show the real-time daily load and the weather normalized load for 2019 and 2020.

Weather normalized load is calculated using the historic relationship between PJM daily load and HDD, CDD, and time of year for 2015 through 2018. Figure 3-13 shows that the weather normalized load was very close to actual load under market conditions in 2019. Figure 3-14 shows that from March through May 2020, the actual load was significantly less than the weather normalized load. The difference was a result of changes in the pattern and level of activity due to COVID-19 and associated policy responses.

Figure 3-13 Real-time daily load and weather normalized load: 2019

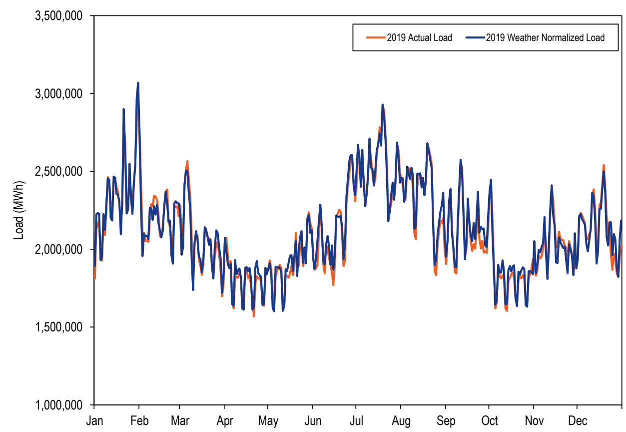
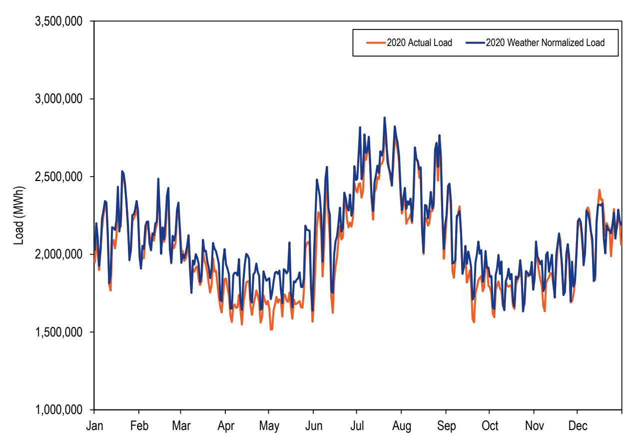


Figure 3-14 Real-time daily load and weather normalized load: 2020



19 A heating degree day is defined as the number of degrees that a day's average temperature is below 65 degrees F (the temperature below which buildings need to be heated). A cooling degree day is the number of degrees that a day's average temperature is above 65 degrees F (the temperature when people will start to use air conditioning to cool buildings). PJM uses 60 degrees F for a heating degree day as stated in Manual 19.
Heating and cooling degree days are calculated by weighting the temperature at each weather station in the individual transmission zones using weights provided by PJM in Manual 19. Then the temperature is weighted by the real-time zonal accounting load for each transmission zone. After calculating an average hourly temperature across PJM, the heating and cooling degree formulas are used to calculate the daily heating and cooling degree days, which are summed for monthly reporting. The weather stations that provided the basis for the analysis are ABE, ACY, AVP, BWI, CAK, CLE, CMH, CRW, CVG, DAY, DCA, ERI, EWR, FWA, IAD, ILG, IPT, LEX, ORD, ORF, PHL, PIT, RIC, ROA, TOL and WAL.

Table 3-9 compares the total monthly actual load and the weather normalized load. Load was 3.4 percent below weather normalized load in 2020.

Table 3-9 Actual load less weather normalized load: 2019 and 2020

	2019			2020		
	Actual Load	Weather Normalized Load	Percent Difference	Actual Load	Weather Normalized Load	Percent Difference
Jan	72,405,320	72,846,056	(0.6%)	66,905,774	68,256,113	(2.0%)
Feb	62,176,069	61,581,587	1.0%	61,717,353	62,471,212	(1.2%)
Mar	63,964,185	63,697,555	0.4%	58,258,178	60,459,812	(3.6%)
Apr	54,064,759	54,471,968	(0.7%)	50,864,950	55,116,626	(7.7%)
May	59,002,657	59,391,808	(0.7%)	53,430,088	57,904,128	(7.7%)
Jun	63,176,026	64,421,443	(1.9%)	63,666,037	67,406,845	(5.5%)
Jul	78,266,354	78,376,631	(0.1%)	78,749,183	80,856,404	(2.6%)
Aug	72,114,112	73,043,672	(1.3%)	72,425,029	74,173,773	(2.4%)
Sep	63,336,261	64,602,899	(2.0%)	58,683,018	60,988,913	(3.8%)
Oct	56,811,067	57,485,940	(1.2%)	55,061,813	56,572,150	(2.7%)
Nov	60,560,333	60,431,775	0.2%	55,993,432	57,678,640	(2.9%)
Dec	66,051,844	66,183,659	(0.2%)	67,232,280	67,074,317	0.2%
Annual	771,928,988	776,534,994	(0.6%)	742,987,135	768,958,933	(3.4%)

Day-Ahead Demand

PJM average hourly day-ahead demand in 2020, including DECs and up to congestion transactions, decreased by 5.7 percent from 2019, from 112,588 MWh to 106,209 MWh. When exports are added, PJM average hourly day-ahead demand in 2020 decreased by 5.1 percent from 2019, from 115,444 MWh to 109,506 MWh.

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

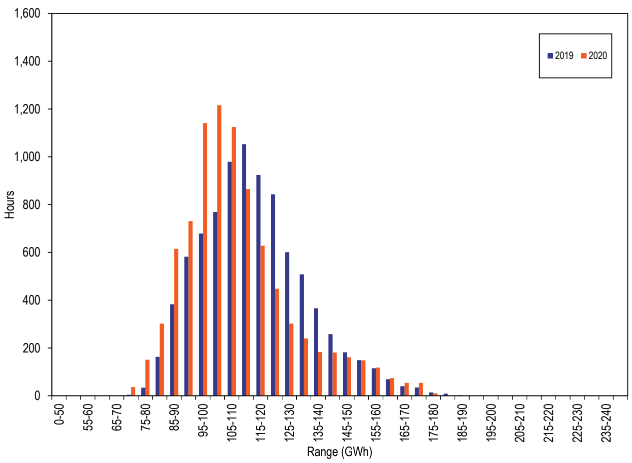
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero. A DEC can be submitted by any market participant.
- **Up to Congestion Transaction (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 total of the five types of cleared demand bids.

PJM Day-Ahead Demand Duration

Figure 3-15 shows the hourly distribution of PJM day-ahead demand in 2019 and 2020.

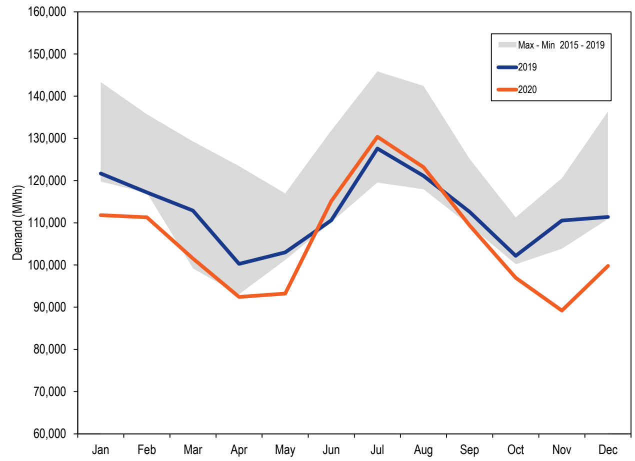
Figure 3-15 Distribution of day-ahead demand plus exports: 2019 and 2020[20]



PJM Day-Ahead, Monthly Average Demand

Figure 3-16 compares the day-ahead, monthly average hourly demand, including decrement bids and up to congestion transactions in 2019 and 2020 with the historic five-year range.

Figure 3-16 Day-ahead monthly average hourly demand: 2019 through 2020



PJM Day-Ahead, Average Demand

Table 3-10 presents day-ahead hourly demand summary statistics from 2001 through 2020.

Table 3-10 Average hourly day-ahead demand and day-ahead demand plus exports: 2001 through 2020

	PJM Day-Ahead Demand (MWh)				Year to Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2001	33,370	6,562	33,757	6,431	NA	NA	NA	NA
2002	42,305	10,161	42,413	10,208	26.8%	54.8%	25.6%	58.7%
2003	44,674	7,841	44,807	7,811	5.6%	(22.8%)	5.6%	(23.5%)
2004	62,101	16,654	63,455	17,730	39.0%	112.4%	41.6%	127.0%
2005	93,534	17,643	96,447	17,952	50.6%	5.9%	52.0%	1.3%
2006	98,527	16,723	101,592	17,197	5.3%	(5.2%)	5.3%	(4.2%)
2007	105,503	16,686	108,932	17,030	7.1%	(0.2%)	7.2%	(1.0%)
2008	101,903	15,871	105,368	16,119	(3.4%)	(4.9%)	(3.3%)	(5.3%)
2009	94,941	15,869	98,094	15,999	(6.8%)	(0.0%)	(6.9%)	(0.7%)
2010	103,937	21,358	108,069	21,640	9.5%	34.6%	10.2%	35.3%
2011	113,866	20,708	117,681	20,929	9.6%	(3.0%)	8.9%	(3.3%)
2012	131,612	17,421	134,947	17,527	15.6%	(15.9%)	14.7%	(16.3%)
2013	144,858	18,489	148,132	18,570	10.1%	6.1%	9.8%	6.0%
2014	142,251	32,664	146,120	32,671	(1.8%)	76.7%	(1.4%)	75.9%
2015	111,644	18,716	114,827	18,872	(21.5%)	(42.7%)	(21.4%)	(42.2%)
2016	127,374	21,513	130,808	21,803	14.1%	14.9%	13.9%	15.5%
2017	125,794	19,402	128,757	19,625	(1.2%)	(9.8%)	(1.6%)	(10.0%)
2018	110,091	19,521	112,885	19,724	(12.5%)	0.6%	(12.3%)	0.5%
2019	112,588	18,163	115,444	18,386	2.3%	(7.0%)	2.3%	(6.8%)
2020	106,209	18,972	109,506	19,270	(5.7%)	4.5%	(5.1%)	4.8%

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

Real-Time and Day-Ahead Demand

Table 3-11 presents summary statistics for 2019 and 2020 day-ahead and real-time demand. The last two columns of Table 3-11 are the day-ahead demand minus the real-time demand: the first column is the total physical day-ahead load (fixed demand plus price-sensitive demand) less the physical real-time load; and the second column is the total day-ahead demand less the total real-time demand.

Table 3-11 Cleared day-ahead and real-time demand (MWh): 2019 and 2020

		Day-Ahead						Real-Time		Day-Ahead Less Real-Time	
	Year	Fixed Demand	Price Sensitive	DEC Bids	Up-to Congestion	Exports	Total Demand	Load	Total Demand	Load	Demand
Average	2019	86,756	1,265	3,704	20,862	2,857	115,444	88,120	92,920	(99)	22,524
	2020	82,417	1,217	4,318	18,257	3,297	109,506	84,584	90,059	(950)	19,447
Median	2019	84,908	1,274	3,370	20,664	2,754	113,793	85,857	90,527	326	23,267
	2020	79,869	1,215	3,847	19,196	3,247	105,764	81,950	87,286	(866)	18,478
Standard Deviation	2019	15,212	239	1,707	4,732	782	18,386	15,867	16,085	(416)	2,301
	2020	15,356	248	2,101	5,908	753	19,270	16,016	16,233	(412)	3,037
Peak Average	2019	95,383	1,393	4,137	22,303	2,940	126,155	96,383	101,199	392	24,956
	2020	90,254	1,344	5,091	18,960	3,464	119,113	92,373	97,921	(774)	21,193
Peak Median	2019	93,202	1,413	3,864	22,120	2,859	123,167	93,730	98,524	885	24,643
	2020	87,768	1,369	4,670	19,883	3,408	113,946	89,399	94,731	(263)	19,215
Peak Standard Deviation	2019	13,194	224	1,726	4,506	829	15,655	14,229	14,688	(811)	967
	2020	14,448	252	2,189	5,866	780	18,850	15,400	15,757	(700)	3,093
Off-Peak Average	2019	79,234	1,153	3,327	19,606	2,784	106,104	80,915	85,701	(528)	20,403
	2020	75,519	1,106	3,637	17,639	3,151	101,050	77,729	83,140	(1,105)	17,911
Off-Peak Median	2019	77,517	1,161	3,011	19,274	2,690	104,073	78,928	83,519	(250)	20,555
	2020	73,429	1,115	3,243	18,490	3,126	98,821	75,553	80,963	(1,009)	17,858
Off-Peak Standard Deviation	2019	12,647	190	1,597	4,565	730	15,227	13,539	13,579	(702)	1,649
	2020	12,569	183	1,758	5,877	697	15,256	13,161	13,216	(409)	2,040

Figure 3-17 shows the average hourly cleared volumes of day-ahead demand and real-time demand for 2020. The day-ahead demand includes day-ahead load, day-ahead exports, decrement bids and up to congestion transactions. The real-time demand includes real-time load and real-time exports.

Figure 3-17 Day-ahead and real-time demand (Average hourly volumes): 2020

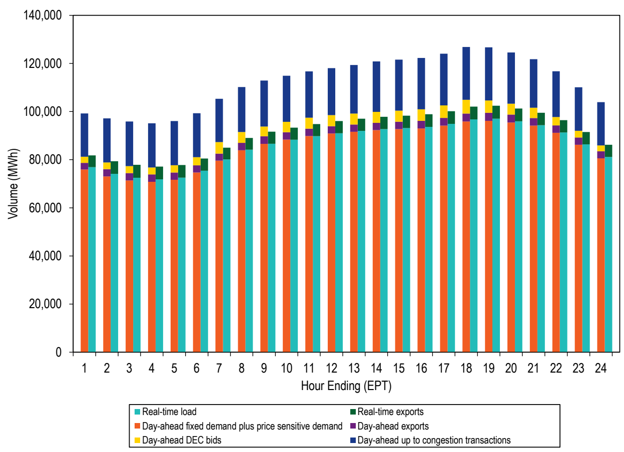
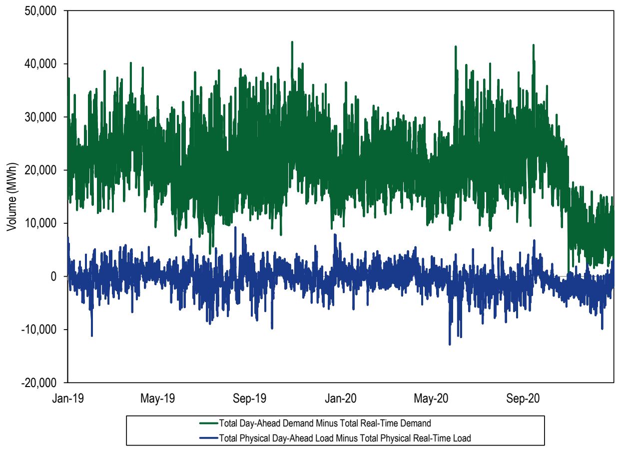


Figure 3-18 shows the difference between the day-ahead and real-time average daily demand for 2019 and 2020.

Figure 3-18 Difference between day-ahead and real-time demand (Average daily volumes): 2019 through 2020



Market Behavior

Supply and Demand: Load and Spot Market

Participants in the PJM Real-Time and Day-Ahead Energy Markets can use their own generation to meet load, to sell in the bilateral market or to sell in the spot market in any hour. Participants can both buy and sell via bilateral contracts and buy and sell in the spot market in any hour. If a participant has positive net bilateral transactions in an hour, it is buying energy through bilateral contracts (bilateral purchase). If a participant has negative net bilateral transactions in an hour, it is selling energy through bilateral contracts (bilateral sale). If a participant has positive net spot transactions in an hour, it is buying energy from the spot market (spot purchase). If a participant has negative net spot transactions in an hour, it is selling energy to the spot market (spot sale).

Load is served by a combination of self supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In addition to directly serving load, load serving entities can also transfer their responsibility to serve load to other parties through InSchedule transactions referred to as wholesale load responsibility (WLR), retail load responsibility (RLR) transactions and generation responsibility. When the responsibility to serve load is transferred via a bilateral contract, the entity to which the responsibility is transferred becomes the load serving entity. Supply from its own generation (self supply) means that the parent company is generating power from resources that it owns. Supply from bilateral purchases means that the parent company is purchasing power under bilateral contracts from a nonaffiliated company at the same time that it is meeting load. Supply from spot market purchases means that the parent company is generating less power from owned resources and/or purchasing less power under bilateral contracts than required to meet load at a defined time and, therefore, is purchasing the required balance from the spot market.

The PJM system's reliance on self supply, bilateral contracts and spot purchases to meet real-time load is calculated by summing across all the parent companies of PJM billing organizations that serve load in the real-time and day-ahead energy markets for each hour.

Real-Time Load and Spot Market

Table 3-12 shows the monthly average share of real-time load served by each parent company's self supply, bilateral contracts and spot purchases in 2019 and 2020. In 2020, 16.1 percent of real-time load was supplied by bilateral contracts, 24.7 percent by spot market purchase and 59.2 percent by self supply. Compared to 2019, reliance on bilateral contracts increased by 0.8 percentage points, reliance on spot supply decreased by 0.1 percentage points and reliance on self supply decreased by 0.7 percentage points.

Table 3-12 Sources of real-time supply: 2019 through 2020[21]

	2019			2020			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	15.4%	23.9%	60.7%	17.1%	24.7%	58.2%	1.7%	0.8%	(2.5%)
Feb	15.4%	25.2%	59.4%	16.6%	23.8%	59.6%	1.2%	(1.3%)	0.1%
Mar	15.2%	27.5%	57.4%	16.9%	23.8%	59.3%	1.8%	(3.7%)	2.0%
Apr	16.7%	24.8%	58.5%	17.2%	21.5%	61.3%	0.4%	(3.3%)	2.9%
May	16.0%	24.3%	59.7%	17.2%	21.6%	61.1%	1.2%	(2.6%)	1.5%
Jun	15.0%	23.8%	61.1%	15.9%	23.3%	60.7%	0.9%	(0.5%)	(0.4%)
Jul	14.4%	23.8%	61.8%	15.3%	25.5%	59.2%	1.0%	1.7%	(2.7%)
Aug	15.3%	24.1%	60.6%	15.9%	24.4%	59.7%	0.6%	0.3%	(0.9%)
Sep	15.5%	25.5%	58.9%	16.1%	25.7%	58.3%	0.5%	0.1%	(0.7%)
Oct	16.7%	27.7%	55.6%	16.0%	28.1%	56.0%	(0.7%)	0.3%	0.4%
Nov	15.7%	28.6%	55.6%	15.3%	26.3%	58.4%	(0.4%)	(2.4%)	2.8%
Dec	19.8%	22.6%	57.6%	14.9%	26.4%	58.7%	(4.8%)	3.8%	1.0%
Annual	15.4%	24.7%	59.9%	16.1%	24.7%	59.2%	0.8%	(0.1%)	(0.7%)

Day-Ahead Load and Spot Market

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

Table 3-13 shows the monthly average share of day-ahead demand served by each parent company's self supply, bilateral contracts and spot purchases in 2019 and 2020. In 2020, 15.3 percent of day-ahead demand was supplied by bilateral contracts, 25.1 percent by spot market purchases and 59.6 percent by self supply. Compared to 2019, reliance on bilateral contracts increased by 0.7 percentage points, reliance on spot supply increased by 0.2 percentage points, and reliance on self supply decreased by 0.9 percentage points.

Table 3-13 Sources of day-ahead supply: 2019 through 2020

	2019			2020			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	14.5%	24.0%	61.5%	16.2%	24.5%	59.3%	1.6%	0.5%	(2.1%)
Feb	14.6%	24.9%	60.5%	15.6%	23.5%	60.9%	1.0%	(1.4%)	0.5%
Mar	14.3%	27.2%	58.5%	15.7%	24.0%	60.3%	1.4%	(3.3%)	1.9%
Apr	15.8%	25.2%	59.0%	16.2%	22.5%	61.3%	0.3%	(2.7%)	2.4%
May	14.8%	25.2%	60.0%	16.1%	22.8%	61.1%	1.3%	(2.4%)	1.1%
Jun	14.2%	24.4%	61.4%	15.1%	24.1%	60.8%	0.9%	(0.3%)	(0.5%)
Jul	13.9%	23.8%	62.3%	14.6%	25.6%	59.8%	0.7%	1.8%	(2.5%)
Aug	14.7%	24.2%	61.1%	15.1%	24.8%	60.0%	0.4%	0.7%	(1.1%)
Sep	14.8%	25.9%	59.3%	15.1%	26.3%	58.6%	0.3%	0.4%	(0.7%)
Oct	15.9%	27.8%	56.3%	15.2%	28.6%	56.2%	(0.7%)	0.9%	(0.1%)
Nov	14.9%	28.2%	56.8%	14.6%	27.1%	58.2%	(0.3%)	(1.1%)	1.4%
Dec	19.0%	22.3%	58.7%	14.2%	27.4%	58.4%	(4.8%)	5.1%	(0.3%)
Annual	14.6%	24.9%	60.5%	15.3%	25.1%	59.6%	0.7%	0.2%	(0.9%)

Generator Offers

In day-ahead market offers, generators define the commitment status and the dispatch status of their units. The commitment status indicates whether the generation owner will turn the unit on, regardless of market signals, or whether the generation owner will allow the energy market to commit the unit. The dispatch status indicates whether the generation owner will produce at full output regardless of market signals or whether the generation owner will follow PJM market dispatch signals. Market commitment is designated as economic status in the offer, allowing the market to decide whether to commit the unit at its economic minimum MW level. The Eco Min column in Table 3-14

21 Table 3-1 and Table 3-2 were calculated as of January 11, 2021. The values may change slightly as billing values are updated by PJM.

is the economic minimum MW of units offering with economic commitment status. Self scheduling is designated as must run status in the offer, meaning the unit owner will commit the unit to run regardless of market signals. Self scheduling includes committing the unit at economic minimum and permitting the balance to be dispatchable or block loading the full output of the unit. The Must Run column in Table 3-14 is the economic minimum MW of units offering with must run commitment status. Economic minimum for a self scheduled unit (must run commitment status) means the output level at which the unit self commits, including any point between the actual, physical economic minimum level and economic maximum level of the unit.

Table 3-14 shows the percent of MW offered as must run, the percent of MW of economic minimum levels of units offered as dispatchable, the percent of MW offered as dispatchable by price range, the percent of MW offered as maximum emergency and the total percent of MW offered as dispatchable. For example, combined cycle offers in the day-ahead energy market are comprised of 7.4 percent must run MW, 41.0 percent economic minimum MW for dispatchable units, 50.7 percent dispatchable MW, and 1.0 percent as emergency maximum MW.

For each price level along the energy offer curves of units in both must run and economic status, Table 3-14 shows the dispatchable MW for each price level by unit type. Units can also designate all or a portion of their capacity as emergency MW. Table 3-14 shows that 1.0 percent of offered MW are emergency MW. Emergency MW are calculated as the difference between the day-ahead submitted emergency max MW and economic max MW. In some cases, the higher share of emergency MW is a result of offer behavior and does not necessarily represent the actual availability of the emergency MW in real time.

In the day-ahead market in 2020, 21.8 percent of MW were offered as must run, 32.1 percent were offered as economic minimum MW for dispatchable units, 45.0 percent were offered as dispatchable MW, and 1.0 percent were offered as emergency maximum MW.

Table 3-14 Dispatchable status of day-ahead energy offers: 2020

			Dispatchable Range											
Unit Type	Must Run	Eco Min	($300) - $0	$0 - $25	$25 - $50	$50 - $75	$75 - $100	$100 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1000	Emergency MW	Dispatchable Percent
CC	7.4%	41.0%	0.3%	44.1%	3.6%	0.7%	0.7%	1.2%	0.1%	0.0%	0.0%	0.0%	1.0%	50.7%
CT	0.5%	68.1%	0.0%	10.3%	8.0%	1.9%	2.0%	6.6%	0.8%	0.1%	0.0%	0.0%	1.5%	29.8%
Diesel	0.0%	100.0%	-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	80.1%	0.1%	3.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	16.8%	3.0%
Nuclear	70.1%	5.4%	15.6%	8.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	24.5%
Solar	22.0%	0.3%	77.6%	-0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	77.6%
Steam - Coal	19.2%	19.0%	0.1%	46.7%	12.6%	0.9%	0.3%	0.3%	0.0%	0.1%	0.0%	0.0%	0.7%	61.1%
Steam - Other	6.2%	34.2%	4.0%	21.8%	10.5%	3.2%	5.4%	11.7%	2.3%	0.0%	0.0%	0.0%	0.8%	58.9%
Wind	7.3%	1.0%	84.6%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	6.6%	85.1%
Other	20.2%	44.6%	4.3%	8.8%	1.6%	0.8%	0.4%	12.4%	2.7%	0.0%	0.0%	0.0%	4.1%	31.1%
Total	21.8%	32.1%	4.7%	29.3%	6.3%	1.0%	1.0%	2.4%	0.3%	0.1%	0.0%	0.0%	1.0%	45.0%

Hourly Offers and Intraday Offer Updates

All participants are able to make hourly offers. Participants must opt in on a monthly basis to make intraday offer updates. Participants that have opted in can only make updates if their fuel cost policy defines the intraday offer update process. Table 3-15 shows the daily average number of units that make hourly offers, that opted in to intraday offer updates and that make intraday offer updates. In 2020, an average of 310 units per day made hourly offers, an increase of three units from 2019. In 2020, 398 units opted in for intraday offer updates, an increase of 20 units from 2019. In 2020, an average of 134 units made intraday offer updates each day, a decrease of eight units from 2019.

Table 3-15 Daily average number of units making hourly offers, opted in for intraday offers and making intraday offer updates: 2019 and 2020

	Fuel Type	2019	2020	Difference
Hourly Offers	Natural Gas	286	291	5
	Other Fuels	21	19	(2)
	Total	307	310	3
Opt In	Natural Gas	338	349	11
	Other Fuels	40	49	9
	Total	378	398	20
Intraday Offer Updates	Natural Gas	135	128	(7)
	Other Fuels	7	6	(1)
	Total	142	134	(8)

ICAP Must Offer Requirement

Generation capacity resources are required to offer their full ICAP MW into the day-ahead and real-time energy market, or report an outage for the difference.[22] 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.

Solar, wind, landfill gas, hydro and batteries can satisfy the must offer requirement by self scheduling or offering as dispatchable. The must offer requirement is thus not applied to these intermittent resource types and compliance is not enforceable.

The current enforcement of the ICAP must offer requirement is inadequate. 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. 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 in a systematic way to ensure consistency.

Ambient derates are an example of 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 offers in the energy market, the derates are never reported as outages in eGADS and are therefore not outages for purposes of defining capacity.

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 intermittent resources be subject to an enforceable ICAP must offer rule 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 2020. On average for all hours, 1,167 MW did not meet the ICAP must offer requirement, but for 10 percent of the hours 2,026 MW did not meet the must offer requirement. These MW levels are larger than the reserve shortages that triggered scarcity pricing in 2020 and larger than most supply contingencies that led to synchronized reserve events in 2020.

Table 3-16 Average hourly estimated capacity (MW) failing the ICAP must offer requirement: 2020

Month	90th Percentile	Average	10th Percentile
Jan-20	1,683	1,001	447
Feb-20	1,368	752	215
Mar-20	1,924	1,250	752
Apr-20	2,192	1,123	510
May-20	2,137	1,291	693
Jun-20	2,205	1,431	519
Jul-20	1,914	1,237	619
Aug-20	1,180	681	320
Sep-20	1,634	910	411
Oct-20	2,358	1,400	668
Nov-20	2,554	1,596	705
Dec-20	2,063	1,320	578
2020	2,026	1,167	487

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 maximum emergency MW. FERC allows generators to include emergency maximum MW as part of ICAP offered in the capacity market.

22 Section 1.10.1A(d) of Schedule 1 to the PJM Operating Agreement.

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.[23]

The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy.[24] Capacity resources should offer their full output in the energy market and subject to economic dispatch. The result will be incentives for correct 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. The capacity performance rules in the capacity market provide incentives for such output during PAI.

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, 10 percent of hours in September 2020 had maximum emergency MW greater than or equal to 3,526 MW while 10 percent of hours in January had maximum emergency MW less than 1,320 MW. The hourly average, in 2020, was 2,248 MW offered as maximum emergency.

Table 3-17 Maximum emergency MW by month

Month	90th Percentile	Average	10th Percentile
Jan-20	2,332	1,814	1,320
Feb-20	2,547	1,998	1,453
Mar-20	2,799	2,197	1,499
Apr-20	3,139	2,653	2,272
May-20	2,734	2,128	1,565
Jun-20	3,044	2,402	1,889
Jul-20	2,886	2,407	1,775
Aug-20	2,809	2,292	1,808
Sep-20	3,526	2,625	2,001
Oct-20	2,875	2,279	1,453
Nov-20	2,451	2,015	1,589
Dec-20	2,769	2,174	1,674
2020	2,883	2,248	1,624

Parameter Limited Schedules

Cost-Based Offers

All capacity resources in PJM are required to submit at least one cost-based offer. For the 2018/2019 and 2019/2020 Delivery Years, PJM procured two types of capacity resources, capacity performance resources and base capacity resources. For the 2020/2021 Delivery Year, PJM procured only capacity performance resources. Cost-based offers, submitted by capacity resources for a defined set of technologies, are parameter limited based on a unit specific parameter limits. Nuclear, wind, solar and hydro units are not subject to parameter limits.

Price-Based Offers

All capacity resources that choose to offer price-based offers are required to make available at least one price-based parameter limited offer (referred to as price-based PLS). For resources that are not capacity resources, the price-based parameter limited schedule is to be used by PJM for committing generation resources when a maximum emergency generation alert is declared. For capacity performance resources, the price-based parameter limited schedule is to be used by PJM for committing generation resources when hot weather alerts and cold weather alerts are declared. For base capacity resources (during the 2018/2019 and 2019/2020 Delivery Years only), the price-based parameter limited schedule is to be used by PJM for committing generation resources when hot weather alerts are declared.

The MMU recommends that in order to ensure effective market power mitigation, PJM always enforce parameter limited values when the TPS test is failed and during high load conditions such as cold and hot weather alerts and emergency conditions.[25] 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. Instead of ensuring that parameter limits apply, PJM chooses the lower of the price-based schedule and the cost-based parameter limited schedule when a resource fails the TPS test. The current implementation is not consistent with the goal of having parameter limited schedules, which is to prevent the use of inflexible operating parameters to exercise market power.

23 OA Schedule 1 Section 1.10.1A (d)

24 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).

25 *See* Protest of the Independent Market Monitor for PJM, Docket No. ER20-995 (February 25, 2020).

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 2020. The analysis includes units with technologies that are subject to parameter limits and offer both price-based and cost based schedules.[26] 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 30.3 percent of unit hours for units that failed the TPS test were committed on price-based schedules that were less flexible than their cost based schedules.

Table 3-18 Parameter mitigation for units failing TPS test: 2020

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	31,381	30.3%
Committed on price schedule as flexible as cost	9,137	8.8%
Total committed on price schedule without parameter limits	40,518	39.1%
Committed on cost (cost capped)	62,146	59.9%
Committed on price PLS	1,013	1.0%
Total committed on PLS schedules (cost or price PLS)	63,159	60.9%

The MMU analyzed the extent of parameter mitigation in the day-ahead energy market for units in regions where a cold or hot weather alert was declared in 2020. PJM declared cold weather alerts on three days and hot weather alerts on 19 days in 2020.[27] The analysis includes units with technologies that are subject to parameter limits, with a CP commitment, in the zones where the cold and hot weather alerts were declared. Base capacity resources are subject to commitment on the price PLS schedule during hot weather alerts and not during cold weather alerts. Table 3-19 shows that 34.5 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.[28]

Table 3-19 Parameter mitigation during weather alerts: 2020

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	31,069	34.5%
Committed on price schedule as flexible as PLS	15,208	16.9%
Total committed on price schedule without parameter limits	46,277	51.4%
Committed on cost (cost capped)	3,228	3.6%
Committed on price PLS	40,495	45.0%
Total committed on PLS schedules (cost or price PLS)	43,723	48.6%

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 MMU recommends that in order to ensure effective market power mitigation when the TPS test is failed and during high load conditions such as cold and hot weather alerts or more severe emergencies, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available non-PLS price-based offer, and that the price-MW pairs in the price-based PLS offer be exactly equal to the price-based non-PLS offer. This recommendation would ensure that market power that results from inflexible parameters is mitigated during high load conditions and when a market seller fails the TPS test, consistent with the goal of having parameter limited schedules.

26 In previous reports, this analysis included all units that failed the TPS test, regardless of the technology type. The analysis in this report is updated to include only those units with technologies that are subject to parameter limits on their cost-based and price-based parameter limited schedules.

27 *2020 State of the Market Report for PJM*, Section 3: Energy Market, at Emergency Procedures.

28 In previous reports, this analysis included all units with CP commitment in the zones with the emergency alerts regardless of the technology type. The analysis in this report is updated to include only those units with technologies that are subject to parameter limits on their cost-based and price-based parameter limited schedules.

Parameter Limits

Beginning in the 2016/2017 Delivery Year, resources that had capacity performance (CP) commitments were required to submit, in their parameter limited schedules (cost-based offers and price-based PLS offers), unit specific parameters that reflect the physical capability of the technology type of the resource. For the 2018/2019 and 2019/2020 Delivery Years, resources that have base capacity commitments were also required to submit, in their parameter limited schedules, unit specific parameters that reflect the physical capability of the technology type of the resource. Startup and notification times are limited for capacity performance resources beginning June 1, 2016, and base capacity resources beginning June 1, 2018, in accordance with predetermined unit specific parameter limits. The unit specific parameter limits for capacity performance and base 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.

Beginning June 1, 2018, all RPM procured capacity resources were either capacity performance or base capacity resources. Entities that elected the fixed resource requirement (FRR) option were allowed to procure the legacy annual capacity product for the 2018/2019 Delivery Year. Beginning June 1, 2019, all capacity resources, including resources in FRR capacity plans, are either capacity performance or base capacity resources. Beginning June 1, 2020, all capacity resources, including resources in FRR capacity plans, are capacity performance resources. 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. However, the tariff currently does not make it clear what parameter limit values are applicable for resources without a capacity commitment. 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 performance resources.

Unit Specific Adjustment Process

Market participants can request an adjustment to the default values of parameter limits for capacity performance and base 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 performance resources and base 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.[29] 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 been provided unit specific adjustments for some of the parameters. Table 3-20 shows, for the delivery year beginning June 1, 2020, the number of units that submitted and had approved unit specific parameter limit adjustments, and the number of units that used the default parameter limits published by PJM. Table 3-20 shows that 85.3 percent of subcritical coal steam units and 88.4 percent of supercritical coal steam units had an adjustment approved to one or more parameter limits from the default limits published by

29 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>.

PJM, while only 31.6 percent of combined cycle units, and 35.0 percent of frame combustion turbine units, and 24.2 percent of aero derivative combustion turbine units had an adjustment approved to one or more parameter limits from the default limits published by PJM.

Table 3-20 Adjusted unit specific parameter limit statistics: 2020/2021 Delivery Year

Technology Classification	Units Using Default Parameter Limits	Units with One or More Adjusted Parameter Limits	Percentage of Units with One or More Adjusted Parameter Limits
Aero CT	125	40	24.2%
Frame CT	178	96	35.0%
Combined Cycle	80	37	31.6%
Reciprocating Internal Combustion Engines	68	3	4.2%
Solid Fuel NUG	36	6	14.3%
Oil and Gas Steam	10	15	60.0%
Subcritical Coal Steam	10	58	85.3%
Supercritical Coal Steam	5	38	88.4%
Pumped Storage	10	0	0.0%

Real-Time Values

The MMU recommends that PJM market rules recognize the difference between operational parameters that indicate to PJM operators what a unit is capable of during the operating day and the parameters that used to calculate uplift payments. The parameters provided to PJM operators each day should reflect what units are physically capable of so that operators can operate the system. However, the parameters which determine the amount of uplift payments to those generators should reflect the flexibility goals of the capacity performance construct and the assignment of performance risk to generation owners.

PJM market rules allow generators to communicate a resource's current operational capabilities to PJM when a resource cannot operate according to the unit specific parameters. These values are called real-time values (RTVs). The real-time values submittal process is not specified in the PJM Operating Agreement. The process is defined in PJM Manual 11. Unlike parameter exceptions, the use of real-time values makes a unit ineligible for make whole payments, unless the market seller can justify such operation based on an actual constraint.[30]

In practice, real-time values were meant to be used to communicate lower Turn Down Ratios which result from reduced Economic Max MW due to a derate (partial outage) on a unit, or from a requirement to operate at a defined output for equipment tests, environmental tests, or inspections. The RTV functionality allows units to communicate accurate short term operational parameters to PJM without requiring PJM customers to pay additional uplift charges, if the unit operates out of the money for routine tests and inspections. However, using real-time values to extend the time to start parameters (startup times and notification times) or minimum run time or minimum down time is inconsistent with the goal of real-time values. The protection offered by making units ineligible for uplift is only effective if the unit is committed and operated out of the money because of the RTVs. In the case of the notification time parameter, start time parameter, minimum run time and minimum down time parameters, a longer real-time value decreases the likelihood of the unit being committed at all, and may prevent unit commitment in real time, making the RTV a mechanism for exercising market power through withholding and for failing to meet the obligations of capacity resources.

Currently, a resource that is staffed or has remote start capability and offers according to its physical capability, and a resource that makes the economic choice not to staff or invest in remote start and economically or physically withholds to decrease the likelihood of commitment, are compensated identically in the capacity market. If a market seller makes an economic decision to not staff the unit or to not have remote start capability, and uses real-time values to communicate the longer time to start to PJM, the unit's actual parameters are not recognized as inconsistent with its obligations as a capacity resource, not reflected in forced outages, and not reflected in eligibility for uplift payments. The market seller is able to withhold the unit in the energy market with no consequence, while other similarly situated units incur the costs associated with meeting their obligations.

The MMU recommends that PJM institute rules to assess a penalty for resources that choose to submit real-time values that are less flexible than their unit specific

30 See PJM Operating Agreement, Schedule 1, Section 3.2.3 (e).

parameter limits or approved parameter limit exceptions based on tariff defined justifications. The changes to the RTV rules proposed by PJM in the stakeholder process do not include a penalty and do not create incentives for resources to offer flexibly. PJM's proposed rules on RTVs instead encourage resources to use RTVs to offer parameter limited schedules with parameter values that violate the unit specific limits on days without weather alerts, with no consequences. PJM's proposed RTV rules weaken the market power protections offered by the parameter limited schedules rules in the PJM tariff.

Generator Flexibility Incentives under Capacity Performance

In its June 9, 2015, order on capacity performance, the Commission determined that capacity performance resources should be able to reflect actual constraints based on not just the resource physical constraints, but also other constraints, such as contractual limits that are not based on the physical characteristics of the generator.[31] The Commission directed that capacity performance resources with parameters based on nonphysical constraints should receive uplift payments.[32] The Commission directed PJM to submit tariff language 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.[33]

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 taking on 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, unlike generating unit operational limits, are a function of the interests and incentives of the parties to the contracts. 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 fact that a contract may be entered into by two willing parties does not mean that is the only possible arrangement between the two parties or that it is consistent with an efficient market outcome or that such a contract can reasonably impose costs on customers who were not party to the contract. The actual contractual terms are a function of the incentives and interests of the parties, who may be affiliates or have market power. The fact that a just and reasonable contract exists between a generation owner and a gas supplier does not mean that it is appropriate or efficient to impose the resultant costs on electric customers or that it incorporates an efficient allocation of performance risk between the generation owner and other market participants.

