OCC EXHIBIT_______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the OVEC Generation Purchase Rider Audits Required by R.C. 4928.148 for Duke Energy Ohio, Inc., the Dayton Power and Light Company, and AEP Ohio.	)))))	Case No. 21-477-EL-RDR

DIRECT TESTIMONY
OF
JOSEPH S. PEREZ

On Behalf of the
Office of the Ohio Consumers' Counsel
65 East State Street, Suite 700
Columbus, Ohio 43215

October 10, 2023

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I. BACKGROUND AND PURPOSE OF TESTIMONY

Q1. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A1. My name is Joseph Perez and I represent the Office of the Ohio Consumers' Counsel ("OCC") as Senior Administrator of Resource Planning and Forecasting. My business address is 65 East State Street, Suite 700, Columbus, Ohio 43215.

Q2. PLEASE BRIEFLY SUMMARIZE YOUR PROFESSIONAL EXPERIENCE AND EDUCATION.

A2. I'm an economist with over 17 years of experience in the energy sector at various levels, including researcher, analyst, and senior manager.

In 2011, I started my career with American Electric Power Company ("AEP") as an analyst in load research. In 2013, I moved into integrated resource planning where I spent the next 10 years as a resource planner conducting production cost and expansion planning using industry-standard unit commitment and economic dispatch software (i.e., PLEXOS). Additional responsibilities I had were to develop and support expert testimony in regulatory proceedings regarding economic evaluations of long-term resource plans including coal plant retirements.

I left AEP in 2022 and worked for ibV Energy Partners, a commercial solar and battery developer as senior manager of power analytics. There I managed a small team of analysts running zonal and nodal pricing studies on all major US power markets.

I joined OCC in 2023 as Senior Administrator of Resource Planning and Forecasting. I represent OCC in various capacities, such as writing testimony and performing economic analysis on an array of electric utility matters and assessing the impacts on consumers. I earned certifications in commodities trading and power systems modeling. I received my master's degree in financial economics from Ohio University and hold a bachelor's degree in business administration from Franklin University.

Q3. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN UTILITY CASES BEFORE THE PUCO OR ANY OTHER REGULATORY COMMISSION?

A3. This is my first time testifying before the PUCO. However, I submitted testimony before the Arkansas Public Service Commission in Docket No. 21-070-U.

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A4. My testimony reviews the Coal Plant Subsidy costs billed to AEP, DP&L, and Duke (the "Utilities") by Ohio Valley Electric Corporation ("OVEC") through the Legacy Generation Rider ("LGR)". I also introduce State of the Market Reports by the PJM Independent Monitor and the MISO Independent Monitor for 2020. Further, I examine the reasonableness of OVEC's unit commitment strategy in the PJM Day-Ahead Energy Market during the audit period. I also introduce certain emails from the 2019 audits of Coal Plant Subsidy costs by London Economics.

Q5. ***WHAT WERE THE PRIMARY SOURCES OF DATA AND INFORMATION USED IN YOUR TESTIMONY?***

A5. I refer to the audit reports and corresponding discovery prepared by London Economics Consulting ("London Economics" or "Auditor"). Further, I use my direct experience in utility production costing of generating units. Third, I rely on the testimony of OCC witness Dr. Elizabeth Stanton. Additionally, I also rely on MISO Independent Market Monitor. And lastly, I depend on certain emails from London Economic's 2019 audit of the Coal Plant Subsidy costs.

II. FINDINGS AND RECCOMMENDATIONS

Q6. ***PLEASE SUMMARIZE YOUR FINDINGS.***

A6. My key findings include:

1. The hourly dispatch of the OVEC plants in the PJM Day-Ahead Energy Market is consistent with that of a price-taker bidding strategy, where the unit operates regardless of economics. My screening of OVEC's production costs versus revenues found that OVEC's production costs exceeded energy market revenues most of the time.

   This results from OVEC using a "must-run" commitment status in the PJM Day-Ahead Energy Market most of the time during 2020. This was not prudent. OVEC's actions were not consistent with how merchant coal plant operators attempting to maximize revenues would bid their plants into the PJM Day-Ahead Energy Market. This is not in the best interest of ratepayers.

2. The Utilities failed to oversee the reasonableness of OVEC's unit commitment practices. The 2022 State of the Market Report for the MISO Electricity Markets by the MISO Independent Market Monitor shows that, during the period of 2017-2020, 70% of merchant coal generators schedule their resources using "economic" commitment instead of "must-run" commitment. Unlike merchant plants, the MISO Independent Market Monitor's report found that regulated utilities are more likely to offer their units as "must-run" resulting in negative profits. The report also shows that OVEC's near-continuous use of "must-run" commitment was not consistent with how merchant coal plant operators attempting to maximize revenues would bid their plants into the PJM Day-Ahead Energy Market. The MISO Independent Market Monitor report is relevant due to the similarities between the MISO and PJM markets. The corresponding PJM report also shows that most operators bid their plants as "economic," but the data is not reported in the same degree of detail.

3. The London Economics Auditor did not go far enough in her analysis or recommendations. For example, the Auditor stated: "Ideally, the units would be committed based on economics all or most of the time."[1] The

[1] Audit Report of Duke at 10 (Dec. 17, 2021).

units were not committed based on economics most of the time during 2020, so the Auditor should have concluded that: (a) the coal plants were operated imprudently; (b) the coal plants were not operated consistently with how merchant coal plant operators attempting to maximize revenues would bid their plants into the PJM Day-Ahead Energy Market; and (c) the coal plants were not operated in a manner that was in the best interest of retail ratepayers.

4. During London Economic's audit of the OVEC plants for 2019, the Auditor concluded in her draft audit report of AEP: "Therefore, keeping the plants running does not seem to be in the best interests of the ratepayers." However, after review of the draft report the PUCO Staff directed her to use a "milder tone and intensity." In response to PUCO Staff's direction, the Auditor removed this sentence from the final version of her audit report. The Auditor and the PUCO Staff acted improperly. This compromised the Auditor's independence. The Staff did not conduct its own audit and it should not have asked the Auditor to change her findings.

Auditors are supposed to maintain objectivity and impartiality throughout the audit process. Changing findings under pressure can undermine their ability to provide an unbiased assessment. The PUCO therefore should give little or no weight to the Auditor's report.

Q7. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A7. My recommendations are as follows:

1. The PUCO should disallow all of the above-market Coal Plant Subsidy costs collected by the Utilities during 2020.

2. The PUCO should ask the PJM Independent Market Monitor, Monitoring Analytics, to prepare a report of the unit commitment practices for coal power plants in the PJM Day-Ahead Energy Market for 2020 for both merchant generators and regulated utilities, similar to the report at page 52 of the MISO Independent Market Montor's 2022 State of the Market Report.

3. Going forward, the PUCO should require OVEC and the Utilities to report on their daily unit commitment decisions in the PJM Day-Ahead Energy Market and the corresponding pricing information used to make those decisions. The PUCO should require OVEC and the Utilities to preserve these records and to make them available to the auditor in future audits.

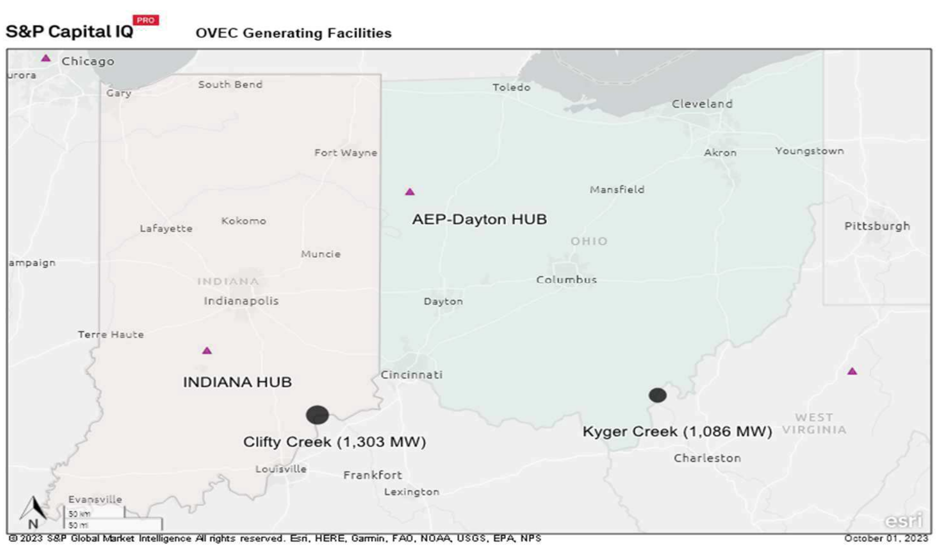
III. OVEC POWER PURCHASE AGREEMENT

Q8. PLEASE PROVIDE A BRIEF SUMMARY OF OVEC AND THE INTER-COMPANY POWER AGREEMENT.

A8. OVEC and its wholly owned subsidiary, Indiana-Kentucky Electric Corporation ("IKEC") (collectively referred to as "OVEC"), was organized on October 1,

1952. OVEC was formed by investor-owned utilities and electric cooperatives furnishing electric service in the Ohio River Valley area and their parent holding companies. OVEC was formed to allow for joint ownership of two power plants to provide electricity for the large electric power requirements projected for the uranium enrichment facilities then under construction by the Atomic Energy Commission ("AEC") near Portsmouth, Ohio.[2] Clifty Creek and Kyger Creek are two coal-fired plants that make up OVEC with an aggregate capacity of ~2,400 MW. OVEC's energy and capacity is contracted through a power agreement with 12 sponsoring companies that form the Inter-Company Power Agreement ("ICPA"). AEP's power participation ratio is 19.93%, DP&L's share is 4.9%, and Duke's share is 9%.[3] This ICPA was amended in August 2011 and goes through 2040.[4]

Figure 1. OVEC Generating Facilities - S&P Global



[2] OVEC 2020 Annual Report p. 1.

[3] *Id.*

[4] *Id.*

Q9. ***HOW IS THE LEGACY GENERATION RIDER RELATED TO OVEC?***

A9. The sponsoring Companies have contractual entitlements to a percentage of OVEC's output (e.g., energy, capacity, ancillary services) defined by their Participation Ratio ("PPR"). OVEC's monthly charges are reconciled and netted against PJM revenues through the Legacy Generation Rider. The LGR Rider states that all retail jurisdictional customers shall be assessed a charge or (credit) as approved by the PUCO to recover any prudently incurred costs related to a legacy generation resource for the period commencing January 1, 2020, and extending up to December 31, 2030. LGR Rider rates are updated every six months and are effective for a six-month period (January 1 through June 30; and July 1 through December 31, in a given year). When the rates are set for the coming half-year, the rates are also trued up for the previous half-year. This process applies to all EDUs that buy energy and capacity from OVEC and are allowed to recover the cost on the LGR Rider.[5]

IV. IN 2020, AEP, DP&L, AND DUKE BURDEN CONSUMERS WITH UNREASONABLE COAL PLANT SUBSIDY COSTS

Q10. ***WHAT UNREASONABLE COAL PLANT SUBSIDY CHARGES DID THE UTILITIES PASS ON TO CONSUMERS?***

A10. The entire amount of the above-market costs collected in 2020.

[5] Audit Report p. 23.

According to PJM's 2020 State of the Market Report, day-ahead power prices were at historic lows, averaging only $21.77 per MWh, owing to weaker demand caused by the pandemic.[6] These prices are consistent with the Auditor's statement in Section 9 of the audit report for Duke, which states, "the OVEC plants cost customers more than the cost of energy and capacity that could be bought on the PJM wholesale markets."[7] OVEC's power cost was $67.00 per MWh for 2020.[8] Even discounting the total power costs by the fixed component, the cost of fuel and variable operations and maintenance costs (VO&M) for the OVEC plants still outweigh revenues from PJM. So, it's not surprising that the LGR Rider is a charge and not a credit to customers.

Q11. DID THE AUDITOR PROVIDEW INFORMATION ABOUT THE DIFFERENCES BETWEEN THE OVEC ENERGY CHARGE AND THE MONTHLY PJM ENERGY PRICES?

A11. Yes. The Auditor provided this data for all three utilities. As an example, the data for Duke is at Figure 30 of the Audit Report, as follows:

6 2020 PJM State of the Market Report p. 11.

7 Duke Audit Report p. 9.

8 OVEC Annual Report p. 4.

Figure 2. OVEC energy charges and monthly PJM market prices

Figure 30. OVEC energy charges and monthly average PJM market prices at DEOK hub

Month	OVEC energy charge ($)	Available energy (billing kWh)	Energy cost per MWh	PJM energy price per MWh	PJM price less OVEC energy cost
January 2020	$ 21,506,055	886,178,000	$ 24.27	$ 22.31	($1.96)
February 2020	$ 19,911,876	785,618,000	$ 25.35	$ 20.30	($5.04)
March 2020	$ 17,259,070	645,727,000	$ 26.73	$ 18.52	($8.21)
April 2020	$ 11,813,372	364,909,000	$ 32.37	$ 17.27	($15.10)
May 2020	$ 11,863,119	411,844,000	$ 28.81	$ 18.20	($10.61)
June 2020	$ 20,509,196	837,329,000	$ 24.49	$ 19.66	($4.83)
July 2020	$ 23,413,253	942,026,000	$ 24.85	$ 25.54	$0.69
August 2020	$ 21,853,536	898,813,000	$ 24.31	$ 22.94	($1.38)
September 2020	$ 17,786,250	666,126,000	$ 26.70	$ 20.21	($6.49)
October 2020	$ 15,596,620	585,854,000	$ 26.62	$ 24.09	($2.53)
November 2020	$ 21,813,799	873,994,000	$ 24.96	$ 21.55	($3.41)
December 2020	$ 27,989,892	1,134,638,000	$ 24.67	$ 25.36	$0.69

Source: LEI-DR-01-022 CONF Attachment 1 and third-party data provider (DEOK Day Ahead LMP - Monthly Average).

As you can observe from Figure 30, OVEC energy costs were higher than PJM around-the-clock prices or average ten out of twelve months. I would note, however, that this table understates the true cost of the coal plant subsidies to consumers. The "OVEC energy charge" component of the PJM bill only includes fuel, and not variable operation and maintenance (VO&M). So, in other words, OVEC could not even recover the fuel portion of its production costs with prevailing market prices much less fuel and VO&M that compromise the total variable cost. By including VO&M in this figure, the results would likely show all twelve months created even larger charge to consumers for the coal plant subsidy, with no credits.

V. UNIT COMMITMENT SCHEDULING PRACTICES WERE UNREASONABLE

Q12. WHAT IS YOUR EXPERIENCE WITH UNIT COMITTMENT AND ECONOMIC DISPATCH?

A12. My experience in production costing was running unit commit and economic dispatch computer models for resource planning. These models simulate the day-to-day operations of a power plant at the hourly level for up to 30 years in the future. They are sophisticated linear programming tools that try and optimize generator profits by minimizing cost, subject to constraints (start-up cost, min up/down time). My duties were to screen the economics of generating technologies including wind, solar, thermal, and battery storage and to analyze generation patterns. Unit commitment and Economic Dispatch ("UC/ED") is twofold. First, the unit commitment problem is binary and determines whether to start or shut down a unit. Secondly, economic dispatch determines at what megawatt levels the unit should operate. Coal units are not flexible, meaning they can't start up and shut down quickly in response to price signals like gas combustion turbines ("GGCT") or combined cycle ("CC") plants.

VI. MISO MARKET REPORTS SUGGEST MOST MERCHANT COAL GENERATOR OFFERS ARE DESIGNATED AS ECONOMIC VERSUS MUST-RUN

Q13. ARE THE MISO AND PJM WHOLESALE MARKETS FUNDAMENTALLY SIMILAR OR DIFFERENT FROM EACH OTHER?

A13. The MISO and PJM wholesale markets are fundamentally similar to each other. Both markets cover a widespread, multi-state area. Both MISO and PJM have a wide variety of power plants of all types. Both MISO and PJM have a capacity, energy and ancillary services markets. Both of these markets operate in a similar fashion, and each has an independent market monitor. Therefore, market fundamentals, data, and analyses of commitment decisions in MISO can reliably inform market fundamentals, data, and analyses of commitment decisions in PJM.

Q14. WHEN CHOOSING BETWEEN A "MUST RUN" AND AN "ECONOMIC" COMMITMENT, WHAT TYPE OF ANALYSIS SHOULD A REASONABLE PLANT OPERATOR PERFORM?

A14. The plant operator should do a daily analysis of the costs and expected revenues from participating in the Day-Ahead Energy Market. The analysis should cover not only that day, but the next several days ahead for units that are not easily turned on and off. If the analysis shows that the expected revenue will cover the plant's variable operating cost, then the operator can commit the plant to the Day-Ahead Energy Market. If the plant's variable operating costs, plus shutdown and start-up costs, are projected to exceed expected revenues for a few days or longer, then the operator should either designate the plant as economic or shut down the plant until prices recover.

Q15. DOES DUKE FOLLOW THIS PRACTICE IN OPERATING ITS OWN PLANTS OTHER THAN OVEC?

A15. Yes. I reviewed the testimony of Duke witness John Swez in this proceeding, and he indicates that this is the practice Duke follows for its non-OVEC Indiana plants.[9]

Q16. DOES THE AUDIT REPORT STATE WHETHER OVEC OPERATED THE PLANTS AS MUST RUN DURING ANY EXTENDED PERIODS OF TIME WHEN OVEC'S VARIABLE OPERATING COSTS EXCEEDED THE PJM MARKET PRICE?