The approach to parameters defined in the June 9th Order will increase 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 and base capacity resources (during the June through September period) 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 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, to the extent possible, the incentives to follow PJM's dispatch instructions during high demand conditions. The proposed operating parameters should be based on the physical capability of the Reference Resource used in the Cost of New Entry, currently two GE Frame 7FA turbines with dual fuel capability. All resources that are less flexible than the reference resource are expected to be scheduled and running during high demand conditions anyway, while the flexible CTs that are used as peaking plants would still have the incentive to follow LMP and dispatch

31 151 FERC ¶ 61,208 at P 437 (2015) (June 9th Order).
32 *Id* at P 439.
33 *Id* at P 440.

instructions. CCs would also have the capability to be as flexible as the reference resource. These units will be exempt from nonperformance charges and made whole as long as they perform in accordance with their parameters. This ensures that all the peaking units that are needed by PJM for flexible operation do not self schedule at their maximum output, and follow PJM dispatch instructions during high demand conditions. If any of the less flexible resources need to be dispatched down by PJM for reliability reasons, they would be exempt from nonperformance charges.

Such an approach is consistent with the Commission's no excuses policy for nonperformance because the flexibility target is set based on the optimal OEM-defined capability for the marginal resource that is expected to meet peak demand, which is consistent with the level of performance that customers are paying for in the capacity market. Any resource that is less flexible is not excused for nonperformance and any resource that meets the flexibility target is performing according to the commitments made in the capacity market.

The June 9th Order pointed out that the way to ensure that a resource's parameters are exposed to market consequences is to not allow any parameter limitations as an excuse for nonperformance. The same logic should apply to energy market uplift rules. A resource's parameters should be exposed to market consequences and the resource should not be made whole if it is operating less flexibly than the reference resource. Paying energy market uplift on the basis of parameters consistent with the flexibility goals of the capacity performance construct would ensure that performance incentives are consistent across the capacity and energy markets and ensure that performance risk is appropriately assigned to generation owners.

Parameter Impacts of Gas Pipeline Conditions

During extreme cold weather conditions, and recently, 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. In 2020, there were 13 units in PJM that experienced gas pipeline restrictions leading to requests for 24 hour minimum run time on their parameter limited schedules.

Key parameters like startup and notification time were not included in the PLS matrix in 2017 and prior periods, even though other parameters were subject to parameter limits. Some resource owners notified PJM that they needed extended notification times based on the claimed necessity for generation owners to nominate gas prior to gas nomination cycle deadlines.

The MMU observed instances when generators submitted temporary parameter exceptions based on claimed pipeline constraints even though these constraints are based on the nature of the transportation service that the generator procured from the pipeline. In some instances, generators requested temporary exceptions based on ratable take requirements stated in pipeline tariffs, even though the requirement is not enforced by the pipelines on a routine basis. If a unit were to be dispatched uneconomically using the inflexible parameters, the unit would receive make whole payments based on these temporary exceptions. The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not routinely enforced or on inferior transportation service chosen by the generator.

Virtual Offers and Bids

There is a substantial volume of 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 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. 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.[34] Up to congestion transactions may be submitted between any two buses on a list of 47 buses eligible for up to congestion transaction bidding.[35] Import and export transactions may be submitted at any interface pricing point, where an import is equivalent to a virtual offer that is injected into PJM and an export is equivalent to a virtual bid that is withdrawn from PJM.

Figure 3-19 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve of imports, the system aggregate supply curve without increment offers and imports, the system aggregate supply curve with increment offers, and the system aggregate supply curve with increment offers and imports for an example day in 2020.

Figure 3-19 Day-ahead aggregate supply curves: 2020 example day

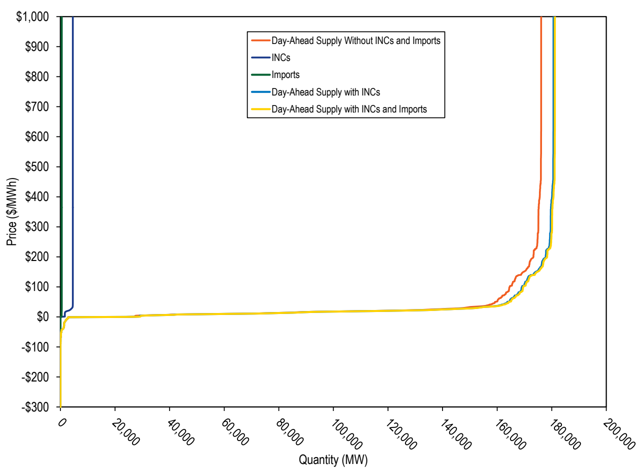


Figure 3-20 shows example PJM day-ahead aggregate supply curves for the typical dispatch price range.

Figure 3-20 Typical dispatch price range for day-ahead aggregate supply curves: 2020 example day

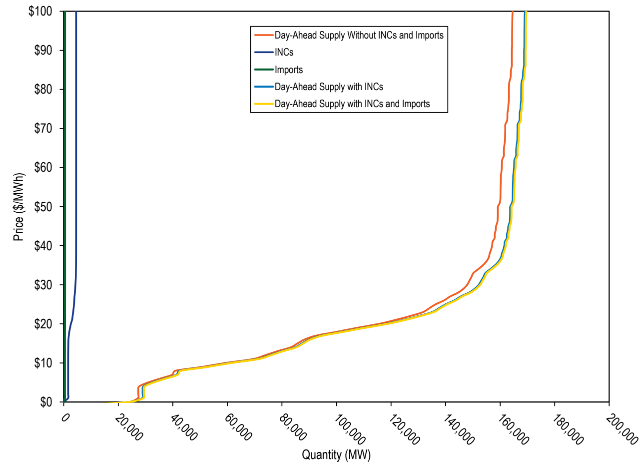


Table 3-21 shows the hourly average number of cleared and submitted increment offers and decrement bids by month for 2019 and 2020. The hourly average submitted increment MW increased by 2.7 percent and cleared increment MW decreased by 16.0 percent. The hourly average submitted decrement MW increased by 24.4 percent and cleared decrement MW increased by 16.6 percent.

34 162 FERC ¶ 61,139.

35 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>.

Table 3-21 Average hourly number of cleared and submitted INCs and DECs by month: 2019 through 2020

		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
2019	Jan	2,934	6,777	282	1,122	3,856	7,149	215	834
2019	Feb	2,895	5,776	260	1,029	3,441	6,115	197	781
2019	Mar	2,973	5,961	268	1,057	3,319	6,830	181	859
2019	Apr	3,048	6,008	286	1,060	3,104	6,226	154	733
2019	May	3,107	6,468	273	1,082	4,236	6,903	178	726
2019	Jun	2,892	6,363	226	977	4,408	7,245	226	863
2019	Jul	2,655	6,712	202	1,051	4,544	9,223	251	1,086
2019	Aug	2,577	6,573	220	1,100	3,744	7,056	217	860
2019	Sep	2,715	6,737	221	972	5,046	8,790	255	900
2019	Oct	3,034	6,967	283	1,141	3,218	7,226	186	776
2019	Nov	3,373	7,896	304	1,261	2,745	6,930	187	831
2019	Dec	2,482	6,398	232	995	2,782	6,455	191	694
2019	Annual	2,889	6,558	255	1,071	3,704	7,186	203	829
2020	Jan	2,684	6,395	261	1,063	2,547	5,856	187	662
2020	Feb	2,544	7,043	233	1,046	2,990	6,653	222	702
2020	Mar	2,435	7,119	258	1,069	3,203	7,688	251	762
2020	Apr	2,655	7,738	299	1,167	3,400	8,312	261	840
2020	May	2,695	6,931	254	1,050	4,361	8,257	307	814
2020	Jun	2,353	7,185	235	1,011	5,140	9,843	404	1,083
2020	Jul	2,247	6,936	252	1,071	5,515	11,233	436	1,293
2020	Aug	1,915	6,084	209	973	5,148	10,165	451	1,217
2020	Sep	2,472	6,486	254	1,150	5,217	9,414	468	1,156
2020	Oct	2,492	6,086	309	1,084	4,884	9,696	392	1,229
2020	Nov	2,505	7,000	277	1,125	4,612	9,570	335	1,037
2020	Dec	2,141	5,911	241	974	4,746	10,450	321	1,190
2020	Annual	2,427	6,737	257	1,065	4,318	8,937	337	1,000

Table 3-22 shows the average hourly number of up to congestion transactions and the average hourly MW from 2019 and 2020. In 2020, the average hourly submitted and cleared up to congestion MW decreased by 23.8 percent and 12.4 percent, compared to 2019.

Table 3-22 Average hourly cleared and submitted up to congestion bids by month: 2019 through 2020

		Up to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2019	Jan	20,624	65,533	1,219	2,489
2019	Feb	21,341	66,240	1,005	2,013
2019	Mar	23,205	75,760	1,045	2,144
2019	Apr	21,323	63,388	872	1,669
2019	May	19,407	59,684	862	1,713
2019	Jun	18,598	51,678	1,021	1,953
2019	Jul	19,197	56,161	1,128	2,265
2019	Aug	20,247	58,841	1,254	2,550
2019	Sep	20,005	74,494	1,136	2,523
2019	Oct	22,233	75,107	1,093	2,302
2019	Nov	23,678	77,890	1,019	2,265
2019	Dec	20,567	55,020	1,040	2,104
2019	Annual	20,864	64,952	1,059	2,168
2020	Jan	19,106	37,533	1,127	2,087
2020	Feb	19,415	40,281	1,100	2,133
2020	Mar	19,513	40,998	990	1,970
2020	Apr	18,267	37,298	955	1,859
2020	May	18,028	41,503	1,122	2,425
2020	Jun	23,038	59,520	1,403	2,726
2020	Jul	21,014	64,376	1,227	2,539
2020	Aug	22,478	63,368	1,159	2,306
2020	Sep	22,900	65,866	1,136	2,315
2020	Oct	19,587	55,904	933	1,957
2020	Nov	8,667	21,141	578	1,053
2020	Dec	7,156	17,968	526	942
2020	Annual	18,257	45,501	1,021	2,026

Table 3-23 shows the average hourly number of day-ahead import and export transactions and the average hourly MW from January 2019 through December 2020. In 2020, the average hourly submitted and cleared import transaction MW decreased by 46.1 and 42.4 percent, and the average hourly submitted and cleared export transaction MW increased by 14.9 and 15.4 percent, compared to 2019.

Table 3-23 Hourly average day-ahead number of cleared and submitted import and export transactions by month: 2019 through 2020

		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
2019	Jan	545	653	7	9	3,569	3,593	22	22
2019	Feb	564	671	6	8	3,169	3,182	17	18
2019	Mar	387	449	5	7	2,675	2,686	15	15
2019	Apr	255	288	4	5	2,483	2,496	15	15
2019	May	279	298	3	4	2,426	2,458	15	15
2019	Jun	291	308	3	4	2,790	2,806	17	17
2019	Jul	283	311	4	5	3,075	3,106	15	15
2019	Aug	277	303	3	4	2,907	2,923	16	16
2019	Sep	162	177	3	3	3,163	3,193	17	17
2019	Oct	433	463	4	5	2,694	2,721	15	15
2019	Nov	540	563	5	6	2,205	2,214	12	12
2019	Dec	468	505	4	6	3,133	3,144	25	25
2019	Annual	373	414	4	6	2,857	2,876	17	17
2020	Jan	427	445	5	6	3,034	3,041	28	28
2020	Feb	324	346	4	5	2,737	2,742	29	29
2020	Mar	254	269	3	4	3,084	3,085	27	27
2020	Apr	173	188	2	3	3,057	3,062	25	25
2020	May	207	231	3	4	3,075	3,080	23	23
2020	Jun	159	152	2	2	3,782	3,798	31	31
2020	Jul	83	112	2	2	3,907	3,922	31	31
2020	Aug	100	128	2	2	3,909	3,920	29	29
2020	Sep	118	115	2	2	3,424	3,448	28	28
2020	Oct	171	164	2	2	3,268	3,231	26	26
2020	Nov	189	199	2	2	3,158	3,182	32	32
2020	Dec	173	180	2	2	3,106	3,113	31	31
2020	Annual	215	223	3	3	3,298	3,304	28	28

Table 3-24 shows the frequency with which generation offers, import or export transactions, up to congestion transactions, decrement bids, increment offers and price-sensitive demand were marginal in 2019 and 2020. The frequency of marginal up to congestion transactions deceased significantly in November 2020, due to decreased UTC activity beginning November 1, 2020, when FERC required UTCs to pay uplift.[36]

Table 3-24 Type of day-ahead marginal resources: 2019 through 2020

	2019						2020					
	Generation	Dispatchable Transaction	Up to Congestion Transaction	Decrement Bid	Increment Offer	Price Sensitive Demand	Generation	Dispatchable Transaction	Up to Congestion Transaction	Decrement Bid	Increment Offer	Price Sensitive Demand
Jan	13.4%	0.3%	59.1%	17.4%	9.9%	0.0%	27.7%	0.1%	44.7%	10.6%	16.9%	0.0%
Feb	11.7%	0.1%	60.0%	15.4%	12.8%	0.0%	20.7%	0.1%	48.5%	12.5%	18.2%	0.0%
Mar	9.3%	0.1%	60.5%	17.0%	13.1%	0.0%	19.5%	0.0%	52.2%	14.7%	13.6%	0.0%
Apr	8.3%	0.1%	64.9%	14.8%	11.9%	0.0%	18.2%	0.0%	49.3%	16.6%	15.9%	0.0%
May	9.9%	0.1%	53.1%	21.0%	15.9%	0.0%	16.6%	0.1%	55.2%	15.2%	13.0%	0.0%
Jun	10.5%	0.0%	49.0%	23.7%	16.8%	0.0%	14.1%	0.0%	60.8%	15.5%	9.6%	0.0%
Jul	9.1%	0.0%	51.5%	26.0%	13.4%	0.0%	11.8%	0.1%	57.4%	20.4%	10.3%	0.0%
Aug	13.0%	0.1%	63.1%	14.1%	9.6%	0.0%	10.5%	0.0%	55.3%	24.9%	9.2%	0.0%
Sep	14.0%	0.1%	60.5%	13.4%	12.0%	0.0%	13.1%	0.1%	54.8%	21.9%	10.1%	0.0%
Oct	16.4%	0.1%	55.9%	13.8%	13.8%	0.0%	14.7%	0.2%	58.2%	15.0%	12.0%	0.0%
Nov	16.2%	0.0%	57.9%	13.2%	12.8%	0.0%	21.0%	0.1%	27.6%	27.1%	24.2%	0.0%
Dec	23.2%	0.1%	55.2%	10.9%	10.5%	0.0%	20.8%	0.2%	32.7%	30.7%	15.5%	0.0%
Annual	12.7%	0.1%	57.4%	17.0%	12.8%	0.0%	16.5%	0.1%	51.4%	18.8%	13.2%	0.0%

36 172 FERC ¶ 61,046 (2020).

Figure 3-21 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month from 2005 through 2020.

Figure 3-21 Monthly bid and cleared INCs, DECs and UTCs (MW): 2005 through 2020

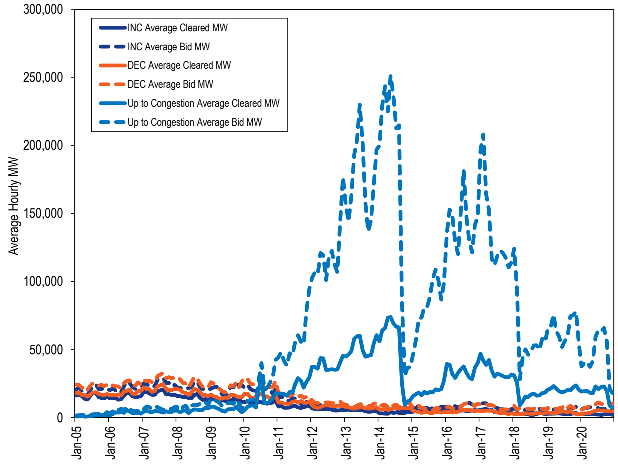
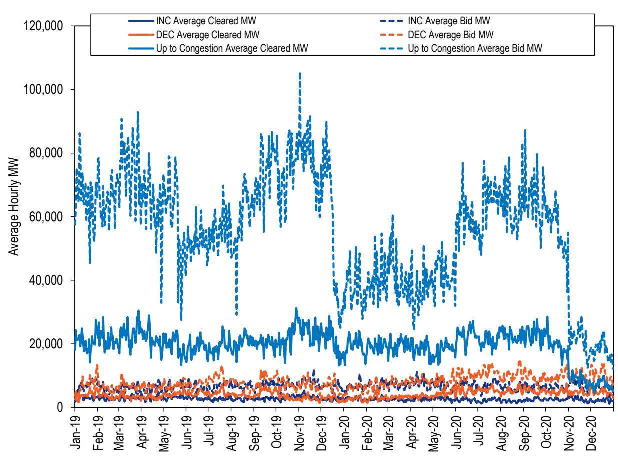


Figure 3-22 shows the daily volume of bid and cleared INC, DEC and up to congestion bids from 2019 through 2020.

Figure 3-22 Daily bid and cleared INCs, DECs, and UTCs (MW): 2019 through 2020



In order to evaluate the ownership of virtual bids, the MMU categorizes all participants making virtual bids in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 3-25 shows, in 2019 and 2020, the total increment offers and decrement bids and cleared MW by type of parent organization.

Table 3-25 INC and DEC bids and cleared MWh by type of parent organization (MWh): 2019 and 2020

	2019				2020			
Category	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent
Financial	103,840,563	86.2%	48,295,203	83.6%	121,335,619	88.2%	48,574,531	82.1%
Physical	16,557,036	13.8%	9,464,401	16.4%	16,234,536	11.8%	10,587,919	17.9%
Total	120,397,599	100.0%	57,759,604	100.0%	137,570,155	100.0%	59,162,450	100.0%

Table 3-26 shows, in 2019 and 2020, the total up to congestion bids and cleared MWh by type of parent organization.

Table 3-26 Up to congestion transactions by type of parent organization (MWh): 2019 and 2020

	2019				2020			
Category	Total Up to Congestion Bid MWh	Percent	Total Up to Congestion Cleared MWh	Percent	Total Up to Congestion Bid MWh	Percent	Total Up to Congestion Cleared MWh	Percent
Financial	553,915,846	97.4%	173,330,340	94.8%	354,377,718	88.7%	140,616,388	87.7%
Physical	15,066,592	2.6%	9,441,573	5.2%	45,299,144	11.3%	19,753,718	12.3%
Total	568,982,438	100.0%	182,771,913	100.0%	399,676,862	100.0%	160,370,106	100.0%

Table 3-27 shows, in 2019 and 2020, the total import and export transactions by whether the parent organization was financial or physical.

Table 3-27 Import and export transactions by type of parent organization (MW): 2019 and 2020

		2019		2020	
	Category	Total Import and Export MW	Percent	Total Import and Export MW	Percent
Day-Ahead	Financial	7,734,097	27.3%	12,513,761	41.1%
	Physical	20,553,709	72.7%	17,908,057	58.9%
	Total	28,287,806	100.0%	30,421,818	100.0%
Real-Time	Financial	12,269,622	23.4%	15,520,882	31.0%
	Physical	40,145,398	76.6%	34,519,916	69.0%
	Total	52,415,020	100.0%	50,040,798	100.0%

Table 3-28 shows increment offers and decrement bids by top 10 locations in 2019 and 2020.

Table 3-28 Virtual offers and bids by top 10 locations (MW): 2019 and 2020

2019					2020				
Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW	Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW
MISO	INTERFACE	114,883	6,034,524	6,149,408	MISO	INTERFACE	58,106	8,624,237	8,682,344
WESTERN HUB	HUB	1,159,532	2,025,863	3,185,395	WESTERN HUB	HUB	723,568	2,699,364	3,422,932
AEP-DAYTON HUB	HUB	519,622	973,759	1,493,381	AEP-DAYTON HUB	HUB	383,865	1,423,100	1,806,965
DOM_RESID_AGG	RESIDUAL METERED EDC	269,198	1,223,935	1,493,133	BGE_RESID_AGG	RESIDUAL METERED EDC	295,127	1,340,188	1,635,315
LINDENVFT	INTERFACE	36,615	1,374,392	1,411,007	DOM_RESID_AGG	RESIDUAL METERED EDC	202,235	1,240,902	1,443,137
SOUTHIMP	INTERFACE	1,361,985	0	1,361,985	NYIS	INTERFACE	752,258	298,276	1,050,534
BGE_RESID_AGG	RESIDUAL METERED EDC	276,217	960,392	1,236,610	NEW JERSEY HUB	HUB	548,816	400,685	949,501
DOMINION HUB	HUB	544,395	654,169	1,198,564	PECO_RESID_AGG	RESIDUAL METERED EDC	666,172	242,847	909,019
N ILLINOIS HUB	HUB	539,287	649,189	1,188,477	LINDENVFT	INTERFACE	38,492	858,203	896,695
NYIS	INTERFACE	772,228	248,645	1,020,873	N ILLINOIS HUB	HUB	377,415	509,377	886,792
Top ten total		5,593,962	14,144,869	19,738,831			4,046,055	17,637,179	21,683,234
PJM total		25,309,648	32,449,958	57,759,606			21,316,711	37,927,647	59,244,357
Top ten total as percent of PJM total		22.1%	43.6%	34.2%			19.0%	46.5%	36.6%

Table 3-29 shows up to congestion transactions by import bids for the top 10 locations and associated profits at each path in 2019 and 2020. The NORTHWEST interface was eliminated effective October 1, 2020. Before the elimination of this interface, trades sourcing at NORTHWEST were the largest source of revenue for import as well as overall up to congestion transactions in 2020.[37]

Table 3-29 Cleared up to congestion import bids by top 10 source and sink pairs (MW): 2019 and 2020

2019							
Imports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	4,867,357	$4,725,588	($1,793,203)	$2,932,386
NORTHWEST	INTERFACE	CHICAGO GEN HUB	HUB	2,868,027	$1,799,693	($683,359)	$1,116,334
NORTHWEST	INTERFACE	COMED_RESID_AGG	AGGREGATE	2,702,231	$3,334,781	($1,669,112)	$1,665,669
NYIS	INTERFACE	RECO_RESID_AGG	AGGREGATE	1,844,665	($734,523)	$987,205	$252,682
NEPTUNE	INTERFACE	JCPL_RESID_AGG	AGGREGATE	1,534,041	$593,430	($443,930)	$149,500
MISO	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	1,516,032	$486,571	$229,194	$715,765
NORTHWEST	INTERFACE	CHICAGO HUB	HUB	1,114,768	$762,111	$41,197	$803,307
SOUTHIMP	INTERFACE	AEP GEN HUB	HUB	890,981	$368,101	($224,941)	$143,161
SOUTHIMP	INTERFACE	AEPAPCO_RESID_AGG	AGGREGATE	767,345	$482,803	($126,515)	$356,288
NORTHWEST	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	601,045	$601,399	($126,755)	$474,644
Top ten total				18,706,492	$12,419,955	($3,810,220)	$8,609,735
PJM total				36,735,678	$23,345,179	($8,019,291)	$15,325,888
Top ten total as percent of PJM total				50.9%	53.2%	47.5%	56.2%
2020							
Imports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	3,619,492	$2,799,055	($1,530,939)	$1,268,116
NORTHWEST	INTERFACE	COMED_RESID_AGG	AGGREGATE	3,243,735	$2,585,246	($1,009,193)	$1,576,053
NORTHWEST	INTERFACE	CHICAGO GEN HUB	HUB	1,851,417	$1,501,158	($991,825)	$509,332
MISO	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	1,449,045	$355,909	$596,289	$952,198
NEPTUNE	INTERFACE	JCPL_RESID_AGG	AGGREGATE	1,128,108	($747,445)	$625,201	($122,244)
NYIS	INTERFACE	RECO_RESID_AGG	AGGREGATE	1,035,117	($487,128)	$527,353	$40,226
SOUTHIMP	INTERFACE	AEPAPCO_RESID_AGG	AGGREGATE	891,868	($318,309)	$421,182	$102,872
NORTHWEST	INTERFACE	CHICAGO HUB	HUB	626,033	$571,965	($364,315)	$207,650
NORTHWEST	INTERFACE	AEP-DAYTON HUB	HUB	604,248	$731,513	($344,272)	$387,241
NORTHWEST	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	536,686	$286,865	($36,716)	$250,149
Top ten total				14,985,749	$7,278,829	($2,107,235)	$5,171,594
PJM total				26,395,388	$7,680,460	$406,128	$8,086,588
Top ten total as percent of PJM total				56.8%	94.8%	(518.9%)	64.0%

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

Table 3-30 shows up to congestion transactions by export bids for the top 10 locations and associated profits at each path in 2019 and 2020. The NIPSCO interface was eliminated effective June 1, 2020. Prior to the elimination of this interface, trades sinking at NIPSCO were a large source of revenue for both export and overall up-to congestion transactions in 2020.

Table 3-30 Cleared up to congestion export bids by top 10 source and sink pairs (MW): 2019 and 2020

2019							
Exports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
COMED_RESID_AGG	AGGREGATE	NIPSCO	INTERFACE	2,636,234	$1,831,550	$1,096,309	$2,927,859
N ILLINOIS HUB	HUB	NIPSCO	INTERFACE	2,337,969	$2,218,567	($1,210,629)	$1,007,938
CHICAGO GEN HUB	HUB	NIPSCO	INTERFACE	1,800,701	$165,259	$879,090	$1,044,350
CHICAGO HUB	HUB	NIPSCO	INTERFACE	1,366,410	$1,169,912	$195,344	$1,365,256
AEP GEN HUB	HUB	SOUTHEXP	INTERFACE	1,220,031	($620,959)	$1,662,042	$1,041,083
CHICAGO HUB	HUB	MISO	INTERFACE	816,878	$221,881	($129,516)	$92,365
N ILLINOIS HUB	HUB	SOUTHEXP	INTERFACE	754,401	$741,293	($402,807)	$338,486
N ILLINOIS HUB	HUB	MISO	INTERFACE	661,485	($626,991)	$587,860	($39,131)
CHICAGO GEN HUB	HUB	MISO	INTERFACE	595,663	($225,954)	$315,061	$89,107
COMED_RESID_AGG	AGGREGATE	MISO	INTERFACE	572,642	$331,145	($329,439)	$1,706
Top ten total				12,762,414	$5,205,704	$2,663,314	$7,869,018
PJM total				22,157,844	$2,417,205	$10,295,407	$12,712,612
Top ten total as percent of PJM total				57.6%	215.4%	25.9%	61.9%
2020							
Exports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
COMED_RESID_AGG	AGGREGATE	NIPSCO	INTERFACE	1,565,759	$1,394,315	($951,202)	$443,113
COMED_RESID_AGG	AGGREGATE	MISO	INTERFACE	1,461,150	($240,423)	$610,322	$369,899
CHICAGO GEN HUB	HUB	MISO	INTERFACE	971,764	($343,602)	$543,641	$200,038
COMED_RESID_AGG	AGGREGATE	NORTHWEST	INTERFACE	964,493	($1,182,161)	$2,569,062	$1,386,900
CHICAGO HUB	HUB	NIPSCO	INTERFACE	709,858	$303,801	($170,272)	$133,529
CHICAGO HUB	HUB	MISO	INTERFACE	614,476	($461,132)	$584,862	$123,730
N ILLINOIS HUB	HUB	NIPSCO	INTERFACE	549,227	$204,334	($54,058)	$150,276
CHICAGO GEN HUB	HUB	NIPSCO	INTERFACE	409,116	$318,507	($296,361)	$22,146
AEP GEN HUB	HUB	SOUTHEXP	INTERFACE	383,878	($232,230)	$694,516	$462,286
COMED_RESID_AGG	AGGREGATE	SOUTHEXP	INTERFACE	381,385	($139,863)	$367,974	$228,111
Top ten total				8,011,106	($378,456)	$3,898,484	$3,520,028
PJM total				14,306,955	($3,271,371)	$8,389,570	$5,118,199
Top ten total as percent of PJM total				56.0%	11.6%	46.5%	68.8%

Table 3-31 shows up to congestion transactions by wheel bids and associated profits at each path for the top 10 locations in 2019 and 2020.

Table 3-31 Cleared up to congestion wheel bids by top 10 source and sink pairs (MW): 2019 and 2020

2019							
Wheels							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
MISO	INTERFACE	NIPSCO	INTERFACE	2,289,188	$1,849,277	($95,821)	$1,753,456
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	2,196,956	$2,222,121	($386,523)	$1,835,598
MISO	INTERFACE	SOUTHEXP	INTERFACE	1,172,080	($629,574)	$2,849,345	$2,219,771
NORTHWEST	INTERFACE	MISO	INTERFACE	1,156,963	$1,083,671	($312,206)	$771,464
MISO	INTERFACE	NORTHWEST	INTERFACE	839,589	$587,108	($69,742)	$517,366
SOUTHIMP	INTERFACE	NIPSCO	INTERFACE	476,351	$314,813	$463,417	$778,231
LINDENVFT	INTERFACE	HUDSONTP	INTERFACE	402,375	$232,113	($186,590)	$45,523
SOUTHIMP	INTERFACE	MISO	INTERFACE	360,845	$474,711	($260,955)	$213,757
NORTHWEST	INTERFACE	SOUTHEXP	INTERFACE	319,613	$455,625	($26,307)	$429,318
IMO	INTERFACE	SOUTHEXP	INTERFACE	218,225	$120,942	$390,584	$511,525
Top ten total				9,432,185	$6,710,808	$2,365,202	$9,076,010
PJM total				11,064,646	$7,141,228	$2,048,737	$9,189,965
Top ten total as percent of PJM total				85.2%	94.0%	115.4%	98.8%
2020							
Wheels							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
NORTHWEST	INTERFACE	MISO	INTERFACE	1,717,422	$1,581,021	($612,251)	$968,770
LINDENVFT	INTERFACE	HUDSONTP	INTERFACE	897,659	($373,207)	$433,877	$60,670
SOUTHIMP	INTERFACE	MISO	INTERFACE	842,473	($246,631)	$242,109	($4,522)
MISO	INTERFACE	NIPSCO	INTERFACE	746,976	$230,632	($156,299)	$74,333
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	674,341	$339,914	($111,066)	$228,849
MISO	INTERFACE	SOUTHEXP	INTERFACE	669,729	$178,511	($40,126)	$138,385
NORTHWEST	INTERFACE	SOUTHEXP	INTERFACE	265,988	$58,105	($171,180)	($113,075)
MISO	INTERFACE	NORTHWEST	INTERFACE	192,999	$44,905	$12,964	$57,870
SOUTHIMP	INTERFACE	NORTHWEST	INTERFACE	78,432	$25,283	$60,548	$85,831
NEPTUNE	INTERFACE	HUDSONTP	INTERFACE	60,743	$26,933	($44,079)	($17,146)
Top ten total				6,146,761	$1,865,467	($385,503)	$1,479,964
PJM total				6,960,599	$1,607,197	($205,644)	$1,401,553
Top ten total as percent of PJM total				88.3%	116.1%	187.5%	105.6%

The top 10 internal up to congestion transaction paths were 22.3 percent of the PJM total internal up to congestion transaction MW in 2020.

Table 3-32 shows up to congestion transactions by internal bids for the top 10 locations and associated profits at each path in 2019 and 2020. The total internal UTC profits increased by $9.8 million, from $6.5 million in 2019 to $16.3 million in 2020. The total internal cleared MW decreased by 0.1 million MW, or 0.08 percent, from 112.8 million MW in 2019 to 112.7 million MW in 2020.

Table 3-32 Cleared up to congestion internal bids by top 10 source and sink pairs (MW): 2019 and 2020

2019							
Internal							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
AEP GEN HUB	HUB	AEPOHIO_RESID_AGG	AGGREGATE	2,846,126	$842,698	($370,498)	$472,200
SMECO_RESID_AGG	AGGREGATE	BGE_RESID_AGG	AGGREGATE	2,660,863	$1,080,285	($337,062)	$743,223
OVEC_RESID_AGG	AGGREGATE	DEOK_RESID_AGG	AGGREGATE	2,453,785	($523,510)	$382,033	($141,477)
AEP GEN HUB	HUB	AEP-DAYTON HUB	HUB	2,127,248	$1,209,043	($1,050,912)	$158,131
OVEC_RESID_AGG	AGGREGATE	DAY_RESID_AGG	AGGREGATE	2,003,971	$208,198	($109,728)	$98,470
N ILLINOIS HUB	HUB	CHICAGO HUB	HUB	1,974,408	$776,321	($587,077)	$189,244
AEP GEN HUB	HUB	FEOHIO_RESID_AGG	AGGREGATE	1,803,194	$764,467	($753,713)	$10,753
AECO_RESID_AGG	AGGREGATE	VINELAND_RESID_AGG	AGGREGATE	1,452,479	($518,639)	($172,886)	($691,526)
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	1,398,835	$158,044	$143,641	$301,685
WESTERN HUB	HUB	AEP-DAYTON HUB	HUB	1,220,937	$1,156,104	($741,121)	$414,982
Top ten total				19,941,846	$5,153,010	($3,597,322)	$1,555,687
PJM total				112,813,746	$20,715,529	($14,188,778)	$6,526,752
Top ten total as percent of PJM total				17.7%	24.9%	25.4%	23.8%
2020							
Internal							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
AEP GEN HUB	HUB	AEPOHIO_RESID_AGG	AGGREGATE	3,744,340	($286,705)	$762,854	$476,149
AEP GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	3,669,318	$84,850	$720,478	$805,328
COMED_RESID_AGG	AGGREGATE	AEPIM_RESID_AGG	AGGREGATE	3,246,574	($1,304,762)	$3,024,576	$1,719,814
SMECO_RESID_AGG	AGGREGATE	BGE_RESID_AGG	AGGREGATE	2,963,981	$266,416	($179,122)	$87,294
N ILLINOIS HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	2,891,427	($945,347)	$1,719,669	$774,323
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	2,004,395	($34,813)	$745,091	$710,278
CHICAGO HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	1,833,368	($203,825)	$866,211	$662,386
OVEC_RESID_AGG	AGGREGATE	DEOK_RESID_AGG	AGGREGATE	1,766,602	$62,510	($251,174)	($188,664)
OVEC_RESID_AGG	AGGREGATE	DAY_RESID_AGG	AGGREGATE	1,590,128	($78,682)	($29,508)	($108,190)
AEP GEN HUB	HUB	DAY_RESID_AGG	AGGREGATE	1,414,620	($145,613)	$203,404	$57,791
Top ten total				25,124,751	($2,585,971)	$7,582,479	$4,996,508
PJM total				112,707,163	($27,263,473)	$43,544,453	$16,280,980
Top ten total as percent of PJM total				22.3%	9.5%	17.4%	30.7%

Table 3-33 shows the number of source-sink pairs that were offered and cleared monthly for January 1, 2019 through December 31, 2020.

Table 3-33 Number of offered and cleared source and sink pairs: 2019 through 2020

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
2019	Jan	1,693	1,893	1,527	1,712
2019	Feb	1,701	1,881	1,496	1,733
2019	Mar	1,673	1,806	1,506	1,653
2019	Apr	1,555	1,806	1,395	1,653
2019	May	1,584	1,856	1,424	1,718
2019	Jun	1,770	1,970	1,601	1,797
2019	Jul	1,767	1,950	1,635	1,819
2019	Aug	1,880	2,034	1,690	1,879
2019	Sep	1,891	2,007	1,702	1,842
2019	Oct	1,837	1,935	1,607	1,756
2019	Nov	1,796	1,984	1,576	1,700
2019	Dec	1,687	1,935	1,507	1,769
2019	Annual	1,736	1,921	1,555	1,753
2020	Jan	1,658	1,942	1,523	1,857
2020	Feb	1,710	1,975	1,568	1,725
2020	Mar	1,789	2,013	1,591	1,832
2020	Apr	1,804	1,978	1,567	1,760
2020	May	1,913	2,126	1,681	1,900
2020	Jun	1,974	2,111	1,803	2,020
2020	Jul	1,886	2,085	1,749	1,970
2020	Aug	1,760	1,993	1,575	1,854
2020	Sep	1,656	1,851	1,498	1,641
2020	Oct	1,544	1,689	1,358	1,525
2020	Nov	1,306	1,497	1,203	1,387
2020	Dec	1,305	1,508	1,184	1,359
2020	Annual	1,719	1,977	1,561	1,805

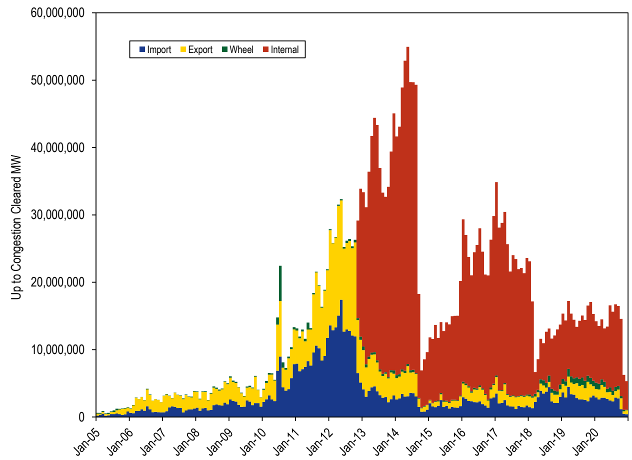
Table 3-34 and Figure 3-23 show total cleared up to congestion transactions and share of the top ten up to congestion paths by transaction type (import, export, or internal) in 2019 and 2020. Total up to congestion transactions decreased by 12.3 percent from 182.8 million MW in 2019 to 160.3 million MW in 2020. Internal up to congestion transactions in 2020 were 70.3 percent of all up to congestion transactions compared to 61.7 percent in 2019.

Table 3-34 Cleared up to congestion transactions and share of top 10 paths by type (MW): 2019 and 2020

	2019				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	18,706,492	12,762,414	9,432,185	19,941,846	60,842,938
PJM total (MW)	36,735,678	22,157,844	11,064,646	112,813,746	182,771,913
Top ten total as percent of PJM total	50.9%	57.6%	85.2%	17.7%	33.3%
PJM total as percent of all up to congestion transactions	20.1%	12.1%	6.1%	61.7%	100.0%
	2020				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	14,985,749	8,011,106	6,146,761	25,124,751	54,268,367
PJM total (MW)	26,395,388	14,306,955	6,960,599	112,707,163	160,370,106
Top ten total as percent of PJM total	56.8%	56.0%	88.3%	22.3%	33.8%
PJM total as percent of all up to congestion transactions	16.5%	8.9%	4.3%	70.3%	100.0%

Figure 3-23 shows the initial increase and continued increase in internal up to congestion transactions by month following the November 1, 2012, rule change permitting such transactions, until September 8, 2014. 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.[38] 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 February 22, 2018.[39] 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.[40]

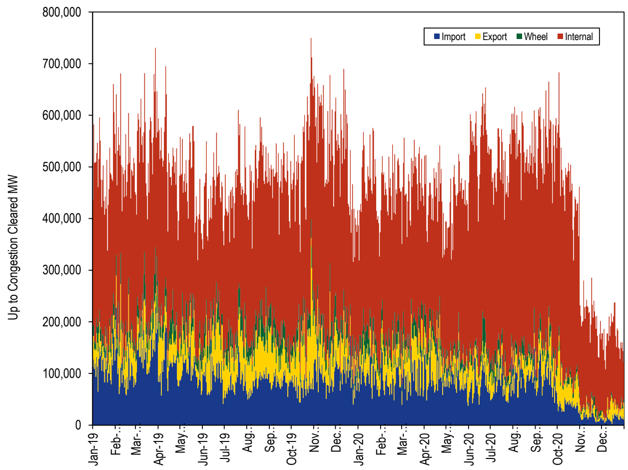
Figure 3-23 Monthly cleared up to congestion transactions by type (MW): 2005 through 2020



38 See 162 FERC ¶ 61,139 (2018).
39 *Id.*
40 See 172 FERC ¶ 61,046 (2020).

Figure 3-24 shows the daily cleared up to congestion MW by transaction type from January 1, 2019 through December 31, 2020.