A16. Yes, the Auditor states "there were times during which the PJM DA [day-ahead] prices did not cover the variable cost of running the plants."[10] The Auditor goes on to say that the PJM prices were lower that the OVEC energy charges in five months during the audit period.[11]

Q17. HOW DOES PJM AND MISO OFFER THEIR COAL UNITS IN THE DAY-AHEAD MARKETS?

A17. The State of the market reports from the PJM and MISO Independent Market Monitors for 2020 confirm that coal generators are offered as economic instead of must-run most of the time. I have attached these reports to my testimony as Attachments JSP-1 and JSP-2. The PJM Independent Market Monitor's State of the Market report shows only 21% of unit offers for all types of generators were

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[9] Direct Testimony of John D. Swez at 28.

[10] LEI Audit Report at 10.

[11] *Id.*

"must-run" in 2020.[12] The MISO Independent Market Monitor's State of the Market report provides more detailed information by presenting the data solely for coal generators and by breaking out the unit commitment data by regulated versus merchant coal plants. Table 8 at page 52 of the MISO report entitled "Coal-Fired Resource Operation and Profitability" shows that regulated utilities are more likely to operate their units as must-run than their merchant counterparts. For both regulated utilities and merchant operators, the use of "must-run" designation for unprofitable coal plants was rare. For regulated plants, the "must-run" designation for unprofitable coal plants accounted for 13% of total coal plant starts from 20217-2020 versus 3% for merchant coal plant generators using "must-run" as shown below:

Figure 3. ***Potomac Economics, 2022 State of the Market Report for the MISO Electricity Markets (June 15, 2023)*** **Table 8 at page 52.**[13]

Table 8: Coal-Fired Resource Operation and Profitability
2017–2022

	2017-2020			2021			2022		
	Annual Starts	% of Starts	Net Rev. ($/MWh)	Starts	% of Starts	Net Rev. ($/MWh)	Starts	% of Starts	Net Rev. ($/MWh)
Regulated Utilities	1839		**$3.54**	1718		**$14.04**	1765		**$22.41**
Profitable Starts	1570	87%		1564	91%		1635	93%	
Offered Economically	*727*	*39%*		*885*	*52%*		*754*	*43%*	
Must-Run and profitable	*843*	*48%*		*679*	*40%*		*881*	*50%*	
Unprofitable (Must Run)	269	13%		154	9%		130	7%	
Merchants	187		**$5.05**	124		**$14.96**	84		**$30.42**
Profitable Starts	184	97%		124	100%		84	100%	
Offered Economically	*143*	*70%*		*124*	*100%*		*84*	*100%*	
Must-Run and profitable	*41*	*27%*		*0*	*0%*		*0*	*0%*	
Unprofitable (Must Run)	4	3%		0	0%		0	0%	

[12] Monitoring Analytics, LLC, State of the Market Report for PJM Volume II at 111 (March 11, 2021).

[13] Potomac Economics, 2022 State of the Market Report for the MISO Electricity Markets at 52 (June 15, 2023).

Q18. WHAT CONCLUSIONS DO YOU DRAW FROM THIS DATA?

A18. I conclude that: (a) the OVEC coal plants were operated imprudently; (b) the OVEC coal plants were not operated consistently with how merchant coal plant operators attempting to maximize revenues would bid their plants into the PJM Day-Ahead Energy Market; and (c) the OVEC coal plants were not operated in a manner that was in the best interest of retail ratepayers. The Auditor should have reached these same conclusions but failed to do so.

The Auditor failed to evaluate data from the PJM Independent Market Monitor and the MISO Independent Market Monitor for 2020 showing how frequently plants were committed as “must-run” in the Day-Ahead Energy Market. In the absence of this data, the Auditor had insufficient data to evaluate whether (a) the OVEC coal plants were operated imprudently; (b) the OVEC coal plants were not operated consistently with how merchant coal plant operators attempting to maximize revenues would bid their plants into the PJM Day-Ahead Energy Market; or (c) the OVEC coal plants were not operated in a manner that was in the best interest of retail ratepayers.

The Auditor correctly stated: “Ideally, the units would be committed based on economics all or most of the time.”[14] However, this statement doesn’t go far enough, and the Auditor should have reached the same conclusions I outlined above had she properly considered all of the available data.

[14] Audit Report of Duke at 10 (Dec. 17, 2021).

Q19. DID YOU REVIEW ANY INFORMATION FROM LONDON ECONOMIC'S 2019 AUDIT OF THE OVEC COAL PLANTS WHICH CAUSED YOU CONCERN?

A19. Yes. During London Economic's audit of the OVEC plants for 2019, the auditor concluded in her draft audit report of AEP: "Therefore, keeping the plants running does not seem to be in the best interests of the ratepayers." PUCO Staff directed her to use a "milder tone and intensity." In response to PUCO Staff's direction, the auditor removed this sentence from the final version of her audit report. But the Staff's direction to the Auditor went well beyond expressing a concern over "tone and intensity." The Staff directed the Auditor to change a finding, not tone or intensity. Changing tone or intensity would have been if the Auditor had attributed a motive to OVEC's dispatching decisions such as saying that OVEC acted avariciously in its dispatch decisions. But instead, the Staff directed the Auditor to change a fundamental finding that was reached after an audit was conducted and data reviewed and analyzed. The PUCO Staff acted improperly in directing the Auditor to alter her findings, especially considering the Staff did not conduct its own audit and had no basis for demanding the change. And the Auditor acted improperly by willingly shedding her independence in what was supposed to be an independent audit. The Auditor and the PUCO Staff acted improperly. The emails documenting this incident are at Attachment JSP-3 and were obtained by OCC through a public records request to the PUCO. The Auditor's independence was clearly compromised.

This very same Auditor conducted the audit in this case. Given the past evidence that the Auditor changed the audit findings in response to a Staff requests, the Auditor's independence in this case is called into question. Because of that the PUCO should give little weight to her ultimate conclusion.

VII. RECOMMENDATION

Q20. REQUESTING AN OPINION FROM THE PJM INDEPENDENT MARKET MONITOR IS CONSISTENT WITH PUCO PRECEDENT REQUIRING "RIGOROUS REVIEW" OF THE COAL PLANT SUBSIDY COSTS.

A20. When the PUCO approved the Coal Plant Subsidy charges, parties raised concerns that the utilities might act unreasonably in bidding the plants into the PJM markets. The PUCO assured stakeholders that these matters would be subject to "rigorous review"[15] and **that the utilities would be held to the same standard as a competitive merchant operator regarding how the plants are bid into the PJM market.**[16] In light Dr. Stanton's analysis and the reports from the PJM Independent Market Monitor and the MISO Independent Market Monitor and in light of how the PUCO auditor's opinion has been compromised, the PUCO should continue to apply this "rigorous review" standard as part of its prudence review. R.C. 4928.148(A)(1) states that the PUCO's prudency review shall

[15] *In re Ohio Power PPA Rider,* Case No. 14-1693-EL-RDR Joint Stipulation and Recommendation at 7 (Dec. 14, 2015).

[16] *See* footnote 2, *supra* (emphasis added).

include "decisions related to offering the contractual commitment into the wholesale markets."[17]

It would therefore be just and reasonable for the PUCO to ask the PJM Independent Market Monitor whether competitive bidding practices were used. The Commission should closely monitor the chronic under earnings at OVEC. The Office of the PJM Independent Market Monitor is established under PJM's Open Access Transmission Tariff.[18] The tariff provides for the PJM Independent Market Monitor to provide reports to state public utility commissions upon request:

> **Studies or Reports for State Commissions:** Upon request in writing by the OPSI Advisory Committee, the Market Monitoring Unit may, in its discretion, provide such studies or reports on wholesale market issues, including wholesale market transactions occurring under a state-administered auction process, as may affect one or more states within the PJM area. Any such request for such a study or report, as well as any resulting study or report, shall be made simultaneously available to the public, with simultaneous notice to PJM members, subject to the protection of confidential information.[19]

The PJM Independent Market Monitor's vigorous participation in the underlying case where the PUCO approved the Coal Plant Subsidy charge shows the PJM Independent Market Monitor's strong interest in the bidding practices at issue in this case. The PUCO should ask the PJM Independent Market Monitor for a report on whether competitive bidding practices were used to bid the coal plants

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[17] R.C. 4928.148(A)(1).

[18] PJM Open Access Transmission Tariff, Attachment M.

[19] *Id.*

into the PJM energy market during the audit period. The PUCO should file the report in the docket and provide parties with an opportunity to comment. The PUCO should evaluate the PJM Independent Market Monitor's report and the parties' comments before it reaches its decision in this case.

VIII. CONCLUSION

Q21. DOES THIS CONCLUDE YOUR TESTIMONY?

A21. Yes. However, I reserve the right to supplement my testimony if additional testimony is filed, or if new information or data in connection with this proceeding becomes available.

CERTIFICATE OF SERVICE

I hereby certify that a copy of this Direct Testimony of Joseph S. Perez on Behalf of the Office of the Ohio Consumers' Counsel was served on the persons stated below via electronic transmission, this 10th day of October 2023.

/s/ John Finnigan
John Finnigan
Assistant Consumers' Counsel

The PUCO's e-filing system will electronically serve notice of the filing of this document on the following parties:

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State of the Market Report for PJM

Volume 2: Detailed Analysis

Monitoring Analytics, LLC
Independent Market Monitor for PJM

2020

3.11.2021

Preface

The PJM Market Monitoring Plan provides:

> The Market Monitoring Unit shall prepare and submit contemporaneously to the Commission, the State Commissions, the PJM Board, PJM Management and to the PJM Members Committee, annual state-of-the-market reports on the state of competition within, and the efficiency of, the PJM Markets, and quarterly reports that update selected portions of the annual report and which may focus on certain topics of particular interest to the Market Monitoring Unit. The quarterly reports shall not be as extensive as the annual reports. In its annual, quarterly and other reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview. The annual reports shall, and the quarterly reports may, address, among other things, the extent to which prices in the PJM Markets reflect competitive outcomes, the structural competitiveness of the PJM Markets, the effectiveness of bid mitigation rules, and the effectiveness of the PJM Markets in signaling infrastructure investment. These annual reports shall, and the quarterly reports may include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required.[1]

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM),[2] and is also known as the Independent Market Monitor for PJM (IMM), submits this *2020 Annual State of the Market Report for PJM*.[3]

1 PJM Open Access Transmission Tariff (OATT) Attachment M (PJM Market Monitoring Plan) § VI.A. Capitalized terms used herein and not otherwise defined have the meaning provided in the OATT, PJM Operating Agreement, PJM Reliability Assurance Agreement (RAA), the Consolidated Transmission Owners Agreement (CTOA) or other tariffs that PJM has on file with the Federal Energy Regulatory Commission (FERC or Commission).

2 OATT Attachment M.

3 All references to this report should refer to the source as Monitoring Analytics, LLC, and should include the complete name of the report: *2020 Annual State of the Market Report for PJM.*

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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

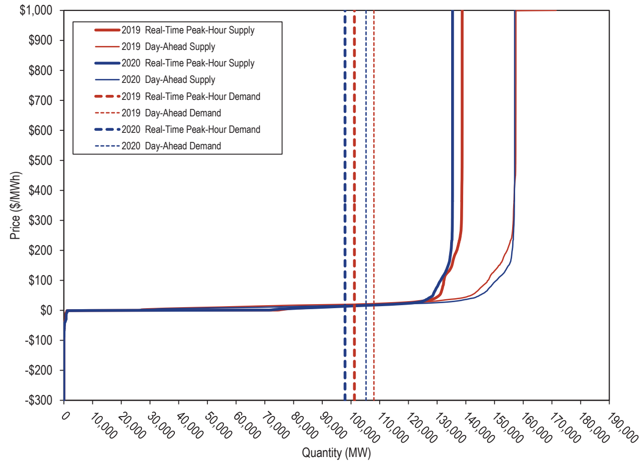
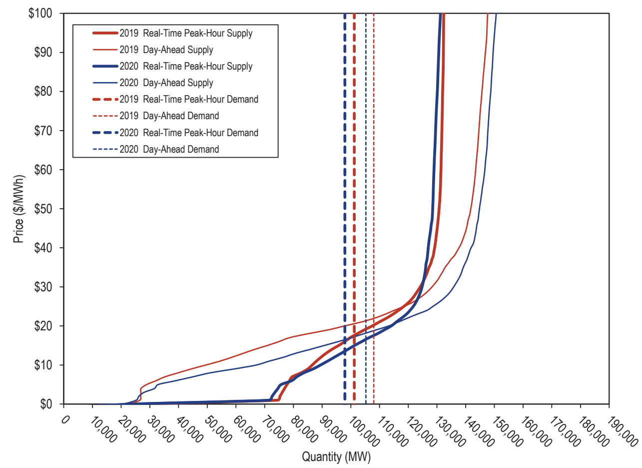


Figure 3-2 Typical dispatch range of supply curves



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.

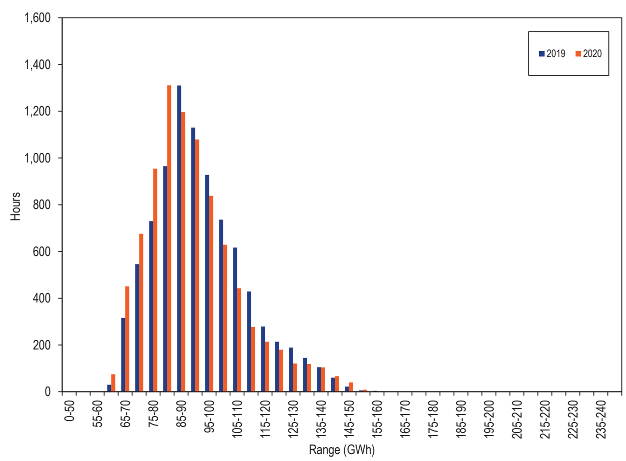
In the PJM Real-Time Energy Market, there are three types of supply offers:

- **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.

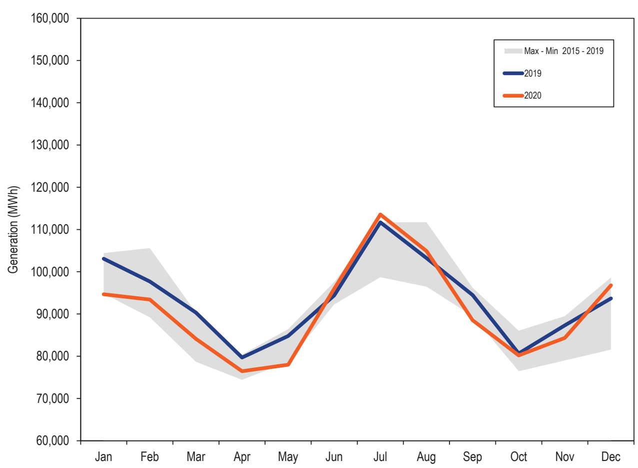
Table 3-3 Average hourly real-time generation and real-time generation plus imports: 2001 through 2020

	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.

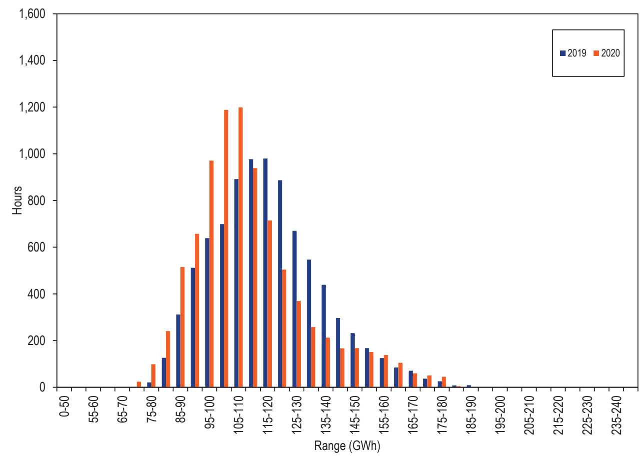
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

- **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.