Figure 3-24 Daily cleared up to congestion transaction by type (MW): 2019 through 2020



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.[41]

A key assumption underlying the February 2018 order is 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.[42] 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 since the February 2018 order.

The assumption that modeling differences are averaged out over aggregate nodes does not hold for multiple 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 this reason, the MMU recommends eliminating UTC bidding at the following nodes: DPLEASTON_RESID_AGG, PENNPOWER_RESID_AGG, UGI_RESID_AGG, SMECO_RESID_AGG, AEPKY_RESID_AGG, and VINELAND_RESID_AGG.

Prices at larger aggregate nodes can also be affected by transmission constraints, especially when constraints are violated and transmission penalty factors are applied in the real-time energy market. 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 in the tens to hundreds of dollars, 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.

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.

41 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."

42 162 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."

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 the creation of a closed loop interface 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 penalty factors, and committing reserves beyond the requirement.

Real-time and day-ahead energy market load-weighted prices were 20.3 percent and 21.4 percent lower in 2020 than in 2019. As a combined result of weather and COVID-19 related demand reductions, and low gas prices, energy prices were lower in 2020 than in any year since the beginning of PJM markets on April 1, 1999.

The average real-time LMP in 2020 decreased 20.6 percent from 2019, from $26.02 per MWh to $20.66 per MWh. The load-weighted average real-time LMP in 2020 decreased 20.3 percent from 2019, from $27.32 per MWh to $21.77 per MWh.

The, load-weighted, average, real-time LMP for 2020 was 11.4 percent lower than the fuel-cost adjusted, load-weighted, average real-time LMP for 2020. If fuel and emission costs in 2020 had been the same as in 2019, holding everything else constant, the load-weighted LMP would have been higher, $24.56 per MWh instead of the observed $21.77 per MWh.

The average day-ahead LMP in 2020 decreased 21.9 percent from 2019, from $26.03 per MWh to $20.33 per MWh. The load-weighted average day-ahead LMP decreased 21.4 percent from 2019, from $27.23 per MWh to $21.40 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.[43] 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, such 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.[44]

LMP may, at times, be set by transmission penalty factors, which exceed $1,000 per MWh. 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 penalty factors. The shadow price directly affects the LMP. Transmission penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing.

43 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.

44 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).

Real-Time Average LMP

Real-time, average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[45]

PJM Real-Time, Average LMP

Table 3-35 shows the PJM real-time, average LMP for 1998 through 2020.[46]

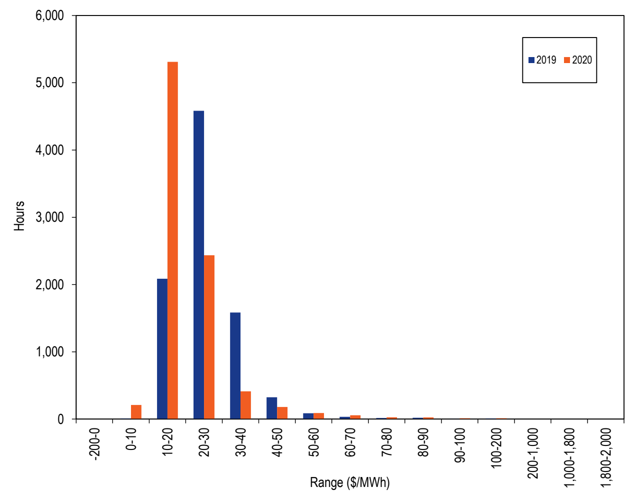
Table 3-35 Real-time, average LMP (Dollars per MWh): 1998 through 2020

	Real-Time LMP			Year to Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.72	$16.60	$31.45	NA	NA	NA
1999	$28.32	$17.88	$72.42	30.4%	7.7%	130.3%
2000	$28.14	$19.11	$25.69	(0.6%)	6.9%	(64.5%)
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.41	(12.6%)	(8.3%)	(50.2%)
2003	$38.28	$30.79	$24.71	35.2%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	(15.2%)	(12.1%)	(8.9%)
2007	$57.58	$49.92	$34.60	16.9%	20.4%	5.8%
2008	$66.40	$55.53	$38.62	15.3%	11.2%	11.6%
2009	$37.08	$32.71	$17.12	(44.1%)	(41.1%)	(55.7%)
2010	$44.83	$36.88	$26.20	20.9%	12.7%	53.1%
2011	$42.84	$35.38	$29.03	(4.4%)	(4.1%)	10.8%
2012	$33.11	$29.53	$20.67	(22.7%)	(16.5%)	(28.8%)
2013	$36.55	$32.25	$20.57	10.4%	9.2%	(0.5%)
2014	$48.22	$34.46	$65.08	31.9%	6.8%	216.4%
2015	$33.39	$26.61	$27.80	(30.7%)	(22.8%)	(57.3%)
2016	$27.57	$24.10	$14.76	(17.4%)	(9.4%)	(46.9%)
2017	$29.42	$25.44	$17.40	6.7%	5.6%	17.9%
2018	$35.75	$28.28	$29.52	21.5%	11.2%	69.7%
2019	$26.02	$22.89	$21.19	(27.2%)	(19.1%)	(28.2%)
2020	$20.66	$18.35	$11.77	(20.6%)	(19.8%)	(44.4%)

PJM Real-Time Average LMP Duration

Figure 3-25 shows the hourly distribution of PJM real-time, average LMP for 2019 and 2020. There were 14 hours with an average LMP greater than $100 per MWh, and two hours with an average LMP greater than $200 per MWh in 2020.

Figure 3-25 Average LMP for the real-time energy market: 2019 and 2020



Real-Time, Load-Weighted, Average LMP

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

45 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>.

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

PJM Real-Time, Load-Weighted, Average LMP

Table 3-36 shows the PJM real-time, load-weighted, average LMP for 1998 through 2020.

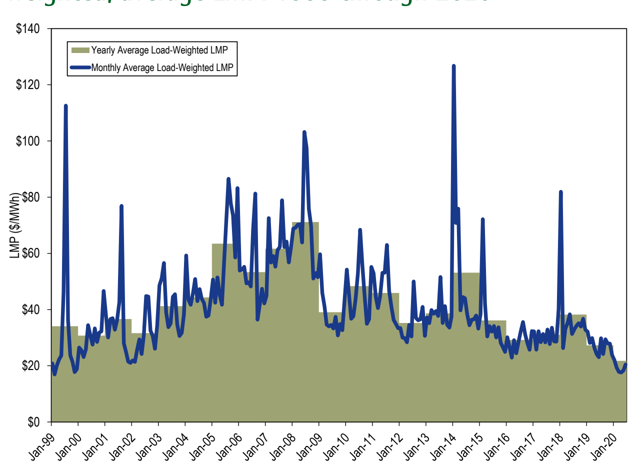
Table 3-36 Real-time, load-weighted, average LMP (Dollars per MWh): 1998 through 2020

	Real-Time, Load-Weighted, Average LMP			Year to Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.7%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	15.4%	8.9%	10.9%
2009	$39.05	$34.23	$18.21	(45.1%)	(42.5%)	(55.6%)
2010	$48.35	$39.13	$28.90	23.8%	14.3%	58.7%
2011	$45.94	$36.54	$33.47	(5.0%)	(6.6%)	15.8%
2012	$35.23	$30.43	$23.66	(23.3%)	(16.7%)	(29.3%)
2013	$38.66	$33.25	$23.78	9.7%	9.3%	0.5%
2014	$53.14	$36.20	$76.20	37.4%	8.9%	220.4%
2015	$36.16	$27.66	$31.06	(31.9%)	(23.6%)	(59.2%)
2016	$29.23	$25.01	$16.12	(19.2%)	(9.6%)	(48.1%)
2017	$30.99	$26.35	$19.32	6.0%	5.4%	19.9%
2018	$38.24	$29.55	$32.89	23.4%	12.1%	70.2%
2019	$27.32	$23.63	$23.12	(28.6%)	(20.0%)	(29.7%)
2020	$21.77	$19.07	$12.50	(20.3%)	(19.3%)	(45.9%)

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

Figure 3-26 shows the PJM real-time monthly and annual load-weighted LMP for 1999 through 2020.

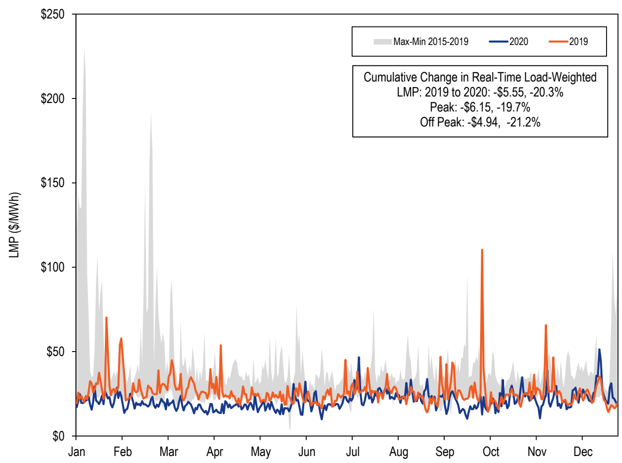
Figure 3-26 Real-time, monthly and annual, load-weighted, average LMP: 1999 through 2020



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

Figure 3-27 shows the PJM real-time, daily, load-weighted LMP for 2019 and 2020.

Figure 3-27 Real-time, daily, load-weighted, average LMP: 2019 and 2020



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

Figure 3-28 shows the PJM real-time, monthly, load-weighted, average LMP and inflation adjusted, monthly, load-weighted, average LMP from January 1998 through December 2020.[47] Table 3-37 shows the PJM real-time, load-weighted, average LMP and inflation adjusted load-weighted, average LMP for every year from 1998 through 2020. The PJM real-time inflation adjusted, load-weighted, average LMP for 2020 was the lowest value since PJM real-time markets started on April 1, 1999 at $13.58 per MWh. The real-time, inflation adjusted, monthly, load-weighted, average LMP for April 2020 was the lowest monthly value since PJM markets started in April 1999 at $11.08 per MWh.

47 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 January 13, 2021)

Figure 3-28 Real-time, monthly, load-weighted, average LMP unadjusted and adjusted for inflation: 1998 through 2020

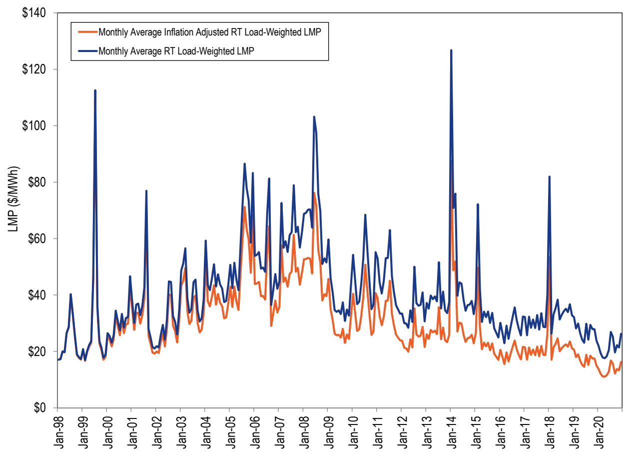


Table 3-37 Real-time, load-weighted, average LMP unadjusted and adjusted for inflation: 1998 through 2020

	Load-Weighted, Average LMP	Inflation Adjusted Load-Weighted, Average LMP
1998	$24.16	$23.94
1999	$34.07	$33.04
2000	$30.72	$28.80
2001	$36.65	$33.45
2002	$31.60	$28.35
2003	$41.23	$36.24
2004	$44.34	$37.91
2005	$63.46	$52.37
2006	$53.35	$42.73
2007	$61.66	$48.06
2008	$71.13	$53.27
2009	$39.05	$29.46
2010	$48.35	$35.83
2011	$45.94	$33.01
2012	$35.23	$24.80
2013	$38.66	$26.82
2014	$53.14	$36.37
2015	$36.16	$24.69
2016	$29.23	$19.68
2017	$30.99	$20.43
2018	$38.24	$24.65
2019	$27.32	$17.28
2020	$21.77	$13.58

Real-Time Dispatch and Pricing

The PJM Real-Time Energy Market consists of a series of applications that produce the generator dispatch for energy and reserves, and five minute locational marginal prices (LMPs). These applications include the ancillary services optimizer (ASO), real-time security constrained economic dispatch (RT SCED), and the locational pricing calculator (LPC).[48] The final real-time LMPs and ancillary service clearing prices are determined for every five minute interval by LPC.

The dispatch of reserves in LPC determines whether PJM implements scarcity pricing. Scarcity pricing transparency requires greater transparency around the processes used to determine load bias in RT SCED, to approve RT SCED cases, and the use of RT SCED cases by LPC.

Real-Time SCED and LPC

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 at a future point in time, called the target time. On average, PJM operators approve more than 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. As a result, a number of dispatch directives are not reflected in real-time energy market prices. 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. However, LPC assigns the prices to a five minute interval that does not contain the target time of the RT SCED case it used. On October 15, 2020, PJM updated its pricing process to use an approved RT SCED solution that solves for the same target time as the end of each five minute pricing interval to calculate LMPs applicable for that five minute interval, although the SCED cases are still for 10 minutes ahead while the LPC cases are for each five minute interval.

Table 3-38 shows, on a monthly basis in 2020, 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. Until February 24, 2020, RT SCED was automatically executed every three minutes with operators having the ability to execute additional cases in between the automatically executed cases. Beginning February 24, 2020, PJM changed the RT SCED automatic execution frequency to once every four minutes. On June 22, 2020, PJM changed the RT SCED execution frequency to once every five minutes. PJM operators continue to have the ability to execute additional RT SCED cases. PJM retains the discretion to

48 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 112 (Jan. 5, 2021)

change the automatic RT SCED execution frequency at any time, as the frequency is not documented in the PJM Market Rules. Each execution of RT SCED produces three solutions, using three different levels of load bias. Since prices are calculated every five minutes while three 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.

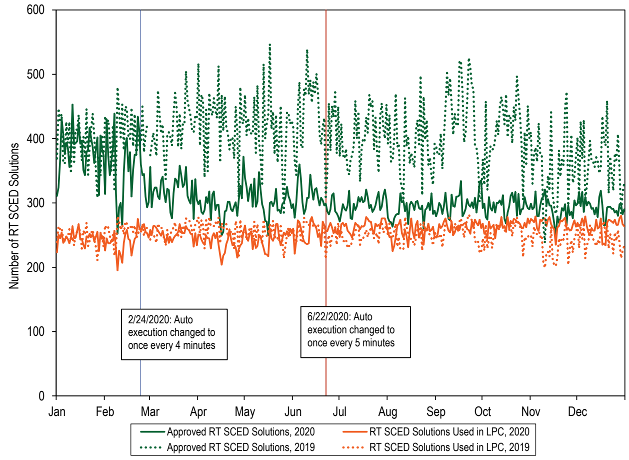
Table 3-38 shows that in 2020 only 82.1 percent of approved RT SCED solutions that were used to send dispatch signals to generators were used in calculating real-time energy market prices. The percent of approved solutions used for pricing increased from 69.0 percent to 78.7 percent from February to March and further increased to 88.6 percent in July with the decrease in the frequency of executed RT SCED cases.

Figure 3-29 shows the daily number of RT SCED cases approved by PJM operators to send dispatch signals to resources and the subset of approved RT SCED cases that were used in LPC to calculate LMPs in 2019 and 2020, and the dates when the frequency of RT SCED auto execution was changed. Figure 3-29 shows that changing the auto execution frequency of RT SCED from once every three minutes to once every four minutes on February 24 and to five minutes on June 22 reduced the number of approved RT SCED cases used to send dispatch signals in 2020 compared to 2019. This change in the frequency of approved solutions reduced the difference between the number of approved solutions and the number of solutions used in pricing in 2020 relative to 2019.

Table 3-38 RT SCED cases solved, approved and used in pricing: 2020

Month (2020)	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	51,022	11,860	7,612	64.2%
Feb	46,247	10,149	7,005	69.0%
Mar	38,680	9,914	7,799	78.7%
Apr	36,543	8,888	7,132	80.2%
May	36,648	9,416	7,590	80.6%
Jun	34,327	9,165	7,666	83.6%
Jul	30,342	9,241	8,190	88.6%
Aug	30,775	8,962	7,868	87.8%
Sep	30,632	8,972	7,881	87.8%
Oct	32,429	9,145	8,199	89.7%
Nov	30,360	8,695	8,004	92.1%
Dec	31,859	9,095	8,190	90.0%
Total	429,864	113,502	93,136	82.1%

Figure 3-29 Daily RT SCED solutions approved for dispatch signals and solutions used in pricing: 2019 and 2020



PJM's process for solving and approving RT SCED cases, and selecting approved RT SCED cases to use in LPC to calculate LMPs has inconsistencies that lead to downstream impacts for energy and reserve dispatch and settlements. PJM does not link dispatch and settlement intervals. RT SCED moved from automatically executing a case every three minutes to every five minutes in 2020, and cases are approved irregularly, while settlements are linked to five minute intervals. RT SCED solves the dispatch problem for a target time that is generally 10 to 14 minutes in the future. An RT SCED case is approved and sends dispatch signals to generators based on a 10 minute ramp time. The look ahead time for the load forecast and the look ahead time for the resource dispatch target do not match, and a new RT SCED case overrides the previously approved case before resources have time to achieve the previous target dispatch. Prior to October 15, 2020, the interval that was priced in LPC was consistently before the target time from the RT SCED case used for the dispatch signal. LPC took the most recently approved RT SCED case to calculate LMPs for the present five minute interval. For example, the LPC case that calculates prices for the interval ending 10:05 EPT used an approved RT SCED case that sent MW dispatch signals for the target time of 10:10 EPT. This discrepancy created a mismatch between the MW dispatch and real-time LMPs and undermined generators' incentive to follow dispatch. Under new RT SCED changes that were implemented on October 15, 2020, PJM resolved the mismatch between LPC and the RT SCED target time, but prices no longer apply at the time when resources receive and follow that dispatch signal.[49] For example, the LPC case that calculates prices for the interval ending 10:05 EPT uses an approved RT SCED case that sent MW dispatch signals at 9:55 EPT which are no longer effective from 10:00 to 10:05 EPT. There is still a mismatch between the MW dispatch and real-time LMPs that undermines generators' incentive to follow dispatch. The timing remains incorrect until all three (the pricing interval, the dispatch interval, and the RT SCED target time) all correspond to one another.

The extent to which dispatch instructions from approved SCED solutions are reflected in concurrent prices in the PJM Real-Time Energy Market can be measured by comparing the start and end times when the dispatch instructions from the RT SCED solution were effective with the start and end times when the corresponding prices applied. The start time for a dispatch instruction is the time at which PJM approves the RT SCED solution, which triggers sending the resulting dispatch instructions to resources. The end time for a dispatch instruction is the time when the next RT SCED solution is approved. Dispatch and pricing would be perfectly aligned if the start and end times of the dispatch instructions from an approved RT SCED solution matched with the start and end times of the LPC pricing interval that used the same RT SCED solution. In a perfectly aligned five minute market, these times would both be five minutes in duration. However, RT SCED uses a 10 minute ramp time to dispatch resources, while LPC applies prices to five minute intervals.

Table 3-39 shows the average duration of the period when dispatch instructions corresponded to the prevailing prices in 2020. Prior to October 15, 2020, PJM used the latest approved RT SCED solution available at the time of LPC execution, regardless of the SCED target time, to calculate prices for the current five minute pricing interval. The average duration of correspondence ranged from 3 minutes 11 seconds to 3 minutes 37 seconds from January through October 15, 2020, varying with changes to the frequency of automatic RT SCED execution. The percent of time that prices were consistent with the dispatch instructions was 67.2 to 69.9 percent, on average. This is far from the goal of 100 percent correspondence between five minute dispatch instructions and prices. With the short term changes to RT SCED that were implemented on October 15, 2020, the prices no longer correspond to the dispatch instructions. Table 3-41 shows that during the period from October 15, 2020 through December 31, 2020, the dispatch instructions were consistent with prevailing prices for only 39 seconds. During this period, the percent of time that prices were consistent with the dispatch instructions was 9.9 percent. This is because by the time LMPs reflect the dispatch signals from an approved RT SCED solution, dispatchers have approved a new solution, and resources are instructed to follow new dispatch signals that do not align with the LMPs used to settle the current five minute interval. In other words, prices consistently lag dispatch instructions by five minutes, except in cases where dispatchers have not approved a new SCED solution five minutes after a previously approved solution.

Table 3-39 Dispatch instructions reflected in prices: 2020

Period	RT SCED Automatic Execution Frequency	Dispatch Duration Reflected in Prices (Minutes:Seconds)	Percent Dispatch Duration Reflected in Prices
Jan 1, 2020 - Feb 23, 2020	Every 3 minutes	03:11	67.9%
Feb 24, 2020 - Jun 22, 2020	Every 4 minutes	03:27	67.2%
Jun 23, 2020 - Oct 14, 2020	Every 5 minutes	03:37	69.9%
Oct 15, 2020 - Dec 31, 2020	Every 5 minutes	00:39	9.9%

For correct price signals and compensation, energy (LMP) and ancillary service pricing should align with the dispatch solution that is the basis for those prices and with the actual physical dispatch period during which that dispatch solution is realized for each and every real-time market interval.[50] This will only happen if RT SCED and LPC both use a five minute ramp time, consistent with the five minute real-time settlement period in PJM. The MMU recommends that PJM approve one RT SCED case for each five minute interval to dispatch resources during that interval using a five minute ramp time, and that PJM calculate prices using LPC for that five minute interval using the same approved RT SCED case. This will result in prices used to settle energy for the five minute interval that ends at the RT SCED dispatch target time.

49 See Docket No. ER19-2573-000.

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

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 17:00 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 17:00 of the second business day following the operating day.[51] Table 3-40 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 2019 and 2020. In 2020, PJM recalculated LMPs for 943 five minute intervals or 0.89 percent of the total 105,408 five minute intervals. On August 3 and August 4 2020, PJM systems experienced a widespread outage. For nearly two hours on August 3 and for one hour on August 4, PJM dispatched resources manually. PJM later reconstructed LMPs based on the manual dispatch instructions that were sent out during the outage period.[52]

Table 3-40 Number of five minute interval real-time prices recalculated: 2019 through 2020

	2019		2020	
Month	Number of Five Minute Intervals	Number of Five Minute Intervals for which LMPs were recalculated	Number of Five Minute Intervals	Number of Five Minute Intervals for which LMPs were recalculated
January	8,928	10	8,928	193
February	8,064	14	8,352	12
March	8,916	51	8,916	110
April	8,640	19	8,640	50
May	8,928	19	8,928	37
June	8,640	28	8,640	64
July	8,928	69	8,928	67
August	8,928	79	8,928	251
September	8,640	45	8,640	20
October	8,928	115	8,928	37
November	8,652	74	8,652	22
December	8,928	11	8,928	80
Total	105,120	534	105,408	943

Day-Ahead Average LMP

Day-ahead, average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[53]

PJM Day-Ahead, Average LMP

Table 3-41 shows the PJM day-ahead, average LMP for 2000 through 2020.

Table 3-41 Day-ahead, average LMP (Dollars per MWh): 2000 through 2020

	Day-Ahead LMP			Year to Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$31.97	$24.42	$21.33	NA	NA	NA
2001	$32.75	$27.05	$30.42	2.4%	10.8%	42.6%
2002	$28.46	$23.28	$17.68	(13.1%)	(14.0%)	(41.9%)
2003	$38.73	$35.22	$20.84	36.1%	51.3%	17.8%
2004	$41.43	$40.36	$16.60	7.0%	14.6%	(20.4%)
2005	$57.89	$50.08	$30.04	39.7%	24.1%	81.0%
2006	$48.10	$44.21	$23.42	(16.9%)	(11.7%)	(22.0%)
2007	$54.67	$52.34	$23.99	13.7%	18.4%	2.4%
2008	$66.12	$58.93	$30.87	20.9%	12.6%	28.7%
2009	$37.00	$35.16	$13.39	(44.0%)	(40.3%)	(56.6%)
2010	$44.57	$39.97	$18.83	20.5%	13.7%	40.6%
2011	$42.52	$38.13	$20.48	(4.6%)	(4.6%)	8.8%
2012	$32.79	$30.89	$13.27	(22.9%)	(19.0%)	(35.2%)
2013	$37.15	$34.63	$15.46	13.3%	12.1%	16.5%
2014	$49.15	$38.10	$51.88	32.3%	10.0%	235.6%
2015	$34.12	$29.09	$22.59	(30.6%)	(23.7%)	(56.5%)
2016	$28.10	$25.76	$10.68	(17.7%)	(11.4%)	(52.7%)
2017	$29.48	$26.94	$11.69	4.9%	4.6%	9.5%
2018	$35.69	$30.96	$22.32	21.1%	14.9%	91.0%
2019	$26.03	$24.36	$9.35	(27.1%)	(21.3%)	(58.1%)
2020	$20.33	$18.99	$7.00	(21.9%)	(22.0%)	(25.2%)

51 OA Schedule 1 § 1.10.8(e).

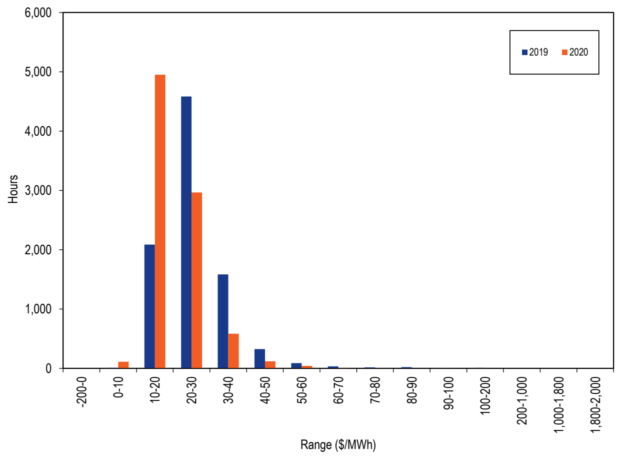
52 PJM changed this practice effective November 19, 2020. See PJM Manual 11: Energy and Ancillary Services Market Operations, Section 2.10 PJM Real-Time Price Verification Procedure, Rev. 111 (November 19, 2020).

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

PJM Day-Ahead Average LMP Duration

Figure 3-30 shows the hourly distribution of PJM day-ahead, average LMP in 2019 and 2020.

Figure 3-30 Average LMP for the day-ahead energy market: 2019 and 2020



Day-Ahead, Load-Weighted, Average LMP

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

PJM Day-Ahead, Load-Weighted, Average LMP

Table 3-42 shows the PJM day-ahead, load-weighted, average LMP in 2000 through 2020.

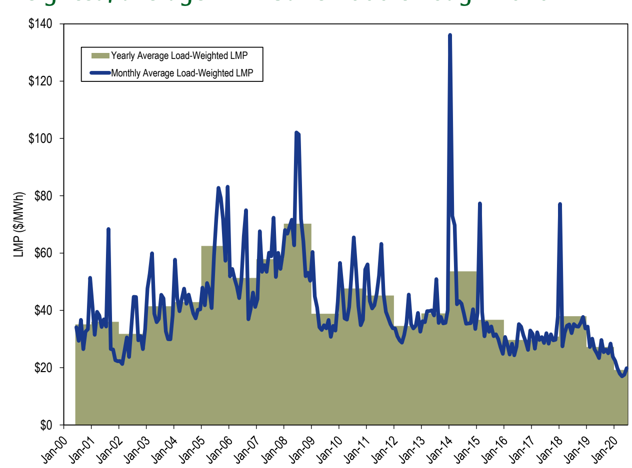
Table 3-42 Day-ahead, load-weighted, average LMP (Dollars per MWh): 2000 through 2020

	Day-Ahead, Load-Weighted, Average LMP			Year to Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$35.12	$28.50	$22.26	NA	NA	NA
2001	$36.01	$29.02	$37.48	2.5%	1.8%	68.4%
2002	$31.80	$26.00	$20.68	(11.7%)	(10.4%)	(44.8%)
2003	$41.43	$38.29	$21.32	30.3%	47.3%	3.1%
2004	$42.87	$41.96	$16.32	3.5%	9.6%	(23.4%)
2005	$62.50	$54.74	$31.72	45.8%	30.4%	94.3%
2006	$51.33	$46.72	$26.45	(17.9%)	(14.6%)	(16.6%)
2007	$57.88	$55.91	$25.02	12.8%	19.7%	(5.4%)
2008	$70.25	$62.91	$33.14	21.4%	12.5%	32.4%
2009	$38.82	$36.67	$14.03	(44.7%)	(41.7%)	(57.7%)
2010	$47.65	$42.06	$20.59	22.7%	14.7%	46.8%
2011	$45.19	$39.66	$24.05	(5.2%)	(5.7%)	16.8%
2012	$34.55	$31.84	$15.48	(23.5%)	(19.7%)	(35.6%)
2013	$38.93	$35.77	$18.05	12.7%	12.3%	16.6%
2014	$53.62	$39.84	$59.62	37.8%	11.4%	230.4%
2015	$36.73	$30.60	$25.46	(31.5%)	(23.2%)	(57.3%)
2016	$29.68	$27.00	$11.64	(19.2%)	(11.8%)	(54.3%)
2017	$30.85	$28.21	$12.64	3.9%	4.5%	8.6%
2018	$37.97	$32.49	$24.76	23.1%	15.2%	95.9%
2019	$27.23	$25.28	$10.18	(28.3%)	(22.2%)	(58.9%)
2020	$21.40	$19.78	$7.59	(21.4%)	(21.7%)	(25.5%)

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

Figure 3-31 shows the PJM day-ahead, monthly and annual, load-weighted LMP from June 1, 2000 through 2020.[54]

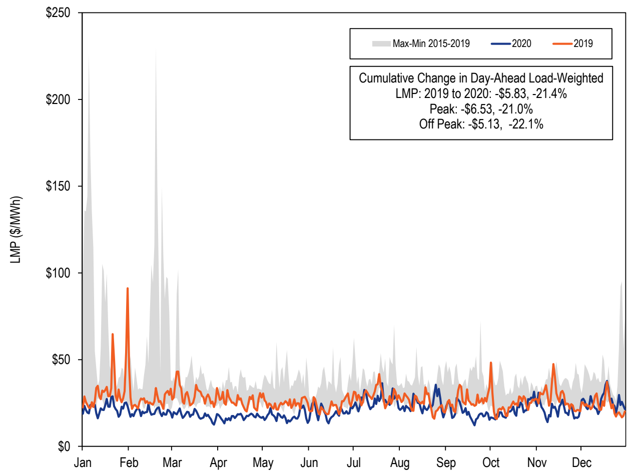
Figure 3-31 Day-ahead, monthly and annual, load-weighted, average LMP: June 2000 through 2020



54 Since the day-ahead energy market did not start until June 1, 2000, the day-ahead data for 2000 only includes data for the last seven months of that year.

Figure 3-32 shows the PJM day-ahead daily, load-weighted, LMP for 2019 and 2020 compared to the historic five year price range.

Figure 3-32 Day-ahead, daily, load-weighted, average LMP: 2019 and 2020



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

Figure 3-33 shows the PJM day-ahead, monthly, load-weighted, average LMP and inflation adjusted monthly day-ahead, load-weighted, average LMP for June 2000 through 2020.[55] Table 3-43 shows the PJM day-ahead, load-weighted, average LMP and inflation adjusted load-weighted, average LMP for every year from 2001 through 2020. The PJM day-ahead, inflation adjusted, load-weighted, average LMP for 2020 was the lowest ($13.35 per MWh) since PJM day-ahead markets started in 2000. The day-ahead inflation adjusted monthly load-weighted, average LMP for April 2020 ($10.70 per MWh) was the lowest monthly value since the day-ahead markets started.

Figure 3-33 Day-ahead, monthly, load-weighted, average LMP unadjusted and inflation adjusted: June 2000 through December 2020

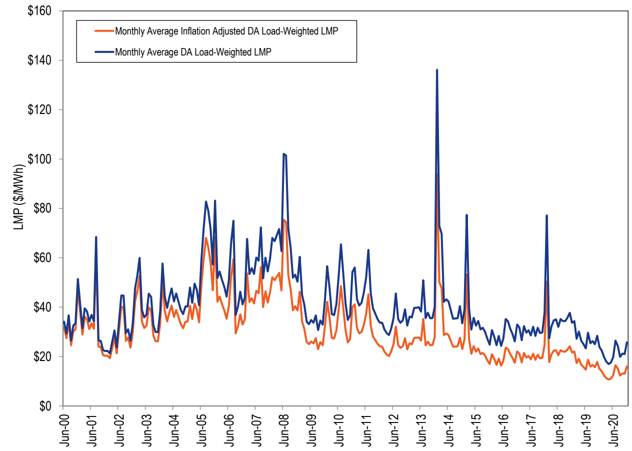


Table 3-43 Day-ahead, yearly, load-weighted, average LMP unadjusted and inflation adjusted: 2001 through 2020

	Load-Weighted, Average LMP	Inflation Adjusted Load-Weighted, Average LMP
2000	$35.13	$32.74
2001	$36.01	$32.87
2002	$31.80	$28.53
2003	$41.43	$36.42
2004	$42.87	$36.65
2005	$62.50	$51.58
2006	$51.33	$41.12
2007	$57.88	$45.11
2008	$70.25	$52.61
2009	$38.82	$29.29
2010	$47.65	$35.32
2011	$45.19	$32.48
2012	$34.55	$24.33
2013	$38.93	$27.00
2014	$53.62	$36.71
2015	$36.73	$25.08
2016	$29.68	$19.98
2017	$30.85	$20.34
2018	$37.97	$24.47
2019	$27.23	$17.23
2020	$21.40	$13.35

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.

55 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 January 13, 2021).

In practice, virtuals can profit anytime there is a difference in prices at any location in any hour between the day-ahead and real-time energy markets. Profitable 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 be profitable but cannot change the underlying reason for the price difference. The virtual transactions will continue to profit from the activity for that reason 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 profit from price differences between the day-ahead and real-time energy market. In theory, profitable virtual transactions contribute to price convergence, but with false arbitrage, high 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 price for energy, the INC makes a profit. The buyer of a DEC must sell energy in the real-time energy market to fulfill the financial obligation to buy energy. If the day-ahead price for energy is lower than the real-time price for energy, the DEC makes a profit.

The profitability of a UTC transaction is the net of the separate profitability of the component INC and DEC. A UTC can be net profitable if the profit on one side of the UTC transaction exceeds the losses on the other side.

Table 3-44 shows the number of cleared UTC transactions, the number of profitable cleared UTCs, the number of cleared UTCs that were profitable at their source point and the number of cleared UTCs that were profitable at their sink point in 2019 and 2020. In 2020, 50.1 percent of all cleared UTC transactions were net profitable. Of cleared UTC transactions, 62.1percent were profitable on the source side and 38.0 percent were profitable on the sink side, but only 7.3 percent were profitable on both the source and sink side.

Table 3-44 Cleared UTC profitability by source and sink point: 2019 and 2020[56]

	Cleared UTCs	Profitable UTCs	UTC Profitable at Source Bus	UTC Profitable at Sink Bus	UTC Profitable at Source and Sink	Profitable UTC	Profitable Source	Profitable Sink	Profitable at Source and Sink
2019	9,274,991	4,558,269	6,332,711	2,995,264	629,304	49.1%	68.3%	32.3%	6.8%
2020	8,967,923	4,497,081	5,568,865	3,410,843	652,476	50.1%	62.1%	38.0%	7.3%

Table 3-45 shows the number of cleared INC and DEC transactions and the number of profitable cleared transactions in 2019 and 2020. Of cleared INC and DEC transactions in 2020, 64.1 percent of INCs were profitable and 39.6 percent of DECs were profitable.

Table 3-45 Cleared INC and DEC profitability: 2019 and 2020

	Cleared INC	Profitable INC	Profitable INC Percent	Cleared DEC	Profitable DEC	Profitable DEC Percent
2019	2,230,626	1,542,439	69.1%	1,779,154	622,569	35.0%
2020	2,256,236	1,445,248	64.1%	2,956,349	1,169,256	39.6%

56 Calculations exclude PJM administrative charges.

Figure 3-34 shows total UTC daily gross profits, the sum of all positive profit UTC transactions, gross losses, the sum of all negative profit UTC transactions, and net profits and losses in 2020.

Figure 3-34 UTC daily gross profits and losses and net profits: 2020[57]

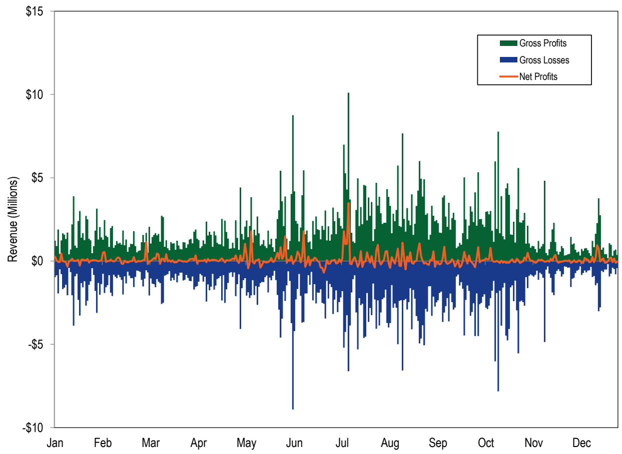


Figure 3-35 shows the cumulative UTC daily profits for each year from 2013 through 2020.

Figure 3-35 Cumulative daily UTC profits: 2013 through 2020

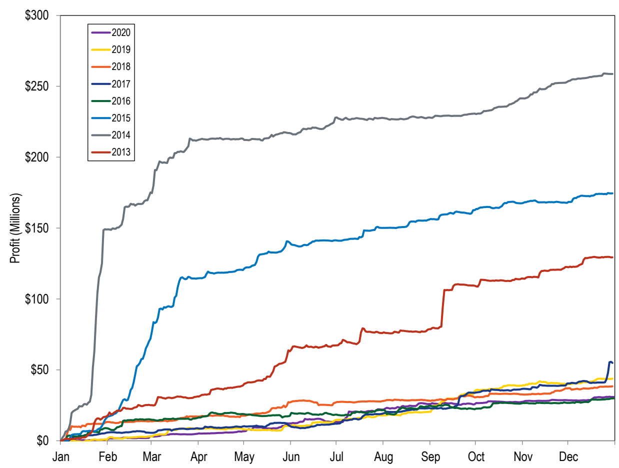


Table 3-46 shows UTC profits by month for 2013 through 2020. May 2016, September 2016, February 2017, June 2018 and September 2020 were the only months in this seven year period in which monthly profits were negative.

Table 3-46 UTC profits by month: 2013 through 2020

	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

57 Calculations exclude PJM administrative charges.

Figure 3-36 shows total INC and DEC daily gross profits, the sum of all positive profit transactions, gross losses, the sum of all negative profit transactions, and net profits and losses in 2020.