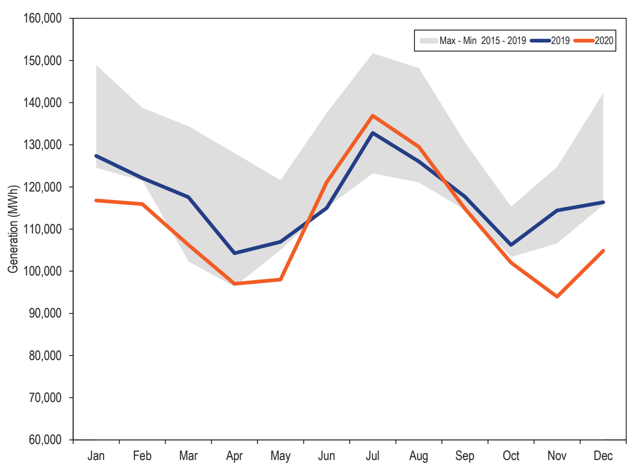
Table 3-4 Average hourly day-ahead cleared supply and day-ahead cleared supply plus imports: 2001 through 2020

	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

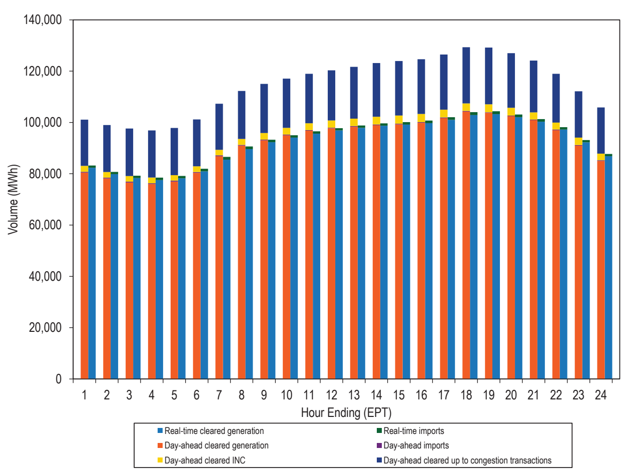
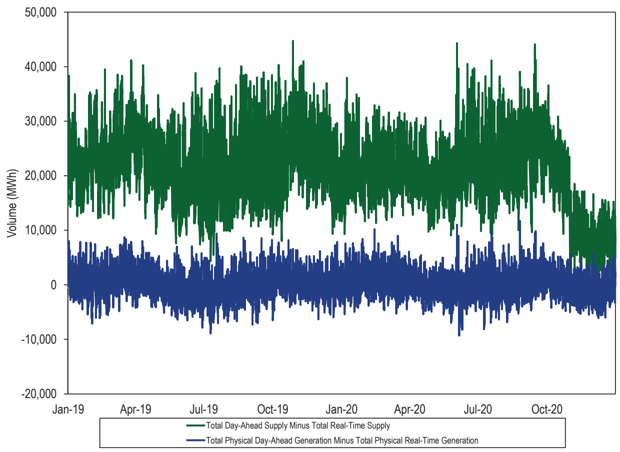


Figure 3-8 shows the difference between the day-ahead and real-time average daily supply in 2019 and 2020.

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.

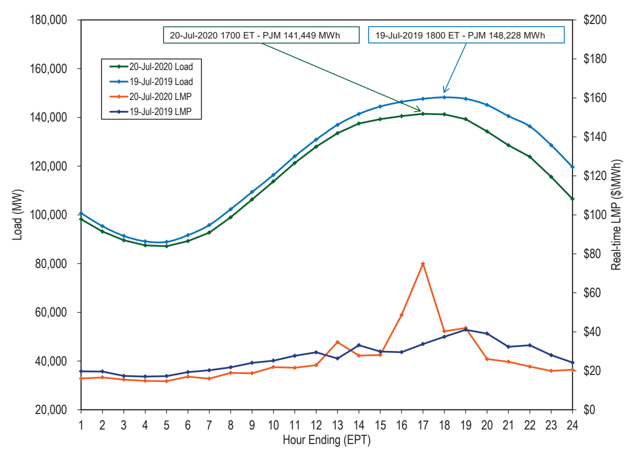
Table 3-6 shows the peak loads for 1999 through 2020.

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.

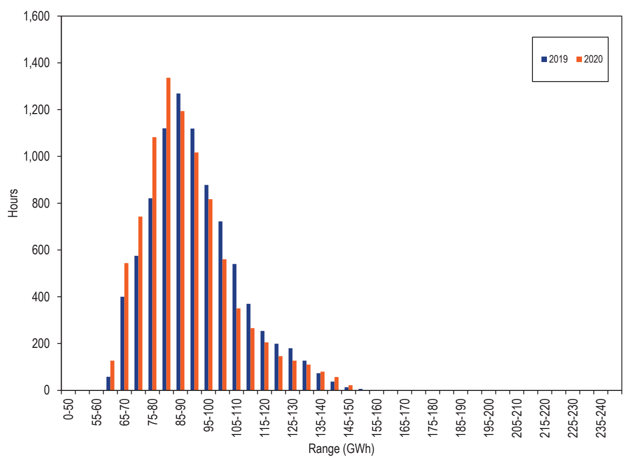
In the PJM Real-Time Energy Market, there are two types of demand:

- **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.

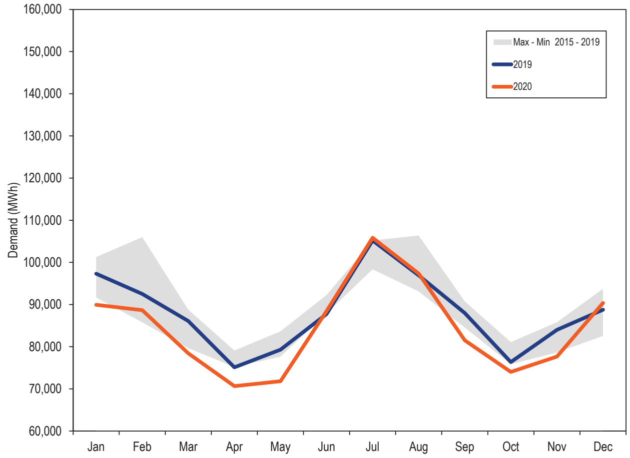
Table 3-7 Real-time load and real-time load plus exports: 2001 through 2020

	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.

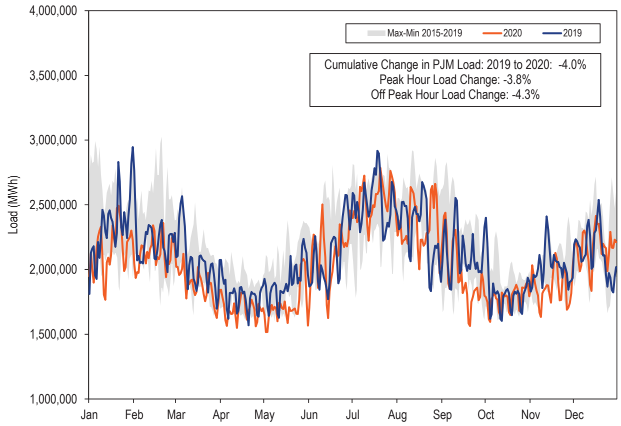
Figure 3-11 Real-time monthly average hourly load: 2019 through 2020



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%)

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.

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

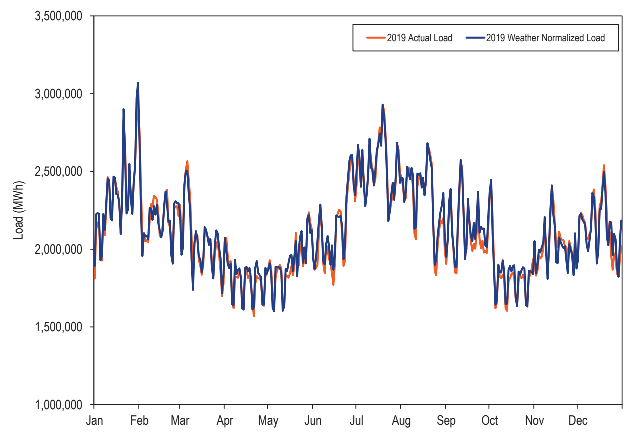


Figure 3-14 Real-time daily load and weather normalized load: 2020

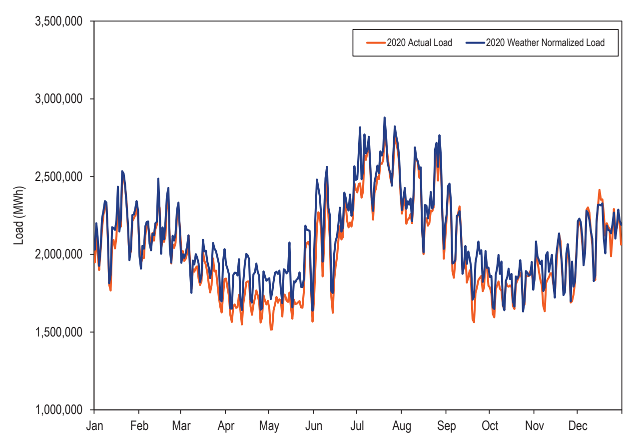


Table 3-9 compares the total monthly actual load and the weather normalized load. Load was 3.4 percent below weather normalized load in 2020.

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:

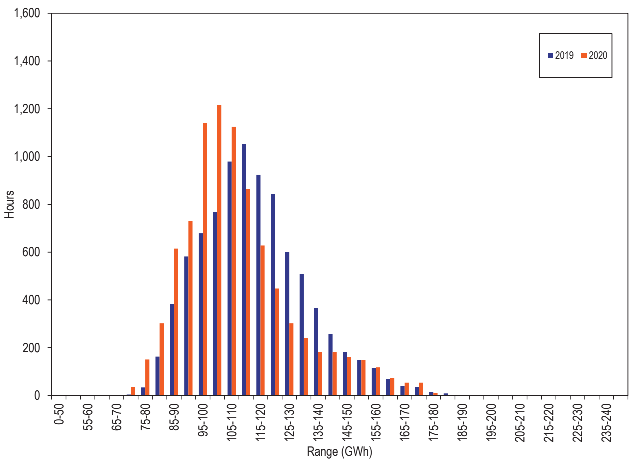
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of 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, Average Demand

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

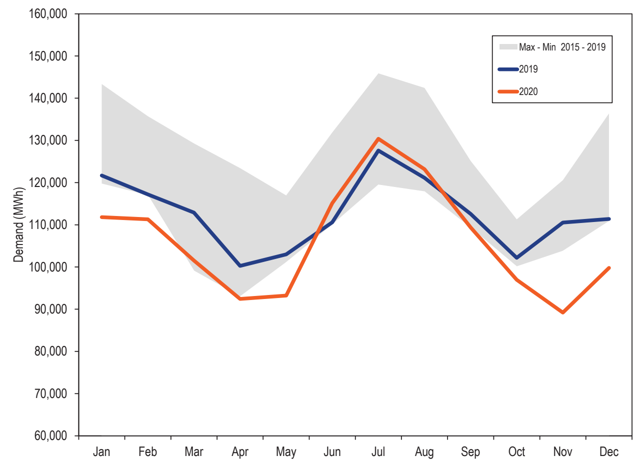
Table 3-10 Average hourly day-ahead demand and day-ahead demand plus exports: 2001 through 2020

	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%

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



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

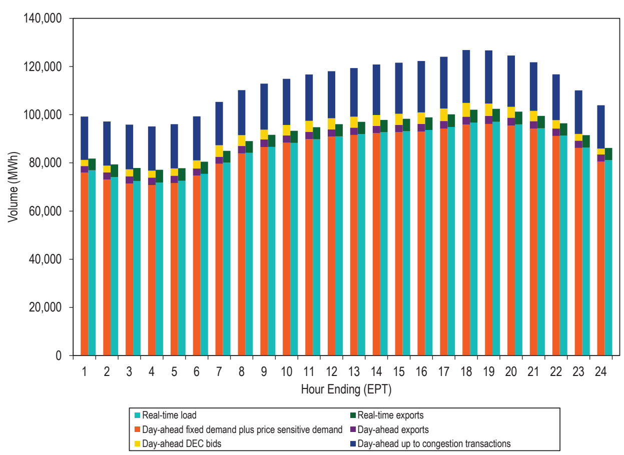
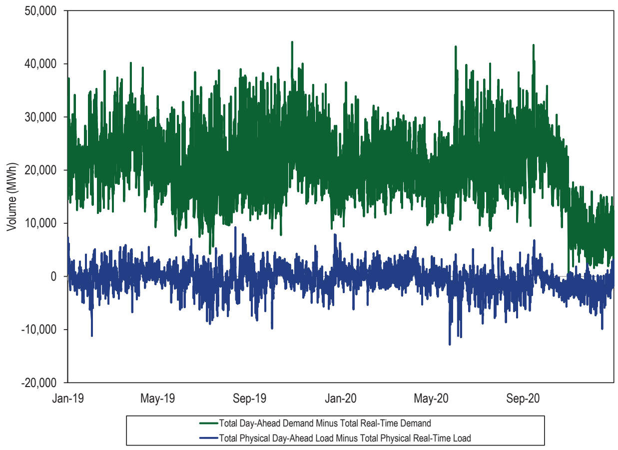


Figure 3-18 shows the difference between the day-ahead and real-time average daily demand for 2019 and 2020.

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

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).

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.

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

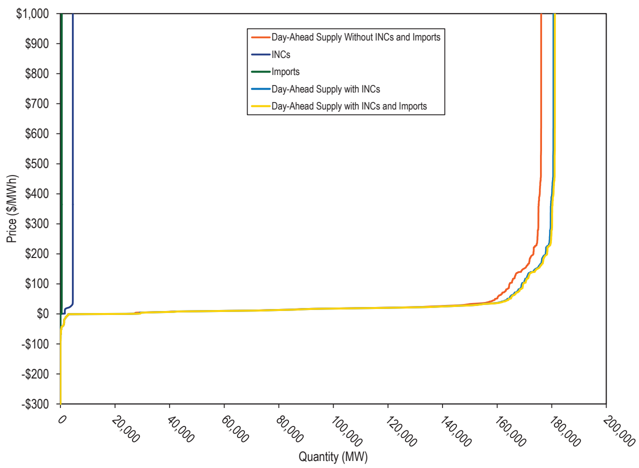


Figure 3-20 shows example PJM day-ahead aggregate supply curves for the typical dispatch price range.

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

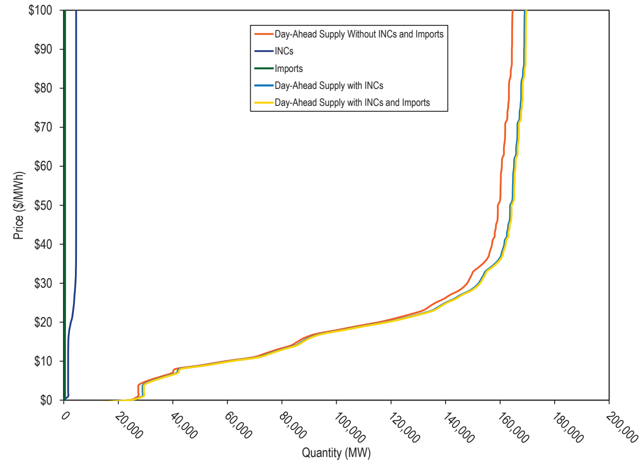


Table 3-21 shows the hourly average number of cleared and submitted increment offers and decrement bids by month for 2019 and 2020. The hourly average submitted increment MW increased by 2.7 percent and cleared increment MW decreased by 16.0 percent. The hourly average submitted decrement MW increased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

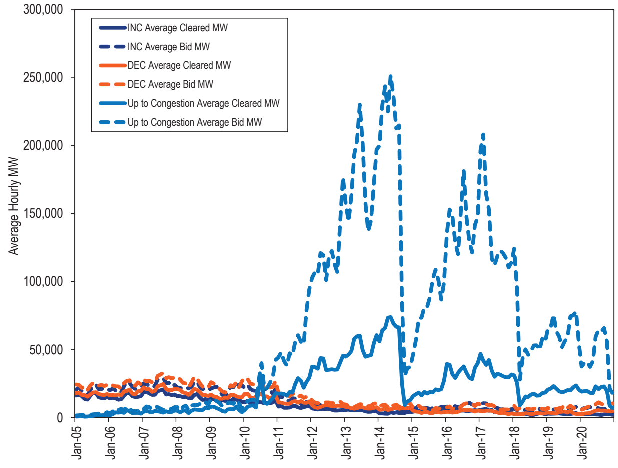
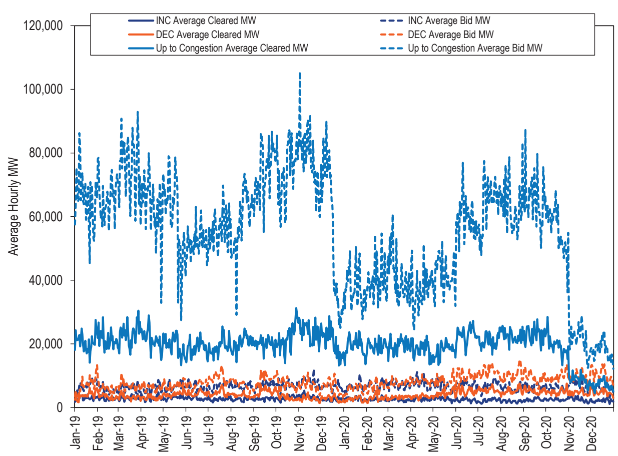


Figure 3-22 shows the daily volume of bid and cleared INC, DEC and up to congestion bids from 2019 through 2020.

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

Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
2019							
Wheels							
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

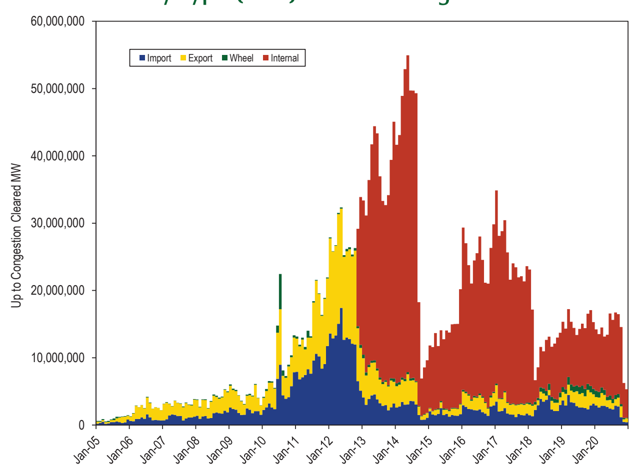
Table 3-34 and Figure 3-23 show total cleared up to congestion transactions and share of the top ten up to congestion paths by transaction type (import, export, or internal) in 2019 and 2020. Total up to congestion transactions decreased by 12.3 percent from 182.8 million MW in 2019 to 160.3 million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

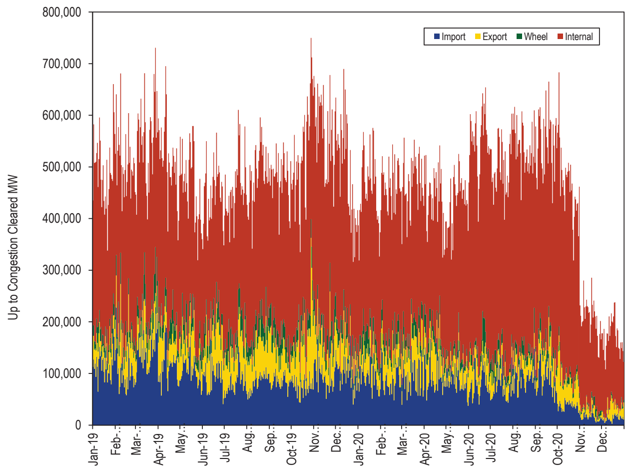
Figure 3-23 Monthly cleared up to congestion transactions by type (MW): 2005 through 2020



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]

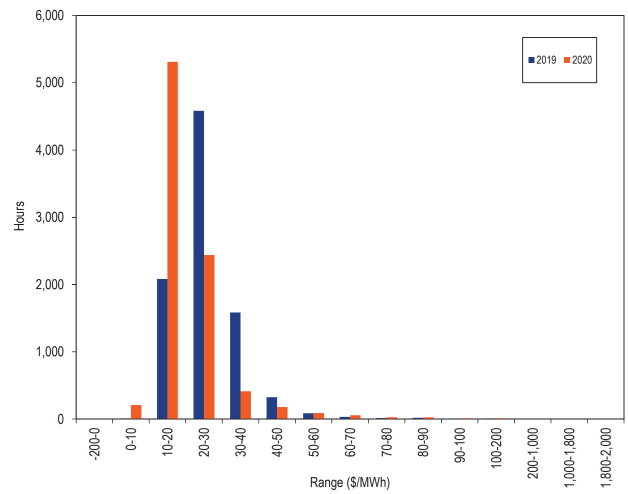
Table 3-35 Real-time, average LMP (Dollars per MWh): 1998 through 2020

	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.

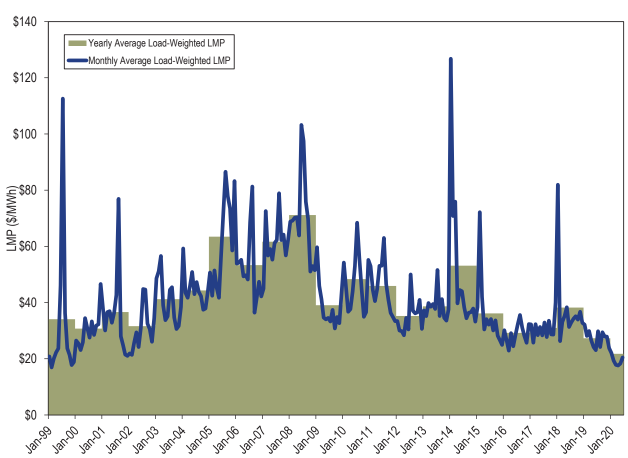
Table 3-36 Real-time, load-weighted, average LMP (Dollars per MWh): 1998 through 2020

	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.

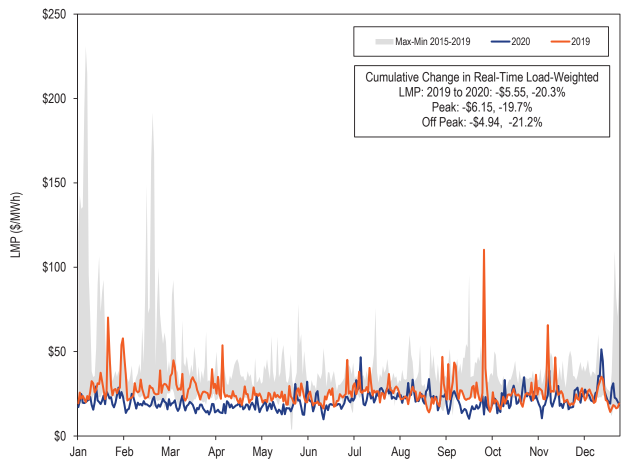
Figure 3-26 Real-time, monthly and annual, load-weighted, average LMP: 1999 through 2020



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

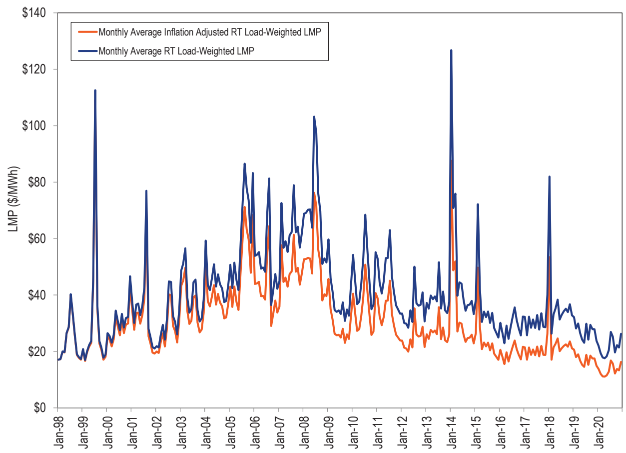


Table 3-37 Real-time, load-weighted, average LMP unadjusted and adjusted for inflation: 1998 through 2020

	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.

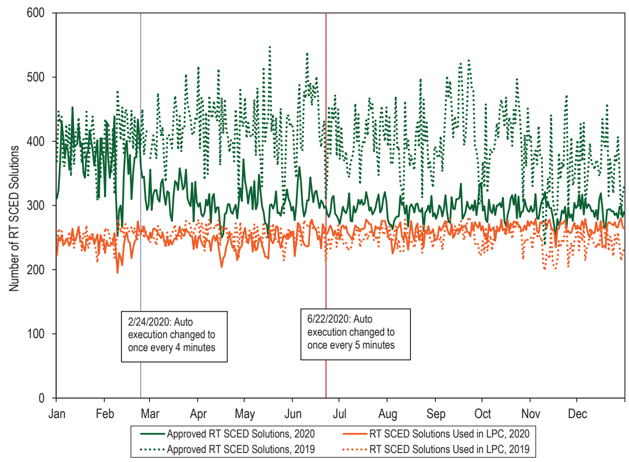
Table 3-38 shows that in 2020 only 82.1 percent of approved RT SCED solutions that were used to send dispatch signals to generators were used in calculating real-time energy market prices. The percent of approved solutions used for pricing increased from 69.0 percent to 78.7 percent from February to 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).

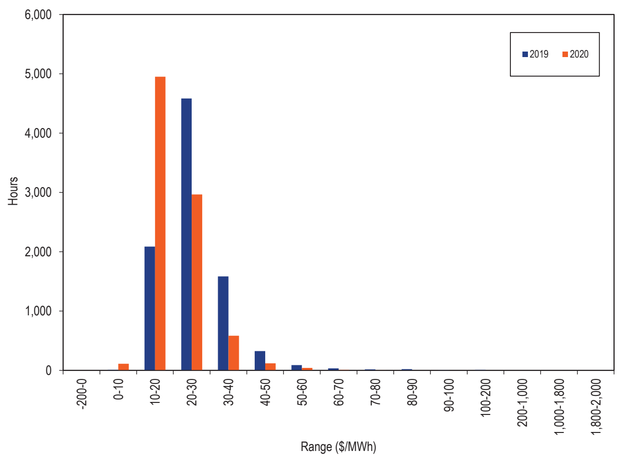
52 PJM changed this practice effective November 19, 2020. See PJM Manual 11: Energy and Ancillary Services Market Operations, Section 2.10 PJM Real-Time Price Verification Procedure, Rev. 111 (November 19, 2020).

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.

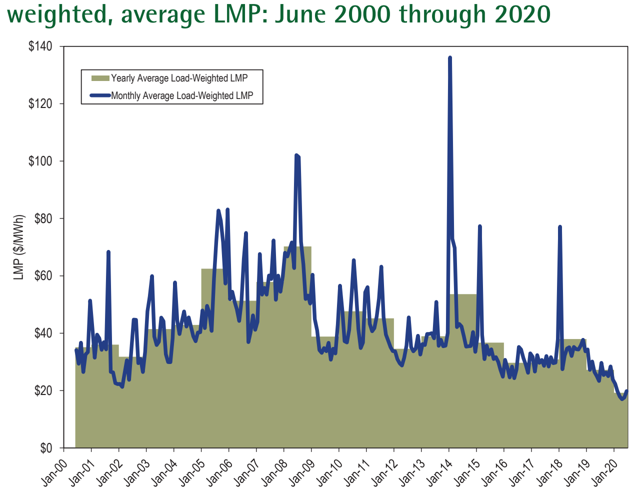
Table 3-42 Day-ahead, load-weighted, average LMP (Dollars per MWh): 2000 through 2020

	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]

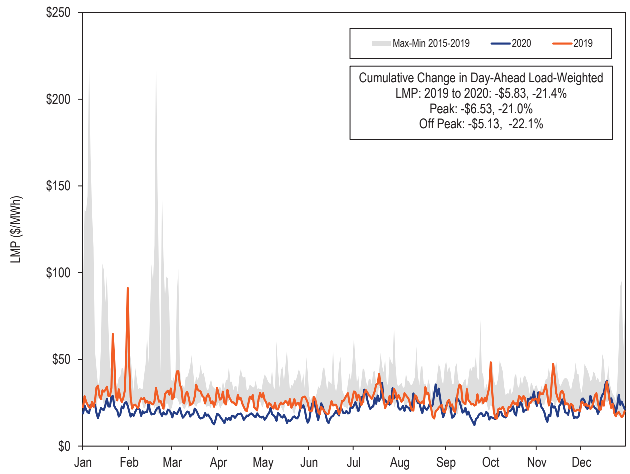
Figure 3-31 Day-ahead, monthly and annual, load-weighted, average LMP: June 2000 through 2020



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.

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).

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

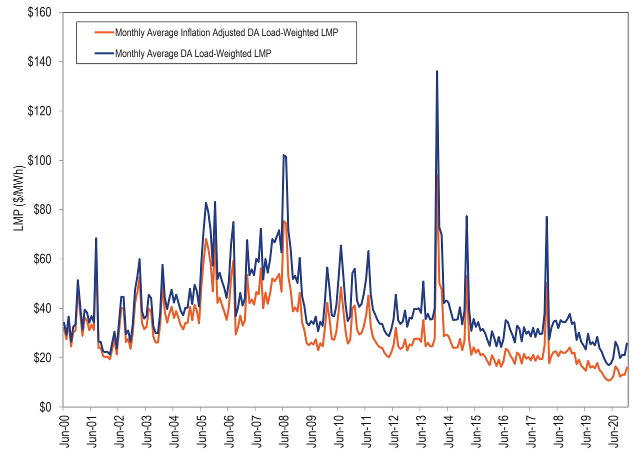


Table 3-43 Day-ahead, yearly, load-weighted, average LMP unadjusted and inflation adjusted: 2001 through 2020

	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.

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]

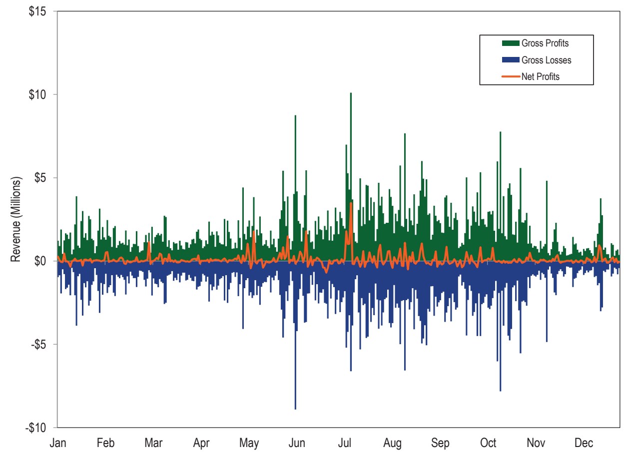


Figure 3-35 shows the cumulative UTC daily profits for each year from 2013 through 2020.

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

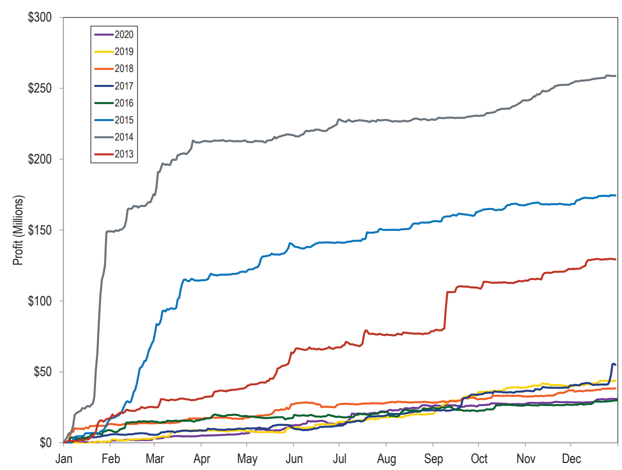


Table 3-46 shows UTC profits by month for 2013 through 2020. May 2016, September 2016, February 2017, June 2018 and September 2020 were the only months in this seven year period in which monthly profits were negative.

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]

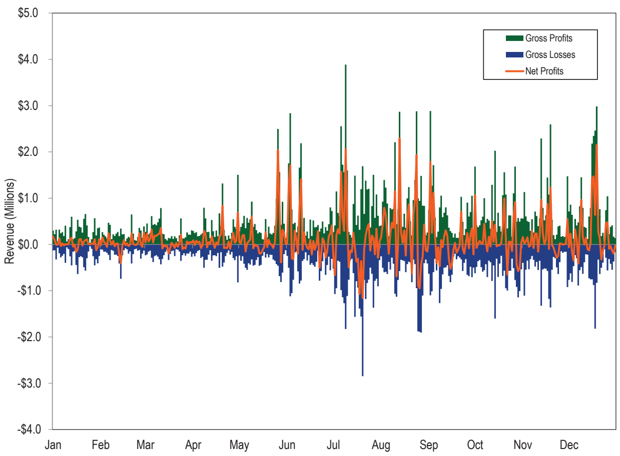


Figure 3-37 shows total INC daily gross profits and losses and net profits and losses in 2020.

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

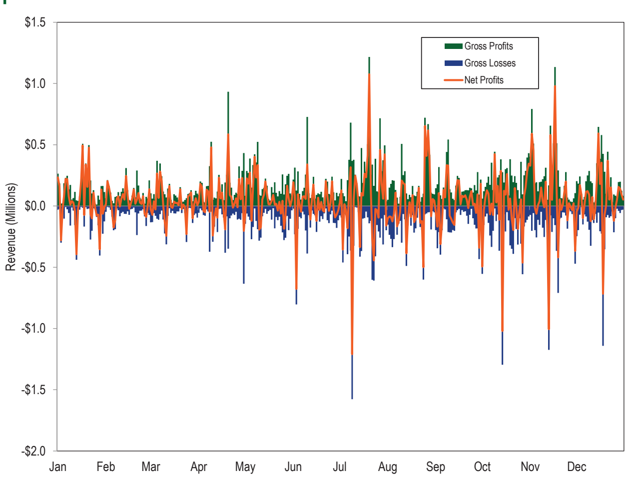


Figure 3-38 shows total DEC daily gross profits and losses and net profits and losses in 2020.

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

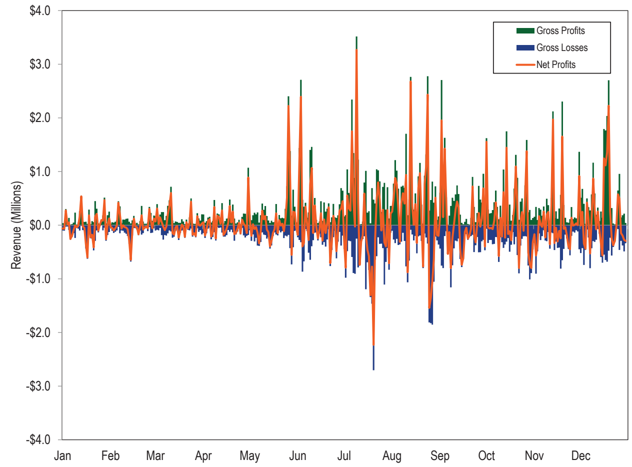
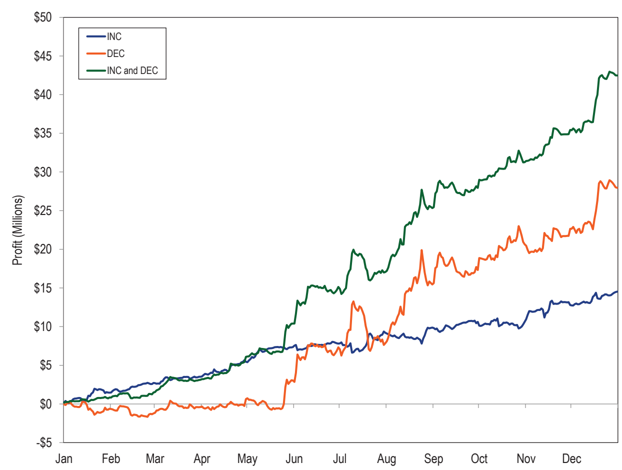


Figure 3-39 shows the cumulative INC and DEC daily profits for 2020.