Figure 3-36 INC and DEC daily gross profits and losses and net profits: 2020[58]

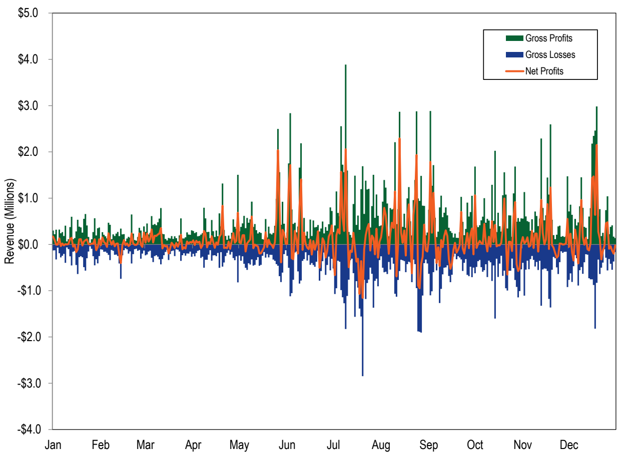


Figure 3-37 shows total INC daily gross profits and losses and net profits and losses in 2020.

Figure 3-37 INC daily gross profits and losses and net profits: 2020[59]

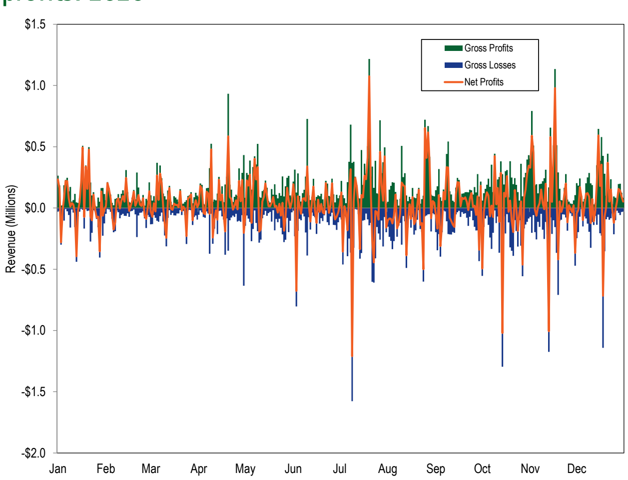


Figure 3-38 shows total DEC daily gross profits and losses and net profits and losses in 2020.

Figure 3-38 DEC daily gross profits and losses and net profits: 2020[60]

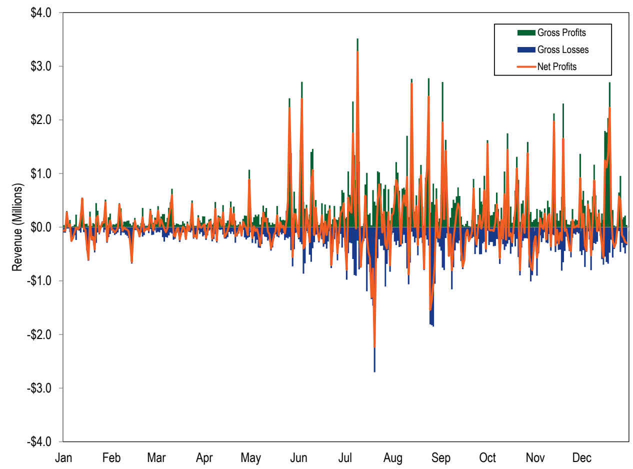
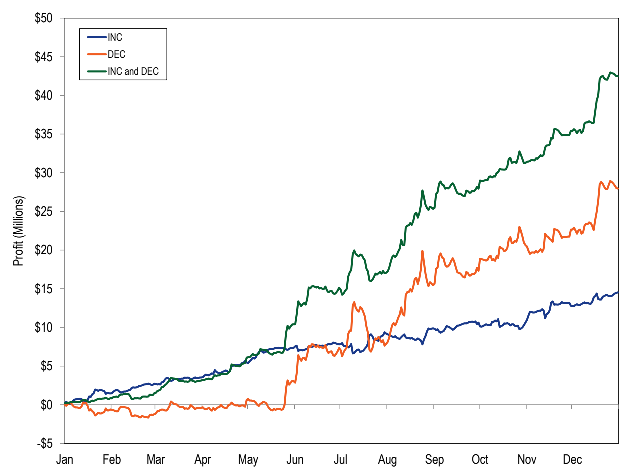


Figure 3-39 shows the cumulative INC and DEC daily profits for 2020.

Figure 3-39 Cumulative daily INC and DEC profits: 2020



58 Calculations exclude PJM administrative charges.
59 Calculations exclude PJM administrative charges.
60 Calculations exclude PJM administrative charges.

Table 3-47 shows INC and DEC profits by month for 2020.

Table 3-47 INC and DEC profits by month: 2020

	January	February	March	April	May	June	July	August	September	October	November	December	Total
INCs	$1,455,089	$1,259,625	$803,233	$1,944,109	$1,893,382	$452,115	$1,402,597	$659,910	$749,252	$7,784	$2,161,744	$1,730,590	$10,619,313
DECs	($614,734)	($606,579)	$833,364	$1,017,052	$2,404,925	$4,289,805	$522,583	$7,609,006	$1,857,777	$3,322,309	$2,019,746	$5,295,040	$17,313,199
INCs and DECs	$840,356	$653,046	$1,636,597	$2,961,161	$4,298,306	$4,741,920	$1,925,180	$8,268,916	$2,607,029	$3,330,093	$4,181,491	$7,025,630	$27,932,511

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 guarantee that such activity will result in price convergence and no data to support that claim. As a general matter, virtual offers and bids are based on expectations about both day-ahead and real-time energy market conditions and reflect the uncertainty about conditions in both markets, 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.

Table 3-48 shows that the difference between the average real-time price and the average day-ahead price was -$0.01 per MWh in 2019 and $0.33 per MWh in 2020. The difference between average peak real-time price and the average peak day-ahead price was -$0.09 per MWh in 2019 and $0.42 per MWh in 2020.

Table 3-48 Day-ahead and real-time average LMP (Dollars per MWh): 2019 and 2020[61]

	2019				2020			
	Day-Ahead	Real-Time	Difference	Percent of Real Time	Day-Ahead	Real-Time	Difference	Percent of Real Time
Average	$26.03	$26.02	($0.01)	(0.1%)	$20.33	$20.66	$0.33	1.6%
Median	$24.36	$22.89	($1.47)	(6.4%)	$18.99	$18.35	($0.64)	(3.5%)
Standard deviation	$9.35	$21.19	$11.84	55.9%	$7.00	$11.77	$4.78	40.6%
Peak average	$30.23	$30.13	($0.09)	(0.3%)	$23.67	$24.09	$0.42	1.7%
Peak median	$27.95	$25.34	($2.61)	(10.3%)	$21.64	$20.52	($1.12)	(5.5%)
Peak standard deviation	$9.87	$26.26	$16.39	62.4%	$7.24	$13.99	$6.74	48.2%
Off peak average	$22.38	$22.43	$0.06	0.3%	$17.39	$17.64	$0.25	1.4%
Off peak median	$21.07	$20.35	($0.72)	(3.5%)	$16.54	$16.29	($0.25)	(1.5%)
Off peak standard deviation	$7.08	$14.55	$7.47	51.4%	$5.23	$8.30	$3.08	37.0%

The price difference between the real-time and the day-ahead energy markets results in part, from conditions in the real-time energy market that are difficult, or impossible, to anticipate in the day-ahead energy market.

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

Table 3-49 shows the difference between the real-time load-weighted and the day-ahead load-weighted energy market prices for 2001 through 2020.

Table 3-49 Day-ahead load-weighted and real-time load-weighted, average LMP (Dollars per MWh): 2001 through 2020

	Day-Ahead	Real-Time	Difference	Percent of Real Time
2001	$32.75	$32.38	($0.37)	(1.1%)
2002	$28.46	$28.30	($0.16)	(0.6%)
2003	$38.73	$38.28	($0.45)	(1.2%)
2004	$41.43	$42.40	$0.97	2.3%
2005	$57.89	$58.08	$0.18	0.3%
2006	$48.10	$49.27	$1.17	2.4%
2007	$54.67	$57.58	$2.90	5.3%
2008	$66.12	$66.40	$0.28	0.4%
2009	$37.00	$37.08	$0.08	0.2%
2010	$44.57	$44.83	$0.26	0.6%
2011	$42.52	$42.84	$0.32	0.7%
2012	$32.79	$33.11	$0.32	1.0%
2013	$37.15	$36.55	($0.60)	(1.6%)
2014	$49.15	$48.22	($0.93)	(1.9%)
2015	$34.12	$33.39	($0.73)	(2.1%)
2016	$28.10	$27.57	($0.53)	(1.9%)
2017	$29.48	$29.42	($0.06)	(0.2%)
2018	$35.69	$35.75	$0.06	0.2%
2019	$26.03	$26.02	($0.01)	(0.1%)
2020	$20.33	$20.66	$0.33	1.6%

Table 3-50 includes frequency distributions of the differences between PJM real-time, load-weighted, hourly LMP and PJM day-ahead, load-weighted, hourly LMP for 2019 and 2020.

Table 3-50 Frequency distribution by hours of real-time, load-weighted LMP minus day-ahead, load-weighted LMP (Dollars per MWh): 2019 and 2020

	2019		2020	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($1,000)	0	0.00%	0	0.00%
($1,000) to ($750)	0	0.00%	0	0.00%
($750) to ($500)	0	0.00%	0	0.00%
($500) to ($450)	0	0.00%	0	0.00%
($450) to ($400)	0	0.00%	0	0.00%
($400) to ($350)	0	0.00%	0	0.00%
($350) to ($300)	0	0.00%	0	0.00%
($300) to ($250)	0	0.00%	0	0.00%
($250) to ($200)	0	0.00%	0	0.00%
($200) to ($150)	0	0.00%	0	0.00%
($150) to ($100)	0	0.00%	0	0.00%
($100) to ($50)	5	0.06%	0	0.00%
($50) to $0	6,013	68.70%	5,522	62.86%
$0 to $50	2,681	99.30%	3,221	99.53%
$50 to $100	29	99.63%	35	99.93%
$100 to $150	16	99.82%	2	99.95%
$150 to $200	2	99.84%	2	99.98%
$200 to $250	3	99.87%	0	99.98%
$250 to $300	3	99.91%	1	99.99%
$300 to $350	1	99.92%	1	100.00%
$350 to $400	2	99.94%	0	100.00%
$400 to $450	1	99.95%	0	100.00%
$450 to $500	0	99.95%	0	100.00%
$500 to $750	4	100.00%	0	100.00%
$750 to $1,000	0	100.00%	0	100.00%
$1,000 to $1,250	0	100.00%	0	100.00%
>= $1,250	0	100.00%	0	100.00%

Figure 3-40 shows the hourly differences between day-ahead and real-time hourly LMP in 2020.

Figure 3-40 Real-time hourly, LMP minus day-ahead hourly LMP: 2020

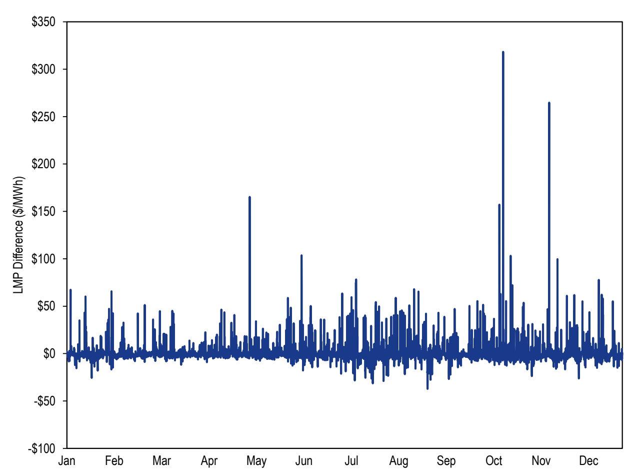
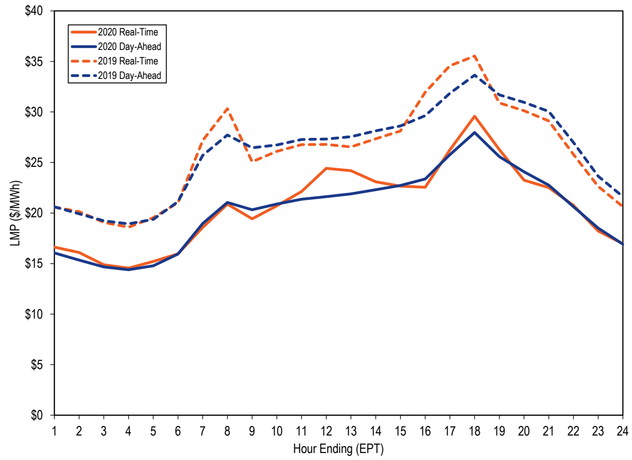


Figure 3-41 shows day-ahead and real-time, load-weighted, average hourly LMP 2019 and 2020.

Figure 3-41 System hourly average LMP: 2020



Zonal LMP and Dispatch

Table 3-51 shows zonal real-time, and real-time, load-weighted, average LMP in 2019 and 2020.

Table 3-51 Zonal real-time and real-time, load-weighted, average LMP (Dollars per MWh): 2019 and 2020

	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
Zone	2019	2020	Percent Change	2019	2020	Percent Change
AECO	$23.72	$18.44	(22.3%)	$25.07	$19.72	(21.3%)
AEP	$26.92	$21.17	(21.3%)	$28.21	$22.14	(21.5%)
APS	$26.55	$21.29	(19.8%)	$27.83	$22.40	(19.5%)
ATSI	$26.86	$21.34	(20.5%)	$28.06	$22.55	(19.6%)
BGE	$28.95	$23.98	(17.2%)	$30.82	$25.78	(16.3%)
ComEd	$23.53	$19.04	(19.1%)	$24.72	$20.18	(18.4%)
DAY	$27.96	$22.08	(21.0%)	$29.52	$23.23	(21.3%)
DEOK	$27.02	$21.33	(21.1%)	$28.49	$22.37	(21.5%)
DLCO	$27.59	$21.85	(20.8%)	$29.08	$23.05	(20.7%)
Dominion	$25.16	$20.68	(17.8%)	$27.71	$22.90	(17.4%)
DPL	$26.45	$21.37	(19.2%)	$27.69	$22.79	(17.7%)
EKPC	$26.54	$21.07	(20.6%)	$28.18	$22.14	(21.4%)
JCPL	$23.90	$18.63	(22.0%)	$25.40	$20.05	(21.1%)
Met-Ed	$24.92	$19.78	(20.6%)	$26.34	$21.16	(19.6%)
OVEC	$25.98	$20.64	(20.5%)	$26.23	$20.75	(20.9%)
PECO	$23.43	$18.25	(22.1%)	$24.75	$19.29	(22.1%)
PENELEC	$25.19	$19.94	(20.9%)	$26.17	$20.84	(20.4%)
Pepco	$28.03	$22.23	(20.7%)	$29.68	$23.59	(20.5%)
PPL	$23.55	$18.44	(21.7%)	$24.85	$19.42	(21.9%)
PSEG	$24.11	$18.73	(22.3%)	$25.28	$19.69	(22.1%)
RECO	$24.44	$19.38	(20.7%)	$25.72	$20.74	(19.4%)
PJM	$26.02	$20.66	(20.6%)	$27.32	$21.77	(20.3%)

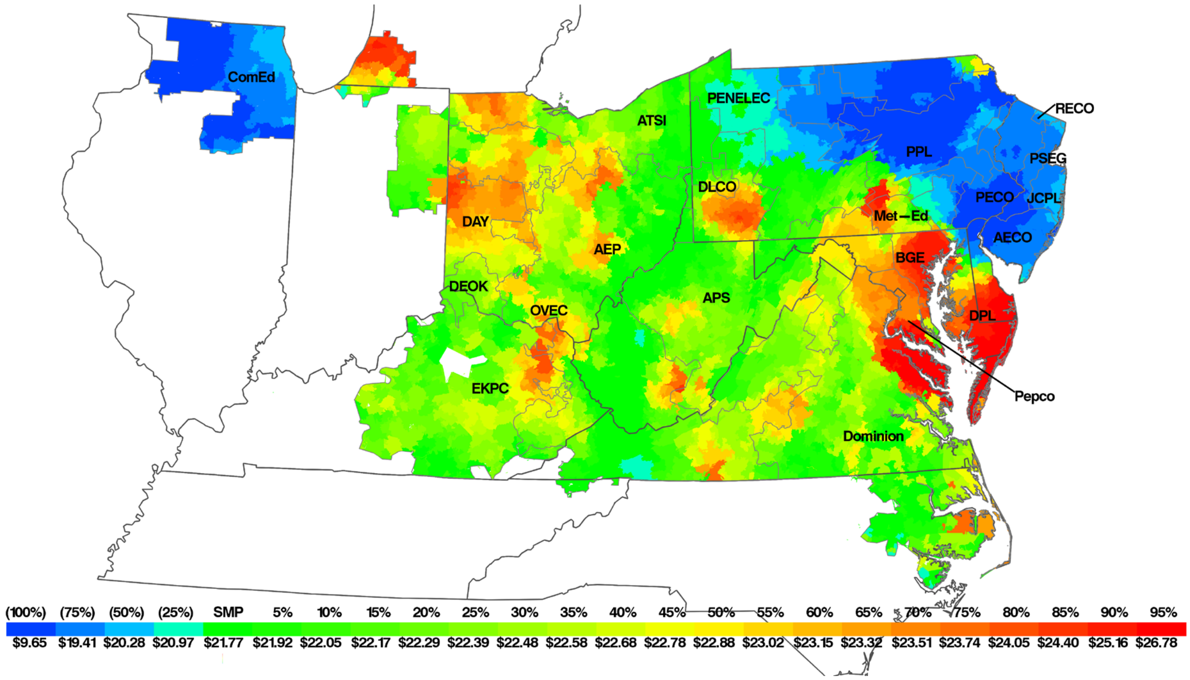
Table 3-52 shows zonal day-ahead, and day-ahead, load-weighted, average LMP in 2019 and 2020.

Table 3-52 Zonal day-ahead and day-ahead, load-weighted, average LMP (Dollars per MWh): 2019 and 2020

	Day-Ahead Average LMP			Day-Ahead, Load-Weighted, Average LMP		
Zone	2019	2020	Percent Change	2019	2020	Percent Change
AECO	$23.70	$18.01	(24.0%)	$24.92	$19.18	(23.0%)
AEP	$26.81	$20.92	(22.0%)	$28.02	$21.89	(21.9%)
APS	$26.68	$20.91	(21.6%)	$27.84	$21.96	(21.1%)
ATSI	$27.05	$20.92	(22.7%)	$28.14	$21.91	(22.2%)
BGE	$29.22	$23.74	(18.7%)	$30.93	$25.36	(18.0%)
ComEd	$23.59	$18.97	(19.6%)	$24.62	$20.01	(18.7%)
DAY	$27.93	$22.00	(21.2%)	$29.27	$23.19	(20.8%)
DEOK	$27.22	$21.35	(21.6%)	$28.64	$22.50	(21.4%)
DLCO	$27.83	$21.66	(22.2%)	$29.33	$22.89	(22.0%)
Dominion	$25.06	$19.55	(22.0%)	$27.44	$21.47	(21.7%)
DPL	$26.63	$21.00	(21.2%)	$27.72	$22.27	(19.6%)
EKPC	$26.39	$20.84	(21.0%)	$27.97	$22.17	(20.7%)
JCPL	$23.78	$18.07	(24.0%)	$25.04	$19.23	(23.2%)
Met-Ed	$24.60	$19.00	(22.8%)	$25.78	$20.23	(21.5%)
OVEC	$25.91	$20.45	(21.1%)	$28.03	$21.12	(24.7%)
PECO	$23.26	$17.78	(23.6%)	$24.38	$18.75	(23.1%)
PENELEC	$25.57	$19.90	(22.2%)	$26.89	$21.13	(21.4%)
Pepco	$28.38	$22.12	(22.1%)	$29.99	$23.55	(21.5%)
PPL	$23.30	$17.92	(23.1%)	$24.39	$18.82	(22.9%)
PSEG	$24.03	$18.24	(24.1%)	$25.13	$19.18	(23.7%)
RECO	$24.60	$18.74	(23.8%)	$25.94	$20.22	(22.0%)
PJM	$26.03	$20.33	(21.9%)	$27.23	$21.40	(21.4%)

Figure 3-42 is a map of the real-time, load-weighted, average LMP in 2020. In the legend, green represents the system marginal price (SMP) and each increment to the right and left of the SMP represents five percent of the pricing nodes above and below the SMP.

Figure 3-42 Real-time, load-weighted, average LMP: 2020



Transmission Penalty Factors

LMP may, at times, be set by transmission penalty factors. When a transmission constraint is binding 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 penalty factors. The shadow price directly affects the LMP. Transmission penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing.

Table 3-53 shows the frequency and average shadow price of transmission constraints in PJM. In 2020, there were 165,963 transmission constraint intervals in the real-time market with a nonzero shadow price. For nearly four percent of these transmission constraint intervals, the line limit was violated, meaning that the flow exceeded the facility limit.[62] In 2020, the average shadow price of transmission constraints when the line limit was violated was nearly 16.8 times higher than when the transmission constraint was binding at its limit.

Table 3-53 Frequency and average shadow price of transmission constraints: 2019 and 2020

	Frequency (Constraint Intervals)		Average Shadow Price	
Description	2019	2020	2019	2020
PJM Internal Violated Transmission Constraints	7,046	7,374	$1,480.03	$1,549.04
PJM Internal Binding Transmission Constraints	92,366	117,867	$96.89	$92.23
Market to Market Transmission Constraints	53,263	40,722	$228.92	$219.15
All Transmission Constraints	152,675	165,963	$206.78	$188.10

62 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.

Transmission penalty factors should be applied without discretion. PJM adopted the MMU's recommendation to remove the constraint relaxation logic and allow transmission penalty factors to set prices in the day-ahead and real-time markets for all internal transmission constraints. PJM also revised the tariff to list the conditions under which transmission 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.

PJM continues the practice of discretionary reduction in line ratings. Table 3-54 shows the frequency of changes to the transmission constraints for binding and violated transmission constraints in the PJM real-time market. In 2020, there were 6,779 or 92 percent of 7,374 internal violated transmission constraint intervals in the real-time market with constraint limit less than 100 percent of the actual constraint limit. In 2020, among the constraints with reduced constraint limits, the constraint limit was reduced on average by 6.8 percent.

Table 3-54 Frequency of reduction in line ratings (constraint intervals): 2019 and 2020

	Frequency (Constraint Intervals)		Constraints with Reduced Line Limits (Constraint Intervals)		Average Reduction (Percentage)	
Description	2019	2020	2019	2020	2019	2020
PJM Internal Violated Transmission Constraints	7,046	7,374	5,465	6,779	6.88%	6.80%
PJM Internal Binding Transmission Constraints	92,366	117,867	90,033	115,866	9.08%	8.87%
Market to Market Transmission Constraints	53,263	40,722	10,699	9,841	5.54%	5.94%
All Transmission Constraints	152,675	165,963	106,197	132,486	8.61%	8.54%

Table 3-55 shows the frequency of changes to the magnitude of transmission penalty factors for binding and violated transmission constraints in the PJM Real-Time Energy Market. In 2020, there were 5,031 or 68 percent of internal violated transmission constraint intervals in the real-time market with a transmission penalty factor equal to the default $2,000 per MWh.

Table 3-55 Frequency of changes to the magnitude of transmission penalty factor (constraint intervals): 2019 and 2020

	2019			2020		
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
PJM Internal Violated Transmission Constraints	4,623	70	2,353	5,031	88	2,255
PJM Internal Binding Transmission Constraints	86,071	707	5,588	109,731	155	7,981
Market to Market Transmission Constraints	11,033	3	42,227	2,956	-	37,766
All Transmission Constraints	101,727	780	50,168	117,718	243	48,002

Transmission constraint penalty factors frequently set prices when PJM models a surrogate constraint to limit the dispatch of a generator that would experience voltage instability at its full output due to a transmission outage. 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.

PJM uses CT pricing logic to force otherwise uneconomic resources to be marginal and set price in the day-ahead and real-time market solutions. In the event PJM commits a resource that is uneconomic and/or offered with inflexible parameters, PJM uses CT pricing logic to model a constraint with a variable flow limit, paired with an artificial override of the inflexible resource's economic minimum, to force the resource to be marginal in the PJM market solution.[63] Frequently, PJM dispatchers also manually override the transmission violation penalty factor of the

63 PJM dispatchers generally log the resources paired with a constraint in the CT pricing logic. The data presented is based on PJM dispatcher logs.

constraint to match the offer price of the resource to artificially control the shadow price of the constraint. Table 3-56 shows the frequency of CT pricing logic used in the PJM Real-Time Energy Market. In 2020, there were 10,540 constraint intervals in the real-time market where CT pricing logic was used. In the PJM CT pricing logic, there could be one or multiple resources paired with a constraint.

PJM's use of CT pricing logic is inconsistent with the efficient market dispatch and pricing. For that reason, in 2019 FERC declared CT pricing logic to be unjust and unreasonable.[64] PJM should discontinue the use of CT pricing logic, regardless of whether the new fast-start pricing process is in place.

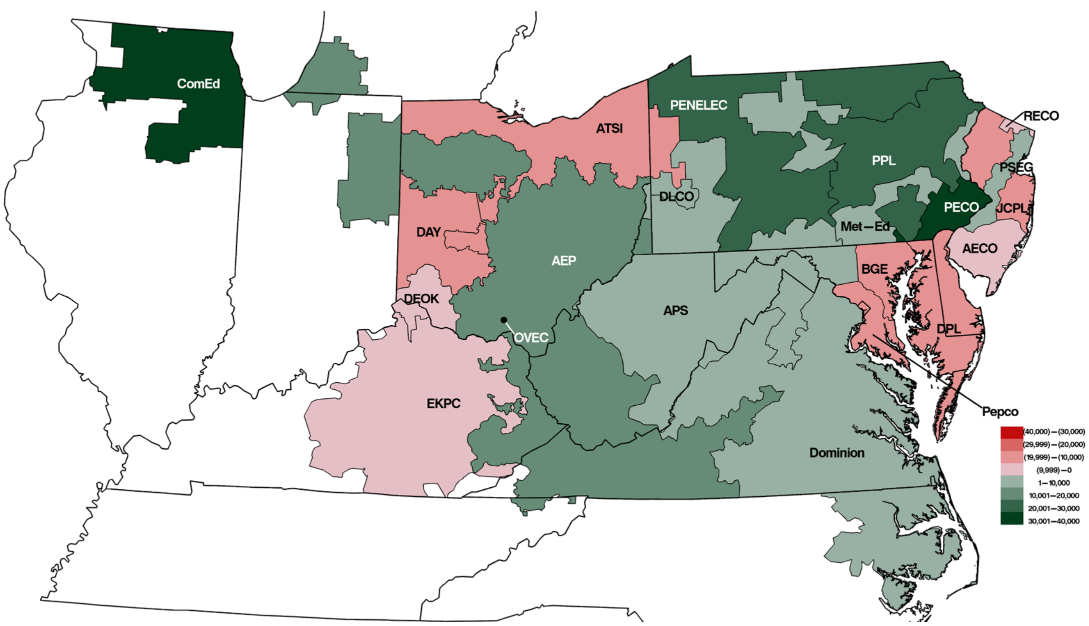
Table 3-56 Frequency of CT pricing logic used in the real-time market (constraint intervals): 2019 and 2020

Month	2019	2020
Jan	650	231
Feb	744	167
Mar	691	122
Apr	378	173
May	1,362	632
Jun	574	825
Jul	1,460	842
Aug	1,725	1,189
Sep	2,027	1,982
Oct	2,301	2,017
Nov	2,229	956
Dec	835	1,404
Total	14,976	10,540

Net Generation by Zone

Figure 3-43 shows the difference between the PJM real-time generation and real-time load by zone in 2020. Figure 3-43 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 3-57 shows the difference between the PJM real-time generation and real-time load by zone in 2019 and 2020.

Figure 3-43 Map of real-time generation, less real-time load, by zone: 2020[65]



64 *PJM Interconnection, L.L.C.*, 167 FERC ¶ 61,058 at P 69 (April 18, 2019).

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

Table 3-57 Real-time generation less real-time load by zone (GWh): 2019 and 2020

	Zonal Generation and Load (GWh)					
	2019			2020		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	6,083.1	9,887.9	(3,804.8)	3,489.7	9,489.2	(5,999.5)
AEP	144,785.2	125,736.1	19,049.1	135,989.6	120,710.5	15,279.1
APS	51,281.0	48,967.5	2,313.5	49,068.0	46,870.7	2,197.3
ATSI	38,923.7	65,005.0	(26,081.3)	46,182.2	62,400.1	(16,217.9)
BGE	18,068.0	31,127.5	(13,059.5)	16,588.2	29,631.1	(13,042.9)
ComEd	134,364.9	94,076.8	40,288.1	128,261.3	90,687.4	37,573.9
DAY	1,079.5	17,122.3	(16,042.8)	1,055.1	16,426.9	(15,371.8)
DEOK	18,402.7	26,800.9	(8,398.2)	18,686.7	25,464.3	(6,777.6)
Dominion	98,283.0	100,869.9	(2,586.8)	105,501.9	98,774.8	6,727.1
DPL	5,098.2	18,290.2	(13,192.1)	5,163.8	17,724.5	(12,560.6)
DLCO	16,330.6	13,383.6	2,947.1	16,052.6	12,818.6	3,234.0
EKPC	6,910.1	12,741.2	(5,831.1)	8,177.8	12,407.8	(4,230.0)
JCPL	11,370.9	21,998.2	(10,627.3)	8,492.6	21,515.4	(13,022.7)
Met-Ed	22,901.1	15,485.4	7,415.7	19,838.6	14,999.2	4,839.4
OVEC	11,234.4	127.9	11,106.4	9,033.1	111.9	8,921.1
PECO	69,694.5	39,480.2	30,214.3	73,151.5	37,413.7	35,737.8
PENELEC	41,064.4	16,871.0	24,193.3	38,245.1	16,424.3	21,820.8
Pepco	12,316.6	29,495.4	(17,178.8)	11,342.9	27,059.6	(15,716.7)
PPL	64,378.2	40,427.5	23,950.7	62,309.6	39,286.2	23,023.4
PSEG	45,906.2	42,608.7	3,297.5	42,237.0	41,385.2	851.8
RECO	0.0	1,425.7	(1,425.7)	0.0	1,385.8	(1,385.8)

Net Generation and Load

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

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

The MMU recommends that during 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 3-58 shows PJM generation by fuel source in GWh for 2019 and 2020. In 2020, generation from coal units decreased 20.6 percent, generation from natural gas units increased 6.9 percent, and generation from oil increased 14.9 percent compared to 2019. Wind and solar output rose by 12.5 percent compared to 2019, supplying 3.7 percent of PJM energy in 2020. Output from coal fell twice as much as total PJM output, but was offset by the increase in output from natural gas.

Table 3-58 Generation (By fuel source (GWh)): 2019 and 2020[66] [67] [68]

	2019		2020		Change in
	GWh	Percent	GWh	Percent	Output
Coal	197,165.3	23.8%	156,575.9	19.3%	(20.6%)
Bituminous	169,958.4	20.5%	143,556.3	17.7%	(15.5%)
Sub Bituminous	20,981.7	2.5%	7,726.0	1.0%	(63.2%)
Other Coal	6,225.2	0.8%	5,293.7	0.7%	(15.0%)
Nuclear	278,911.8	33.6%	276,607.6	34.2%	(0.8%)
Gas	302,116.9	36.4%	322,504.5	39.8%	6.7%
Natural Gas CC	278,218.4	33.6%	294,712.8	36.4%	5.9%
Natural Gas CT	15,955.2	1.9%	18,825.6	2.3%	18.0%
Natural Gas Other Units	5,793.3	0.7%	7,019.2	0.9%	21.2%
Other Gas	2,150.1	0.3%	1,946.9	0.2%	(9.4%)
Hydroelectric	16,696.7	2.0%	16,423.3	2.0%	(1.6%)
Pumped Storage	4,642.9	0.6%	4,950.4	0.6%	6.6%
Run of River	10,728.7	1.3%	10,036.7	1.2%	(6.5%)
Other Hydro	1,325.1	0.2%	1,436.2	0.2%	8.4%
Wind	24,167.1	2.9%	26,460.7	3.3%	9.5%
Waste	4,237.3	0.5%	4,423.1	0.5%	4.4%
Oil	1,787.9	0.2%	2,054.8	0.3%	14.9%
Heavy Oil	102.9	0.0%	86.0	0.0%	(16.4%)
Light Oil	271.9	0.0%	282.2	0.0%	3.8%
Diesel	71.7	0.0%	30.1	0.0%	(58.0%)
Other Oil	1,341.4	0.2%	1,656.4	0.2%	23.5%
Solar, Net Energy Metering	2,780.6	0.3%	3,842.1	0.5%	38.2%
Battery	18.8	0.0%	36.1	0.0%	92.0%
Biofuel	1,279.6	0.2%	914.3	0.1%	(28.5%)
Total	829,162.0	100.0%	809,842.4	100.0%	(2.3%)

66 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.

67 Net Energy Metering is combined with Solar due to data confidentiality reasons.

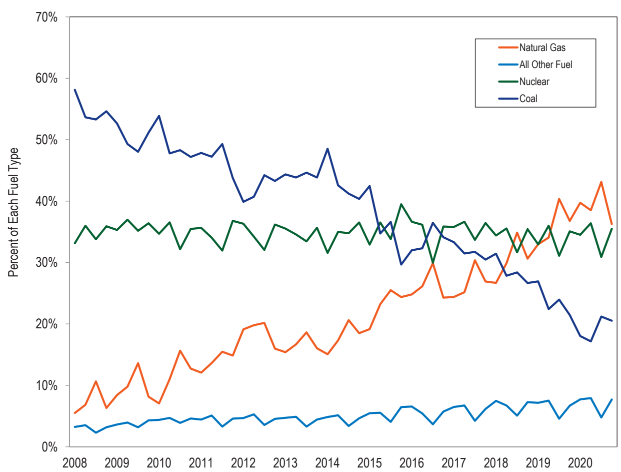
68 Other Gas includes: Landfill, Propane, Butane, Hydrogen, Gasified Coal, and Refinery Gas. Other Coal includes: Lignite, Liquefied Coal, Gasified Coal, and Waste Coal. Other oil includes: Gasoline, Jet Oil, Kerosene, and Petroleum-Other.

Table 3-59 Monthly generation (By fuel source (GWh)): 2020

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Coal		13,301.6	12,829.4	9,998.2	7,986.2	9,746.6	13,983.2	19,592.9	17,666.9	11,469.3	10,093.9	12,884.7	17,023.2	156,575.9
	Bituminous	12,414.8	11,741.5	9,255.7	7,144.5	9,154.6	12,865.0	17,474.9	15,775.6	10,393.7	9,299.0	11,968.4	16,068.3	143,556.3
	Sub Bituminous	348.1	570.5	340.4	452.2	295.2	834.4	1,661.9	1,389.1	592.6	290.4	537.5	413.6	7,726.0
	Other Coal	538.6	517.3	402.2	389.5	296.8	283.7	456.1	502.1	482.9	504.4	378.8	541.3	5,293.7
Nuclear		25,012.5	22,067.6	22,062.1	20,904.1	22,691.8	23,638.2	24,158.5	24,192.5	22,699.4	21,836.6	22,734.6	24,609.6	276,607.6
Gas		28,107.6	25,976.7	26,074.6	21,799.1	21,613.3	28,264.2	38,435.5	34,183.3	26,937.7	24,478.2	20,599.1	26,035.5	322,504.5
	Natural Gas CC	26,839.6	25,157.8	25,188.7	20,970.9	20,094.7	24,960.9	31,183.8	29,734.4	24,922.9	22,051.3	18,993.4	24,614.5	294,712.8
	Natural Gas CT	736.3	482.7	614.0	544.9	1,029.3	2,166.3	4,804.6	2,862.7	1,529.0	1,879.7	1,111.3	1,064.7	18,825.6
	Natural Gas Other Units	343.8	159.1	83.4	108.3	314.3	987.9	2,294.9	1,433.8	335.4	403.8	350.1	204.5	7,019.2
	Other Gas	187.9	177.1	188.6	174.9	174.9	149.1	152.1	152.5	150.4	143.4	144.3	151.8	1,946.9
Hydroelectric		1,474.0	1,558.7	1,489.8	1,410.3	1,651.6	1,571.4	1,380.4	1,318.9	1,093.3	905.0	1,123.1	1,446.9	16,423.3
	Pumped Storage	370.7	309.2	324.9	273.5	447.8	495.3	654.1	603.9	465.1	327.0	290.7	388.2	4,950.4
	Run of River	1,014.4	1,127.3	1,082.5	1,078.5	1,085.5	908.7	511.4	512.3	499.4	480.1	756.0	980.7	10,036.7
	Other Hydro	88.9	122.2	82.4	58.3	118.3	167.4	215.0	202.8	128.7	97.9	76.4	78.0	1,436.2
Wind		2,589.6	2,564.5	2,739.5	2,679.8	2,261.8	1,662.4	959.8	925.9	1,606.9	2,332.0	3,278.4	2,860.1	26,460.7
Waste		366.3	297.0	391.2	357.9	380.3	352.5	400.5	389.9	362.6	358.2	369.7	397.0	4,423.1
Oil		128.2	159.1	165.2	160.2	152.9	165.9	307.8	178.1	162.0	142.5	159.5	173.4	2,054.8
	Heavy Oil	0.0	0.0	0.0	0.0	0.0	0.0	24.9	14.2	33.9	13.0	0.0	0.0	86.0
	Light Oil	10.8	6.4	2.2	2.2	3.7	29.9	132.5	26.0	11.7	9.9	28.9	18.2	282.2
	Diesel	7.5	0.2	0.3	0.1	0.0	1.5	10.3	2.4	1.6	1.8	1.6	2.7	30.1
	Other Oil	109.9	152.6	162.8	157.9	149.2	134.5	140.1	135.5	114.8	117.8	129.0	152.5	1,656.4
Solar, Net Energy Metering		187.3	208.8	288.5	363.0	401.1	424.0	455.5	359.5	319.3	302.0	296.0	237.2	3,842.1
Battery		2.0	2.4	3.6	3.0	3.0	3.1	3.4	3.4	3.1	3.2	3.0	2.9	36.1
Biofuel		84.7	101.9	102.2	36.6	46.8	66.2	96.3	91.7	94.7	63.9	71.9	57.5	914.3
Total		71,253.7	65,766.2	63,314.9	55,700.0	58,949.2	70,131.1	85,790.5	79,310.2	64,748.3	60,515.4	61,519.9	72,843.2	809,842.4

Figure 3-44 shows generation by natural gas, coal, nuclear and other fuel types in the real-time energy market since 2008.

Figure 3-44 Share of generation by fuel source: 2008 through 2020



Fuel Diversity

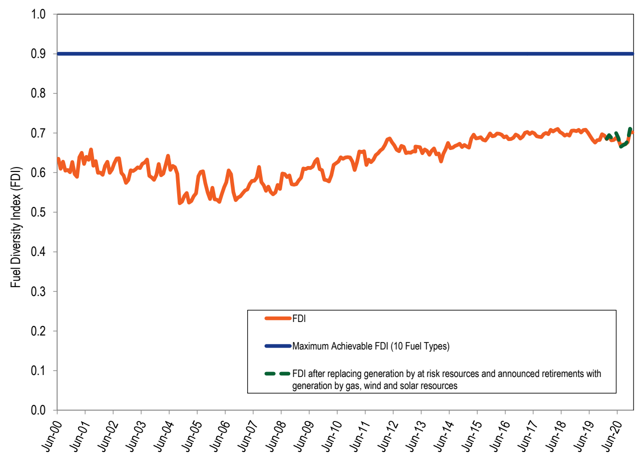
Figure 3-45 shows the fuel diversity index (FDI_e) for PJM energy generation.[69] The FDI_e is defined as $1-\sum_{i=1}^{N} s_i^2$, where s_i is the share of fuel type i. The minimum possible value for the FDI_e is zero, corresponding to all generation from a single fuel type. The maximum possible value 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 3-59 with nonzero

69 Monitoring Analytics 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.

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 35.4 percent from 2012 through 2019. 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 Control Zones and the increased shares of coal and nuclear that resulted.[70] The increasing trend that began in 2008 is a result of decreasing coal generation, increasing gas generation and increasing wind generation. Coal generation as a share of total generation was 54.9 percent for 2008 and 19.3 percent for 2020. Gas generation as a share of total generation was 7.4 percent for 2008 and 39.8 percent for 2020. Wind generation as a share of total generation was 0.5 percent for 2008 and 3.3 percent for 2020.

The FDI_e decreased 1.5 percent for 2020 compared to 2019. The FDI_e was also used to measure the impact on fuel diversity of potential retirements. A total of 4,763 MW of coal, CT, and other capacity were identified as being at risk of retirement.[71] Generation owners that intend to retire a generator are required by the tariff to notify PJM at least 90 days in advance.[72] There are 4,163.9 MW of generation that have requested retirement after December 31, 2020.[73] The at risk units and other generators with deactivation notices generated 23,945.2 GWh in 2020. The dashed line in Figure 3-45 shows a counterfactual result for FDI_e assuming the 23,945.2 GWh of generation from at risk units and other generators with deactivation notices were replaced by gas, wind and solar generation.[74] The FDI_e for 2020 under the counterfactual assumption would have been 0.5 percent higher than the actual FDI_e.

Figure 3-45 Fuel diversity index for monthly generation: June 2000 through December 2020



Natural Gas Supply Issues

A combination of pipeline transportation and natural gas supplies is needed to deliver natural gas to power plants. A generator could purchase a delivered service in which the seller bundles both the transportation and fuel to make deliveries to the plant. The delivered service could be purchased on either a term contract or a spot basis. A generator could secure pipeline transportation for part or all of the supplies needed to run the plant and purchase commodity natural gas separately with a term supply contract or through daily purchases in the spot market. Other options are also possible.

The increase in natural gas fired capacity in PJM has highlighted issues with the dependence of the 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, creates risks for the bulk power system. PJM should collect data on each individual generator's fuel supply arrangements, and analyze the associated locational and regional risks to reliability.

In 2019 and 2020, a number of interstate gas pipelines that supply fuel for generators in the PJM service territory issued restriction notices limiting the availability of nonfirm transportation services. These notices include warnings of operational flow orders (OFO) and actual OFOs. These notices may, depending on the nature of the transportation service purchased, permit the pipelines to

70 See the *2019 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 control zones occurred in October 2004.
71 See Table 7-47 in the *2020 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.
72 See PJM. OATT: § V "Generation Deactivation."
73 See *2020 State of the Market Report for PJM*, Section 12: Generation and Transmission Planning, Table 12-11.
74 It is assumed that 10,724.0 GWh of the replacement energy is from new wind and solar units. This value represents the increase over 2020 levels in renewable generation that is required by RPS in 2021, assuming zero load growth. The split between solar and wind, 7,509.0 GWh solar and 3,215.0 GWh wind, is based on queue data.

restrict the provision of gas to 24 hour ratable takes which means that hourly nominations must be the same for each of the 24 hours in the gas day, with penalties for deviating from the nominated quantities. Pipelines may also enforce strict balancing constraints which limit the ability of gas users, depending on the nature of the transportation service purchased, to deviate from the 24 hour ratable take and which may limit the ability of users to have access to unused gas.

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 highlights the potential shortcomings of a gas pipeline network that relies on individual pipelines to manage the balancing of supply and demand. The independent operational restrictions imposed by pipelines and the impact on electric generators during extreme conditions demonstrates 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.

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 3-60 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 2020, coal units were 17.5 percent and natural gas units were 72.3 percent of marginal resources. In 2020, natural gas combined cycle units were 64.3 percent of marginal resources. In 2019, coal units were 24.4 percent and natural gas units were 69.4 percent of the total marginal resources. In 2019, natural gas combined cycle units were 62.1 percent of the total marginal resources.

In 2020, 92.8 percent of the wind marginal units had negative offer prices, 7.2 percent had zero offer prices and none had positive offer prices. In 2019, 94.3 percent of the wind marginal units had negative offer prices, 5.0 percent had zero offer prices and 0.8 percent of wind marginal units had positive offer prices.

The proportion of marginal nuclear units increased from 1.31 percent in 2019 to 1.35 percent in 2020. Most nuclear units are offered as fixed generation in the PJM market. A small number of nuclear units were offered with a dispatchable range since 2015. The dispatchable nuclear units do not always respond to dispatch instructions.

Table 3-60 Type of fuel used and technology (By real-time marginal units): 2016 through 2020[75]

Fuel	Technology	2016	2017	2018	2019	2020
Gas	CC	31.22%	44.63%	53.45%	62.13%	64.33%
Coal	Steam	46.39%	32.28%	27.26%	24.37%	17.53%
Wind	Wind	2.98%	7.28%	2.56%	3.81%	6.75%
Gas	CT	6.57%	4.70%	7.80%	5.97%	5.89%
Gas	Steam	4.66%	3.52%	1.68%	1.29%	2.12%
Uranium	Steam	1.06%	1.23%	1.04%	1.31%	1.35%
Oil	CT	5.98%	5.18%	4.58%	0.49%	1.25%
Other	Solar	0.02%	0.18%	0.12%	0.07%	0.33%
Oil	Steam	0.04%	0.05%	0.29%	0.03%	0.06%
Other	Steam	0.12%	0.19%	0.15%	0.06%	0.03%
Municipal Waste	Steam	0.01%	0.01%	0.04%	0.02%	0.02%
Landfill Gas	CT	0.00%	0.00%	0.02%	0.01%	0.01%
Oil	RICE	0.75%	0.26%	0.42%	0.00%	0.00%
Oil	CC	0.02%	0.01%	0.13%	0.01%	0.00%
Municipal Waste	RICE	0.00%	0.00%	0.00%	0.00%	0.00%
Gas	Fuel Cell	0.00%	0.00%	0.00%	0.00%	0.00%
Municipal Waste	CT	0.00%	0.00%	0.00%	0.00%	0.00%
Landfill Gas	Steam	0.02%	0.04%	0.00%	0.00%	0.00%
Gas	RICE	0.12%	0.40%	0.41%	0.00%	0.00%
Landfill Gas	RICE	0.04%	0.02%	0.04%	0.00%	0.00%

75 The unit type RICE refers to Reciprocating Internal Combustion Engines.

Figure 3-46 shows the type of fuel used by marginal resources in the real-time energy market since 2004. The role of coal as a marginal resource has declined while the role of gas as a marginal resource has increased.

Figure 3-46 Type of fuel used (By real-time marginal units): 2004 through 2020

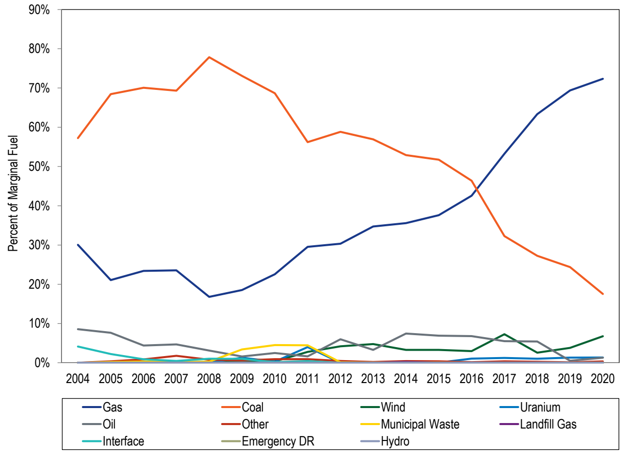


Table 3-61 shows the type of fuel used and technology where relevant, of marginal resources in the day-ahead energy market. In 2020, up to congestion transactions were 51.34 percent of marginal resources. Up to congestion transactions were 57.39 percent of marginal resources in 2019.

Table 3-61 Day-ahead marginal resources by type/fuel used and technology: 2016 through 2020

Type/Fuel	Technology	2016	2017	2018	2019	2020
Up to Congestion Transaction	NA	81.72%	79.35%	62.30%	57.39%	51.34%
DEC	NA	8.58%	10.15%	16.90%	17.04%	18.79%
INC	NA	4.15%	5.49%	9.78%	12.76%	13.24%
Gas	CC	2.14%	2.10%	5.34%	7.42%	9.91%
Coal	Steam	2.32%	1.95%	4.63%	4.45%	5.12%
Gas	Steam	0.40%	0.36%	0.28%	0.38%	0.47%
Wind	Wind	0.06%	0.15%	0.13%	0.10%	0.38%
Uranium	Steam	0.11%	0.08%	0.12%	0.10%	0.21%
Gas	CT	0.04%	0.04%	0.20%	0.11%	0.21%
Oil	CT	0.41%	0.25%	0.04%	0.05%	0.10%
Dispatchable Transaction	NA	0.05%	0.04%	0.13%	0.10%	0.10%
Gas	RICE	0.00%	0.02%	0.04%	0.06%	0.05%
Other	Steam	0.01%	0.00%	0.01%	0.01%	0.04%
Other	Solar	0.00%	0.00%	0.02%	0.01%	0.02%
Municipal Waste	RICE	0.00%	0.00%	0.01%	0.01%	0.01%
Oil	Steam	0.00%	0.00%	0.04%	0.01%	0.01%
Price Sensitive Demand	NA	0.00%	0.00%	0.02%	0.00%	0.00%
Oil	RICE	0.00%	0.01%	0.00%	0.00%	0.00%
Oil	CC	0.00%	0.00%	0.02%	0.00%	0.00%
Municipal Waste	Steam	0.00%	0.00%	0.00%	0.00%	0.00%
Water	Hydro	0.00%	0.01%	0.00%	0.00%	0.00%
Total		100.00%	100.00%	100.00%	100.00%	100.00%

Figure 3-47 shows, for the day-ahead energy market from January 2014 through December 2020, the daily proportion of marginal resources that were up to congestion transactions and/or generation units. The UTC share decreased from 57.39 percent in 2019 to 51.34 percent in 2020.

Up to congestion transaction volumes decreased following the allocation of uplift charges on November 1, 2020.[76] The average number of up to congestion bids submitted in the day-ahead energy market decreased by 6.6 percent, from 52,046 bids per day in 2019 to 48,618 bids per day in 2020. The average cleared volume of up to congestion bids submitted in the day-ahead energy market decreased by 12.5 percent, from 500,819 MWh per day in 2019, to 438,170 MWh per day in 2020.

76 172 FERC ¶ 61,046 (2020).

Figure 3-47 Day-ahead marginal up to congestion transaction and generation units: 2014 through 2020

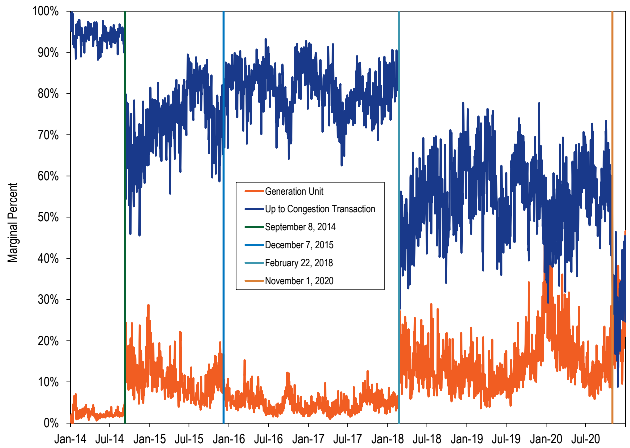
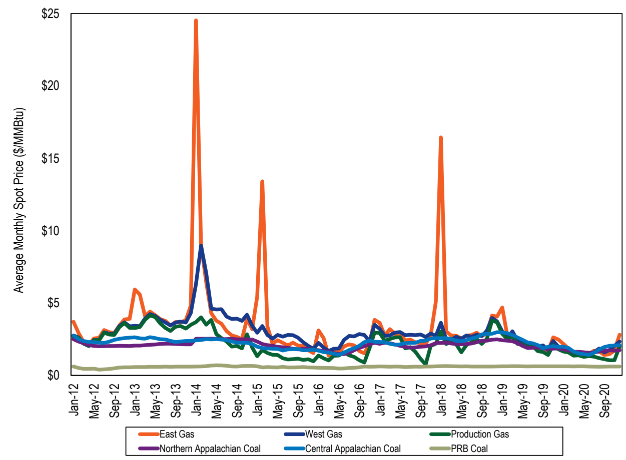


Figure 3-48 Spot average fuel price comparison: 2012 through 2020[78]



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 3-48 shows fuel prices in PJM for 2012 through 2020. Natural gas prices decreased in 2020 compared to 2019. The price of natural gas in the Marcellus Shale production area is lower than in other areas of PJM. A number of new combined cycle plants have located in the production area since 2016. In 2020, the price of production gas was 34.6 percent lower than in 2019, the price of eastern natural gas was 30.9 percent lower and the price of western natural gas was 24.6 percent lower. The price of Northern Appalachian coal was 18.2 percent lower; the price of Central Appalachian coal was 23.9 percent lower; and the price of Powder River Basin coal was 1.9 percent lower.[77] The price of ULSD NY Harbor Barge was 36.3 percent lower.

Table 3-62 compares the PJM real-time fuel-cost adjusted, load-weighted, average LMP in 2020 to the load-weighted, average LMP in 2019.[79] The real-time, load-weighted average LMP in 2020 decreased by $5.55 or -20.3 percent from the real-time load-weighted, average LMP in 2019. The real-time load-weighted, average LMP for 2020 was 11.4 percent lower than the real-time, fuel-cost adjusted, load-weighted average LMP for 2020. The real-time, fuel-cost adjusted, load-weighted, average LMP for 2020 was 10.1 percent lower than the real-time, load-weighted, average LMP for 2019. If fuel and emissions costs in 2020 had been the same as in the 2019, holding the market dispatch constant, the real-time, load-weighted, average LMP in 2020 would have been higher, $24.56 per MWh, than the observed $21.77 per MWh. Only 50.3 percent of the decrease in real-time, load-weighted, average LMP, $2.79 per MWh out of $5.55 per MWh, is directly attributable to fuel costs. Contributors to the other $2.76 per MWh are decreased load, adjusted dispatch, including adjustments to dispatch due to changes in relative fuel costs among units, and lower markups.

77 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.

78 This figure is modified from the corresponding figure in the *2020 Quarterly State of the Market Report for PJM: January through June*, which included an error.

79 The fuel-cost adjusted LMP reflects both the fuel and emissions where applicable, including NO_x, CO_2 and SO_x costs.

Table 3-62 Real-time, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): 2019 and 2020

	2020 Fuel-Cost Adjusted, Load-Weighted LMP	2020 Load-Weighted LMP	Change	Percent Change
Average	$24.56	$21.77	($2.79)	(11.4%)
	2019 Load-Weighted LMP	2020 Fuel-Cost Adjusted, Load-Weighted LMP	Change	Percent Change
Average	$27.32	$24.56	($2.76)	(10.1%)
	2019 Load-Weighted LMP	2020 Load-Weighted LMP	Change	Change
Average	$27.32	$21.77	($5.55)	(20.3%)

Table 3-63 shows the impact of each fuel type on the difference between the fuel-cost adjusted, load-weighted, average LMP and the load-weighted, LMP in 2020. Table 3-63 shows that lower natural gas prices explain 80.9 percent of the fuel-cost related decrease in the real-time annual, load-weighted, average LMP in 2020 from 2019.

Table 3-63 Share of change in fuel-cost adjusted LMP ($/MWh) by fuel type: 2020 adjusted to 2019 fuel prices

Fuel Type	Share of Change in Fuel Cost Adjusted, Load Weighted LMP	Percent
Gas	($2.25)	80.9%
Coal	($0.50)	17.9%
Oil	($0.03)	1.2%
Uranium	$0.00	0.0%
Municipal Waste	$0.00	0.0%
Other	$0.00	0.0%
NA	$0.00	0.0%
Wind	$0.00	0.0%
Total	($2.79)	100.0%

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 marginal units determine system LMPs, based on their offers and up to fourteen minute ahead forecasts of system conditions. 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 unit offers.

Cost offers of marginal units are separated into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs are calculated using spot prices for NO_x, SO_2 and CO_2 emission credits, emission rates for NO_x, emission rates for SO_2 and emission rates for CO_2. The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware, Maryland, and New Jersey.[80] The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal.

Since the implementation of scarcity pricing on October 1, 2012, PJM jointly optimizes the commitment and dispatch of energy and reserves. In periods of scarcity 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. In addition, in periods when the SCED solution does not meet the reserve requirements, PJM should invoke shortage pricing. During shortage conditions, the LMPs of marginal generators reflect the cost of not meeting the reserve requirements, the scarcity adder, which is defined by the operating reserve demand curve.

The components of LMP are shown in Table 3-64, including markup using unadjusted cost-based offers.[81] Table 3-64 shows that in 2020, 23.7 percent of the load-weighted LMP was the result of coal costs, 41.5 percent was the result of gas costs and 1.7 percent was the result of the cost of carbon emission allowances. Using unadjusted cost-based offers, markup was 2.3 percent of the load-weighted LMP. The fuel-related components of LMP reflect the degree to which the cost of the identified fuel affects LMP and does not reflect the other components of the offers of units burning that fuel. The component NA is the 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. The percent

80 New Jersey withdrew from RGGI, effective January 1, 2012, and rejoined RGGI effective January 1, 2020.

81 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>.

column is the difference (in percentage points) in the proportion of LMP represented by each component in 2020 and 2019.

Table 3-64 Components of real-time (Unadjusted), load-weighted, average LMP: 2019 and 2020

	2019		2020		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Gas	$11.51	42.1%	$9.03	41.5%	(0.7%)
Coal	$7.21	26.4%	$5.17	23.7%	(2.7%)
Ten Percent Adder	$2.07	7.6%	$1.68	7.7%	0.1%
Constraint Violation Adder	$1.85	6.8%	$1.67	7.7%	0.9%
Variable Maintenance	$1.71	6.3%	$1.34	6.2%	(0.1%)
Variable Operations			$0.84	3.9%	3.9%
NA	$0.35	1.3%	$0.57	2.6%	1.3%
Markup	$1.55	5.7%	$0.50	2.3%	(3.4%)
CO_2 Cost	$0.21	0.8%	$0.37	1.7%	0.9%
LPA Rounding Difference	$0.15	0.5%	$0.18	0.8%	0.3%
Ancillary Service Redispatch Cost	$0.24	0.9%	$0.13	0.6%	(0.3%)
Scarcity Adder	$0.24	0.9%	$0.08	0.4%	(0.5%)
Oil	$0.06	0.2%	$0.07	0.3%	0.1%
Opportunity Cost Adder	$0.10	0.4%	$0.07	0.3%	(0.0%)
Increase Generation Adder	$0.10	0.4%	$0.06	0.3%	(0.1%)
LPA-SCED Differential	$0.01	0.0%	$0.01	0.1%	0.0%
NO_x Cost	$0.02	0.1%	$0.01	0.0%	(0.0%)
Market-to-Market Adder	$0.00	0.0%	$0.00	0.0%	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
Other	$0.00	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	0.0%
Landfill Gas	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Renewable Energy Credits	($0.02)	(0.1%)	($0.01)	(0.0%)	0.1%
Decrease Generation Adder	($0.05)	(0.2%)	($0.02)	(0.1%)	0.1%
Total	$27.32	100.0%	$21.77	100.0%	0.0%

In order to accurately assess the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach (Table 3-64 and Table 3-66), markup is simply the difference between the price offer and the cost-based offer (unadjusted markup). In the second approach (Table 3-65 and Table 3-67), the 10 percent markup is removed from the cost-based offers of coal, gas, and oil units (adjusted markup).

The components of LMP are shown in Table 3-65, including markup using adjusted cost-based offers.

Table 3-65 Components of real-time (Adjusted), load-weighted, average LMP: 2019 and 2020

	2019		2020		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Gas	$11.51	42.1%	$9.03	41.5%	(0.7%)
Coal	$7.21	26.4%	$5.17	23.7%	(2.7%)
Markup	$3.63	13.3%	$2.19	10.0%	(3.2%)
Constraint Violation Adder	$1.85	6.8%	$1.67	7.7%	0.9%
Variable Maintenance	$1.71	6.3%	$1.34	6.2%	(0.1%)
Variable Operations			$0.84	3.9%	3.9%
NA	$0.35	1.3%	$0.57	2.6%	1.3%
CO_2 Cost	$0.21	0.8%	$0.37	1.7%	0.9%
LPA Rounding Difference	$0.15	0.5%	$0.18	0.8%	0.3%
Ancillary Service Redispatch Cost	$0.24	0.9%	$0.13	0.6%	(0.3%)
Scarcity Adder	$0.24	0.9%	$0.08	0.4%	(0.5%)
Oil	$0.06	0.2%	$0.07	0.3%	0.1%
Opportunity Cost Adder	$0.10	0.4%	$0.07	0.3%	(0.0%)
Increase Generation Adder	$0.10	0.4%	$0.06	0.3%	(0.1%)
LPA-SCED Differential	$0.01	0.0%	$0.01	0.1%	0.0%
NO_x Cost	$0.02	0.1%	$0.01	0.0%	(0.0%)
Market-to-Market Adder	$0.00	0.0%	$0.00	0.0%	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
Ten Percent Adder	$0.00	0.0%	$0.00	0.0%	(0.0%)
Other	$0.00	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	0.0%
Landfill Gas	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Renewable Energy Credits	($0.02)	(0.1%)	($0.01)	(0.0%)	0.1%
Decrease Generation Adder	($0.05)	(0.2%)	($0.02)	(0.1%)	0.1%
Total	$27.32	100.0%	$21.77	100.0%	0.0%

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, day-ahead scheduling reserve (DASR) adder and the 10 percent cost offer adder. INC offers, DEC bids and up to congestion transactions are dispatchable injections and withdrawals in the day-ahead 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.

Table 3-66 shows the components of the PJM day-ahead, annual, load-weighted, average LMP. In 2020, 24.4 percent of the load-weighted LMP was the result of coal costs, 18.8 percent of the load-weighted, LMP was the result of gas costs, 24.0 percent was the result of DEC bid costs, 15.2 percent was the result of INC bid costs and 3.0 percent was the result of the up to congestion transaction costs.

Table 3-66 Components of day-ahead, (unadjusted), load-weighted, average LMP (Dollars per MWh): 2019 and 2020

	2019		2020		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$6.01	22.1%	$5.22	24.4%	2.4%
DEC	$5.81	21.3%	$5.13	24.0%	2.6%
Gas	$5.36	19.7%	$4.02	18.8%	(0.9%)
INC	$5.69	20.9%	$3.25	15.2%	(5.7%)
Ten Percent Cost Adder	$1.28	4.7%	$1.12	5.2%	0.5%
Variable Maintenance	$1.21	4.4%	$0.89	4.1%	(0.3%)
Variable Operations			$0.74	3.4%	3.4%
Up to Congestion Transaction	$0.69	2.5%	$0.64	3.0%	0.4%
CO_2	$0.14	0.5%	$0.28	1.3%	0.8%
DASR LOC Adder	($0.04)	(0.1%)	$0.08	0.4%	0.5%
Dispatchable Transaction	$0.31	1.1%	$0.05	0.2%	(0.9%)
Constrained Off	$0.00	0.0%	$0.03	0.2%	0.2%
Oil	$0.06	0.2%	$0.02	0.1%	(0.1%)
Price Sensitive Demand	$0.01	0.0%	$0.01	0.1%	0.0%
NO_x	$0.01	0.0%	$0.01	0.0%	(0.0%)
DASR Offer Adder	$0.01	0.0%	$0.00	0.0%	(0.0%)
SO_2	$0.00	0.0%	$0.00	0.0%	(0.0%)
Other	$0.01	0.0%	$0.00	0.0%	(0.0%)
Municipal Waste	($0.00)	(0.0%)	$0.00	0.0%	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%	0.0%
Wind	($0.01)	(0.1%)	($0.00)	(0.0%)	0.0%
Markup	$0.70	2.6%	($0.11)	(0.5%)	(3.1%)
NA	$0.00	0.0%	$0.03	0.2%	0.2%
Total	$27.23	100.0%	$21.40	100.0%	0.0%

Table 3-67 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 or oil units.

Table 3-67 Components of day-ahead, (adjusted), load-weighted, average LMP (Dollars per MWh): 2019 and 2020

	2019		2020		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$6.01	22.1%	$5.22	24.4%	2.4%
DEC	$5.81	21.3%	$5.13	24.0%	2.6%
Gas	$5.36	19.7%	$4.02	18.8%	(0.9%)
INC	$5.69	20.9%	$3.25	15.2%	(5.7%)
Markup	$1.97	7.2%	$1.01	4.7%	(2.5%)
Variable Maintenance	$1.21	4.4%	$0.89	4.1%	(0.3%)
Variable Operations			$0.74	3.4%	3.4%
Up to Congestion Transaction	$0.69	2.5%	$0.64	3.0%	0.4%
CO_2	$0.14	0.5%	$0.28	1.3%	0.8%
DASR LOC Adder	($0.04)	(0.1%)	$0.08	0.4%	0.5%
Dispatchable Transaction	$0.31	1.1%	$0.05	0.2%	(0.9%)
Constrained Off	$0.00	0.0%	$0.03	0.2%	0.2%
Oil	$0.06	0.2%	$0.02	0.1%	(0.1%)
Price Sensitive Demand	$0.01	0.0%	$0.01	0.1%	0.0%
NO_x	$0.01	0.0%	$0.01	0.0%	(0.0%)
DASR Offer Adder	$0.01	0.0%	$0.00	0.0%	(0.0%)
SO_2	$0.00	0.0%	$0.00	0.0%	(0.0%)
Other	$0.01	0.0%	$0.00	0.0%	(0.0%)
Municipal Waste	($0.00)	(0.0%)	$0.00	0.0%	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%	0.0%
Ten Percent Cost Adder	$0.01	0.0%	($0.00)	(0.0%)	(0.0%)
Wind	($0.01)	(0.1%)	($0.00)	(0.0%)	0.0%
NA	$0.00	0.0%	$0.03	0.2%	0.2%
Total	$27.23	100.0%	$21.40	100.0%	0.0%

Scarcity

PJM's energy market experienced five minute shortage pricing for nine five minute intervals on six days in 2020. Table 3-68 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in 2019 and 2020. In 2020, there were no emergency actions that triggered a Performance Assessment Interval (PAI). The days with shortage pricing intervals did not correspond to the days with emergency alerts.

Table 3-68 Summary of emergency events declared: 2019 and 2020

	Number of days events declared	
Event Type	2019	2020
Cold Weather Alert	9	3
Hot Weather Alert	16	19
Maximum Emergency Generation Alert	2	0
Primary Reserve Alert	0	0
Voltage Reduction Alert	0	0
Primary Reserve Warning	0	0
Voltage Reduction Warning	0	0
Pre Emergency Mandatory Load Management Reduction Action	1	0
Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time)	0	0
Maximum Emergency Action	0	0
Emergency Energy Bids Requested	0	0
Voltage Reduction Action	0	0
Shortage Pricing	17	6
Energy export recalls from PJM capacity resources	0	0

Figure 3-49 shows the number of days that weather and capacity emergency alerts were issued in PJM from 2016 through 2020. Figure 3-50 shows the number of days emergency warnings were issued or actions taken in PJM from 2016 through 2020.

Figure 3-49 Declared emergency alerts: 2016 through 2020

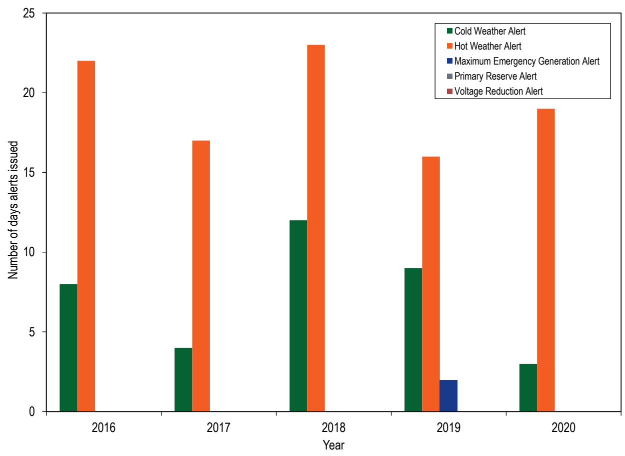
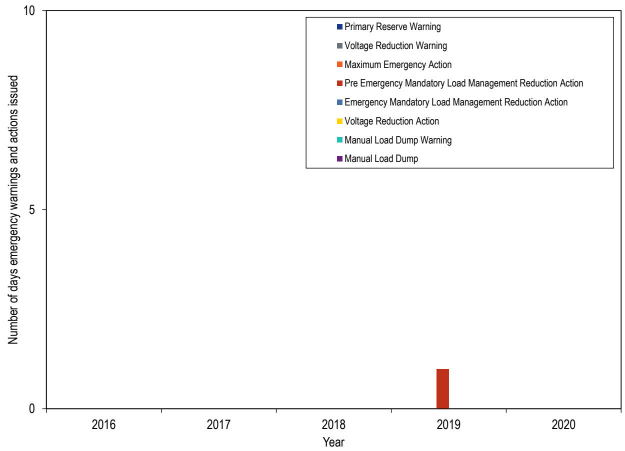


Figure 3-50 Declared emergency warnings and actions: 2016 through 2020[82]



Emergency Procedures

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

Table 3-69 provides a description of PJM declared emergency procedures.[83 84 85 86]

Table 3-69 Description of emergency procedures

Emergency Procedure	Purpose
Cold Weather Alert	To prepare personnel and facilities for extreme cold weather conditions, generally when forecast weather conditions approach minimum or temperatures fall below ten degrees Fahrenheit.
Hot Weather Alert	To prepare personnel and facilities for extreme hot and/or humid weather conditions, generally when forecast temperatures exceed 90 degrees with high humidity.
Maximum Emergency Generation Alert	To provide an early alert at least one day prior to the operating day that system conditions may require the use of the PJM emergency procedures and resources must be able to increase generation above the maximum economic level of their offers.
Primary Reserve Alert	To alert members of a projected shortage of primary reserve for a future period. It is implemented when estimated primary reserve is less than the forecast requirement.
Voltage Reduction Alert	To alert members that a voltage reduction may be required during a future critical period. It is implemented when estimated reserve capacity is less than forecasted synchronized reserve requirement.
Pre-Emergency Load Management Reduction 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
Emergency Mandatory Load Management Reduction Action	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, generally declared simultaneously with NERC Energy Emergency Alert Level 2 (EEA2)
Primary Reserve Warning	To warn members that available primary reserve is less than required and present operations are becoming critical. It is implemented when available primary reserve is less than the primary reserve requirement but greater than the synchronized reserve requirement.
Maximum Emergency Generation Action	To provide real time notice to increase generation above the maximum economic level. It is implemented whenever generation is needed that is greater than the maximum economic level.
Voltage Reduction Warning & Reduction of Non-Critical Plant Load	To warn members that actual synchronized reserves are less than the synchronized reserve requirement and that voltage reduction may be required.
Deploy All Resources Action	For emergency events that do not evolve over time, but rather develop rapidly and without prior warning, PJM issues this action to instruct all generation resources to be online immediately and to all load management resources to reduce load immediately.
Manual Load Dump Warning	To warn members of the critical condition of present operations that may require manually dumping load. Issued when available primary reserve capacity is less than the largest operating generator or the loss of a transmission facility jeopardizes reliable operations after all other possible measures are taken to increase reserve.
Voltage Reduction Action	To reduce load to provide sufficient reserve capacity to maintain tie flow schedules and preserve limited energy sources. It is implemented when load relief is needed to maintain tie schedules.
Manual Load Dump Action	To provide load relief when all other possible means of supplying internal PJM RTO load have been used to prevent a catastrophe within the PJM RTO or to maintain tie schedules so as not to jeopardize the reliability of the other interconnected regions.

82 In prior reports, this graph incorrectly classified a local load shed directive in 2018 in the AEP zone for voltage control due to transmission outages as a Manual Load Dump.
83 See PJM. "Manual 13: Emergency Operations," Rev. 77 (Jan. 1, 2021), Section 3.3 Cold Weather Alert.
84 See PJM. "Manual 13: Emergency Operations," Rev. 77 (Jan. 1, 2021), Section 3.4 Hot Weather Alert.
85 See PJM. "Manual 13: Emergency Operations," Rev. 77 (Jan. 1, 2021), Section 2.3.1 Advanced Notice Emergency Procedures: Alerts.
86 See PJM. "Manual 13: Emergency Operations," Rev. 77 (Jan. 1, 2021), 2.3.2 Real-Time Emergency Procedures (Warnings and Actions).

Table 3-70 shows the dates when emergency alerts and warnings were declared and when emergency actions were implemented in 2020.

Table 3-70 Declared emergency alerts, warnings and actions: 2020

Date	Cold Weather Alert	Hot Weather Alert	Maximum Emergency Generation Alert	Primary Reserve Alert	Voltage Reduction Alert	Primary Reserve Warning	Voltage Reduction Warning and Reduction of Non-Critical Plant Load	Maximum Emergency Generation Action	Pre-Emergency Mandatory Load Management Reduction	Emergency Mandatory Load Management Reduction	Voltage Reduction	Manual Load Dump Warning	Manual Load Dump Action	Load Shed Directive
1/19/2020	ComEd													
1/20/2020	ComEd													
1/21/2020	ComEd													
6/22/2020		Mid-Atlantic												
6/23/2020		Mid-Atlantic and Dominion												
7/3/2020		PJM RTO												
7/6/2020		PJM RTO												
7/7/2020		PJM RTO												
7/8/2020		Mid-Atlantic and Western												
7/9/2020		Mid-Atlantic and Western												
7/18/2020		PJM RTO												
7/19/2020		PJM RTO												
7/20/2020		PJM RTO												
7/21/2020		Mid-Atlantic and Southern												
7/22/2020		Mid-Atlantic and Southern												
7/26/2020		Mid-Atlantic and Southern												
7/27/2020		Mid-Atlantic and Southern												
7/28/2020		Mid-Atlantic and Southern												
7/29/2020		Mid-Atlantic												
7/30/2020		Mid-Atlantic												
8/26/2020		ComEd												
8/27/2020		ComEd, Mid-Atlantic and Dominion												

Power Balance Constraint Violation

On October 1, 2019, the power balance constraint was violated in 11 approved RT SCED solutions. On February 16, 2020, the power balance constraint was violated in one approved RT SCED solution which was used to set prices for three five minute intervals. On April 21, 2020, the power balance constraint was violated in one approved RT SCED solution. 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. In some cases, the power balance constraint is violated while the reserve requirements are satisfied.

The current process for meeting energy and reserve requirements in real time, and 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 would convert reserves to energy before violating power balance. It is unclear whether and when PJM would use its authority under the tariff to curtail exports from PJM capacity resources to meet the power balance constraint. 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 ASO to energy to satisfy the power balance constraint.[87] SCED solutions from October 1, 2019, February 16, 2020, and April 21, 2020, indicate that the currently defined logic meets transmission constraint limits and reserve requirements but violates the power balance constraint, and does not reflect this constraint violation in prices. This logic, if correctly described, is not consistent with basic economics. The overall solution is complex and must be integrated with the approach to scarcity pricing.

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 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. The average energy component of LMP in those 5 minute intervals with artificially increased supply to satisfy the power balance constraint was $351.56 per MWh in 2020.

Table 3-71 shows the number of five minute intervals for which the RT SCED solutions used to set prices did not balance demand and supply. PJM reran the RT SCED with artificially increased supply to satisfy the power balance constraint. In 2020, there were four 5 minute intervals using RT SCED solutions with a violated power balance constraint. The average energy component of LMP in those 5 minute intervals with artificially increased supply to satisfy the power balance constraint was $351.56 per MWh in 2020.[88]

Table 3-71 Number of five minute intervals using RT SCED solutions with violated power balance constraint by year

Year	Number of five minute intervals	Average Energy Component of LMP ($/MWh)
2013	-	
2014	655	$36.29
2015	71	($0.76)
2016	42	$93.06
2017	31	$279.86
2018	16	$268.21
2019	36	$845.48
2020	5	$351.56

Balancing Ratio for Local Emergency Events

The balancing ratio is theoretically defined as the ratio of actual load and reserve requirements in an area during an emergency event to the total committed capacity in the area. In the case of the PAIs declared in 2018 that were triggered due to transmission outages in limited locations, if the area is defined as the location where the load was shed, the balancing ratio is undefined because there were no committed resources in the area, other than less than 1.0 MW of demand response.[89] It is not appropriate or correct to calculate a balancing ratio as a measure of capacity needed during these events by defining a wider area to include committed capacity. It is also not appropriate to use a balancing ratio defined in

87 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.

88 The energy component of LMP, or the shadow price of the power balance constraint, is the incremental cost of meeting a one MWh increase in the system load.

89 *2018 State of the Market Report for PJM: Volume 2*, Section 3: Energy Market, at Scarcity, pp. 201 – 202.

that way in defining the capacity market offer cap. PJM calculated the balancing ratio for the localized load shed that occurred in the AEP Edison area in 2018 and used the average balancing ratio during the event to calculate the capacity market seller offer cap for all LDAs for the 2022/2023 Delivery Year.[90] These events occurred in a very small local area where no capacity resources were held to CP performance requirements. Assessing nonperformance to resources located in the wider area would not be appropriate because their performance would not have helped, and may have even exacerbated the transmission issues identified during these events. These events also do not reflect the type of events that are modeled to define the target installed reserve margin in the capacity market. The MMU recommends that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs) in the calculation of the capacity market default offer cap, and only include those events that trigger emergencies at a defined zonal or higher level.

Scarcity and Scarcity Pricing

In electricity markets, scarcity means that demand, including reserve requirements, is nearing the limits of the currently available capacity of the system. Scarcity pricing is a mechanism for signaling scarcity conditions through energy prices. Under the PJM rules that were in place through September 30, 2012, scarcity 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. But this was not an efficient way to manage scarcity pricing and made it difficult to distinguish between market power and scarcity pricing. Shortage pricing is an administrative scarcity pricing mechanism in which PJM sets a high energy price at a predetermined level when the system operates with less real-time reserves than required.

In 2020, there were nine 5 minute intervals with shortage pricing that occurred on six days in PJM.

With 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.[91] 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. PJM did not implement the rule as intended in Order No. 825, because RT SCED can indicate a shortage that PJM does not use in pricing. 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.

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 that condition, even if the data do not show a shortage of reserves.[92]

Operating Reserve Demand Curves

Since July 12, 2017, the PJM synchronized reserve requirement in a reserve zone or a subzone is the actual output of the single largest online unit in that reserve zone or subzone. The primary reserve requirement in a reserve zone or a subzone is 150 percent of the actual output of the single largest online unit in that reserve zone or subzone. The first step of the demand curves for primary and synchronized reserves are set at the primary and synchronized reserve requirement. Since the primary and synchronized reserve requirements are based on the actual output of the largest resource, the MW value of the first step changes in real time based on the real-time dispatch solution. The first step is priced at $850 per MWh. The second step of the primary and synchronized reserve demand curves extends the primary and synchronized reserve requirements. The extended primary and synchronized reserve requirements are

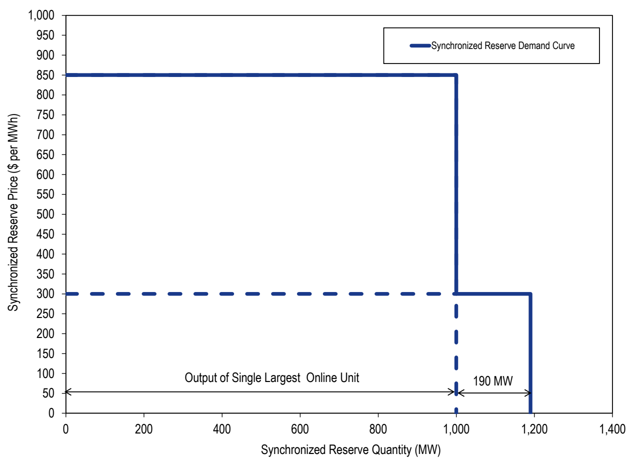
90 *See* PJM, "Capacity Market Seller Offer Cap Values," (March 15, 2019), *which can be accessed at* <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-cp-market-seller-offer-cap-values.ashx?la=en?>.