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

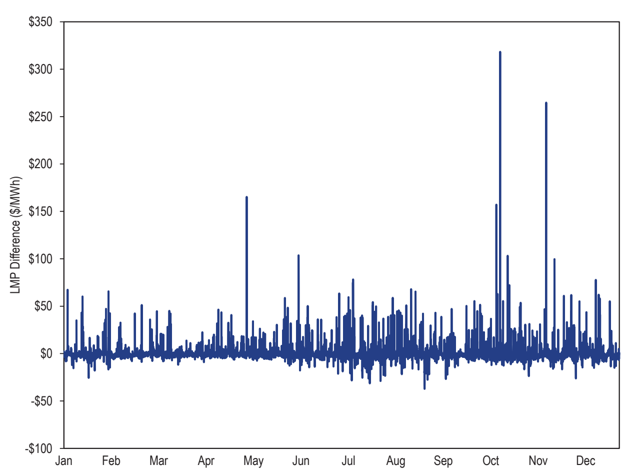
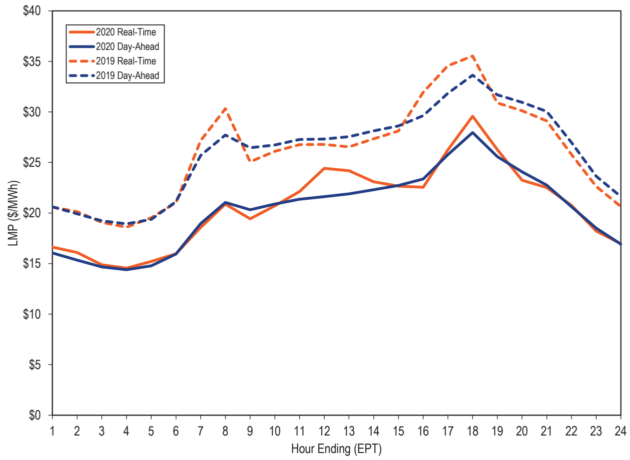


Figure 3-41 shows day-ahead and real-time, load-weighted, average hourly LMP 2019 and 2020.

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%)

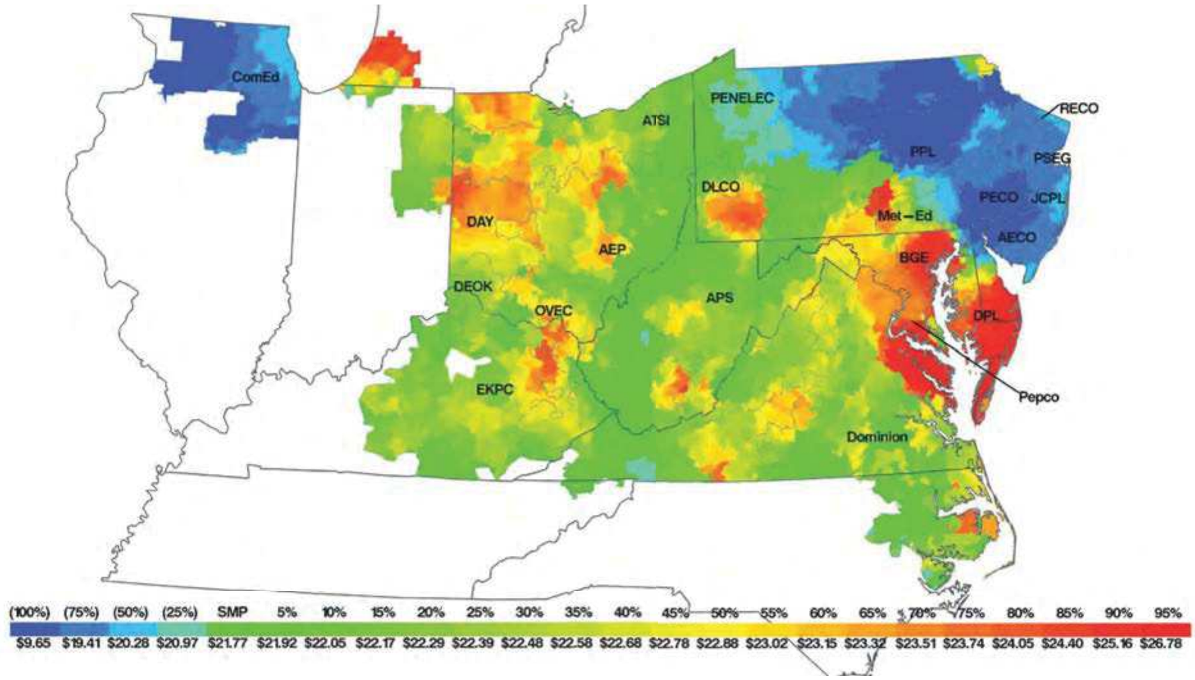
Table 3-52 shows zonal day-ahead, and day-ahead, load-weighted, average LMP in 2019 and 2020.

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.

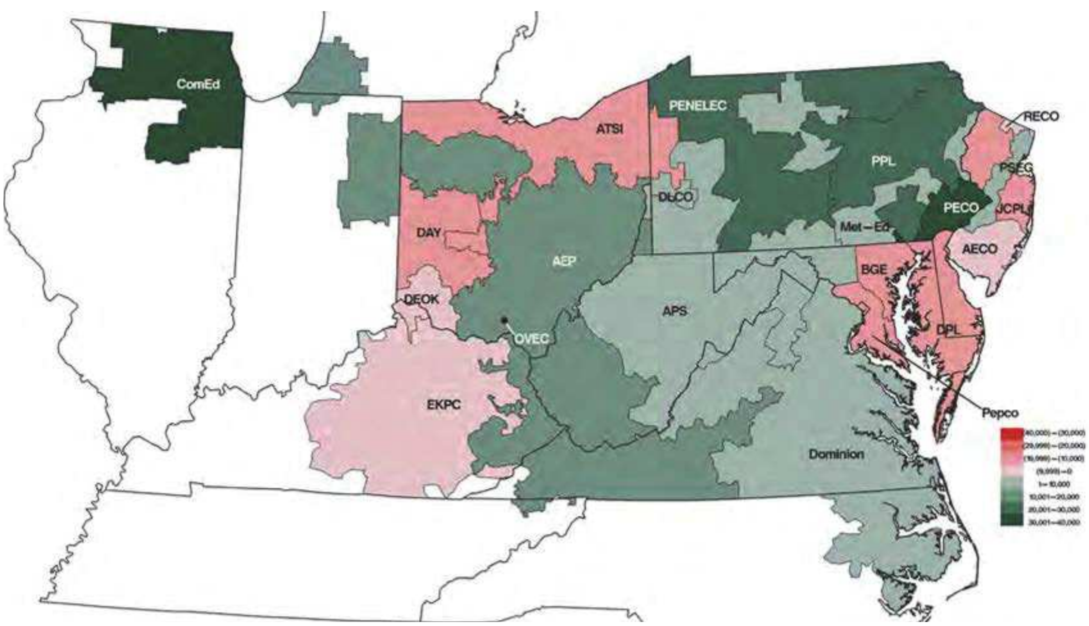
Table 3-56 Frequency of CT pricing logic used in the real-time market (constraint intervals): 2019 and 2020

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.

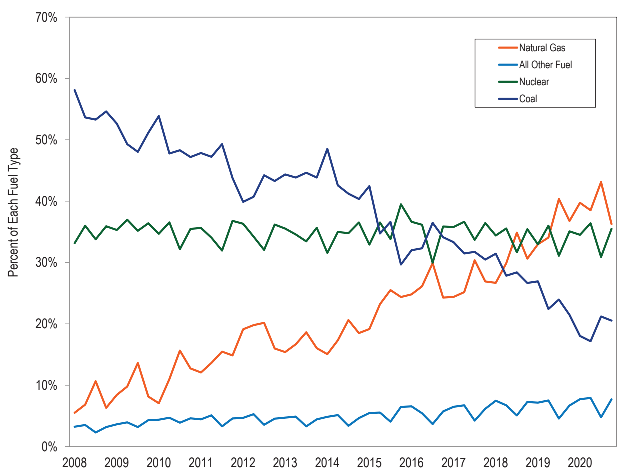
68 Other Gas includes: Landfill, Propane, Butane, Hydrogen, Gasified Coal, and Refinery Gas. Other Coal includes: Lignite, Liquefied Coal, Gasified Coal, and Waste Coal. Other oil includes: Gasoline, Jet Oil, Kerosene, and Petroleum-Other.

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.

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.

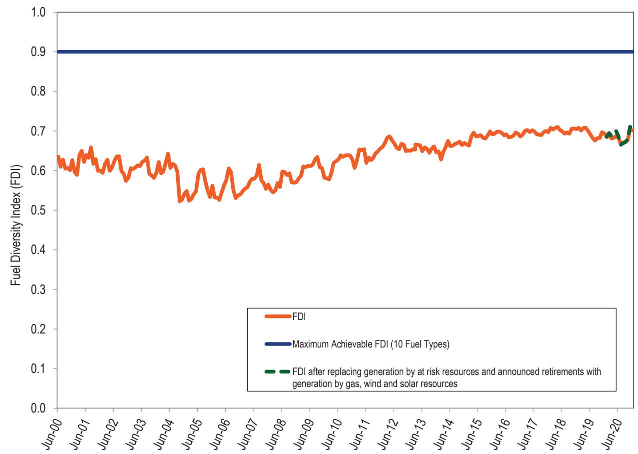
71 See Table 7-47 in the *2020 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

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.

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 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

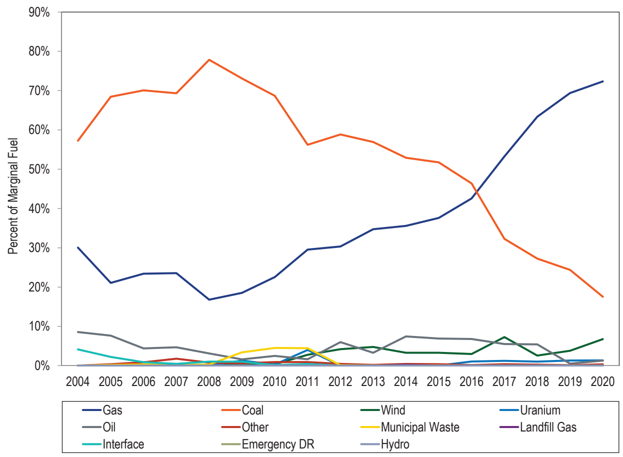


Table 3-61 shows the type of fuel used and technology where relevant, of marginal resources in the day-ahead energy market. In 2020, up to congestion transactions were 51.34 percent of marginal resources. Up to congestion transactions were 57.39 percent of marginal resources in 2019.

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

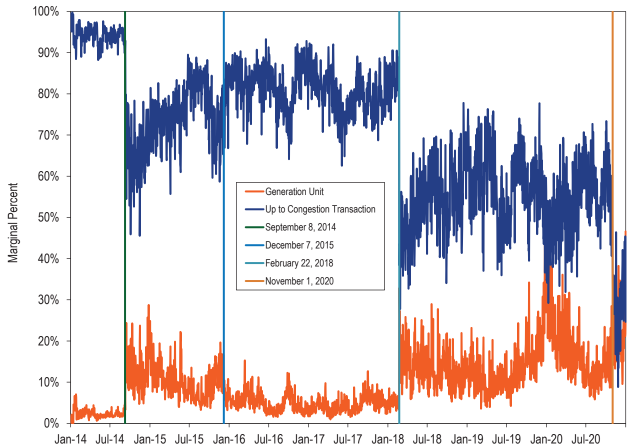
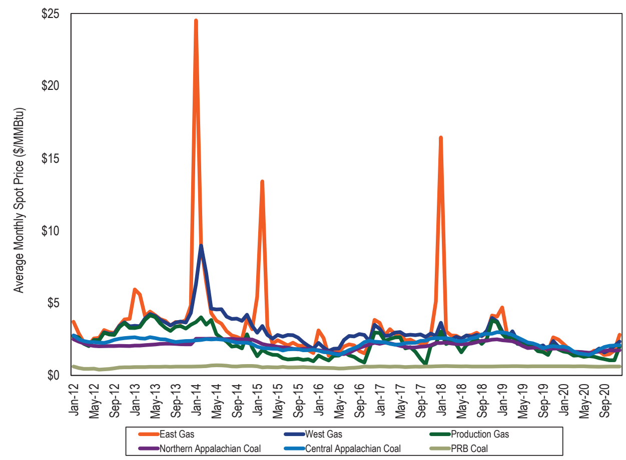


Figure 3-48 Spot average fuel price comparison: 2012 through 2020[78]



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

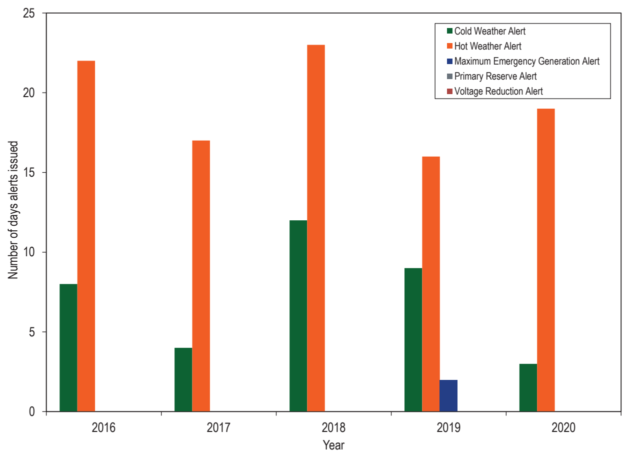
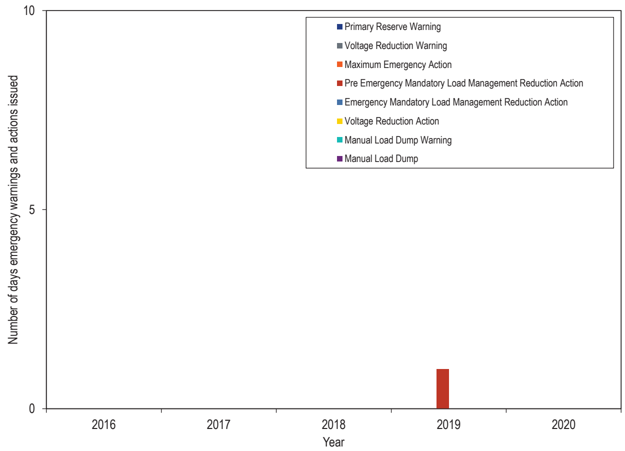


Figure 3-50 Declared emergency warnings and actions: 2016 through 2020[82]



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

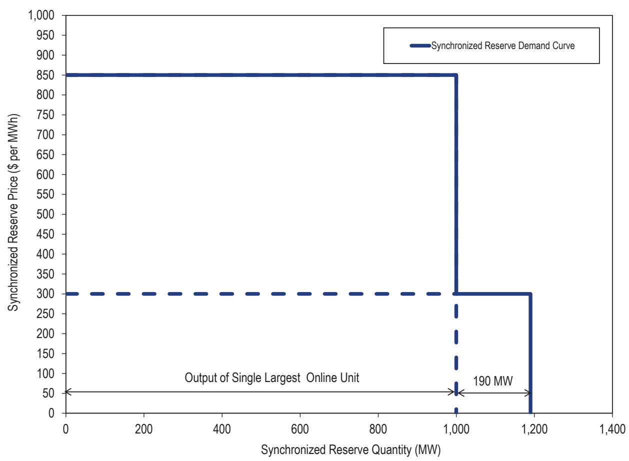
90 *See* PJM, "Capacity Market Seller Offer Cap Values," (March 15, 2019), *which can be accessed at* <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-cp-market-seller-offer-cap-values.ashx?la=en?>.