91 155 FERC ¶ 61,276 ("Order No. 825") at P 162.

92 *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).

defined as the primary and synchronized reserve requirements, plus 190 MW. This 190 MW second step is priced at $300 per MWh. Figure 3-51 shows an example of the updated synchronized reserve demand curve when the output of the single largest unit in the region equals 1,000 MW.

Figure 3-51 Synchronized reserve demand curve showing the permanent second step



Scarcity Pricing and Energy Price Formation

The current operating reserve demand curves (ORDC) in PJM define an administrative price for estimated reserves (primary and synchronized reserves) up to the extended reserve requirement quantities. The demand curve shown in Figure 3-51 drops to a zero price for quantities above the extended reserve requirement. The price for reserve quantities less than the reserve requirement is $850 per MWh, and the price for reserve quantities above the reserve requirement to 190 MW above the reserve requirement is $300 per MWh.

The shortage prices set by the ORDC are added to LMP during shortages. When multiple reserve products are short or when reserves are short in multiple zones, the ORDC prices are additive. Currently, the highest possible scarcity adder is $1,700 per MWh, which is the $850 per MWh price times two, for two reserve products (synchronized reserve and nonsynchronized reserve). The current market rules cap the additive reserve shortage penalty factors in MAD to the sum of the synchronized reserve penalty factor and the primary reserve penalty factor.[93]

Table 3-72 shows five example scenarios, under the current ORDC, with combinations of energy offers, reserve shortage penalty factors and transmission constraint penalty factors that can add up to produce LMPs at sample pnodes in the MAD Reserve Subzone and outside the MAD Reserve Subzone. In scenario B, there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones, that results in the $1,700 per MWh scarcity adder in MAD and RTO. The $1,700 per MWh scarcity adder applies any time PJM initiates a manual load dump action or voltage reduction action.[94] In scenario C, there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones, that results in the $1,700 per MWh scarcity adder, and a violated transmission constraint with a $2,000 per MWh penalty factor that results in a $3,750 per MWh LMP.[95]

In Scenario E, the energy component of LMP is at its highest level, $2,000 per MWh and there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones that results in the $1,700 per MWh scarcity adder, and a violated transmission constraint with $2,000 per MWh penalty factor that results in a $5,700 per MWh LMP. The LMPs in Scenario E are not the highest possible LMPs in the PJM energy market under the current rules. If there are multiple violated transmission constraints, the transmission constraint penalty factor's contribution to the LMP at a pnode can exceed $2,000 per MWh resulting in LMPs higher than $5,700 per MWh. The extent to which each violated transmission penalty factor affects the LMP at a pnode is directly proportional to the pnode's distribution factor (dfax) with respect to that constraint.

93 *See* PJM Operating Agreement, Schedule 1, Section 3.2.3A(d)(ii). The cap on the additive reserve shortage penalty factors in MAD was not reflected in the prior report and the maximum in MAD was therefore overstated. See: *2020 Quarterly State of the Market Report for PJM: January through September*, p. 192.

94 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 112 (Jan. 5, 2021), 2.8 The Calculation of Locational Marginal Prices (LMPs) During Emergency Procedures.

95 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.

Table 3-72 Additive penalty factors under reserve shortage and transmission constraint violations: Status Quo

Scenario	Energy Component of LMP	Synchronized Reserve Penalty Factor RTO	Synchronized Reserve Penalty Factor MAD	Primary Reserve Penalty Factor RTO	Primary Reserve Penalty Factor MAD	Capped Reserve Shortage Penalty Factor	Transmission Constraint Penalty Factor	Total LMP in MAD	Total LMP outside MAD
A	$50	$850	$0	$0	$0	$850	$0	$900	$900
B	$50	$850	$850	$850	$850	$1,700	$0	$1,750	$1,750
C	$50	$850	$850	$850	$850	$1,700	$2,000	$3,750	$3,750
D	$1,000	$850	$850	$850	$850	$1,700	$2,000	$4,700	$4,700
E	$2,000	$850	$850	$850	$850	$1,700	$2,000	$5,700	$5,700

Changes to the ORDC, approved by FERC and planned for implementation in 2022, will increase the price for reserve quantities less than the reserve requirement to $2,000 per MWh. For each reserve quantity greater than the reserve requirement, PJM will multiply an assumed probability of a reserve shortage, based on historic forecast error, by $2,000 per MWh, creating an extended downward sloping ORDC. The extended ORDC is an administratively determined reserve price that will be added to LMP, as a scarcity pricing adder, when no shortage exists. The $2,000 per MWh price is unjustified because the highest possible energy offer under most circumstances is only $1,000 per MWh. Only in the unusual circumstance when short run marginal costs exceed $1,000 per MWh is a higher ORDC price justified. When energy offers exceed $1,000 per MWh, they have to be verified and pre-approved by PJM and cannot exceed $2,000 per MWh, to be eligible to set LMP in the PJM energy market.

The highest possible scarcity adder increases under the planned changes to the ORDC. The highest possible scarcity adder will be $10,000 per MWh, which is the $2,000 per MWh price times five. The five products are the synchronized and nonsynchronized reserve products for RTO and MAD Zones plus a new secondary 30 minute reserve product for the RTO Zone.

Table 3-73 shows example scenarios, under the ORDCs planned for implementation in 2022, with combinations of energy offers, reserve shortage penalty factors and transmission constraint penalty factors that can add up to produce LMPs at sample pnodes in the MAD Reserve Subzone and outside the MAD Reserve Subzone. In scenario B, there is a reserve shortage for both primary and synchronized reserves in both the MAD and RTO Reserve Zones and reserve shortage for secondary reserve in the RTO Zone that results in the $10,000 per MWh scarcity adder in MAD. The $10,000 per MWh scarcity adder applies any time PJM initiates a manual load dump action or voltage reduction action. In scenario C, there is a reserve shortage for both primary and synchronized reserves in both the MAD and RTO Reserve Zones, a reserve shortage for secondary reserve in the RTO Zone, that results in the $10,000 per MWh scarcity adder, and a violated transmission constraint with a $2,000 per MWh penalty factor that results in a $12,050 per MWh LMP at a pnode in MAD.[96]

In Scenario E, the Energy Component of LMP is at its highest level, $2,000 per MWh and there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones and a secondary reserve shortage, resulting in the $10,000 per MWh scarcity adder, and a violated transmission constraint with a $2,000 per MWh penalty factor that results in a $14,000 per MWh LMP at a pnode in MAD. The LMPs in Scenario E are not the highest possible LMPs in the PJM energy market under the ORDCs planned for implementation in 2022. If there are multiple violated transmission constraints, the transmission constraint penalty factors' contribution to the LMP at a pnode can exceed $2,000 per MWh resulting in LMPs higher than $14,000 per MWh. The extent to which each violated transmission penalty factor affects the LMP at a pnode is directly proportional to the pnode's distribution factor (dfax) with respect to that constraint.

96 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 sum of the product of transmission constraint penalty factors and distribution factors.

Table 3-73 Additive penalty factors under shortage conditions and transmission constraint violations

Scenario	Energy Component of LMP	Synchronized Reserve Penalty Factor RTO	Synchronized Reserve Penalty Factor MAD	Primary Reserve Penalty Factor RTO	Primary Reserve Penalty Factor MAD	Secondary Reserve Penalty Factor RTO	Transmission Constraint Penalty Factor	Total LMP in MAD	Total LMP outside MAD
A	$50	$2,000	$200	$200	$200	$0	$0	$2,650	$2,250
B	$50	$2,000	$2,000	$2,000	$2,000	$2,000	$0	$10,050	$6,050
C	$50	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$12,050	$8,050
D	$1,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$13,000	$9,000
E	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$14,000	$10,000

Operator Actions

Actions taken by PJM operators to maintain reliability, such as committing more reserves than required, may suppress reserve prices. The need to commit more reserves could instead be directly reflected in the ORDC when operational issues arise, allowing the market to efficiently account for the reliability commitment in the energy and reserves markets. Instead, the new ORDC will be inflated at all times based on average historical forecast error that may or may not have resulted in operator actions to commit additional reserves.

Locational Reserve Requirements

In addition to the construction of the operating reserve demand curves to reflect the value of maintaining reserves and avoiding a loss of load event, the modeling of reserve requirements should reflect locational needs and should price operator actions to, for example, commit more reserves when specific needs arise.

The current operating reserve demand curves are modeled for reserve requirements for the RTO level (RTO Reserve Zone) and for the Mid-Atlantic and Dominion region (MAD Subzone). This was a result of historical congestion patterns where limits to transmission capacity to deliver power from outside the MAD Subzone into the MAD Subzone necessitated maintaining reserves in the MAD area to respond to disturbances within the subzone. On most days, the MAD Subzone is no longer relevant. PJM may need to maintain or operate resources in other local areas to maintain local reliability. Currently, these units are committed out of market for reliability reasons, or the reserve need is modeled as an artificial closed loop interface with limited deliverability modeled inside the closed loop from resources located outside. The value of operating these resources, including generators that are manually committed for reliability and demand resources that may be dispatched inside a closed loop, is not correctly reflected in prices. A more efficient way to reflect these requirements would be to have locational reserve requirements that are adjusted based on PJM forecasts and reliability studies.

Reserve Shortages in 2020

Reserve Shortage in Real-Time SCED

The MMU analyzed the RT SCED solutions to determine how many of the RT SCED solutions indicated a shortage of any of the reserve products (synchronized reserve and primary reserve at RTO Reserve Zone and MAD Reserve Subzone), how many of these solutions were approved by PJM, and how many of these were used in LPC to calculate prices. Reserves are considered short if the quantity (MW) of reserves dispatched by RT SCED for a five minute interval was less than the extended reserve requirement. Table 3-74 shows the number and percent of RT SCED solutions that indicated a shortage of any of the four reserve products (RTO synchronized reserve, RTO primary reserve, MAD synchronized reserve, and MAD primary reserve), the number and percent of the RT SCED solutions with shortage that were approved by PJM, and the number and percent of the RT SCED solutions with shortage that were used in LPC to calculate real-time prices.

Table 3-74 shows that, in 2020, PJM operators approved eight RT SCED solutions that indicated a shortage of reserves, from a total of 2,867 RT SCED solutions that indicated shortage. Among the eight approved RT SCED solutions with reserve shortage, seven were used in LPC for LMPs and reserve clearing prices. Among the seven RT SCED shortage solutions, two solutions were used in LPC for two consecutive five minute intervals in each instance, resulting in a total of nine five minute intervals with shortage prices in 2020. In 2019, PJM operators approved 47 solutions that indicated a shortage of reserves, from a total of 5,652 RT SCED solutions that indicated shortage. It is unclear what criteria PJM operators use to approve the RT SCED solutions to send dispatch signals to resources. The RT SCED approval process remains inconsistent and undefined.

Table 3-74 RT SCED cases with reserve shortage: 2020

Month (2020)	Number of RT SCED Solutions	Number of RT SCED Solutions With Reserve Shortage	Number of Approved RT SCED Solutions With Reserve Shortage	Number of Approved RT SCED Solutions With Reserve Shortage Used in LPC	Solutions With Reserve Shortage as Percent of Total RT SCED Solutions	Approved RT SCED Solutions With Reserve Shortage as Percent of RT SCED Solutions With Shortage	RT SCED Solutions With Shortage Used in LPC as Percent of RT SCED Solutions With Shortage
Jan	51,022	337	0	0	0.7%	0.0%	0.0%
Feb	46,247	186	0	0	0.4%	0.0%	0.0%
Mar	38,680	282	0	0	0.7%	0.0%	0.0%
Apr	36,543	420	2	1	1.1%	0.5%	0.2%
May	36,648	167	0	0	0.5%	0.0%	0.0%
Jun	34,327	169	0	0	0.5%	0.0%	0.0%
Jul	30,342	136	0	0	0.4%	0.0%	0.0%
Aug	30,775	115	0	0	0.4%	0.0%	0.0%
Sep	30,632	96	0	0	0.3%	0.0%	0.0%
Oct	32,429	481	2	2	1.5%	0.4%	0.4%
Nov	30,360	249	3	3	0.8%	1.2%	1.2%
Dec	31,859	229	1	1	0.7%	0.4%	0.4%
Total	429,864	2,867	8	7	0.7%	0.3%	0.2%

While there were 2,867 RT SCED solutions that indicated shortage, the number of RT SCED target times for which RT SCED indicated shortage was only 1,819. PJM solves multiple RT SCED cases with three solutions per case, for each five minute target time.[97] [98]

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 3-75 shows, for each month of 2020, 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 more than one RT SCED solution showed a shortage of reserves, and the number of five minute pricing intervals for which the LPC solution showed a shortage of reserves. Table 3-75 shows that 1,819 target times, or 1.7 percent of all five minute target times in 2020, had at least one RT SCED solution showing a shortage of reserves, and 592 target times, or 0.6 percent of all five minute target times in 2020, had more than one RT SCED solution showing a shortage of reserves.

97 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.
98 PJM updated the RT SCED execution frequency to solve one case for each five minute target time beginning June 22, 2020.

Table 3-75 Five minute SCED target times and pricing intervals with shortage: 2019 and 2020

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
2019 Jan	8,928	87	1.0%	34	0.4%	3	3.4%
2019 Feb	8,064	184	2.3%	79	1.0%	0	0.0%
2019 Mar	8,916	347	3.9%	173	1.9%	10	2.9%
2019 Apr	8,640	424	4.9%	217	2.5%	7	1.7%
2019 May	8,928	203	2.3%	94	1.1%	0	0.0%
2019 Jun	8,640	233	2.7%	93	1.1%	0	0.0%
2019 Jul	8,928	312	3.5%	134	1.5%	3	1.0%
2019 Aug	8,928	218	2.5%	85	1.0%	0	0.0%
2019 Sep	8,640	288	3.4%	131	1.5%	4	1.4%
2019 Oct	8,928	284	3.2%	139	1.6%	3	1.1%
2019 Nov	8,652	283	3.3%	125	1.4%	1	0.4%
2019 Dec	8,928	183	2.0%	101	1.1%	2	1.1%
2019 Total	105,120	3,046	2.9%	1,405	1.3%	33	1.1%
2020 Jan	8,928	172	1.9%	89	1.0%	0	0.0%
2020 Feb	8,352	94	1.1%	44	0.5%	0	0.0%
2020 Mar	8,916	173	1.9%	66	0.7%	0	0.0%
2020 Apr	8,640	208	2.4%	99	1.1%	2	1.0%
2020 May	8,928	113	1.3%	36	0.4%	0	0.0%
2020 Jun	8,640	114	1.3%	30	0.3%	0	0.0%
2020 Jul	8,928	110	1.2%	17	0.2%	0	0.0%
2020 Aug	8,928	95	1.1%	14	0.2%	0	0.0%
2020 Sep	8,640	64	0.7%	21	0.2%	0	0.0%
2020 Oct	8,928	327	3.7%	91	1.0%	3	0.9%
2020 Nov	8,652	181	2.1%	44	0.5%	3	1.7%
2020 Dec	8,928	168	1.9%	41	0.5%	1	0.6%
2020 Total	105,408	1,819	1.7%	592	0.6%	9	0.5%

While a single RT SCED solution indicating a shortage for a target time among multiple RT SCED solutions that solved for that target time could be the result of operator load bias or erroneous inputs, it is less likely that a target time with multiple RT SCED solutions indicating shortage was the result of an error. There were nine 5 minute intervals with shortage pricing that occurred in 2020, while there were 592 five minute target times for which multiple RT SCED solutions showed a shortage of reserves. In 2019, out of 3,046 target times for which one or more RT SCED solutions indicated a shortage of reserves, there were 33 five minute intervals in LPC, or 1.1 percent, with shortage pricing. In 2020, out of 1,819 target times for which one or more RT SCED solutions indicated a shortage of reserves, there were nine five minute intervals in LPC, or 0.5 percent, with shortage pricing.

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. 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. 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 clearly define the criteria for operator approval of RT SCED cases used to send dispatch signals to resources, and for pricing, to minimize operator discretion and implement a rule based approach.

Shortage Pricing Intervals in LPC

There were nine five minute intervals with shortage pricing in 2020, compared to 33 intervals in 2019, in PJM. Table 3-76 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 nine intervals with shortage pricing due to synchronized reserve shortage. Table 3-77 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 seven intervals with shortage pricing due to synchronized reserve shortage. Table 3-78 shows 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 one interval with shortage pricing due to primary reserve shortage. Table 3-79 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 one interval with shortage pricing due to primary reserve shortage.

PJM enforces an RTO wide reserve requirement and a supplemental reserve requirement for the MAD region. The MAD Reserve Subzone is nested within 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.[99] The synchronized reserve clearing price of the MAD Reserve Subzone, nested within the RTO Reserve Zone, 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.

In seven out of the nine intervals in 2020 with shortage pricing, both the RTO Zone and the MAD Subzone cleared with synchronized reserves less than their extended requirement. In four of the nine intervals, the synchronized reserves in the RTO Zone were short of the minimum reserve requirement, resulting in a $850 per MWh penalty factor. In five of the nine intervals, the synchronized reserves in the RTO zone were greater than or equal to the minimum reserve requirement but less than the 190 MW extended requirement. The clearing price for synchronized reserves in the RTO Zone is the sum of the shadow prices of the synchronized reserve constraint for the RTO Zone and the primary reserve constraint for the RTO Zone. The clearing price for synchronized reserves in the MAD Subzone is the sum of the shadow prices of the synchronized reserve constraints for the RTO Zone and MAD Subzone and the shadow prices of the primary reserve constraints in the RTO and MAD Subzone.

Table 3-76 RTO synchronized reserve shortage intervals: 2020

Interval (EPT)	RTO Extended Synchronized Reserve Requirement (MW)	Total RTO Synchronized Reserves (MW)	RTO Synchronized Reserve Shortage (MW)	RTO Synchronized Reserve Clearing Price ($/MWh)
30-Apr-20 12:05	1,817.2	1,614.6	202.6	$850.0
30-Apr-20 12:10	1,817.2	1,614.6	202.6	$850.0
12-Oct-20 00:35	1,537.3	1,273.6	263.7	$850.0
14-Oct-20 11:25	2,728.0	2,538.0	190.0	$874.4
14-Oct-20 11:30	2,728.0	2,538.0	190.0	$874.4
12-Nov-20 17:35	1,785.0	1,771.3	13.7	$300.0
13-Nov-20 17:55	1,783.0	1,727.6	55.4	$600.0
13-Nov-20 18:00	1,782.0	1,246.7	535.3	$1,700.0
16-Dec-20 11:45	1,860.0	1,735.5	124.5	$300.0

Table 3-77 MAD synchronized reserve shortage intervals: 2020

Interval (EPT)	MAD Extended Synchronized Reserve Requirement (MW)	Total MAD Synchronized Reserves (MW)	MAD Synchronized Reserve Shortage (MW)	MAD Synchronized Reserve Clearing Price ($/MWh)
12-Oct-20 00:35	1,537.3	1,273.6	263.7	$1,700.0
14-Oct-20 11:25	2,728.0	2,538.0	190.0	$1,662.2
14-Oct-20 11:30	2,728.0	2,538.0	190.0	$1,662.2
12-Nov-20 17:35	1,785.0	1,771.3	13.7	$600.0
13-Nov-20 17:55	1,783.0	1,727.6	55.4	$900.0
13-Nov-20 18:00	1,782.0	1,246.7	535.3	$1,700.0
16-Dec-20 11:45	1,860.0	1,735.5	124.5	$600.0

99 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.

Table 3-78 RTO primary reserve shortage intervals: 2020

Interval (EPT)	RTO Extended Primary Reserve Requirement (MW)	Total RTO Primary Reserves (MW)	RTO Primary Reserve Shortage (MW)	RTO Primary Reserve Clearing Price ($/MWh)
13-Nov-20 18:00	2,578.0	2,104.6	473.4	$850.0

Table 3-79 MAD primary reserve shortage intervals: 2020

Interval (EPT)	MAD Extended Primary Reserve Requirement (MW)	Total MAD Primary Reserves (MW)	MAD Primary Reserve Shortage (MW)	MAD Primary Reserve Clearing Price ($/MWh)
13-Nov-20 18:00	2,578.0	2,104.6	473.4	$850.0

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 tier 1 bias or 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.[100] 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. Instead of addressing these complexities through generator modeling improvements, PJM relies on a nontransparent method of adjusting generator parameters, called Degree of Generator Performance (DGP).[101] [102] 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.

PJM adjusts ramp rates using DGP, deselects specific units from providing reserves, and overrides the dispatch signal to certain units to set the dispatch signal equal to actual resource output. These manual interventions are, at best, rough approximations of the capability of generators and result in an inaccurate measurement of reserves.

Competitive Assessment

Market Structure

Market Concentration

The Herfindahl-Hirschman Index (HHI) concentration ratio is calculated by summing the squares of the market shares of all firms in a market. Hourly PJM energy market HHIs are based on the real-time energy output of generators adjusted with scheduled imports.

The HHI may not accurately capture market power issues in situations where, for example, there is moderate

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

101 *See* "PJM Manual 12: Balancing Operations," Rev. 41 (Nov. 19, 2020) Attachment A, P78. "PJM Manual 11: Energy and Ancillary Services Market Operations," does not mention the use of DGP in the market clearing engine.

102 PJM published a whitepaper that defines DGP and describes its use, which can be accessed at <http://www.pjm.com/~/media/etools/oasis/system-information/generation-performance-monitor-and-degree-of-generator-performance-white-paper.ashx> (July 2, 2020).

concentration in all on line resources but there is a high level of concentration in resources needed to meet increases in load. The HHIs for supply curve segments are an indicator of the ownership of incremental resources. But an aggregate pivotal supplier test is required to accurately measure the ability of incremental resources to exercise market power.

Hourly HHIs for the baseload, intermediate and peaking segments of generation supply are based on hourly energy market shares, unadjusted for imports.

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 between 1000 and 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.[103]

Analysis of supply curve segments of the PJM energy market in 2020 indicates low concentration in the base load segment, moderate concentration in the intermediate segment, and high concentration in the peaking segment.[104] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal in the aggregate market. The fact that the average HHI is in the unconcentrated range and the maximum hourly HHI is in the moderately concentrated 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.

When transmission constraints exist, local markets are created with ownership that is typically significantly more concentrated than the overall energy market. PJM offer capping rules that limit the exercise of local market power were generally effective in preventing the exercise of market power in 2020, 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 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 during 2020 was unconcentrated on average, although there were 233 hours, or 2.7 percent of the hours in 2020 with HHI in the moderately concentrated range (Table 3-80).[105]

Table 3-80 Hourly energy market HHI: 2019 and 2020

By offering supplier	Hourly Market HHI (2019)	Hourly Market HHI (2020)
Average	781	790
Minimum	577	569
Maximum	1153	1166
Highest market share (One hour)	28%	28%
Average of the highest hourly market share	20%	20%
# Hours	8,760	8,784
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-81 includes HHI values by supply curve segment, including base, intermediate and peaking plants for 2019 and 2020. On average, ownership in the baseload segment was unconcentrated, in the intermediate segment was moderately concentrated, and in the peaking segment was highly concentrated.

Table 3-81 Generation segment HHI: 2019 and 2020

By offering	2019			2020		
supplier	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	659	818	1188	667	834	1203
Intermediate	701	1822	9105	743	1551	6815
Peak	716	5942	10000	651	5757	10000

103 See *Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement*, 77 FERC ¶ 61,263 *mimeo* at 80 (1996).

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

105 The HHI calculations use actual real time settled generation data for each unit in PJM. Each unit's output is assigned to the supplier that is responsible for offering the unit in the energy market. Prior to this report, each unit's generation was assigned to the supplier that was paid for the unit's output. For units that are jointly owned, the output was assigned to multiple suppliers using each supplier's share of the unit's output. The result of the new method is a slight increase in calculated HHIs.

Figure 3-52 shows the total installed capacity (ICAP) MW of units in the baseload, intermediate and peaking segments by fuel source in 2020.[106]

Figure 3-52 Fuel source distribution in unit segments: 2020[107]

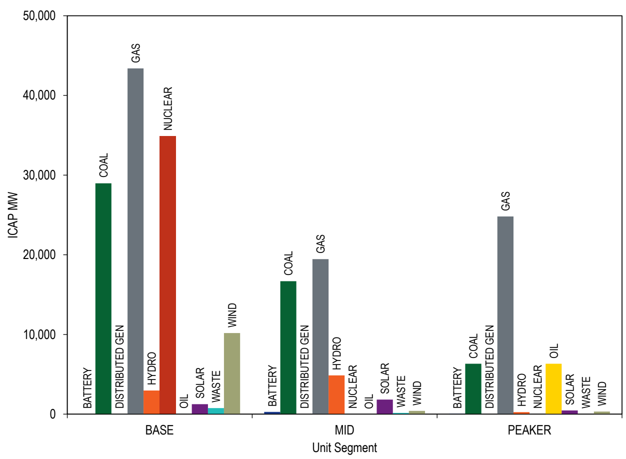


Figure 3-53 shows the ICAP of coal fired and gas fired units in PJM that are classified as baseload, intermediate and peaking from 2016 through 2020. Figure 3-53 shows that the total ICAP of coal fired units in PJM that are classified as baseload has been steadily decreasing and the total ICAP of gas fired units in PJM that are classified as baseload has been steadily increasing, based on operating history for the period from 2016 through 2020. In 2019, the ICAP of gas fired units classified as baseload exceeded the ICAP of coal fired units classified as baseload for the first time.

Figure 3-53 Unit segment classification by fuel: 2016 through 2020

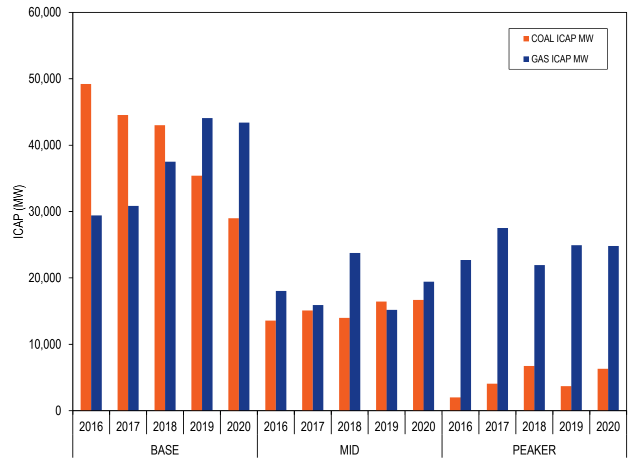
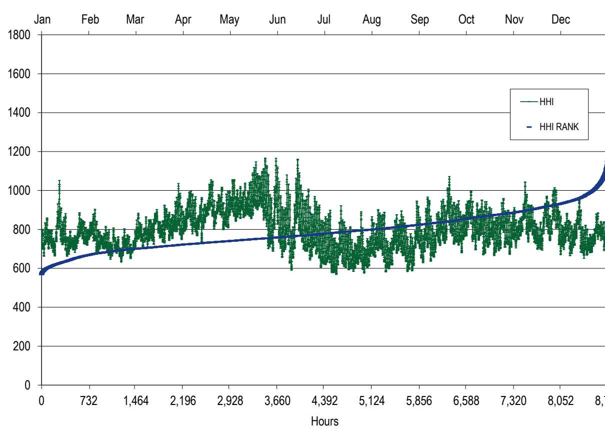


Figure 3-54 presents the hourly HHI values in chronological order and an HHI duration curve for 2020.

Figure 3-54 Hourly energy market HHI: 2020



Market-Based Rates

Participation in the PJM market using offers that exceed costs requires market-based rate approval from FERC, which reviews the market-based rate authority of PJM market sellers on a triennial schedule to ensure that market sellers do not have market power or that market power is appropriately mitigated. The current triennial review for PJM nontransmission owning utilities began in June 2020. The next triennial review for PJM transmission owners will begin in December 2022.

With Order No. 861, FERC no longer uses structural market power assessments to determine whether sellers have market power in the PJM markets. Instead,

106 The installed capacity (ICAP) used for wind and solar units here is their nameplate capacity in MW. In PJM's Capacity Market, the ICAP value of wind and solar units is derated from the nameplate capacity to reflect their effective load carrying capability.

107 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) <http://www.pjm.com/~/media/committees-groups/task-forces/nemstf/postings/20120628-first-read-item-04-nemstf-report-and-proposed-manual-revisions.ashx>.

FERC relies on a rebuttable presumption that market monitoring and market power mitigation are sufficient to ensure competitive market outcomes.[108]

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. The MMU has found that the capacity market is not competitive because the default Market Seller Offer Cap (MSOC) is inflated due to the use of an inaccurate estimate for the expected number of Performance Assessment Intervals (PAIs).[109] With these results and the supporting evidence, the MMU has challenged the rebuttable presumption of sufficient market power mitigation for the pending triennial review filings and recommended that conditions limiting sellers to cost-based energy offers and a revised capacity market offer cap be required until improvements are made to the offer capping processes in the energy and capacity markets so that suppliers cannot exercise market power.[110]

Merger Reviews

FERC reviews contemplated 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."[111]

FERC applies tests set forth in the 1996 Merger Policy Statement.[112] [113]

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. Following the 1992 Guidelines, FERC applies a five step framework, which includes: (1) defining the market; (2) analyzing market concentration; (3) analyzing mitigative effects of new entry; (4) assessing efficiency gains; and (5) assessing viability of the parties without a merger. FERC also evaluates a Competitive Analysis Screen.[114]

The MMU reviews proposed mergers based on analysis of the impact of the merger or acquisition on market power given actual market conditions. The analysis includes use of the three pivotal supplier test results in the real-time energy market. The MMU's review ensures that mergers are evaluated based on their impact on local market power in the PJM energy market using actual observed market conditions, actual binding constraints and actual congestion results. This is contrast to the typical merger filing that uses predefined local markets rather than the actual local markets. The MMU routinely files comments including such analyses.[115] The MMU has proposed that FERC adopt this approach when evaluating mergers in PJM.[116] FERC has considered the MMU's analysis in reviewing mergers.[117]

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 3-82 shows transactions that involved an entire generation unit or unit owner that were completed in 2020, as reported to the Commission. Table 3-83 shows transactions that involved transfers of partial unit ownership that were completed in 2020, as reported to the Commission.[118]

108 *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, 168 FERC ¶ 61,040 ("Order No. 861") (July 18, 2019).

109 *See* "Complaint of the Independent Market Monitor for PJM", Docket No. EL19 - 47, (February 21, 2019), which can be accessed at <https://www.monitoringanalytics.com/Filings/2019/IMM_Complaint_Docket_No_EL19-XXX_20190221.pdf>.

110 *See* for example, "Protest of the Independent Market Monitor for PJM," Docket No. ER10-1556 (August 28, 2020).

111 18 U.S.C. § 824b.

112 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).

113 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.

114 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)

115 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).

116 See Comments of the Independent Market Monitor for PJM, Docket No. RM16-21 (Dec. 12, 2016).

117 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).

118 The transaction completion date is based on the notices of consummation submitted to the Commission.

Table 3-82 Completed transfers of entire resources: 2020

Generator or Generation Owner Name	From	To	Transaction Completion Date	Docket
FE Coal and Nuclear (Mansfield(retired), Sammis, Eastlake 6, Pleasants, Davis Besse, Perry, Beaver Valley)	FirstEnergy Generation	Avenue Capital (15-20%), Nuveen Asset Management (35 - 40%)	February 27, 2020	EC19-123
Energy Center Dover	Clearway Thermal LLC (Global Infrastructure Management LLC)	DB Energy Assets (DCO Energy and Basalt Infrastructure Partners)	March 2, 2020	EC19-142
Krayn Wind	Krayn Wind LLC	Oppidum Capital, S.L.	March 4, 2020	EC20-26
Beech Ridge Wind	Invenergy	Southern Power	May 1, 2020	EC20-27
Panda Liberty, Panda Patriot	Panda Power Funds	EIG, Carlyle Group	June 17, 2020	EC20-33
Longview Power	Ascribe Capital LLC, KKR Credit Advisors LLC, Seaport Global Securities, Tennenbaum Capital Partners, LLC & Others	Trilogy Portfolio Company, R&F Market LLC, Cetus Capital LLC, Eaton Vance Management & Others	July 30, 2020	EC20-70
Panda Hummel Station	Panda Power Funds	LS Power Development LLC	October 15, 2020	EC20-55
Tilton Energy	The Carlyle Group	Rockland Capital	November 17, 2020	EC20-100

Table 3-83 Completed transfers of partial ownership of resources: 2020

Generator or Geneation Owner Name	From	To	Transaction Completion Date	Docket
Yards Creek (50%)	PSEG	LS Power Development LLC	September 8, 2020	EC20-49
Fowler Ridge Wind Farm (50%)	Dominion Energy, Inc.	BP P.L.C	September 29, 2020	EC20-81

The MMU has also facilitated settlements for mitigation of market power, in cases where market power concerns have been identified.[119] Such mitigation is designed to mitigate behavior over the long term, in addition to or instead of imposing short term asset divestiture requirements.

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 pivotal and has monopoly power in the aggregate energy market. If a small number of suppliers are jointly required to meet load, those suppliers are jointly pivotal and have oligopoly power. 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 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 always 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.[120] The MMU is developing an aggregate market power test for the day-ahead and real-time energy markets based on pivotal suppliers and will propose appropriate market power mitigation rules to address aggregate market power.

Day-Ahead Energy Market Aggregate Pivotal Suppliers

To assess the number of pivotal suppliers in the 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.[121] Generating units, import transactions, economic demand response,

119 See 138 FERC ¶ 61,167 at P 19.

120 One supplier, Exelon, is partially mitigated for aggregate market power through its merger agreement. The agreement is not part of the PJM market rules. See Monitoring Analytics, LLC, Letter attaching Settlement Terms and Conditions, FERC Docket No. EC11-83-000 and Maryland PSC Case No. 9271 (October 11, 2011).

121 Each LMP is scaled by 150 percent to determine the relevant supply, resulting in a different price threshold for each LMP value. The analysis does not solve a redispatch of the PJM market.

and INCs, are included for each supplier. Demand is the total MW required by PJM to meet physical load, cleared load bids, export transactions, and DECs. 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.

Figure 3-55 shows the number of days in 2019 and 2020 with one pivotal supplier, two jointly pivotal suppliers, and three jointly pivotal suppliers for the day-ahead energy market. One supplier was singly pivotal on the summer peak days in 2019 and 2020 and on August 26, 2020. Two suppliers were jointly pivotal on 35 days in 2019 and on 128 days in 2020. Three suppliers were jointly pivotal on 228 days in 2019 and on 301 days in 2020, despite average HHIs at persistently unconcentrated levels. In 2019 and 2020, the highest levels of aggregate market power occurred in the third quarter, PJM's peak load season. Outside the summer months, the frequency of pivotal suppliers increased on high demand days in the first week of October 2019 and around the Martin Luther King Jr. Day holiday in 2019 and 2020. The frequency of pivotal suppliers increased in 2020 compared to 2019.

Figure 3-55 Days with pivotal suppliers and numbers of pivotal suppliers in the day-ahead energy market by quarter

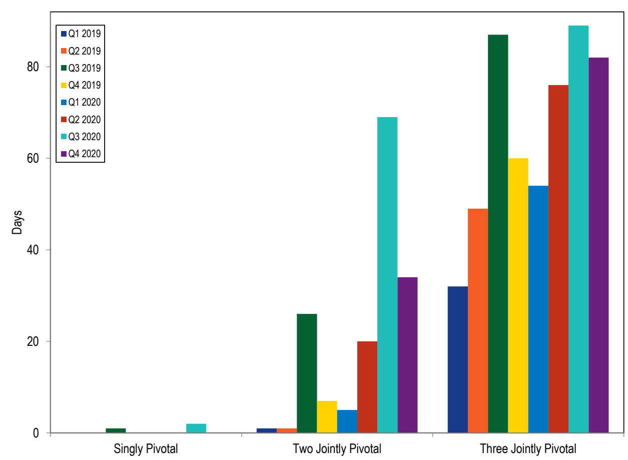


Table 3-84 provides the frequency with which each of the top 10 pivotal suppliers was singly or jointly pivotal for the day-ahead energy market in 2020. The largest pivotal supplier was singly pivotal on two days in 2020. All of the top 10 suppliers were one of two pivotal suppliers on at least 14 days in 2020. All of the top 10 suppliers were one of three pivotal suppliers on at least 158 days in 2020.

Table 3-84 Day-ahead market pivotal supplier frequency: 2020

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	2	0.5%	121	33.1%	300	82.0%
2	0	0.0%	119	32.5%	300	82.0%
3	0	0.0%	113	30.9%	296	80.9%
4	0	0.0%	72	19.7%	271	74.0%
5	0	0.0%	61	16.7%	238	65.0%
6	0	0.0%	26	7.1%	212	57.9%
7	0	0.0%	25	6.8%	202	55.2%
8	0	0.0%	16	4.4%	164	44.8%
9	0	0.0%	15	4.1%	205	56.0%
10	0	0.0%	14	3.8%	158	43.2%

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. 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.[122] If the TPS test is failed, market power mitigation is applied by offer capping the resources of 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-

122 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>.

based energy offers, defined by fuel cost policies, and have the option to submit market-based or 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 one, two or three suppliers are jointly pivotal in a defined local market. The TPS test is applied every time the system solution indicates that out of merit resources are needed to relieve a transmission constraint. 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 is the number of hours that each transmission constraint was binding in the real-time energy market over a period, by zone.

In 2020, the 500 kV system, 10 zones, and MISO experienced congestion resulting from one or more constraints binding for 100 or more hours or resulting from an interface constraint (Table 3-85).[123] Table 3-85 shows that the 500 kV system, three zones and MISO experienced congestion resulting from one or more constraints binding for 100 or more hours or resulting from a binding interface constraint in every year from 2009 through 2020. Four Control Zones did not experience congestion resulting from one or more constraints binding for 100 or more hours or resulting from any binding interface constraint in any year from 2009 through 2020.