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]

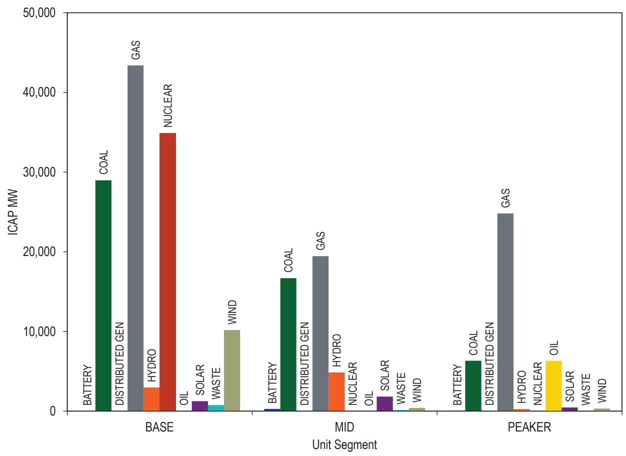


Figure 3-53 shows the ICAP of coal fired and gas fired units in PJM that are classified as baseload, intermediate and peaking from 2016 through 2020. Figure 3-53 shows that the total ICAP of coal fired units in PJM that are classified as baseload has been steadily decreasing and the total ICAP of gas 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

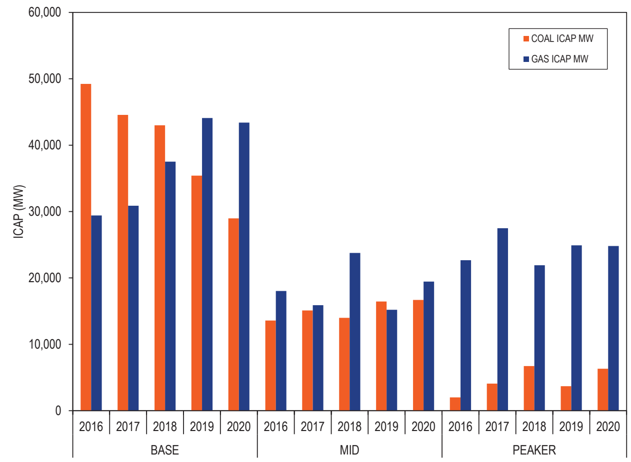
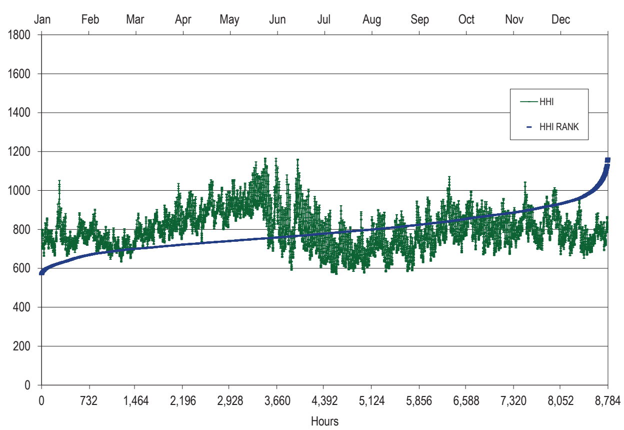


Figure 3-54 presents the hourly HHI values in chronological order and an HHI duration curve for 2020.

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

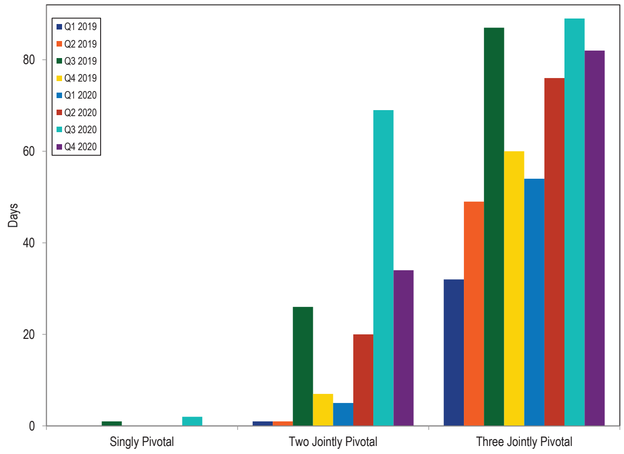


Table 3-84 provides the frequency with which each of the top 10 pivotal suppliers was singly or jointly pivotal for the day-ahead energy market in 2020. The largest pivotal supplier was singly pivotal on two days in 2020. All of the top 10 suppliers were one of two pivotal suppliers on at least 14 days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

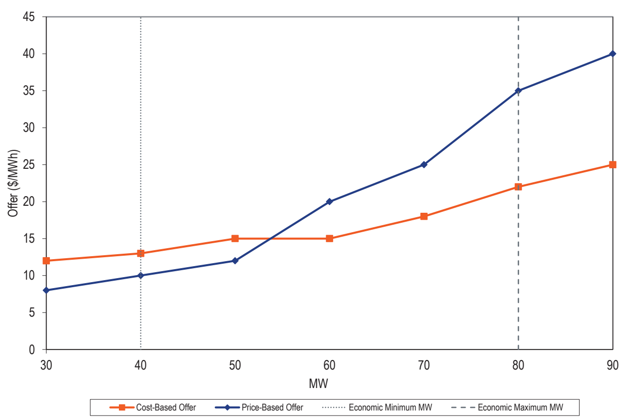


Table 3-91 shows the number and percent of unit schedule hours, by month, when unit offers included crossing curves in the PJM Day-Ahead and Real-Time Energy Markets, in 2020. The analysis only includes units that offer both price-based and cost-based offers. Units in PJM are only required to submit 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

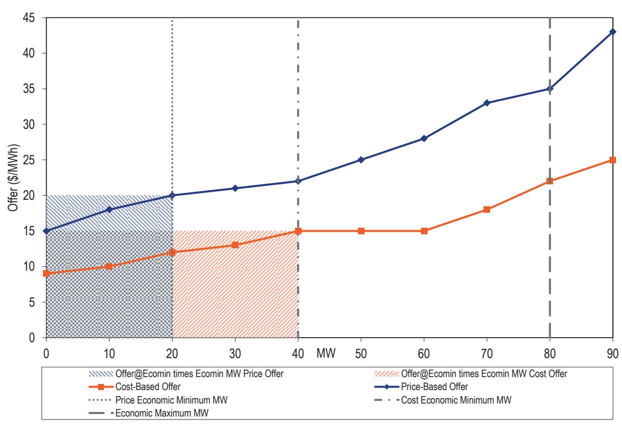


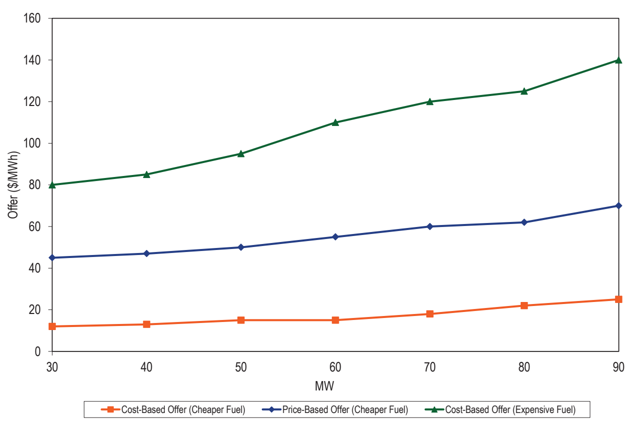
Table 3-93 shows the number and percent of unit schedule hours when units offered lower economic minimum MW in price-based offers than in cost-based offers while having a positive markup in the price-based offer.

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.

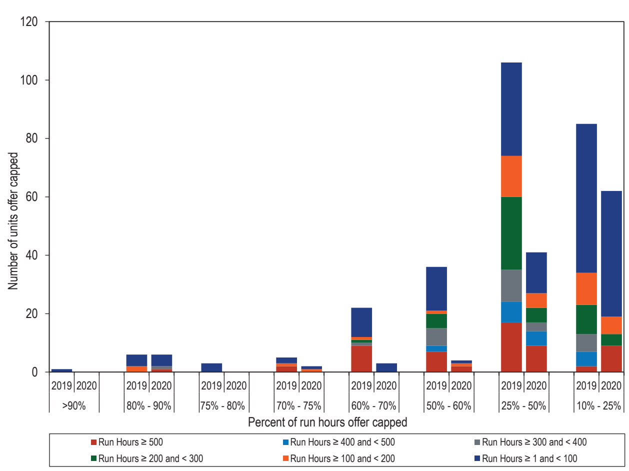
Table 3-97 presents data on the frequency with which units were offer capped in 2019 and 2020 as a result of failing the TPS test to provide energy for constraint relief in the real-time energy market and for reliability reasons. Table 3-97 shows that no units were offer capped for 90 percent or more 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
90%	2019	0	0	0	0	0	1
	2020	0	0	0	0	0	0
80% and < 90%	2019	0	0	0	0	2	4
	2020	1	0	1	0	0	4
75% and < 80%	2019	0	0	0	0	0	3
	2020	0	0	0	0	0	0
70% and < 75%	2019	2	0	0	0	1	2
	2020	0	0	0	0	1	1
60% and < 70%	2019	9	0	1	1	1	10
	2020	0	0	0	0	0	3
50% and < 60%	2019	7	2	6	5	1	15
	2020	2	0	0	0	1	1
25% and < 50%	2019	17	7	11	25	14	32
	2020	9	5	3	5	5	14
10% and < 25%	2019	2	5	6	10	11	51
	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

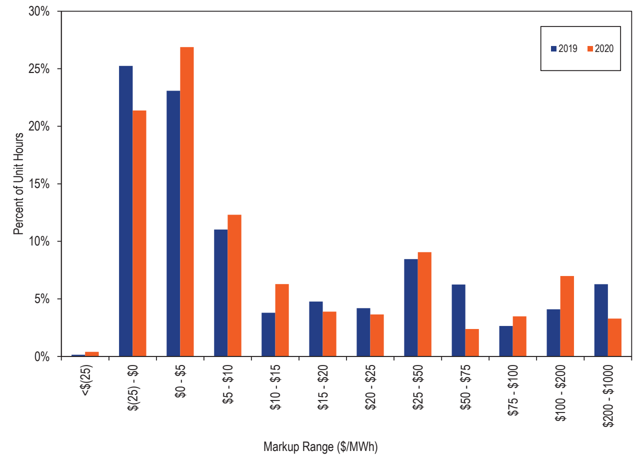


Figure 3-61 shows the frequency distribution of hourly markups for all coal units offered in 2019 and 2020 using unadjusted cost-based offers. Of the coal units offered in the PJM market in 2020, 47.7 percent of coal unit-hours had a maximum markup that was negative or equal to zero, increasing from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

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

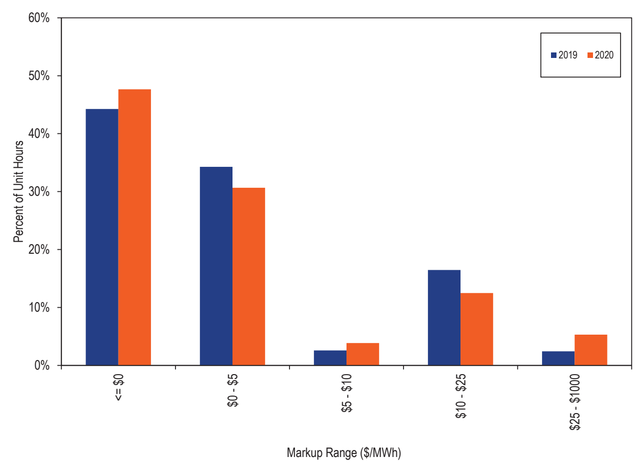
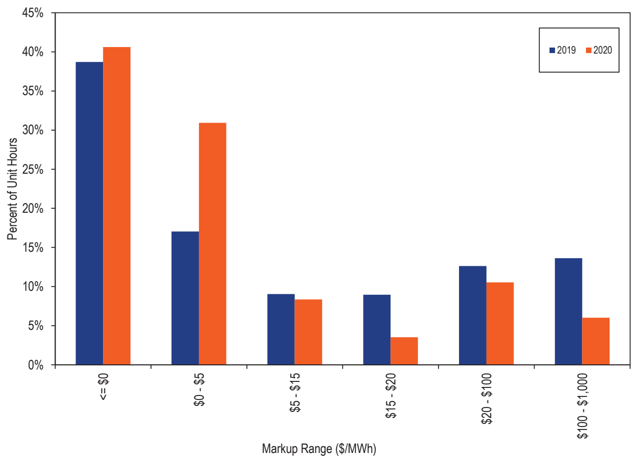


Figure 3-62 shows the frequency distribution of hourly markups for all offered oil units in 2019 and 2020 using unadjusted cost-based offers. Of the oil units offered in the PJM market in 2020, 40.6 percent of oil unit-hours had a maximum markup that was negative or equal to zero. More than 6.0 percent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

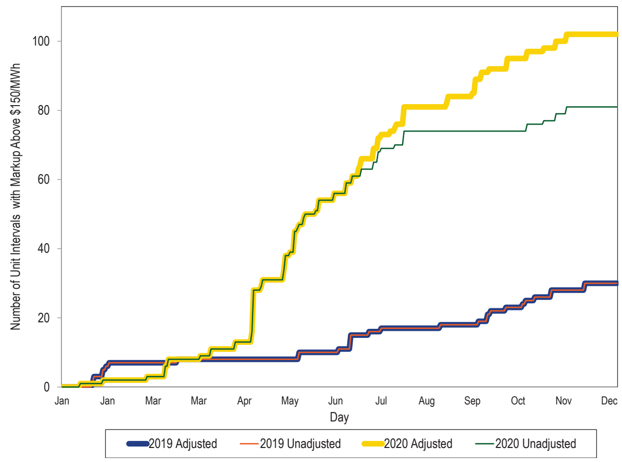


The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion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

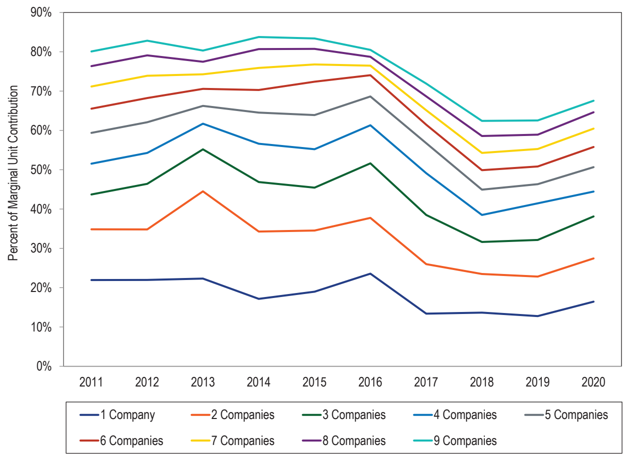


Table 3-113 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.[153] The contribution of each marginal resource to price at each load bus is calculated hourly, and summed by the parent company that offers the marginal resource into the day-ahead energy market. 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

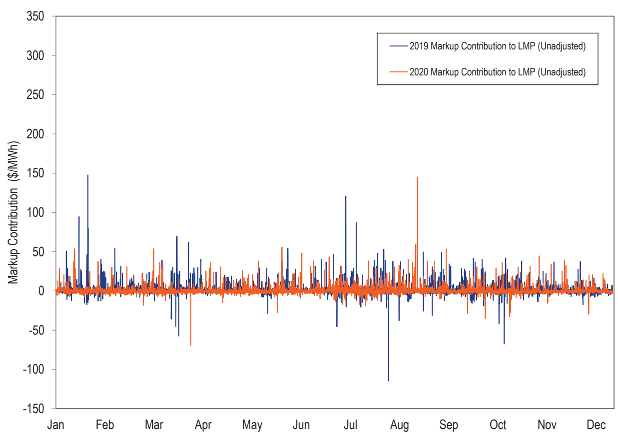
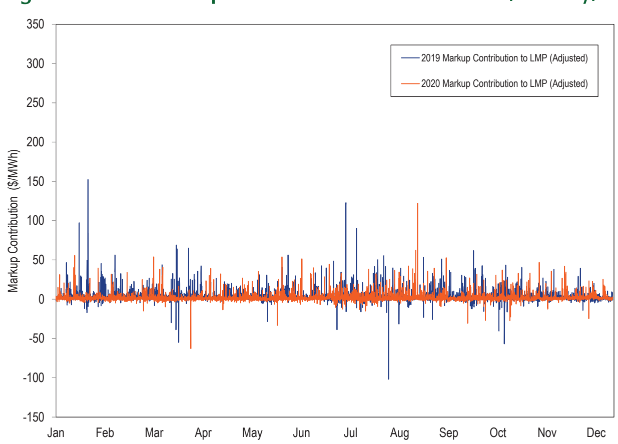


Figure 3-66 Markup contribution to real-time, hourly, load-weighted LMP (Adjusted): 2019 and 2020



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.

2022 State of the Market Report for the MISO Electricity Markets

Prepared By:

POTOMAC
ECONOMICS

**Independent Market Monitor
for the Midcontinent ISO**

June 15, 2023

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AAR	Ambient Adjusted Rating
AMP	Automated Mitigation Procedure
ARC	Aggregator of Retail Customers
ARR	Auction Revenue Rights
ASM	Ancillary Services Market
BCA	Broad Constrained Area
BTMG	Behind-The-Meter Generation
CDD	Cooling Degree Day
CONE	Cost of New Entry
CRA	Competitive Retail Area
CROW	Control Room Operating Window
CTS	Coordinated Transaction Scheduling
DA	Day-Ahead
DAMAP	Day-Ahead Margin Assurance Pmt.
DIR	Dispatchable Intermittent Resource
DR	Demand Response
DRR	Demand Response Resource
ECF	Excess Congestion Fund
EDR	Emergency Demand Response
EEA	Emergency Energy Alert
ELMP	Extended LMP
FERC	Federal Energy Reg. Commission
FFE	Firm Flow Entitlement
FRAC	Fwd. Reliability Assessment Commitment
FSR	Fast-Start Resource
FTR	Financial Transmission Right
GSF	Generation Shift Factor
HDD	Heating Degree Day
HHI	Herfindahl-Hirschman Index
ICAP	Installed Capacity
IESO	Ontario Electricity System Operator
IMM	Independent Market Monitor
ISO-NE	ISO New England, Inc.
JOA	Joint Operating Agreement
LAC	Look-Ahead Commitment
LBA	Local Balancing Area
LMP	Locational Marginal Price
LMR	Load-Modifying Resource
LRZ	Local Resource Zone
LSE	Load-Serving Entity

M2M	Market-to-Market
MCC	Marginal Congestion Component
MCP	Market Clearing Price
MISO	Midcontinent Independent Sys. Operator
MMBtu	Million British thermal units
MSC	MISO Market Subcommittee
MVL	Marginal Value Limit
MW	Megawatt
MWh	Megawatt-hour
NCA	Narrow Constrained Area
NERC	North American Electric Reliability Corp.
NSI	Net Scheduled Interchange
NYISO	New York Independent System Operator
ORDC	Operating Reserve Demand Curve
PJM	PJM Interconnection, Inc.
PRA	Planning Resource Auction
PRMR	Planning Reserve Margin Requirement
PVMWP	Price Volatility Make-Whole Payment
RAN	Resource Availability and Need
RDT	Regional Directional Transfer
RPE	Reserve Procurement Enhancement
RSG	Revenue Sufficiency Guarantee
RT	Real-Time
RTO	Regional Transmission Organization
RTORSGP	Real-Time Offer Revenue Sufficiency Guarantee Pmt.
SMP	System Marginal Price
SOM	State of the Market
SPP	Southwest Power Pool
SSR	System Support Resource
STLF	Short-Term Load Forecast
STR	Short Term Reserves
TCDC	Transmission Constraint Demand Curve
TLR	Transmission Line Loading Relief
TO	Transmission Owner
TVA	Tennessee Valley Authority
UCAP	Unforced Capacity
UDS	Unit Dispatch System
VLR	Voltage and Local Reliability
VOLL	Value of Lost Load
WUMS	Wisconsin-Upper Michigan System

EXECUTIVE SUMMARY

As the Independent Market Monitor (IMM) for the Midcontinent Independent System Operator (MISO), we evaluate the competitive performance and efficiency of MISO's wholesale electricity markets. The scope of our work in this capacity includes monitoring for attempts to exercise market power or manipulate the markets, identifying market design flaws or inefficiencies, and recommending improvements to market design and operating procedures. This Executive Summary to the *2022 State of the Market Report* provides an overview of our assessment of the performance of the markets and summarizes our recommendations.

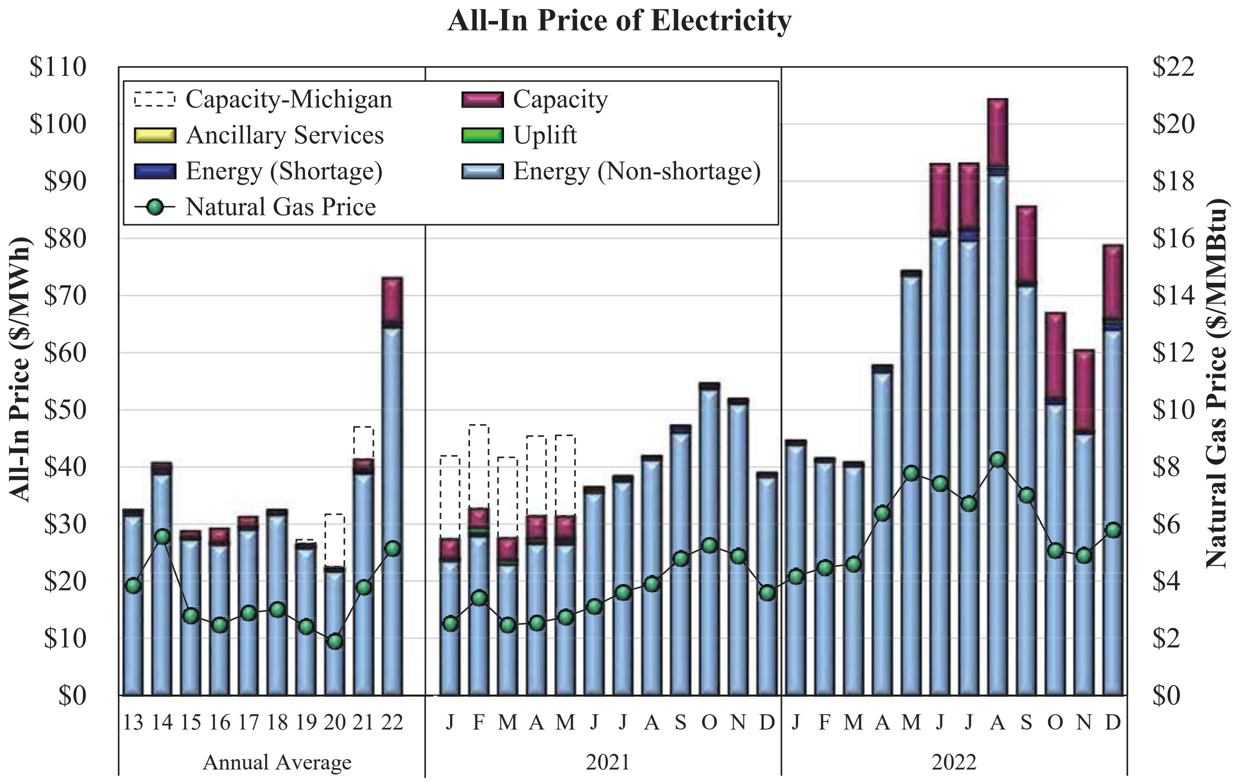
MISO operates competitive wholesale electricity markets in the Midcontinent region that extends geographically from Montana in the west, to Michigan in the east, and to Louisiana in the south. The MISO South subregion shown to the right in blue was integrated in late 2013.

MISO launched its markets for energy and financial transmission rights (FTRs) in 2005, ancillary services market in 2009, and the capacity market in 2013. These markets coordinate the planning, commitment, and dispatch of generation to ensure that resources are meeting system demand reliably at the lowest cost.

Additionally, the MISO markets establish prices that reflect the marginal value of energy at each location on the network (i.e., locational marginal prices or LMPs). These prices facilitate efficient actions by participants in the short term (e.g., to make resources available and to schedule imports and exports) and support long-term decisions (e.g., investment, retirement, and maintenance). The remainder of this Executive Summary provides an overview of market outcomes, a discussion of key market issues, and a list of recommended improvements.

Summary of Market Outcomes and Competitive Performance

The MISO energy and ancillary services markets generally performed competitively in 2022. Multiple factors affected market outcomes, including higher average load caused by economic growth as the effects of COVID-19 diminished, the continuing change in the resource mix, and rising natural gas prices. The figure below shows a 65 percent increase in real-time energy prices throughout MISO, which averaged $65 per MWh. Multiple factors contributed to this increase, including a 36 percent increase in natural gas prices, a reduction in coal conservation measures by the fall, the effects of Winter Storm Elliott in late December, and a 2 percent increase in average load.



Frequent transmission congestion often caused prices to diverge throughout MISO. The value of real-time congestion increased by nearly thirty percent to a record $3.6 billion in 2022, largely because of rising natural gas prices and higher wind output throughout the year. Wind output now contributes to just under half of MISO's real-time congestion. Congestion also resulted in wind curtailments averaging approximately 726 MW per hour and as high as 5.9 GW in some hours. Ten percent of this congestion occurred during Winter Storm Elliott in just two days.

Real-time congestion was higher than optimal because several key issues continue to encumber congestion management, including:

- Conservative static ratings by most transmission owners;
- Not utilizing network reconfigurations to redirect flows around overloaded constraints;
- Issues in defining and coordinating market-to-market constraints;
- More active and larger transmission derates by MISO operators; and
- MISO's limited authority to coordinate outages.

To address these concerns, we continue to recommend a number of improvements to lower the cost of managing congestion on MISO's system. These improvements promise some of the largest short-term benefits of any of the recommendations we make in this report.

Competitive Performance

Outcomes in the MISO markets continue to show a consistent correlation between energy and natural gas prices that is expected in a well-functioning, competitive market. Gas-fired resources are most often the marginal source of supply, and fuel costs constitute the vast majority of most resources' marginal costs. Competition provides a powerful incentive to offer resources at prices reflecting their marginal costs. We evaluate the competitive performance of the markets by assessing the suppliers' conduct using the following two empirical measures of competitiveness:

- A "price-cost mark-up" compares simulated energy prices based on actual offers to energy prices based on competitive offer prices. As in prior years, the price-cost mark-up was effectively zero, indicating the markets were highly competitive.
- The "output gap" is a measure of potential economic withholding. It remained very low, averaging 0.2 percent of load, which is effectively *de minimus*. Consequently, market power mitigation measures were applied infrequently.

These results, as well as the results of our ongoing monitoring, confirm that the MISO markets are delivering the benefits of robust competition to MISO's customers.

Market Design Improvements

Although MISO's markets continue to perform competitively, we have identified a number of key areas that should be improved as MISO's generating fleet evolves in the coming years. Hence, this report provides several recommendations, five of which are new this year. MISO has continued to respond to past recommendations and implemented several key changes in 2022.

Key changes included:

- Transitioning to a seasonal market with availability-based accreditation for conventional resources. The first auction under this new framework ran in the spring of 2023;
- Implementing changes in the reliability commitment process in late 2022 and early 2023 to reduce unnecessary resource commitments and associated RSG;
- Continuing to lower the Generator Shift Factor (GSF) cutoff for constraints, which allows a broader set of generators to be utilized to manage transmission constraints; and
- Improving the demand curves for the Short-Term Reserve (STR) product and the Ramp-Up Capability product.

These improvements have improved the performance of the markets and the operation of the system. These improvements and other recommendations are discussed throughout this report.

Winter Storm Elliott Event

MISO experienced a significant event late in the year—Winter Storm Elliott—that stressed its ability to maintain reliability and assist its neighbors. We evaluate this event because it illuminates market and operational issues that do not arise under normal conditions. During the event, widespread extremely cold temperatures simultaneously increased demand and reduced supply. MISO and most neighboring control areas experienced large load forecasting errors, causing capacity shortfalls in a number of these areas. Tight gas supply conditions contributed to the capacity shortages. These events are evaluated in Section II.E of the report.

The most serious reliability issues were experienced by TVA, which implemented rolling blackouts throughout the day on December 23. MISO provided extensive support to TVA and other neighboring LBAs, including Southern Company, AECI, SPP, and PJM. Unusually large exports and wheels contributed to more than $350 million in real-time congestion on December 23 and 24. MISO took unprecedented actions to maintain exports to its neighbors, including:

- Committing many resources to sustain the exports, even as congestion caused a large number of resources to be "stranded" behind constraints. These commitments generated more than $11 million in RSG;
- Calling a capacity emergency with no forecasted capacity deficiency in order to curtail Load Modifying Resources (LMRs) that would otherwise be unavailable;
- Deciding not to curtail non-firm exports to a number of areas that MISO's operating procedures called for it to cut; and
- Manually redispatching (MRD) generation to manage severe congestion associated with the unusually large net exports to neighboring areas.

The last action, which involves directing a unit's output to a fixed level, can be necessary when the cost of moving the resources needed is higher than the perceived value of managing the flows on the constraint. MRD is not ideal because it prevents the market from properly pricing the congestion, is often inefficient, and can generate large uplift costs. These actions generated an additional $19 million in uplift costs during the event.

Our evaluation of this event highlights opportunities for operational improvements and we provide the following recommendations for MISO to consider:

1. To avoid MRDs in the future, we recommend that MISO:
    a. Add higher-priced steps to the Transmission Constraint Demand Curves (TCDC).
    b. Improve its procedures to increase TCDCs as needed to ensure that the dispatch model will reasonably manage network flows and violations under all conditions.
2. Strengthen controls and logging to reduce deviations from its operating procedures.
3. To the extent that operating actions will be taken in the future primarily to support neighboring areas, MISO should:
    a. Modify its operating procedures to specify these actions and the requisite criteria for taking each action; and
    b. Establish operating agreements with neighboring areas to better coordinate during emergencies and to establish equitable provisions to allocate the associated costs.

Future Market Needs

The MISO system is changing rapidly as the generating fleet transitions and new technologies enter the market. Although the nature and pace of the change is uncertain, MISO will have to adapt to new operational and planning needs. MISO has been grappling with these issues in several initiatives. Fortunately, MISO's markets are robust and well-suited to facilitate this transition without fundamental market changes. However, we discuss below some key improvements that will be needed as this transition occurs.

Over the past decade, the penetration of wind resources has steadily increased as baseload coal resources have retired. This trend is likely to accelerate as large quantities of solar, battery storage resources, and hybrid resources join new wind resources in the interconnection queue. The most significant supply-side challenges include:

- *Wind*: As wind generation increases, the volatility of its output grows as do the errors in forecasting the wind output.
- *Solar*: Solar resources are forecasted to grow more rapidly than any other resource type in the next 20 years. This will lead to significant changes in the system's ramping needs. For example, conventional resources will increasingly have to ramp up quickly in the evenings as the sun sets, particularly in the winter season since load peaks in the evening.
- *Distributed Energy Resources*: MISO is grappling with visibility and uncertainty around these resources. They are generally going to be connected to the distribution system, yet FERC has ordered that DERs be able to participate in all aspects of the RTO markets.[1]
- *Energy Storage*: MISO is working to enable Energy Storage Resources (ESRs) to participate in the markets while recognizing their unique characteristics. Falling costs and rising price volatility should cause ESRs to be increasing economic in the future.

MISO has managed the growth in intermittent resources reliably so far, but we discuss three critical improvements in the following subsections that will be needed:

- Improving shortage pricing to compensate resources that are available and flexible and that allow MISO to maintain reliability when shortages arise;
- Introducing a reliability-based demand curve in the capacity market that will align with the marginal reliability value that capacity provides; and
- Accrediting capacity resources based on their marginal contribution to reliability.

Shortage Pricing in the Energy and Ancillary Services Markets

Virtually all shortages in energy and ancillary markets are of reserve products (i.e., RTOs will hold less reserves rather than not serve the energy demand). When an RTO is short of reserves, the value of the foregone reserves should set the clearing price for reserves and be embedded in

1 See: Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, Order No. 2222, 172 FERC ¶ 61,247 (2020).

all higher-value products, including energy. Efficient shortage prices play a key role in establishing economic signals to guide investment and retirement decisions in the long term, facilitating optimal interchange and generator commitments in the short-run, and efficiently compensating flexible resources. Compensating flexible resources efficiently will be increasingly important as the penetration of renewable resources increases. We expect the frequency of shortages to rise in the future as intermittent output volatility increases.

The shortage value is established by the reserve demand curve for each reserve product, so efficient shortage pricing requires a properly-valued operating reserve demand curve (ORDC). An efficient ORDC should reflect the marginal reliability value of reserves at each shortage level, which is equal to: *the value of lost load (VOLL) * the probability of losing load*. Unfortunately, neither of these two components is efficiently reflected in MISO's ORDC.

Improving the VOLL. We conducted a literature review and ultimately utilized a model developed by Lawrence Berkeley National Laboratory to estimate an updated VOLL for MISO. Based on this analysis, we recommend MISO update its current assumed VOLL of $3500 to an efficient VOLL of $25,000 per MWh. Although we support this value as the basis for an efficient ORDC, we believe it would be reasonable to cap the maximum ORDC at a lower value (e.g., $10,000) because: (i) very few shortages would be priced in this range; (ii) pricing shortages at higher prices could result in inefficient interchange with MISO's neighbors who price shortages at lower levels; and (iii) pricing at higher price levels could cause MISO's dispatch model to make inefficient trade-offs between retaining reserves and managing flows on network constraints.

Improving the Slope of the ORDC. The slope of the ORDC should be determined by how the probability of losing load changes as the level of operating reserves falls. We estimated the probability of losing load using a Monte Carlo model that simulated: generation contingencies, wind forecast errors, load forecast errors, and NSI uncertainty. Considering all these factors produces a flatter slope for the ORDC than MISO's current approach. Adopting this approach to determine the ORDC slope along with a reasonable VOLL will result in more efficient economic signals to govern both short-term and long-term decisions by MISO participants.