Table 3-85 Congestion hours resulting from one or more constraints binding for 100 or more hours or from an interface constraint: 2009 through 2020

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
500 kV System	4,468	6,789	6,109	1,468	3,002	1,596	777	1,487	994	1,120	4,186	2,577
AECO	149	172	234	0	208	0	394	439	0	500	108	0
AEP	1,045	1,636	2,510	0	2,611	2,710	1,274	796	469	1,878	808	1,361
APS	509	1,714	0	206	0	170	167	0	265	246	191	417
ATSI	157	0	0	208	270	489	242	141	1,113	2,856	1,405	306
BGE	152	470	1,041	2,970	1,760	6,255	9,601	11,434	2,178	3,135	812	9,491
ComEd	1,212	2,080	1,134	4,554	5,143	4,119	5,878	7,336	2,257	1,148	457	1,074
DAY	0	0	0	0	0	0	0	0	0	0	0	0
DEOK	0	0	0	109	0	0	112	0	0	0	0	0
DLCO	156	475	206	209	0	223	617	0	0	0	0	0
Dominion	468	905	1,179	1,020	664	0	1,172	459	436	136	196	891
DPL	0	122	0	1,542	639	3,071	2,066	2,719	673	1,117	0	106
EKPC	0	0	0	0	0	0	0	0	0	400	0	0
EXT	0	0	0	0	0	0	0	0	788	0	0	0
JCPL	0	0	0	0	0	0	0	0	0	0	0	0
Met-Ed	0	180	162	0	0	0	222	0	116	1,559	922	1,041
MISO	6,042	5,287	15,637	27,694	18,215	11,460	11,109	11,712	6,297	8,635	9,249	5,673
NYISO	0	0	0	0	167	143	834	2,130	332	0	0	0
OVEC	0	0	0	0	0	0	0	0	0	0	0	0
PECO	247	0	788	386	732	1,953	895	692	1,013	304	0	0
PENELEC	103	284	0	0	176	4,281	1,683	451	3,074	1,648	2,065	2,999
Pepco	149	1	0	143	245	41	0	0	0	0	0	0
PPL	176	118	40	350	452	148	266	936	2,044	436	1,124	891
PSEG	303	549	1,107	913	3,021	4,688	2,665	810	239	226	0	0
RECO	0	0	0	0	0	0	0	0	0	0	0	0

123 A constraint is mapped to the 500 kV system if its voltage is 500 kV and it is located in one of the control zones including AECO, BGE, DPL, JCPK, Met-Ed, 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.

The local market structure in the real-time energy market associated with each of the frequently binding constraints was analyzed using the three pivotal supplier results in 2020.[124] While the real-time constraint hours include constraints that were binding in the five minute real-time pricing solution (LPC), IT SCED 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. 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. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

Table 3-86 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the transfer interface constraints. Table 3-87 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 3-86 and Table 3-87 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.

Table 3-86 Three pivotal supplier test details for interface constraints: 2020

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
AEP - DOM	Peak	93	100	5	1	5
	Off Peak	108	100	6	0	6
AP South	Peak	370	688	19	7	11
	Off Peak	199	609	17	13	4
CPL - DOM	Peak	100	266	6	0	6
	Off Peak	85	197	6	0	5
PA Central	Peak	41	350	4	1	4
	Off Peak	64	351	4	0	4

Table 3-87 Three pivotal supplier test details for top 10 congested constraints: 2020

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Bagley - Graceton	Peak	83	145	13	5	8
	Off Peak	66	129	12	5	7
Lenox - North Meshoppen	Peak	12	35	2	0	2
	Off Peak	6	32	2	0	2
PA Central	Peak	41	350	4	1	4
	Off Peak	64	351	4	0	4
Sub 85 - Sub 18	Peak	24	11	2	0	2
	Off Peak	22	11	2	0	2
Graceton - Safe Harbor	Peak	82	136	13	6	7
	Off Peak	52	106	11	5	6
Three Mile Island	Peak	82	97	10	2	8
	Off Peak	92	130	11	3	8
East Towanda - Hillside	Peak	23	55	2	0	2
	Off Peak	11	57	2	0	2
Paradise - BR Tap	Peak	30	4	2	0	2
	Off Peak	31	4	2	0	2
East Moline	Peak	50	37	3	0	3
	Off Peak	46	29	3	0	3
Logtown - North Delphos	Peak	24	47	1	0	1
	Off Peak	28	36	1	0	1

124 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>.

The three pivotal supplier test is applied every time the IT SCED solution indicates that incremental relief is needed to relieve a transmission constraint. While every system solution that requires incremental relief to transmission constraints will result in a test, not all tested providers of effective supply are eligible for 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.[125] 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, certain online units whose commitment is extended beyond the day-ahead or real-time commitment, 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. 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 3-88 shows that 0.5 percent of unit hours that cleared the day-ahead market on their price based offer were switched to cost in real-time. Table 3-88 shows that 7.1 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 3-88 Day-ahead committed units that cleared real-time: 2020

Period	Day Ahead Price Based Unit Hours That Cleared Real-Time on Cost	Day Ahead Price Based Unit Hours That Cleared Real-Time on Price	Day Ahead Price Based Unit Hours That Failed Real-Time TPS and Cleared Real-Time on Price	Percent Day Ahead Price Based Unit Hours That Cleared Real-Time on Cost	Percent Day Ahead Price Based Unit Hours That Failed Real-Time TPS and Cleared Real-Time on Price
2020	11,847	2,580,561	184,592	0.5%	7.1%

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 3-89 and Table 3-90 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. Tests where there was at least one offline unit or an online unit eligible for offer capping are considered tests that could have resulted in offer capping. The three pivotal supplier tests that resulted in offer capping do not explain all the offer capped units in the real-time energy market. PJM operators also manually commit units for reliability reasons other than providing relief to a binding constraint.

125 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.

Table 3-89 Summary of three pivotal supplier tests applied for interface constraints: 2020

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
AEP - DOM	Peak	143	138	97%	9	6%	7%
	Off Peak	77	77	100%	0	0%	0%
AP South	Peak	81	69	85%	0	0%	0%
	Off Peak	32	32	100%	5	16%	16%
CPL - DOM	Peak	2,185	2,151	98%	2	0%	0%
	Off Peak	1,008	1,007	NA	1	NA	NA
PA Central	Peak	14,986	10,255	68%	2	0%	0%
	Off Peak	15,431	10,590	69%	4	0%	0%

Table 3-90 Summary of three pivotal supplier tests applied for top 10 congested constraints: 2020

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
Bagley - Graceton	Peak	41,335	40,677	98%	314	1%	1%
	Off Peak	29,216	28,920	99%	151	1%	1%
Lenox - North Meshoppen	Peak	20,740	15,118	73%	2	0%	0%
	Off Peak	12,637	5,071	40%	0	0%	0%
PA Central	Peak	14,986	10,255	68%	2	0%	0%
	Off Peak	15,431	10,590	69%	4	0%	0%
Sub 85 - Sub 18	Peak	6,149	1,158	19%	0	0%	0%
	Off Peak	12,403	1,383	11%	0	0%	0%
Graceton - Safe Harbor	Peak	8,550	8,431	99%	40	0%	0%
	Off Peak	12,455	12,374	99%	77	1%	1%
Three Mile Island	Peak	14,719	14,031	95%	43	0%	0%
	Off Peak	4,853	4,674	96%	33	1%	1%
East Towanda - Hillside	Peak	6,022	4,371	73%	1	0%	0%
	Off Peak	3,314	1,569	47%	0	0%	0%
Paradise - BR Tap	Peak	4,721	1,712	36%	2	0%	0%
	Off Peak	2,613	1,080	41%	0	0%	0%
East Moline	Peak	3,982	889	22%	0	0%	0%
	Off Peak	4,165	744	18%	0	0%	0%
Logtown - North Delphos	Peak	6,641	99	1%	0	0%	0%
	Off Peak	5,250	65	1%	0	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, specifically for providing black start and reactive service as well as for conservative operations. There are no explicit rules governing market structure or the exercise of market power in the aggregate energy market.

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 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.

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. This is consistent with the day-ahead energy market objective of clearing resources (including physical and virtual resources) to meet the total demand (including physical and virtual 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.[126]

$$\text{Total Dispatch Cost} = \text{Startup Cost} + \sum_{\text{Min Run}} \text{Hourly Dispatch Cost}$$

where the hourly dispatch cost is calculated for each hour using the offers applicable for that hour as:

$$\text{Hourly Dispatch Cost} = (\text{Incremental Energy Offer@EcoMin} \times \text{EcoMin MW}) + \text{NoLoad Cost}$$

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. Figure 3-56 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 3-56 Offers with varying markups at different MW output levels

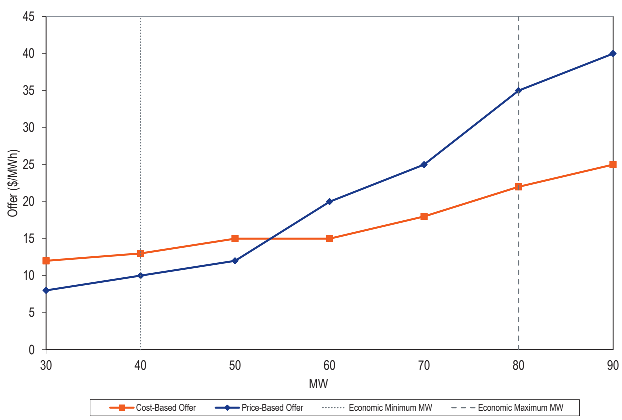


Table 3-91 shows the number and percent of unit schedule hours, by month, when unit offers included crossing curves in the PJM Day-Ahead and Real-Time Energy Markets, in 2020. The analysis only includes units that offer both price-based and cost-based offers. Units in PJM are only required to submit cost-based offers, and they may elect to offer price-based offers, but are not required to do so.

Table 3-91 Units offered with crossing curves in the day-ahead and real-time energy markets: 2020

	Day-Ahead			Real-Time		
2020	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	85,517	837,768	10.2%	81,143	778,951	10.4%
Feb	83,756	794,904	10.5%	78,559	733,533	10.7%
Mar	94,462	854,242	11.1%	86,233	752,204	11.5%
Apr	86,611	824,640	10.5%	76,431	721,582	10.6%
May	102,154	846,408	12.1%	89,419	739,992	12.1%
Jun	109,159	816,144	13.4%	100,921	765,834	13.2%
Jul	122,209	843,408	14.5%	115,707	798,708	14.5%
Aug	134,955	842,616	16.0%	127,447	793,736	16.1%
Sep	121,858	811,944	15.0%	111,939	734,013	15.3%
Oct	106,687	845,496	12.6%	84,722	679,234	12.5%
Nov	92,129	818,139	11.3%	68,596	655,287	10.5%
Dec	89,793	839,400	10.7%	83,011	755,092	11.0%
Total	1,229,290	9,975,109	12.3%	1,104,128	8,908,166	12.4%

126 See PJM Operating Agreement Schedule 1 § 6.4.1(g).

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 offer its 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 3-92 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 3-92 Units offered with lower minimum run time on price compared to cost but with positive markup in the day-ahead and real-time energy markets: 2020

	Day-Ahead			Real-Time		
2020	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	27,504	837,768	3.3%	22,246	778,951	2.9%
Feb	25,392	794,904	3.2%	20,879	733,533	2.8%
Mar	26,751	854,242	3.1%	21,182	752,204	2.8%
Apr	25,920	824,640	3.1%	20,264	721,582	2.8%
May	29,160	846,408	3.4%	22,615	739,992	3.1%
Jun	30,576	816,144	3.7%	26,330	765,834	3.4%
Jul	31,992	843,408	3.8%	27,994	798,708	3.5%
Aug	32,064	842,616	3.8%	27,452	793,736	3.5%
Sep	31,680	811,944	3.9%	25,027	734,013	3.4%
Oct	32,664	845,496	3.9%	24,214	679,234	3.6%
Nov	32,012	818,139	3.9%	23,521	655,287	3.6%
Dec	35,919	839,400	4.3%	27,396	755,092	3.6%
Total	361,634	9,975,109	3.6%	289,120	8,908,166	3.2%

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 cost-based offer. Figure 3-57 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. 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.

Figure 3-57 Offers with a positive markup but different economic minimum MW

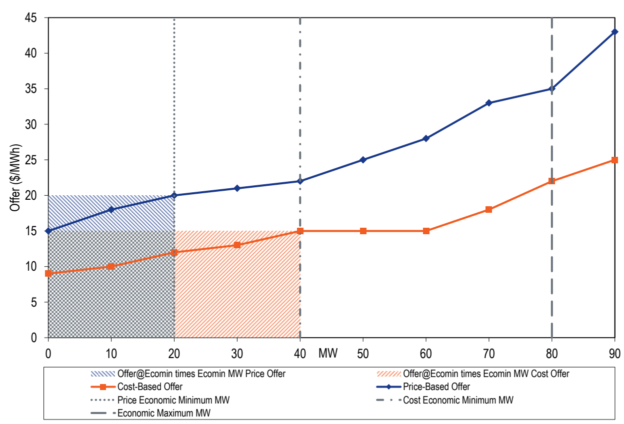


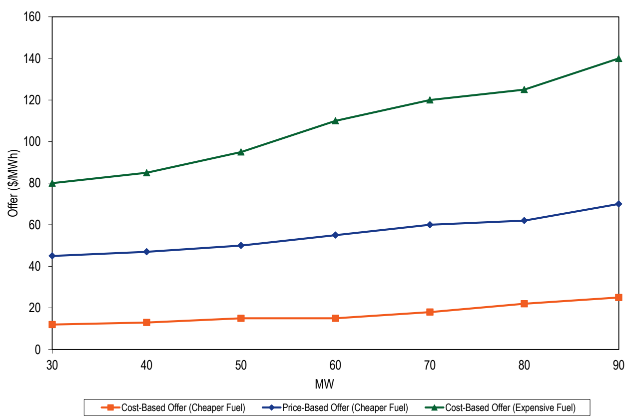
Table 3-93 shows the number and percent of unit schedule hours when units offered lower economic minimum MW in price-based offers than in cost-based offers while having a positive markup in the price-based offer.

Table 3-93 Units offered with lower economic minimum MW on price compared to cost but with positive markup in the day-ahead and real-time energy markets: 2020

	Day-Ahead			Real-Time		
2020	Number of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Number of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost
Jan	168	837,768	0.0%	144	778,951	0.0%
Feb	216	794,904	0.0%	48	733,533	0.0%
Mar	96	854,242	0.0%	96	752,204	0.0%
Apr	72	824,640	0.0%	72	721,582	0.0%
May	168	846,408	0.0%	168	739,992	0.0%
Jun	168	816,144	0.0%	168	765,834	0.0%
Jul	142	843,408	0.0%	134	798,708	0.0%
Aug	216	842,616	0.0%	223	793,736	0.0%
Sep	168	811,944	0.0%	286	734,013	0.0%
Oct	120	845,496	0.0%	279	679,234	0.0%
Nov	265	818,139	0.0%	280	655,287	0.0%
Dec	907	839,400	0.1%	816	755,092	0.1%
Total	2,706	9,975,109	0.0%	2,714	8,908,166	0.0%

In 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 lower cost even when it includes a markup. Figure 3-58 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.

Figure 3-58 Dual fuel unit offers



These issues can be solved by simple rule changes.[127] The MMU recommends that markup of price-based offers over cost-based offers be constant across the offer curve, that there be at least one cost-based offer using the same fuel as the available price-based offer, and that operating parameters on parameter limited schedules (PLS) be at least as flexible as price-based non-PLS offers.

Levels of offer capping have historically been low in PJM, as shown in Table 3-95. 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

127 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.

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.[128] 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.

The offer capping percentages shown in Table 3-94 include units that are committed to provide constraint relief whose owners failed the TPS test in the energy market excluding units that were committed for reliability reasons, providing black start and 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.[129] 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. This is reflected in the slightly higher rate of offer capping in the real-time energy market in since 2017.

Table 3-94 Offer capping statistics – energy only: 2016 to 2020

	Real-Time		Day-Ahead	
Year	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2016	0.4%	0.2%	0.0%	0.0%
2017	0.3%	0.2%	0.0%	0.0%
2018	0.9%	0.5%	0.1%	0.1%
2019	1.7%	1.3%	1.3%	0.9%
2020	1.0%	1.1%	1.6%	1.3%

Table 3-95 shows the offer capping percentages including units committed to provide constraint relief and units committed for reliability reasons, including reactive support. PJM created closed loop interfaces to, in some cases, model reactive constraints. The result was higher LMPs in the closed loop interfaces, which increased economic dispatch, which contributed to the reduction in units offer capped for reactive support. In instances where units are now committed for the modeled closed loop interface constraints, they are considered offer capped for providing constraint relief. They are included in the offer capping percentages in Table 3-94. 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 3-96.

Table 3-95 Offer capping statistics for energy and reliability: 2016 to 2020

	Real-Time		Day-Ahead	
Year	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2016	0.4%	0.3%	0.1%	0.1%
2017	0.4%	0.4%	0.1%	0.2%
2018	1.0%	0.8%	0.2%	0.3%
2019	1.7%	1.3%	1.3%	0.9%
2020	1.0%	1.1%	1.6%	1.3%

Table 3-96 shows the offer capping percentages for units committed for reliability reasons, including units committed for reactive support. The low offer cap 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 as if they had market power. These units are not capped to their cost-based offers because they tend to offer with a negative markup in their price-based offers, particularly at the economic minimum level, which means that PJM's rule results in the use of the price-based offer for commitment. However, the price-based offers have inflexible parameters such as longer minimum run times that may lead to higher total commitment cost if the unit was only needed for a shorter period that is less than its inflexible minimum run time.

Table 3-96 Offer capping statistics for reliability: 2016 to 2020

	Real-Time		Day-Ahead	
Year	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2016	0.1%	0.1%	0.1%	0.1%
2017	0.1%	0.2%	0.1%	0.2%
2018	0.1%	0.3%	0.1%	0.2%
2019	0.0%	0.0%	0.0%	0.0%
2020	0.0%	0.0%	0.0%	0.0%

128 See OATT Attachment K Appendix § 6.4.1.

129 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.

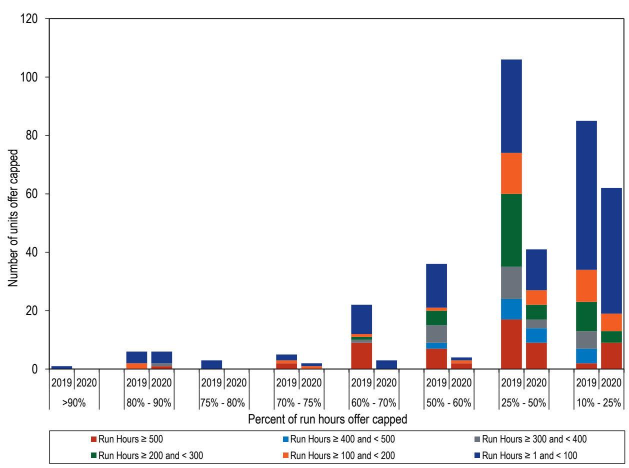
Table 3-97 presents data on the frequency with which units were offer capped in 2019 and 2020 as a result of failing the TPS test to provide energy for constraint relief in the real-time energy market and for reliability reasons. Table 3-97 shows that no units were offer capped for 90 percent or more of their run hours in 2020 compared to one unit in 2019.

Table 3-97 Real-time offer capped unit statistics: 2019 and 2020

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Year	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
	2019	0	0	0	0	0	1
90%	2020	0	0	0	0	0	0
	2019	0	0	0	0	2	4
80% and < 90%	2020	1	0	1	0	0	4
	2019	0	0	0	0	0	3
75% and < 80%	2020	0	0	0	0	0	0
	2019	2	0	0	0	1	2
70% and < 75%	2020	0	0	0	0	1	1
	2019	9	0	1	1	1	10
60% and < 70%	2020	0	0	0	0	0	3
	2019	7	2	6	5	1	15
50% and < 60%	2020	2	0	0	0	1	1
	2019	17	7	11	25	14	32
25% and < 50%	2020	9	5	3	5	5	14
	2019	2	5	6	10	11	51
10% and < 25%	2020	9	0	0	4	6	43

Figure 3-59 shows the frequency with which units were offer capped in 2019 and 2020 for failing the TPS test to provide energy for constraint relief in the real-time energy market and for reliability reasons.

Figure 3-59 Real-time offer capped unit statistics: 2019 and 2020



Markup Index

Markup is a summary measure of participant offer behavior or conduct for individual units. When a seller responds competitively to a market price, markup is zero. When a seller exercises market power in its pricing, 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.[130] 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 3-98 shows the average markup index of marginal units in the real-time energy market, by offer price category using unadjusted cost-based offers. Table 3-99 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. 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.[131] The markup is negative if the cost-based offer of the marginal unit exceeds 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

130 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.

131 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.

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 have also begun to exclude the 10 percent adder. The introduction of hourly offers and intraday offer updates in November 2017 allows gas and oil generators to directly incorporate the impact of ambient temperature changes in fuel consumption in offers.

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.[132]

In 2020, 98.2 percent of marginal units had offer prices less than $50 per MWh. The average dollar markups of units with offer prices less than $10 was negative (-$1.26 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $10 and $15 was positive ($0.15 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 2020, less than one percent had offer prices above $400 per MWh. Among the units that were marginal in 2019, less than one percent had offer prices greater than $400 per MWh. Using the unadjusted cost-based offers, the highest markup for any marginal unit in 2020 was more than $450, and the highest markup in 2019 was more than $450.

Table 3-98 Average, real-time marginal unit markup index (By offer price category unadjusted): 2019 and 2020

	2019			2020		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	0.04	($1.69)	5.9%	(0.06)	($1.26)	15.0%
$10 to $15	0.02	$0.11	14.8%	0.03	$0.15	36.4%
$15 to $20	0.07	$0.94	31.7%	(0.01)	($0.46)	30.1%
$20 to $25	0.01	($0.04)	28.9%	0.02	($0.14)	11.7%
$25 to $50	0.07	$1.77	16.7%	0.09	$2.51	5.1%
$50 to $75	0.35	$19.10	0.9%	0.52	$30.46	0.4%
$75 to $100	0.55	$47.85	0.3%	0.53	$45.89	0.1%
$100 to $125	0.34	$37.04	0.2%	0.11	$12.95	0.5%
$125 to $150	0.45	$61.45	0.0%	0.02	$2.21	0.4%
$150 to $400	0.08	$15.35	0.4%	0.15	$25.29	0.3%
>= $400	0.02	$8.26	0.1%	0.96	>$400.00	0.0%

Table 3-99 Average, real-time marginal unit markup index (By offer price category adjusted): 2019 and 2020

	2019			2020		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	0.08	($1.37)	5.9%	0.00	($0.65)	15.0%
$10 to $15	0.10	$1.33	14.8%	0.11	$1.30	36.4%
$15 to $20	0.15	$2.46	31.7%	0.08	$1.15	30.1%
$20 to $25	0.10	$1.98	28.9%	0.10	$1.87	11.7%
$25 to $50	0.15	$4.32	16.7%	0.17	$5.02	5.1%
$50 to $75	0.40	$22.62	0.9%	0.56	$32.99	0.4%
$75 to $100	0.60	$51.21	0.3%	0.58	$49.64	0.1%
$100 to $125	0.41	$43.48	0.2%	0.20	$22.09	0.5%
$125 to $150	0.50	$68.18	0.0%	0.11	$14.37	0.4%
$150 to $400	0.17	$31.28	0.4%	0.23	$37.58	0.3%
>= $400	0.11	$47.71	0.1%	0.96	>$400.00	0.0%

132 See PJM. "Manual 15: Cost Development Guidelines," Rev. 37 (Dec. 9, 2020).

Table 3-100 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.[133] Table 3-101 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. In 2020, using unadjusted cost-based offers for coal units, 58.4 percent of marginal coal units had negative markups. In 2020, using adjusted cost-based offers for coal units, 34.8 percent of marginal coal units had negative markups.

Table 3-100 Percent of marginal units with markup below, above and equal to zero (By fuel type with unadjusted offers): 2019 and 2020

	2019			2020		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	50.88%	26.41%	22.70%	58.40%	21.72%	19.88%
Gas	31.13%	12.52%	56.35%	38.51%	6.07%	55.42%
Oil	21.12%	77.66%	1.22%	3.99%	95.55%	0.46%

Table 3-101 Percent of marginal units with markup below, above and equal to zero (By fuel type with adjusted offers): 2019 and 2020

	2019			2020		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	35.09%	21.73%	43.17%	34.75%	17.85%	47.40%
Gas	12.76%	7.09%	80.15%	24.66%	4.48%	70.86%
Oil	0.32%	77.09%	22.58%	2.13%	73.80%	24.07%

Figure 3-60 shows the frequency distribution of hourly markups for all gas units offered in 2019 and 2020 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.[134] Of the gas units offered in the PJM market in 2020, 21.8 percent of gas unit-hours had a maximum markup that was negative. More than 10.3 percent of gas fired unit-hours had a maximum markup above $100 per MWh. The number of gas units with markups from $200 to $1,000 per MWh decreased due to increases in the maintenance costs allowable in cost-based offers, not a decrease in the offer level and not a decrease in the markups.

Figure 3-60 Frequency distribution of highest markup of gas units offered using unadjusted cost offers: 2019 and 2020

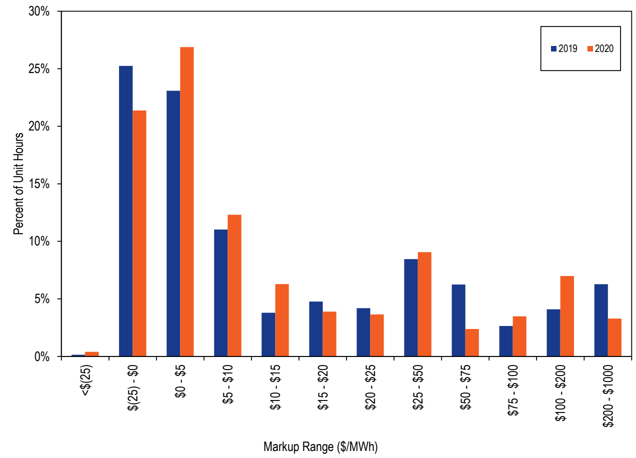


Figure 3-61 shows the frequency distribution of hourly markups for all coal units offered in 2019 and 2020 using unadjusted cost-based offers. Of the coal units offered in the PJM market in 2020, 47.7 percent of coal unit-hours had a maximum markup that was negative or equal to zero, increasing from 44.3 in 2019.

Figure 3-61 Frequency distribution of highest markup of coal units offered using unadjusted cost offers: 2019 and 2020

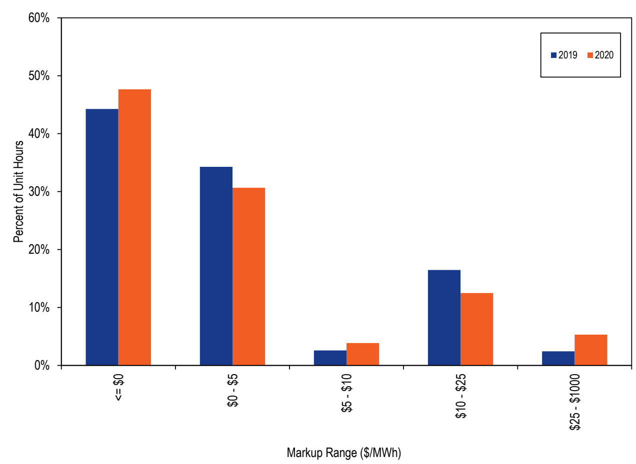
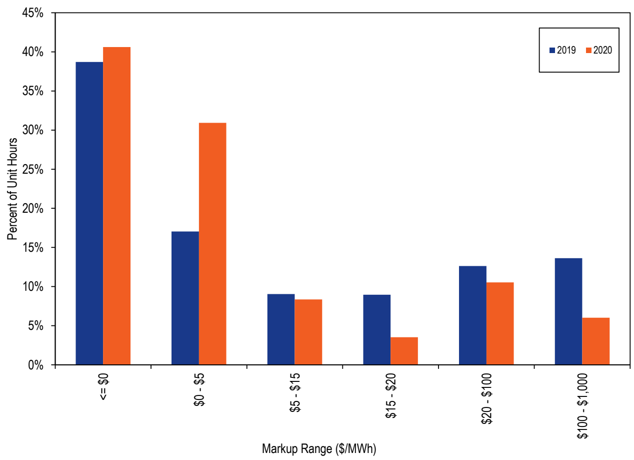


Figure 3-62 shows the frequency distribution of hourly markups for all offered oil units in 2019 and 2020 using unadjusted cost-based offers. Of the oil units offered in the PJM market in 2020, 40.6 percent of oil unit-hours had a maximum markup that was negative or equal to zero. More than 6.0 percent of oil fired unit-hours had

133 Other fuel types were excluded based on data confidentiality rules.
134 The categories in the frequency distribution were chosen so as to maintain data confidentiality.

a maximum markup above $100 per MWh. The number of oil units with markups from $100 to $1,000 per MWh decreased due to increases in the maintenance costs allowable in cost-based offers, not a decrease in the offer level and not a decrease in the markups.

Figure 3-62 Frequency distribution of highest markup of oil units offered using unadjusted cost offers: 2019 and 2020

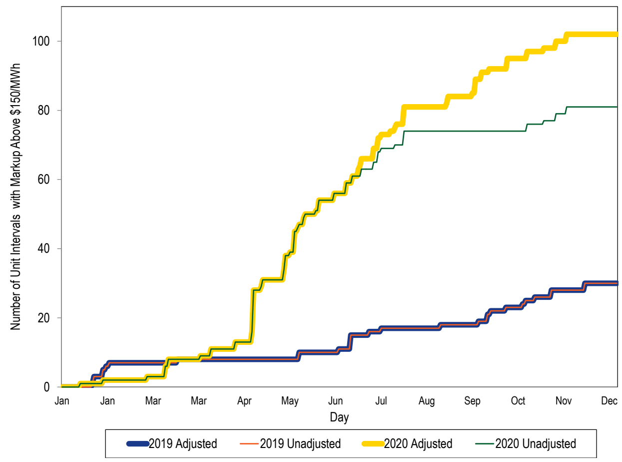


The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion 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.

Figure 3-63 shows the number of marginal unit intervals in 2020 and 2019 with markup above $150 per MWh. For several of the marginal unit intervals with markups above $150 per MWh, the units failed the TPS test for the hour. These exercise of market power are a result of PJM's failure to address the issues with the offer capping process identified by the MMU. If PJM adopted the MMU's recommendations, these exercises of market power would not occur.

Figure 3-63 Cumulative number of unit intervals with markups above $150 per MWh: 2019 and 2020



Day-Ahead Markup Index

Table 3-102 shows the average markup index of marginal generating units in the day-ahead energy market, by offer price category using unadjusted cost-based offers. The majority of marginal units are virtual transactions, which do not have markup. In 2020, 92.9 percent of marginal generating units had offer prices less than $25 per MWh. The average dollar markups of units with offer prices less than $10 was negative (-$1.88 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $10 and $15 was positive ($0.75 per MWh) when using unadjusted cost-based offers.

Some marginal units did have substantial markups. Among the units that were marginal in the day-ahead market in 2019 and 2020, none had offer prices above $400 per MWh. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the day-ahead market in 2020 was more than $70 per MWh while the highest markup in 2019 was more than $90 per MWh.

Table 3-102 Average day-ahead marginal unit markup index (By offer price category, unadjusted): 2019 and 2020

	2019			2020		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	0.25	$0.15	2.9%	(0.05)	($1.88)	10.2%
$10 to $15	0.04	$0.38	9.2%	0.08	$0.75	30.5%
$15 to $20	0.13	$1.90	32.0%	0.08	$0.95	37.4%
$20 to $25	0.02	$0.09	32.8%	0.02	($0.04)	14.7%
$25 to $50	0.07	$1.83	21.8%	0.04	$0.98	6.3%
$50 to $75	0.19	$10.50	0.7%	0.18	$10.55	0.2%
$75 to $100	0.47	$41.28	0.1%	0.30	$24.65	0.0%
$100 to $125	0.52	$53.65	0.0%	(0.01)	($0.78)	0.1%
$125 to $150	0.32	$45.31	0.1%	0.00	$0.33	0.2%
>= $150	0.04	$5.94	0.5%	0.00	$0.69	0.3%

Table 3-103 shows the average markup index of marginal generating units in the day-ahead energy market, by offer price category using adjusted cost-based offers. In 2020, 37.4 percent of marginal generating units had offers between $15 and $20 per MWh, and the average dollar markup and the average markup index were both positive. The average markup index decreased from 0.30 in 2019, to 0.01 in 2020 in the offer price category less than $10.

Table 3-103 Average day-ahead marginal unit markup index (By offer price category, adjusted): 2019 and 2020

	2019			2020		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	0.30	$0.44	2.9%	0.01	($1.37)	10.2%
$10 to $15	0.12	$1.54	9.2%	0.15	$1.85	30.5%
$15 to $20	0.20	$3.33	32.0%	0.15	$2.43	37.4%
$20 to $25	0.10	$2.10	32.8%	0.10	$1.96	14.7%
$25 to $50	0.15	$4.36	21.8%	0.12	$3.64	6.3%
$50 to $75	0.26	$14.66	0.7%	0.25	$14.98	0.2%
$75 to $100	0.51	$45.55	0.1%	0.30	$25.30	0.0%
$100 to $125	0.56	$58.19	0.0%	0.01	$0.64	0.1%
$125 to $150	0.38	$53.81	0.1%	0.02	$2.61	0.2%
>= $150	0.12	$28.39	0.5%	0.08	$12.98	0.3%

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. Table 3-104 shows the caps on the three parts of cost-based and price-based offers.

Table 3-104 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 3-105 shows the number of units that chose the cost-based option and the price-based option. In 2020, 91 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, seven percentage points higher than in 2019.

Table 3-105 Number of units selecting cost-based and price-based no load and start costs: 2019 and 2020

	2019		2020	
No Load and Start Cost Option	Number of units	Percent	Number of units	Percent
Cost-Based	498	84%	534	91%
Price-Based	94	16%	51	9%
Total	592	100%	585	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 3-106 shows the average markup in the no load and start costs in 2019 and 2020. Generators that selected the cost-based start and no load option offered on average with a negative markup on the no load cost (nine percent) and a negative markup on the start costs (six percent). The price-based offers were actually lower than the cost-based offers. Generators that selected the price-based start and no load option offered on average with a negative markup on the no load cost (two percent) but with very large positive markups on the start costs (683 percent).

Table 3-106 No load and start cost markup

Period	No Load and Start Cost Option	No Load Cost	Cold Start Cost	Intermediate Start Cost	Hot Start Cost
2019	Cost-Based	(9%)	(8%)	(7%)	(6%)
	Price-Based	(21%)	311%	358%	367%
2020	Cost-Based	(9%)	(6%)	(6%)	(6%)
	Price-Based	(2%)	568%	710%	772%

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 2020, 7.1 percent of the marginal units set prices based on cost-based offers, 3.2 percentage points less than in 2019.

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. 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. FERC's decision to permit maintenance costs in cost-based offers that are not short run marginal costs also results in overstated 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, in addition, allows for multiple interpretations, which could lead to tariff violations. The incorrect rules will lead to higher energy market prices and higher uplift.

There are three types of costs identified under 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."[135]

Variable costs 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, emission allowance costs, operating costs, and energy market opportunity costs.[136]

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 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.

135 See 167 FERC ¶ 61,030 (2019).
136 See OA Schedule 2(a).

Fuel Cost Policy Review

Table 3-107 shows the status of all fuel cost policies (FCP) as of December 31, 2020. As of December 31, 2020, 773 units (86 percent) had an FCP passed by the MMU, zero units had an FCP under MMU review (submitted) and 121 units (14 percent) had an FCP failed by the MMU. The units with fuel cost policies failed by the MMU represented 23,386 MW. All units' FCPs were approved by PJM. The number of units with fuel cost policies passed by the MMU decreased by 433 in 2020 because solar and other units with zero short run marginal costs were not required to have fuel cost policies effective September 1, 2020.

Table 3-107 FCP Status for PJM generating units: December 31, 2020

	MMU Status			
PJM Status	Pass	Submitted	Fail	Total
Submitted	0	0	0	0
Under Review	0	0	0	0
Customer Input Required	0	0	0	0
Approved	773	0	121	894
Total	773	0	121	894

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.[137] 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.[138] PJM and FERC did not agree that fuel cost policies should be algorithmic, although PJM's effectively requires algorithmic fuel cost policies by describing the requirements.[139] Algorithmic means that the FCP must use a set of defined, logical steps, analogous to a recipe, to calculate the fuel costs.

137 Answer of PJM Interconnection, L.L.C. to Protests and Comments, Docket No. ER16-372-002 (October 7, 2016) ("October 7th Filing") at P 11.
138 Protest of the Independent Market Monitor for PJM, Docket No. ER16-372-002 (September 16, 2016) ("September 16th Filing") at P 8.
139 October 7th Filing at P12; 158 FERC ¶ 61,133 at P 57 (2017).

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').[140]

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:[141] accuracy (reflect applicable costs accurately); procurement practices (provide information sufficient for the verification of the market seller's fuel procurement practices where relevant); fuel contracts (reflect the market seller's applicable commodity and/or transportation contracts where it holds such contracts).

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 unverifiable fuel costs and the use of available market information that results in inaccurate expected costs.

Some of the failed fuel cost polices include unverifiable cost estimates. Some policies include options under which the estimate of the natural gas commodity cost can be calculated by the market seller without specifying a verifiable, systematic method. For example, some FCPs specify that the source of the natural gas cost would be communications with traders within the market seller's organization. A fuel cost from discretionary and undocumented decision making within the market seller's organization is not verifiable. The point of FCPs is to eliminate such practices as the basis for fuel costs, as most companies have done. Verifiability requires that fuel cost estimates be transparently derived from market information and that PJM or the MMU could reproduce the same fuel cost estimates after the fact by applying the methods documented in the FCP to the same inputs. Verifiable is a key requirement of an FCP. If it is not verifiable, an FCP is meaningless and has no value. Unverifiable fuel costs permit the exercise of market power.

Some of the failed fuel cost polices 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 generally 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.

Cost-Based Offer Penalties

In addition to implementing the fuel cost policy approval process, the February 3, 2017, FERC order created a process for penalizing generators identified by PJM or the MMU with cost-based offers that do not comply with Schedule 2 of the PJM Operating Agreement and PJM Manual 15.[142] Penalties became effective May 15, 2017.

In 2020, 142 penalty cases were identified, 124 resulted in assessed cost-based offer penalties, five resulted in disagreement between the MMU and PJM, and 13 remain pending PJM's determination. These cases were from 124 units owned by 25 different companies. Table 3-109 shows the penalties by the year in which participants were notified.

140 September 16th Filing at P 8.
141 See PJM Operating Agreement Schedule 2 § 2.3 (a).
142 158 FERC ¶ 61,133 (2017).

Table 3-108 Cost-based offer penalty cases by year notified: May 2017 through December 2020

Year notified	Cases	Assessed penalties	MMU and PJM Disagreement	Pending cases	Number of units impacted	Number of companies impacted
2017	57	56	1	0	55	16
2018	187	161	26	0	138	35
2019	57	57	0	0	57	19
2020	142	124	5	13	124	25
Total	443	398	32	13	316	55

Since 2017, 443 penalty cases have been identified, 398 resulted in assessed cost-based offer penalties, 32 resulted in disagreement between the MMU and PJM, and 13 remain pending PJM's determination. The 398 cases were from 316 units owned by 55 different companies. The total penalties were $2.7 million, charged to units that totaled 82,180 available MW. The average penalty was $1.50 per available MW. This means that a 100 MW unit would have paid a penalty of $3,589.[143] Table 3-109 shows the total cost-based offer penalties since 2017 by year.

Table 3-109 Cost-based offer penalties by year: May 2017 through December 2020

Year	Number of units	Number of companies	Penalties	Average Available Capacity Charged (MW)	Average Penalty ($/MW)
2017	92	20	$556,826	16,930	$1.56
2018	127	34	$1,265,698	26,343	$2.27
2019	79	20	$490,926	19,798	$1.10
2020	118	24	$364,600	19,109	$0.85
Total	416	58	$2,678,050	82,180	$1.50

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.

2020 Fuel Cost Policy Changes

On July 28, 2020, the Commission approved tariff revisions that modified the fuel cost policy process and the cost-based offer penalties.[144]

The tariff revisions replaced the annual review process with a periodic review set by PJM. The revisions reinstated the periodic review process employed by the MMU prior to PJM's involvement in the review and approval of fuel cost policies. Monitoring participant behavior through the use of fuel cost policies is an ongoing process that necessitates frequent updates. Market sellers must revise their fuel cost policies whenever circumstances change that impact fuel pricing (e.g. different pricing points, dual fuel addition capability).

The tariff revisions removed the requirement for units with zero marginal cost to have an approved fuel cost policy but also included a zero offer cap for cost-based offers for units that do not have an approved fuel cost policy.

The tariff revisions allow a temporary cost offer method for units that do not have an approved fuel cost policy. The revisions allow 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. The proposed approach allows 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.

The tariff revisions replace the fuel cost policy revocation provision with the ability for PJM to terminate fuel cost policies.

The tariff revisions reduce the penalties for noncompliant cost-based offers in two situations. When market sellers report their noncompliant cost-based offers, the penalty is reduced by 75 percent. When market sellers do not meet conditions defined to measure a potential market impact the penalty is reduced by 90 percent. The conditions include if the market seller failed the TPS test, if the unit was committed on its cost-based offer, if the unit was marginal or if the unit was paid uplift.

The tariff revisions eliminate penalties entirely when units submit noncompliant cost-based offers if PJM determines that an unforeseen event hindered the market seller's ability to submit a compliant cost-based

143 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.
144 172 FERC ¶ 61,094.

offer. This new provision 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.

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.

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 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.

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.[145] 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 order, subject to revisions requested by FERC.[146] On October 28, 2019, FERC issued a final order accepting PJM's compliance filing.[147] 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 2020.

The average variable operating and maintenance cost approved by PJM for combustion turbines and diesels for 2020 was 16 percent lower than the approved variable operating and maintenance cost approved by PJM in 2019.[148]

The average variable operating and maintenance cost approved by PJM for combined cycles for 2020 was seven percent higher than the approved variable operating and maintenance cost approved by PJM in 2019.

The average variable operating and maintenance cost approved by PJM for coal units for 2020 was 8 percent lower than the approved variable operating and maintenance cost approved by PJM in 2019.

Table 3-110 shows the amount of capacity offered within several ranges of VOM costs. Table 3-110 shows that 1,000 MW have an approved effective VOM above $100 per MWh and 3,146 MW have an approved effective VOM between $50 and $100 per MWh.

145 See PJM Interconnection Maintenance Adder Revisions to the Amended and Restated Operating Agreement, L.L.C., Docket No. EL19-8-000.
146 167 FERC ¶ 61,030.
147 168 FERC ¶ 61,134.
148 PJM reviews VOM once per year. The results reflect PJM's most recent review.

Table 3-110 2020 Approved effective VOM costs

Approved VOM Range ($/MWh)	Offered MW
$0 to $5 per MWh	71,068
$5 to $10 per MWh	30,635
$10 to $20 per MWh	16,035
$20 to $50 per MWh	4,938
$50 to $100 per MWh	3,146
Above $100 per MWh	1,000

High VOM levels allow generators to economically withhold energy and to exercise market power even when offers are set to cost to mitigate market power. The MMU recommendation to limit cost-based offers to short run marginal costs would prevent such withholding. When units are not committed due to high VOM costs and instead a unit with higher short run marginal costs is committed, the market outcome is inefficient. When units that fail the TPS test are committed on their price-based offer when their short run marginal cost is lower, the market outcome is inefficient.

MMU analysis shows that as CTs, CCs and coal units run for more hours, the VOM cost approved by PJM decreases. This is an indication that fixed costs are included in VOM costs. Fuel costs per MWh remain constant or increase as run hours and the heat rate increase. Fixed costs should not be includable in cost-based energy offers.

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 and PJM's review is dependent on the level of detail provided by the market seller. Recent changes in PJM's review process, triggered by MMU questions, required more details from market sellers and have led to the appropriate exclusion of expenses that were previously included.[149]

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.

The MMU recommends 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 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 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 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

149 See "Maintenance Adder & Operating Cost Submission Process," 55-57 PJM presentation to the 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>.

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.[150]

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.

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 recommends 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.

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.

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

150 The peak adder is equal to $300 times three divided by 5 MW.

August 2019.[151] 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.

Table 3-111 shows, by month, the number of FMUs and AUs in 2019 and 2020. For example, in September 2020, there was one FMU and AU in Tier 1, zero FMUs and AUs in Tier 2, and two FMUs and AUs in Tier 3.

Table 3-111 Number of frequently mitigated units and associated units (By month): 2019 and 2020

	2019				2020			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	0	0	0	0	0	0	0	0
February	0	0	0	0	0	0	0	0
March	0	0	0	0	0	0	0	0
April	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0
June	0	0	0	0	2	0	0	2
July	0	0	0	0	2	0	0	2
August	0	0	0	0	1	0	0	1
September	0	1	0	1	1	0	2	3
October	1	0	0	1	2	0	2	4
November	0	0	0	0	2	1	2	5
December	0	0	0	0	2	1	2	5

Effective in the 2020/2021 planning year, default Avoidable Cost Rates will no longer be defined. If a generating unit's Projected PJM Market Revenues plus the unit's PJM capacity market revenues on a rolling 12-month basis (in $/MW-year) are greater than zero, and if the generating unit does not have an approved unit specific Avoidable Cost Rate, the generating unit will not qualify as an FMU as the Avoidable Cost Rate will be assumed to be zero for FMU qualification purposes.

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 3-112 shows the contribution to real-time, load-weighted LMP by individual marginal resource owners.[152] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of 2020, and summed by the parent company that offers the marginal resource into the real-time energy market. In 2020, the offers of one company resulted in 16.4 percent of the real-time, load-weighted PJM system LMP and the offers of the top four companies resulted in 44.4 percent of the real-time, load-weighted, average PJM system LMP. In 2020, the offers of one company resulted in 16.2 percent of the peak hour real-time, load-weighted PJM system LMP.

151 For a definition of FMUs and AUs, and for historical FMU/AU results, see the *2018 State of the Market Report for PJM*, Volume 2, Section 3, Energy Market, at Frequently Mitigated Units (FMU) and Associated Units (AU).

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

Table 3-112 Marginal unit contribution to real-time, load-weighted LMP (By parent company): 2019 and 2020

2019						2020					
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	12.8%	12.8%	1	13.7%	13.7%	1	16.4%	16.4%	1	16.2%	16.2%
2	10.0%	22.8%	2	10.4%	24.1%	2	11.0%	27.4%	2	13.0%	29.2%
3	9.3%	32.1%	3	8.8%	32.9%	3	10.7%	38.1%	3	9.9%	39.1%
4	9.3%	41.5%	4	7.2%	40.1%	4	6.3%	44.4%	4	6.1%	45.2%
5	4.8%	46.3%	5	5.1%	45.2%	5	6.2%	50.6%	5	5.6%	50.8%
6	4.5%	50.8%	6	4.1%	49.3%	6	5.1%	55.8%	6	5.3%	56.1%
7	4.4%	55.3%	7	4.1%	53.4%	7	4.7%	60.5%	7	5.0%	61.1%
8	3.6%	58.9%	8	3.9%	57.2%	8	4.2%	64.6%	8	3.1%	64.2%
9	3.6%	62.5%	9	3.9%	61.1%	9	2.9%	67.6%	9	3.0%	67.2%
Other (74 companies)	37.5%	100.0%	Other (70 companies)	38.9%	100.0%	Other (75 companies)	32.4%	100.0%	Other (71 companies)	32.8%	100.0%

Figure 3-64 shows the marginal unit contribution to the real-time, load-weighted PJM system LMP summed by parent companies since 2011.

Figure 3-64 Marginal unit contribution to real-time, load-weighted LMP (By parent company): 2011 through 2020

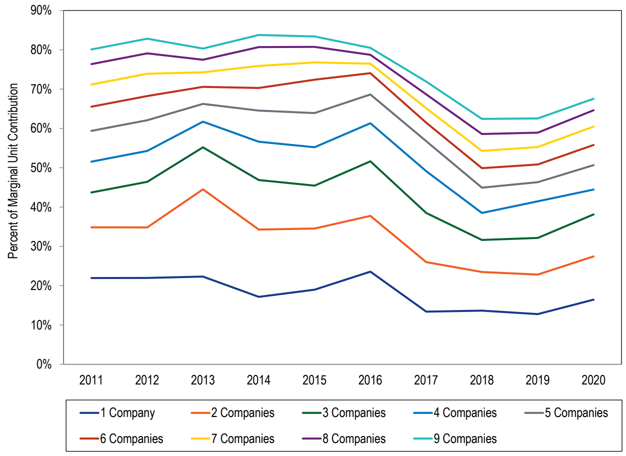


Table 3-113 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.[153] The contribution of each marginal resource to price at each load bus is calculated hourly, and summed by the parent company that offers the marginal resource into the day-ahead energy market. The results show that in 2020, the offers of one company contributed 10.5 percent of the day-ahead, load-weighted, PJM system LMP and that the offers of the top four companies contributed 31.3 percent of the day-ahead, load-weighted, average, PJM system LMP.

Table 3-113 Marginal resource contribution to day-ahead, load-weighted LMP (By parent company): 2019 and 2020

2019						2020					
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	10.0%	10.0%	1	11.9%	11.9%	1	10.5%	10.5%	1	10.9%	10.9%
2	7.8%	17.7%	2	6.6%	6.6%	2	10.4%	20.9%	2	9.5%	20.4%
3	5.9%	23.6%	3	5.7%	5.7%	3	5.7%	26.6%	3	8.8%	29.2%
4	5.8%	29.4%	4	5.4%	5.4%	4	4.8%	31.3%	4	5.3%	34.5%
5	5.6%	35.0%	5	4.8%	4.8%	5	4.5%	35.8%	5	5.0%	39.5%
6	4.4%	39.5%	6	4.3%	4.3%	6	4.3%	40.2%	6	4.4%	43.9%
7	4.1%	43.5%	7	3.8%	3.8%	7	3.9%	44.0%	7	4.1%	48.0%
8	3.5%	47.0%	8	3.3%	3.3%	8	3.7%	47.8%	8	3.3%	51.3%
9	3.0%	50.0%	9	3.0%	3.0%	9	3.7%	51.5%	9	3.0%	54.2%
Other (149 companies)	50.0%	100.0%	Other (137 companies)	51.1%	51.1%	Other (147 companies)	48.5%	100.0%	Other (144 companies)	45.8%	100.0%

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.[154] 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

153 Id.

154 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. The markup analysis does not include markup in start up or no load offers. *See* Calculation and Use of Generator Sensitivity/Unit Participation Factors, 2010 State of the Market Report for PJM: Technical Reference for PJM Markets.

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.

Real-Time Markup

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

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

Table 3-114 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 decreased from \$3.63 per MWh in 2019 to \$2.19 per MWh in 2020. The adjusted markup contribution of coal units in 2020 was \$0.24 per MWh. The adjusted markup component of gas fired units in 2020 was \$1.98 per MWh, a decrease of \$0.91 per MWh from 2019. The markup component of wind units was less than \$0.0 per MWh. If a price-based offer is negative, but less negative than a cost-based offer, the markup is positive. In 2020, among the wind units that were marginal, 92.8 percent had negative offer prices.

Table 3-114 Markup component of real-time, load-weighted, average LMP by primary fuel type and unit type: 2019 and 2020[155]

		2019		2020	
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	(\$0.08)	\$0.77	(\$0.40)	\$0.24
Gas	CC	\$1.64	\$2.62	\$0.78	\$1.61
Gas	CT	\$0.17	\$0.35	\$0.24	\$0.39
Gas	RICE	\$0.02	\$0.02	\$0.02	\$0.03
Gas	Steam	(\$0.17)	(\$0.11)	(\$0.10)	(\$0.06)
Landfill Gas	CT	\$0.00	\$0.00	\$0.00	\$0.00
Municipal Waste	RICE	\$0.00	\$0.00	\$0.00	\$0.00
Oil	CC	(\$0.00)	\$0.00	\$0.00	\$0.00
Oil	CT	\$0.00	\$0.00	(\$0.00)	\$0.00
Oil	RICE	\$0.00	\$0.00	\$0.00	\$0.00
Oil	Steam	(\$0.02)	(\$0.02)	(\$0.03)	(\$0.03)
Other	Steam	(\$0.00)	(\$0.00)	(\$0.00)	(\$0.00)
Wind	Wind	(\$0.01)	(\$0.01)	(\$0.00)	(\$0.00)
Total		\$1.55	\$3.63	\$0.50	\$2.19

Markup Component of Real-Time Price

Table 3-115 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on peak and off peak prices. Table 3-116 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on peak and off peak prices. In 2020, when using unadjusted cost-based offers, \$0.50 per MWh of the PJM real-time, load-weighted, average LMP was attributable to markup. Using adjusted cost-based offers, \$2.19 per MWh of the PJM real-time, load-weighted, average LMP was attributable to markup. In 2020, the peak markup component was highest in August, \$2.88 per MWh using unadjusted cost-based offers and peak markup component was highest in August, \$4.83 per MWh using adjusted cost-based offers. This corresponds to 9.7 percent and 16.3 percent of the real-time, peak, load-weighted, average LMP in August.

Table 3-115 Monthly markup components of real-time, load-weighted, LMP (Unadjusted): 2019 through 2020

	2019			2020		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	\$1.89	\$2.43	\$1.33	\$0.49	\$0.94	\$0.03
Feb	\$2.15	\$2.85	\$1.46	(\$0.15)	(\$0.00)	(\$0.28)
Mar	\$2.11	\$2.57	\$1.67	(\$0.09)	\$0.46	(\$0.66)
Apr	\$1.38	\$2.01	\$0.67	(\$0.07)	\$0.17	(\$0.33)
May	\$1.27	\$2.02	\$0.45	\$0.54	\$1.03	\$0.10
Jun	\$1.36	\$1.74	\$0.98	\$1.24	\$2.02	\$0.30
Jul	\$3.25	\$4.40	\$1.99	\$0.83	\$1.75	(\$0.30)
Aug	\$0.86	\$0.78	\$0.95	\$1.80	\$2.88	\$0.70
Sep	\$1.57	\$2.58	\$0.55	\$0.47	\$0.97	(\$0.08)
Oct	\$1.39	\$2.01	\$0.64	\$0.09	\$0.71	(\$0.57)
Nov	\$1.12	\$1.79	\$0.51	(\$0.01)	\$0.72	(\$0.68)
Dec	\$0.19	\$0.29	\$0.08	\$0.37	\$0.37	\$0.37
Total	\$1.58	\$2.16	\$0.97	\$0.50	\$1.08	(\$0.10)

155 The unit type RICE refers to Reciprocating Internal Combustion Engines.

Table 3-116 Monthly markup components of real-time, load-weighted, LMP (Adjusted): 2019 and 2020

	2019			2020		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$4.45	$5.21	$3.65	$2.21	$2.80	$1.60
Feb	$4.33	$5.11	$3.55	$1.57	$1.85	$1.30
Mar	$4.37	$4.93	$3.84	$1.44	$2.07	$0.81
Apr	$3.40	$4.16	$2.53	$1.43	$1.73	$1.11
May	$3.23	$4.15	$2.22	$1.98	$2.65	$1.39
Jun	$3.21	$3.79	$2.64	$2.77	$3.75	$1.58
Jul	$5.38	$6.71	$3.92	$2.70	$3.81	$1.33
Aug	$2.81	$3.03	$2.55	$3.61	$4.83	$2.35
Sep	$3.61	$4.85	$2.36	$1.89	$2.50	$1.22
Oct	$3.17	$4.00	$2.17	$1.76	$2.51	$0.95
Nov	$3.18	$3.95	$2.49	$1.68	$2.53	$0.88
Dec	$2.12	$2.38	$1.88	$2.46	$2.56	$2.37
Total	$3.64	$4.40	$2.86	$2.19	$2.90	$1.44

Hourly Markup Component of Real-Time Prices

Figure 3-65 shows the markup contribution to the hourly load-weighted, LMP using unadjusted cost offers in 2019 and 2020. Figure 3-66 shows the markup contribution to the hourly load-weighted, LMP using adjusted cost-based offers in 2019 and 2020.

Figure 3-65 Markup contribution to real-time, hourly, load-weighted LMP (Unadjusted): 2019 and 2020

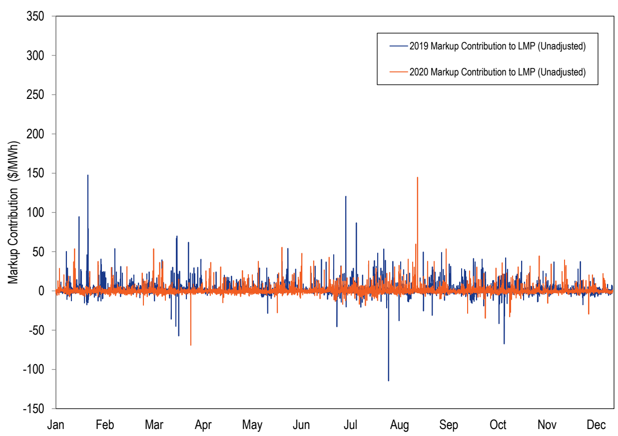
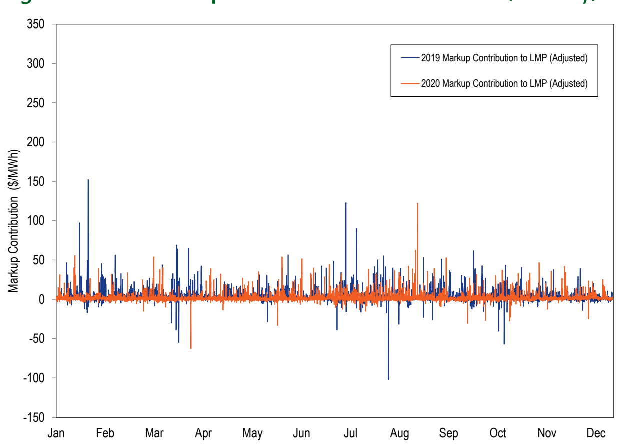


Figure 3-66 Markup contribution to real-time, hourly, load-weighted LMP (Adjusted): 2019 and 2020



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 2019 and 2020 in Table 3-117 and for adjusted offers in Table 3-118.[156] The smallest zonal all hours average markup component using unadjusted offers in 2020, was in the OVEC Control Zone, $0.26 per MWh, while the highest was in the BGE Control Zone, $0.97 per MWh. The smallest zonal on peak average markup component using unadjusted offers in 2020, was in the PPL Control Zone, $0.57 per MWh, while the highest was in the BGE Control Zone, $1.79 per MWh.

Table 3-117 Average, real-time, zonal markup component (Unadjusted): 2019 and 2020

	2019			2020		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	$1.98	$2.45	$1.51	$0.35	$0.77	($0.09)
AEP	$1.56	$2.21	$0.90	$0.51	$1.10	($0.11)
APS	$1.54	$2.15	$0.92	$0.56	$1.20	($0.11)
ATSI	$1.66	$2.28	$1.00	$0.60	$1.24	($0.07)
BGE	$1.62	$2.41	$0.81	$0.97	$1.79	$0.11
ComEd	$0.78	$1.15	$0.38	$0.47	$1.10	($0.22)
DAY	$1.75	$2.51	$0.93	$0.58	$1.18	($0.06)
DEOK	$1.62	$2.33	$0.87	$0.53	$1.11	($0.09)
DLCO	$1.61	$2.20	$0.99	$0.66	$1.36	($0.09)
Dominion	$1.50	$2.12	$0.87	$0.60	$1.27	($0.09)
DPL	$2.06	$2.45	$1.66	$0.33	$0.75	($0.12)
EKPC	$1.50	$2.14	$0.85	$0.49	$1.08	($0.10)
JCPL	$1.90	$2.40	$1.36	$0.31	$0.69	($0.09)
Met-Ed	$1.69	$2.10	$1.26	$0.44	$0.83	$0.02
OVEC	$1.33	$2.01	$0.73	$0.26	$0.82	($0.24)
PECO	$2.00	$2.35	$1.64	$0.32	$0.75	($0.14)
PENELEC	$1.58	$2.08	$1.06	$0.35	$0.81	($0.13)
Pepco	$1.58	$2.29	$0.84	$0.71	$1.37	$0.00
PPL	$1.75	$2.13	$1.36	$0.29	$0.57	($0.00)
PSEG	$1.90	$2.45	$1.32	$0.29	$0.69	($0.14)
RECO	$1.74	$2.19	$1.23	$0.35	$0.77	($0.12)

Table 3-118 Average, real-time, zonal markup component (Adjusted): 2019 and 2020

	2019			2020		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	$3.87	$4.47	$3.26	$1.94	$2.50	$1.37
AEP	$3.67	$4.50	$2.82	$2.21	$2.94	$1.46
APS	$3.66	$4.44	$2.86	$2.26	$3.06	$1.45
ATSI	$3.77	$4.59	$2.91	$2.31	$3.09	$1.48
BGE	$3.92	$4.91	$2.92	$2.84	$3.81	$1.83
ComEd	$2.77	$3.36	$2.14	$2.07	$2.86	$1.23
DAY	$3.94	$4.88	$2.92	$2.37	$3.11	$1.57
DEOK	$3.72	$4.62	$2.80	$2.24	$2.96	$1.48
DLCO	$3.69	$4.47	$2.88	$2.35	$3.22	$1.45
Dominion	$3.69	$4.50	$2.87	$2.34	$3.14	$1.53
DPL	$4.01	$4.54	$3.48	$1.98	$2.55	$1.40
EKPC	$3.62	$4.43	$2.81	$2.20	$2.92	$1.49
JCPL	$3.83	$4.47	$3.14	$1.93	$2.42	$1.40
Met-Ed	$3.66	$4.25	$3.05	$2.07	$2.59	$1.51
OVEC	$3.36	$4.21	$2.60	$1.91	$2.62	$1.29
PECO	$3.88	$4.37	$3.37	$1.89	$2.43	$1.31
PENELEC	$3.58	$4.23	$2.89	$1.98	$2.57	$1.35
Pepco	$3.83	$4.72	$2.89	$2.49	$3.29	$1.65
PPL	$3.66	$4.21	$3.09	$1.86	$2.25	$1.44
PSEG	$3.81	$4.50	$3.09	$1.89	$2.42	$1.33
RECO	$3.63	$4.22	$2.97	$1.98	$2.53	$1.36

156 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.

Markup by Real-Time Price Levels

Table 3-119 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 3-119 Real-time markup contribution (By load-weighted, LMP category, unadjusted): 2019 and 2020

	2019		2020	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $10	($2.04)	0.3%	($1.05)	2.5%
$10 to $15	($0.29)	5.6%	($0.73)	21.7%
$15 to $20	($0.04)	23.3%	($0.80)	39.2%
$20 to $25	($0.16)	35.1%	$0.01	20.3%
$25 to $50	$2.55	32.3%	$3.69	13.6%
$50 to $75	$14.28	2.3%	$10.38	1.9%
$75 to $100	$22.27	0.5%	$13.70	0.6%
$100 to $125	$22.04	0.2%	$7.78	0.1%
$125 to $150	$22.89	0.1%	$2.42	0.0%
>= $150	$21.27	0.3%	$15.45	0.0%

Table 3-120 Real-time markup contribution (By load-weighted, LMP category, adjusted): 2019 and 2020

	2019		2020	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $10	($1.11)	0.3%	($0.17)	2.5%
$10 to $15	$1.00	5.6%	$0.53	21.7%
$15 to $20	$1.60	23.3%	$0.84	39.1%
$20 to $25	$1.86	35.1%	$1.91	20.4%
$25 to $50	$4.94	32.3%	$5.77	13.6%
$50 to $75	$17.05	2.3%	$12.56	1.9%
$75 to $100	$25.74	0.5%	$15.85	0.6%
$100 to $125	$25.91	0.2%	$9.94	0.1%
$125 to $150	$26.13	0.1%	$4.09	0.0%
>= $150	$24.30	0.3%	$17.04	0.0%

Markup by Company

Table 3-121 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 2020, when using unadjusted cost-based offers, the markup of one company accounted for 1.8 percent of the load-weighted, average LMP, the markup of the top five companies accounted for 4.0 percent of the load-weighted, average LMP and the markup of all companies accounted for 2.3 percent of the load-weighted, average LMP. The top five companies' markup contribution to the load-weighted, average LMP and the dollar values of their markup decreased in 2020. The markup contribution to the load-weighted, average LMP and share of the markup contribution to the load-weighted, average LMP also decreased in 2020. The markup contribution of a unit to the real-time, load-weighted, average LMP can be positive or negative.

Table 3-121 Markup component of real-time, load-weighted, average LMP by Company: 2019 and 2020

	2019				2020			
	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	$0.27	1.0%	$0.55	2.0%	$0.39	1.8%	$0.64	2.9%
Top 2 Companies	$0.52	1.9%	$1.01	3.7%	$0.55	2.5%	$0.88	4.0%
Top 3 Companies	$0.76	2.8%	$1.45	5.3%	$0.68	3.1%	$1.11	5.1%
Top 4 Companies	$0.99	3.6%	$1.82	6.6%	$0.79	3.6%	$1.31	6.0%
Top 5 Companies	$1.16	4.3%	$2.14	7.8%	$0.88	4.0%	$1.45	6.7%
All Companies	$1.55	5.7%	$3.63	13.3%	$0.50	2.3%	$2.19	10.0%

Day-Ahead Markup

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

The markup component of the PJM day-ahead, load-weighted average LMP by primary fuel and unit type is shown in Table 3-122. INC, DEC and up to congestion transactions (UTC) have zero markups. UTCs were 51.4 percent of marginal resources, INCs were 13.2 percent of marginal resources and DECs were 18.8 percent of marginal resources in 2020.

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 3-122 shows the markup component of LMP for marginal generating resources. Generating resources were only 16.5 percent of marginal resources in 2020. Using adjusted cost-based offers, the markup component of LMP for marginal generating resources decreased for coal fired steam units from $0.36 to $0.14 per MWh and decreased for gas fired CC units from $1.55 to $0.87 per MWh.

Table 3-122 Markup component of day-ahead, load-weighted, average LMP by primary fuel type and technology type: 2019 and 2020

		2019			2020		
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Frequency	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Frequency
Coal	Steam	($0.34)	$0.36	38.8%	($0.51)	$0.14	35.1%
Gas	CC	$1.03	$1.55	52.5%	$0.45	$0.87	53.4%
Gas	CT	$0.01	$0.01	1.1%	$0.03	$0.04	1.5%
Gas	RICE	($0.00)	($0.00)	0.6%	($0.00)	($0.00)	0.4%
Gas	Steam	($0.06)	($0.02)	3.9%	($0.07)	($0.04)	3.7%
Municipal Waste	RICE	($0.00)	($0.00)	0.1%	$0.00	$0.00	0.1%
Oil	CT	($0.00)	$0.00	0.5%	$0.00	$0.00	0.8%
Oil	Steam	($0.05)	($0.04)	0.1%	($0.01)	($0.01)	0.1%
Other	Solar	$0.00	$0.00	0.1%	$0.00	$0.00	0.1%
Other	Steam	($0.00)	($0.00)	0.1%	($0.00)	($0.00)	0.3%
Uranium	Steam	$0.00	$0.00	1.0%	$0.00	$0.00	1.7%
Wind	Wind	$0.10	$0.10	1.1%	$0.01	$0.01	2.8%
Total		$0.70	$1.97	100.0%	($0.11)	$1.01	100.0%

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 3-123 shows the markup component of average prices and of average monthly on peak and off peak prices using unadjusted cost-based offers. In 2020, when using unadjusted cost-based offers, -$0.11 per MWh of the PJM day-ahead load-weighted, average LMP was attributable to markup. In 2020, the peak markup component was highest in August, $0.70 per MWh using unadjusted cost-based offers.

Table 3-123 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: 2019 through 2020

	2019			2020		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$0.78	$1.68	($0.16)	($0.03)	$0.29	($0.35)
Feb	$0.60	$0.80	$0.41	($0.23)	($0.08)	($0.39)
Mar	$0.65	$0.99	$0.32	($0.21)	($0.19)	($0.23)
Apr	$0.15	$0.30	($0.03)	($0.27)	($0.19)	($0.36)
May	$0.11	$0.13	$0.09	($0.19)	$0.17	($0.52)
Jun	$0.45	$0.38	$0.53	$0.07	$0.39	($0.33)
Jul	$2.50	$4.14	$0.66	($0.54)	($0.41)	($0.72)
Aug	$0.39	$0.44	$0.34	$0.07	$0.70	($0.59)
Sep	($0.09)	($0.28)	$0.09	($0.01)	$0.55	($0.63)
Oct	$1.11	$1.82	$0.25	$0.15	$0.48	($0.21)
Nov	$1.71	$1.75	$1.68	($0.22)	$0.28	($0.70)
Dec	($0.34)	$0.21	($0.87)	$0.13	$0.37	($0.12)
Annual	$0.70	$1.10	$0.28	($0.11)	$0.19	($0.43)

Table 3-124 shows the markup component of average prices and of average monthly on peak and off peak prices using adjusted cost-based offers. In 2020, when using adjusted cost-based offers, $1.01 per MWh of the PJM day-ahead, load-weighted, average LMP was attributable to markup. In 2020, the peak markup component was highest in August, $1.77 per MWh using adjusted cost-based offers.

Table 3-124 Monthly markup components of day-ahead (Adjusted), load-weighted, LMP: 2019 through 2020

	2019			2020		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$2.46	$3.34	$1.55	$1.35	$1.65	$1.03
Feb	$2.12	$2.35	$1.88	$0.99	$1.17	$0.83
Mar	$2.02	$2.28	$1.78	$0.96	$1.02	$0.90
Apr	$1.26	$1.28	$1.24	$0.70	$0.91	$0.47
May	$1.29	$1.17	$1.43	$0.72	$1.00	$0.47
Jun	$1.64	$1.62	$1.67	$1.04	$1.35	$0.67
Jul	$3.67	$5.17	$2.00	$0.65	$0.75	$0.51
Aug	$1.55	$1.48	$1.64	$1.14	$1.77	$0.48
Sep	$1.06	$0.81	$1.32	$0.95	$1.50	$0.34
Oct	$2.02	$2.55	$1.36	$1.12	$1.37	$0.84
Nov	$2.92	$3.01	$2.84	$0.89	$1.29	$0.52
Dec	$1.12	$1.65	$0.61	$1.49	$1.68	$1.29
Annual	$1.97	$2.29	$1.62	$1.01	$1.29	$0.70

Markup Component of Day-Ahead Zonal Prices

The markup component of annual average day-ahead price using unadjusted cost-based offers is shown for each zone in Table 3-125. The markup component of annual average day-ahead price using adjusted cost-based offers is shown for each zone in Table 3-126. The smallest zonal all hours average markup component using adjusted cost-based offers for 2020 was in the Pepco Zone, $0.68 per MWh, while the highest was in the PPL Control Zone, $1.51 per MWh. The smallest zonal on peak average markup using adjusted cost-based offers was in the Pepco Control Zone, $0.85 per MWh, while the highest was in the OVEC Control Zone, $1.83 per MWh.

Table 3-125 Day-ahead, average, zonal markup component (Unadjusted): 2019 and 2020

	2019			2020		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	$1.62	$2.58	$0.63	$0.22	$0.54	($0.11)
AEP	$0.53	$0.83	$0.21	($0.25)	$0.05	($0.56)
APS	$0.35	$0.68	$0.02	($0.26)	$0.02	($0.56)
ATSI	$0.98	$1.58	$0.33	($0.18)	$0.12	($0.51)
BGE	$0.70	$1.53	($0.16)	($0.34)	($0.02)	($0.67)
ComEd	$0.21	$0.12	$0.29	($0.20)	$0.13	($0.54)
DAY	$1.45	$2.54	$0.27	($0.07)	$0.43	($0.60)
DEOK	$1.05	$1.86	$0.19	($0.09)	$0.46	($0.68)
DLCO	$0.63	$1.09	$0.15	($0.30)	($0.06)	($0.57)
Dominion	$0.34	$0.72	($0.05)	($0.17)	$0.24	($0.60)
DPL	$1.25	$1.78	$0.71	$0.16	$0.39	($0.08)
EKPC	$0.59	$0.94	$0.24	($0.18)	$0.23	($0.59)
JCPL	$1.36	$1.97	$0.69	$0.14	$0.40	($0.14)
Met-Ed	$0.88	$1.20	$0.53	($0.02)	($0.04)	($0.01)
OVEC	($0.44)	$0.57	($1.39)	$0.22	$0.63	($0.31)
PECO	$1.37	$1.92	$0.80	$0.18	$0.43	($0.09)
PENELEC	$0.56	$0.75	$0.34	$0.06	$0.28	($0.21)
Pepco	$0.33	$0.80	($0.16)	($0.43)	($0.20)	($0.68)
PPL	$1.17	$1.51	$0.82	$0.47	$0.64	$0.28
PSEG	$1.22	$1.77	$0.63	$0.14	$0.36	($0.11)
RECO	$1.02	$1.50	$0.48	$0.17	$0.45	($0.15)

Table 3-126 Day-ahead, average, zonal markup component (Adjusted): 2019 and 2020

	2019			2020		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	$2.81	$3.70	$1.90	$1.32	$1.64	$0.99
AEP	$1.80	$2.02	$1.58	$0.88	$1.13	$0.62
APS	$1.66	$1.91	$1.39	$0.84	$1.08	$0.58
ATSI	$2.28	$2.81	$1.70	$0.96	$1.25	$0.65
BGE	$2.07	$2.84	$1.27	$0.77	$1.03	$0.50
ComEd	$1.43	$1.33	$1.54	$0.91	$1.22	$0.57
DAY	$2.79	$3.81	$1.69	$1.13	$1.59	$0.63
DEOK	$2.37	$3.10	$1.58	$1.04	$1.53	$0.52
DLCO	$1.88	$2.22	$1.51	$0.78	$0.97	$0.58
Dominion	$1.66	$1.95	$1.36	$1.02	$1.49	$0.53
DPL	$2.44	$2.88	$1.98	$1.26	$1.46	$1.05
EKPC	$1.86	$2.13	$1.59	$0.94	$1.27	$0.60
JCPL	$2.59	$3.13	$2.00	$1.26	$1.51	$0.98
Met-Ed	$2.12	$2.38	$1.83	$1.02	$0.98	$1.07
OVEC	$0.66	$1.48	($0.11)	$1.36	$1.83	$0.74
PECO	$2.57	$3.04	$2.07	$1.26	$1.51	$1.00
PENELEC	$1.80	$1.91	$1.68	$1.07	$1.27	$0.84
Pepco	$1.70	$2.11	$1.26	$0.68	$0.85	$0.50
PPL	$2.37	$2.64	$2.08	$1.51	$1.67	$1.34
PSEG	$2.42	$2.88	$1.92	$1.23	$1.46	$1.00
RECO	$2.23	$2.60	$1.81	$1.25	$1.50	$0.97

Markup by Day-Ahead Price Levels

Table 3-127 and Table 3-128 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 3-127 Average, day-ahead markup component (By LMP category, unadjusted): 2019 and 2020

	2019		2020	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $10	$0.00	0.1%	($0.01)	1.4%
$10 to $15	$0.01	3.9%	($0.08)	17.6%
$15 to $20	$0.01	21.1%	($0.19)	40.2%
$20 to $25	($0.00)	30.9%	($0.00)	24.2%
$25 to $50	$0.42	42.1%	$0.16	16.0%
$50 to $75	$0.23	1.4%	$0.01	0.6%
$75 to $100	$0.03	0.5%	$0.00	0.0%
$100 to $125	($0.02)	0.1%	$0.00	0.0%
$125 to $150	$0.01	0.0%	$0.00	0.0%
>= $150	$0.01	0.0%	$0.00	0.0%

Table 3-128 Average, day-ahead markup component (By LMP category, adjusted): 2019 and 2020

	2019		2020	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $10	$0.00	0.1%	$0.00	1.4%
$10 to $15	$0.04	3.9%	$0.05	17.6%
$15 to $20	$0.23	21.1%	$0.27	40.2%
$20 to $25	$0.43	30.9%	$0.32	24.2%
$25 to $50	$0.98	42.1%	$0.34	16.0%
$50 to $75	$0.24	1.4%	$0.02	0.6%
$75 to $100	$0.04	0.5%	$0.00	0.0%
$100 to $125	($0.01)	0.1%	$0.00	0.0%
$125 to $150	$0.01	0.0%	$0.00	0.0%
>= $150	$0.01	0.0%	$0.00	0.0%

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 that 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:[157]

$$\frac{HHI}{\varepsilon} = \frac{P - MC}{P}$$

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 (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 may understate the degree of market power because, in the absence of aggregate market power mitigation, even the unconcentrated HHI level would imply 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.[158] Using the Lerner Index,

157 *See* Tirole, Jean. *The Theory of Industrial Organization*, MIT (1988), Chapter 5: Short-Run Price Competition.

158 See Patrick, Robert H. and Frank A. Wolak (1997), "Estimating the Customer-Level Demand for Electricity Under Real-Time Market Prices," <https://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/files/Estimating%20the%20Customer-Level%20Demand%20for%20Electricity%20Under%20Real-Time%20Market%20Prices_Aug%201997_Patrick,%20Wolak.pdf>, last accessed August 3, 2018 and Fan, Shu and Rob Hyndman (2010), "The price elasticity of electricity demand in South Australia," <https://robjhyndman.com/papers/Elasticity2010.pdf>.

the elasticities imply, for example, an average markup ranging from 25 to 50 percent at the unconcentrated to moderately concentrated threshold HHI of 1000:[159]

$$\frac{HHI}{\varepsilon} = \frac{0.1}{0.2} = \frac{P - MC}{P} = 50\%$$

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 $21.27 per MWh and an average HHI of 790 in 2020, average PJM prices would theoretically range from $27 to $35 per MWh using the elasticity range of -0.2 to -0.4.[160] The theoretical prices exceed marginal costs because the exercise of market power is profit maximizing in the absence of market power mitigation. Actual prices, averaging $21.77 per MWh, and markups, at 2.3 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.

Market Power Mitigation and Markup

Fully effective 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 3-129 categorizes real-time marginal unit intervals by markup level and TPS test status. In 2020, 5.2 percent of marginal unit intervals 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 5.2 percent of marginal unit intervals failing the TPS test with unmitigated positive markup exceeds the 3.8 percent of marginal unit intervals failing the TPS with zero markup. Marginal units with positive markup are mitigated less often than not.

Table 3-129 Percent of real-time marginal unit intervals with markup and local market power: 2019 and 2020

	2019			2020		
Markup Category	Not Failing TPS Test	Failing TPS Test	Percent in Category	Not Failing TPS Test	Failing TPS Test	Percent in Category
Negative Markup	24.1%	11.5%	35.6%	34.0%	6.5%	40.5%
Zero Markup	12.6%	6.7%	19.4%	11.3%	3.8%	15.1%
$0 to $5	24.3%	6.9%	31.2%	33.8%	4.5%	38.3%
$5 to $10	7.9%	1.7%	9.6%	3.5%	0.4%	3.9%
$10 to $15	1.2%	0.5%	1.7%	0.6%	0.2%	0.8%
$15 to $20	0.5%	0.3%	0.8%	0.3%	0.0%	0.3%
$20 to $25	0.3%	0.1%	0.4%	0.4%	0.0%	0.4%
$25 to $50	0.5%	0.2%	0.7%	0.4%	0.0%	0.4%
$50 to $75	0.2%	0.1%	0.3%	0.1%	0.0%	0.1%
$75 to $100	0.1%	0.0%	0.1%	0.1%	0.0%	0.1%
Above $100	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%
Total Positive Markup	35.0%	10.0%	45.0%	39.2%	5.2%	44.4%
Total	71.8%	28.2%	100.0%	84.5%	15.5%	100.0%

The markup of marginal units was zero or negative in only 55.0 percent of marginal unit intervals in 2019 and 55.6 percent of marginal unit intervals in 2020. Pivotal suppliers in the aggregate market also set prices with high markups in the summer of 2020. 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.

159 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.
160 The average HHI is found in Table 3-80. Marginal costs are the sum of all components of LMP except markup, as shown in Table 3-64.