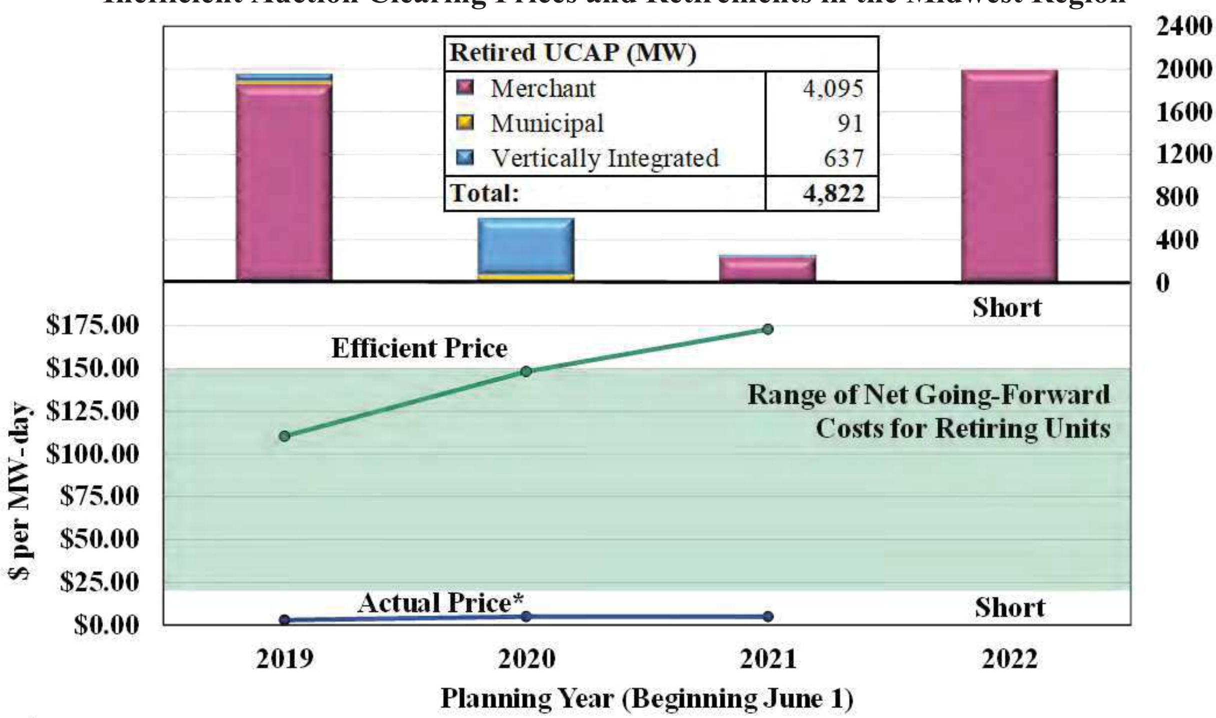
Reliability-Based Capacity Market Demand Curve

One of the most essential changes to the MISO markets is to reform the capacity market so it provides efficient economic incentives. These reforms will generally benefit MISO's regulated utilities that have historically shouldered most of the burden of ensuring resource adequacy. The problem is that the demand for capacity does not reflect its true reliability value. The fixed quantity of required demand subject to a deficiency price represents a "vertical demand curve." The implication of a vertical demand curve is that the first MW of surplus capacity beyond the minimum requirement has no reliability value. Clearing prices under a vertical demand curve (where it intersects supply) will be close to zero when the market has even a small surplus.

In reality, each unit of surplus capacity above the minimum requirement will increase system reliability and lower real-time energy and ancillary services costs for consumers, although these effects diminish as the surplus increases. Hence, the true marginal contribution of surplus capacity to reliability can only be captured by a sloped reliability-based demand curve, which will set capacity prices that reflect this marginal reliability value.

The effect of setting inefficiently low prices has manifested in a shortage in the Midwest region in the 2022/2023 PRA by facilitating a sustained trend of retirements of resources that would have been economic to remain in operation. This outcome is demonstrated in the following figure, which shows: a) the economic capacity in the Midwest (by type of participant) that retired each year; b) the actual capacity prices compared to our estimate of an efficient capacity price in each year; and c) the range of net going-forward costs that resources would have needed to recover in the capacity auction to avoid suspension or retirement.

Inefficient Auction Clearing Prices and Retirements in the Midwest Region



* Actual prices are the unconstrained auction clearing prices of the Midwest. Zone 7 separated in 2019 and 2020.

Most of the inefficient retirements over the past four years were made by merchant generators who rely on market signals to make long-term investment and retirement decisions. Retail ratepayers subsidize resources owned by vertically-integrated utilities and shield those resources from MISO's inefficient capacity prices. MISO's poor capacity market design led to a shortage of resources in the 2022/2023 PRA in the Midwest. MISO was not short in the 2023/2024 PRA as its load forecast and requirements fell and some new capacity resources entered. However, we expect this design flaw to cause the region to struggle to maintain adequate resources.

In conclusion, implementing a reliability-based demand curve should be one of MISO's highest priorities under its Reliability Imperative because it will:

- Establish stable and efficient capacity prices to govern investment and retirement decisions, which is particularly important for unregulated competitive suppliers;
- Ensure that participants supplying more than their share of the required capacity in MISO receive capacity revenues that reflect their contribution to the system's reliability needs (this is most vertically integrated utilities whose regulated retail customers currently support the bulk of the costs of MISO's generating resources); and
- Provide incentives for load-serving entities (LSEs) that do not have sufficient capacity to plan better by contracting for existing capacity or building new capacity.

Improving MISO's Capacity Accreditation

A resource's true reliability value is its expected availability to provide energy or reserves when the system is at risk of load shedding. This value depends on (a) the timing of the system's hours of greatest need and (b) the factors that affect the availability of a resource in those hours. Importantly, the hours of greatest need are affected by the portfolio of generation and the output profile of the portfolio – this value can be characterized as a "marginal value". For resources to be accredited accurately, RTOs must utilize methods that determine their marginal value.

MISO's recently implemented availability-based accreditation is generally consistent with this principle because it measures resources' availability during the tightest hours, which are determined by the operating characteristics of the existing generation portfolio. Intermittent resources are generally accredited using methods that predict the expected output of the resources under different conditions. One such method is the Expected Load Carrying Capability (ELCC) used by MISO, although its current approach is not marginal.

If MISO fails to accredit resources based on their marginal value, the inflated accreditation to low-value (over-saturated) resources will substantially increase costs to consumers and undermine incentives to the resources with high-value attributes that the system needs. Additionally, accurate accreditation will inform the states' integrated resource planning processes and ensure that these processes produce resource plans that will satisfy the reliability needs of the MISO region. For all of these reasons we find that accrediting all resources based on their marginal reliability value is essential for satisfying MISO's reliability imperative.

Other Important Market Design Improvements

As MISO's generating fleet transforms, its markets will play an essential role in integrating new resources and maintaining reliability. Improving shortage pricing, the capacity demand curve, and capacity accreditation are the highest priority changes. However, Section II.B of the report recommends other important improvements to account for the rising system uncertainty and to improve the utilization of the network as transmission flows become more volatile. These are changes that will be key for successfully navigating the transition of MISO's portfolio:

- Introduction of an uncertainty product to reflect MISO's current and future need to commit resources to have sufficient supply available in real time to manage uncertainty;
- Implementation of a look-ahead dispatch and commitment model in the real-time market;
- Introduction of new processes to optimize the operation of the transmission system and improve its utilization; and
- Development of rules and processes for integrating DERs that will satisfy essential reliability and efficiency objectives.

Energy Market Performance and Operations

Day-Ahead Market Performance

The day-ahead market is critical because it coordinates most resource commitments and is the basis for almost all energy and congestion settlements with participants. Day-ahead market performance can be judged by the extent to which day-ahead prices converge with real-time prices, because this will result in resource commitments that efficiently satisfy the system's real-time operational needs. In 2022:

- The difference between day-ahead and real-time prices, including day-ahead and real-time uplift charges, was roughly 3 percent. This is good convergence overall.
- However, episodes of congestion caused by generation and transmission line outages led to transitory periods of divergence at various locations.

Virtual transactions provided essential liquidity and improved the convergence of day-ahead and real-time energy prices. Average cleared virtual transactions in the Midwest and South increased by 36 and 15 percent in 2022, respectively. Our evaluation of virtual transactions revealed:

- The vast majority of the virtual trading was by financial participants whose transactions were the most price sensitive and the most beneficial to the market;
- Most of the virtual transactions improved price convergence and economic efficiency in the day-ahead market based on our detailed assessment of the transactions; and
- Participants continued to submit price-insensitive matching virtual supply and demand transactions to arbitrage congestion differences. The virtual spread product we continue to recommend would facilitate this arbitrage in a more efficient, lower-risk manner.

Real-Time Market Performance and Price Formation

The performance of the real-time market is crucial because it governs the dispatch of MISO's resources. The real-time market sends economic signals that facilitate scheduling in the day-ahead market and longer-term investment and retirement decisions. Efficient price signals during shortages and tight operating conditions provide incentives for resources to be flexible and perform well. Shortage pricing will be increasingly important as intermittent resources continue to grow. Shortage pricing also reduces reliance on revenue from the capacity market to maintain resource adequacy. Hence, improving MISO's ORDC is essential.

In addition to shortage pricing, its ELMP pricing model plays a key role in achieving efficient price formation by allowing online fast-start peaking resources (FSRs) and emergency supply to set prices when they are economic. Initially, ELMP's effectiveness was limited, but MISO has implemented a number of our recommendations in recent years. Section IV.C of this report shows that the average effects of ELMP on MISO's real-time energy prices rose 24 percent to $1.45 per MWh in 2022. While some of this increase is due to the effects of Winter Storm Elliott in December and higher natural gas prices, much of it is due to the recent ELMP changes.

In addition to FSRs, emergency actions and emergency resources can set prices in ELMP during emergencies. In 2021, MISO implemented our recommendations to expand the set of resources that can set prices during an emergency event[2] and increased the default minimum offer floors for emergency resources. These changes significantly improved MISO's emergency pricing.

However, pricing when large quantities of LMRs are deployed is still problematic because the ELMP model cannot ramp other units up quickly enough to replace them. Hence, they can set inefficiently high prices when they are no longer needed. This causes excessive non-firm imports, increased settlement costs, and inflated DAMAP uplift payments to resources that must be held down at overstated prices to make room for the imports and load curtailments. To address this concern, we recommend MISO reintroduce LMR curtailments as an STR demand in the ELMP model instead of energy demand. This will allow the ELMP model to more accurately determine whether they are needed without manipulating the energy dispatch.

Uplift Costs in the Day-Ahead and Real-Time Markets

Evaluating uplift costs is important because they are difficult for customers to forecast and hedge, and generally reveal areas where the market prices do not fully capture the needs of the system. Most uplift costs are the result two primary forms of guarantee payments made to ensure resources cover their as-offered costs and provide incentives to be flexible:

- Revenue Sufficiency Guarantee (RSG) payments ensure that a resource's market revenue is at least equal to its as-offered costs over its commitment period; and
- Price Volatility Make-Whole Payments (PVMWP) ensure suppliers will not be financially harmed by following the five-minute dispatch signals.

Day-ahead RSG. Day-ahead RSG payments fell 25 percent to total $65 million. However, excluding the effects of Winter Storm Uri in 2021, day-ahead RSG fell 9 percent from last year. As usual, almost all day-ahead VLR costs were accumulated in two load pockets in MISO South.

2 Resources offering up to a four hour start and minimum run time may now set the price during emergencies.

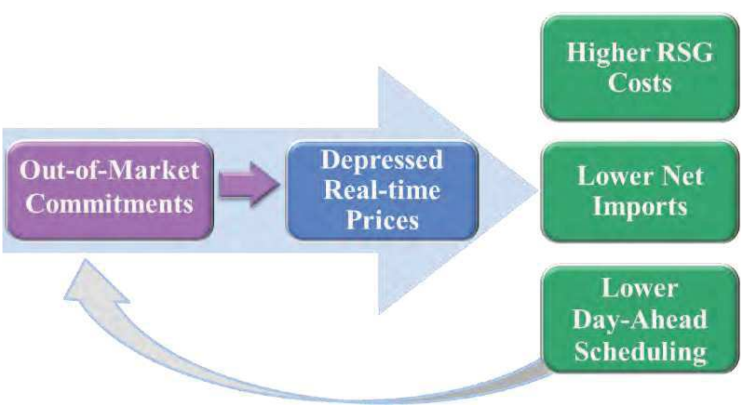
Real-time RSG. Real-time RSG payments fell 40 percent in 2022, largely because RSG payments generated in Winter Storm Uri in 2021 were around $125 million, dwarfing the real-time RSG payments of $24 million paid in Winter Storm Elliott in 2022.

Real-Time Commitment Patterns

Out-of-market commitments by MISO account for most of the RSG incurred in real time, which we assess in Section IV.E of this report. This assessment reveals a pattern of increasing capacity-related commitments beginning in the summer months. During the summer quarter, MISO's day-ahead and real-time RSG payments more than doubled over the prior year. Our evaluation showed that of the RSG costs incurred to maintain sufficient capacity (rather than to manage congestion or satisfy local reliability needs):

- Only 7.5 percent was associated with real-time commitments that were actually needed;
- Another 37 percent appeared to be needed when the commitment decision was made; and
- More than 50 percent was associated with excess commitments that were not forecasted to be needed. More than a third of the excess is associated with resources being started earlier than needed or not being decommitted when they are no longer needed.

These results indicate opportunities for substantial improvements in MISO's commitment processes. This is important because excess out-of-market commitments undermine the markets by creating a self-enforcing cycle of excess commitments. They tend to depress real-time prices, which increases RSG costs and reduces supply – increasing the need for more out-of-market commitments. The lower real-time prices: a) decrease net supply scheduled in the day-ahead market (averaging 97.5 percent of peak real-time load in 2022), and b) reduce net imports in the real-time market.



We have been working with MISO to improve real-time commitment practices to reduce excessive commitments and prevent price suppression. We have recommended a number of improvements designed to reduce the frequency of unnecessary commitments, including:

- Eliminating the use of manual inputs to the LAC model to address uncertainty since they cause it to recommend unnecessary commitments, increasing STR requirements instead.
- Deferring commitments that do not need to be made immediately given resources' start-up times and decommitting them when no longer needed.
- Use reserve demand curves and TCDCs in the LAC and other commitment models that are more closely aligned with the market demand curves.

MISO has created a team to evaluate existing tools and operating practices and has begun working with the IMM to make recommended changes. Improving operator logging is also important because it will facilitate better understanding of the causes of excess commitments.

Real-Time Generator Performance

We monitor and evaluate the poor performance of some generators in following MISO's dispatch instructions on an ongoing basis. Accounting for poor performance over a period of an hour, the accumulated dragging by MISO's generators (producing less output than had they followed MISO's instructions) averaged nearly 1,000 MW and almost 1300 MW in the worst 10 percent of hours. This continues to raise economic and reliability concerns because these deviations are often not detected by MISO's operators. The largest source of dispatch deviations are wind resources, which is due to: (a) forecast errors and (b) the fact that wind resources causing congestion are often indifferent to following dispatch. Section IV.I. provides an example of the latter. Such deviations can result in severe transmission violations and compel MISO to use out-of-market actions.

To address this issue, we propose a deviation penalty based on the marginal congestion component (MCC) of the resource's LMP that is described in Section IV.G. For deviations that load a constraint, we recommend that MISO impose a penalty equal to an escalating share of the MCC beginning with 25 percent in the first interval and rising to 100 percent by the fourth interval. This MCC-based penalty is appropriate because it reflects the congestion value of the deviation volumes and scales with the severity of congestion. Our analysis of this proposal shows that it would produce very small penalties for most types of resources, but the largest penalties for the wind resources that are deviating and causing constraint violations. In summary, the proposed penalties will improve dispatch incentives for all resources, but particularly for those whose deviations cause the most serious reliability concerns.

Coal Resource Operations

As natural gas and energy prices rose during the summer months of 2021, the economic operating margins of MISO's coal-fired resources rose substantially and caused them to operate economically at higher capacity factors than in 2020. This also resulted in more frequent starts and higher output in 2021 until fuel limitations and other supply chain issues compelled many coal resources to begin running less to conserve coal. Many coal resources began engaging in coal conservation strategies in late 2021 that persisted through most of 2022. The coal supply chain issues began to dissipate in the fall of 2022. Apart from this issue, coal units generally operated economically, although regulated utilities designated their units "must-run" roughly half of their operating hours. This compels the market to dispatch them and has resulted in them running uneconomically in seven percent of their operating hours.

Wind Generation and Forecasting

Installed wind capacity now accounts for over 30 GW of MISO's installed capacity and produced 13 percent of all energy in MISO in 2022. Wind output also increased by 23 percent compared to 2021 and almost 75 percent over the past three years to average 11.3 GW per hour. MISO set a new all-time wind record on November 30 at 24 GW. These trends in wind output are likely to continue for the next few years as investment remains strong. The report identifies a number of operational and market issues associated with the growth of wind resources.

Day-Ahead Scheduling. Wind suppliers generally under-schedule wind in the day-ahead market, averaging roughly 1,200 MW less than their real-time output. This can be attributed to the suppliers' contracts and the financial risk related to being allocated RSG costs when day-ahead wind output is over scheduled. Under-scheduling can create price convergence and resource commitment issues. These issues are partially addressed by net virtual suppliers that sell energy in the day-ahead market in place of the wind suppliers.

Real-Time Wind Forecasting. One of MISO's operational challenges is the large dispatch deviations that can be caused by wind forecast errors. The unit's forecast is used by MISO to set the unit's dispatch maximum and, because wind offer prices are low, the forecast also tends to determine the dispatch level. Dispatch deviations caused by wind forecast errors contribute to higher congestion and under-utilization of the transmission network, supply and demand imbalances, and cause non-wind resources to be dispatched at inefficient levels.

Most wind resources rely on the MISO forecast in real-time, which we evaluate in this report. We find that MISO's simple persistence forecast (i.e., the most recently observed wind output will continue) tends to often produce large errors. We developed a forecast methodology that is also persistence-based, but also incorporates the recent direction in output changes. Our analysis of this approach shows that this modest change would substantially improve the MISO forecast – reducing the frequency of the highest portfolio-level errors by more than 90 percent, while reducing the highest average unit-level errors by 45 percent. Improving the forecast of wind resources' output will be increasingly important as the penetration of intermittent resources increases. We recommend that MISO implement such a change in forecast methodology.

Transmission Congestion

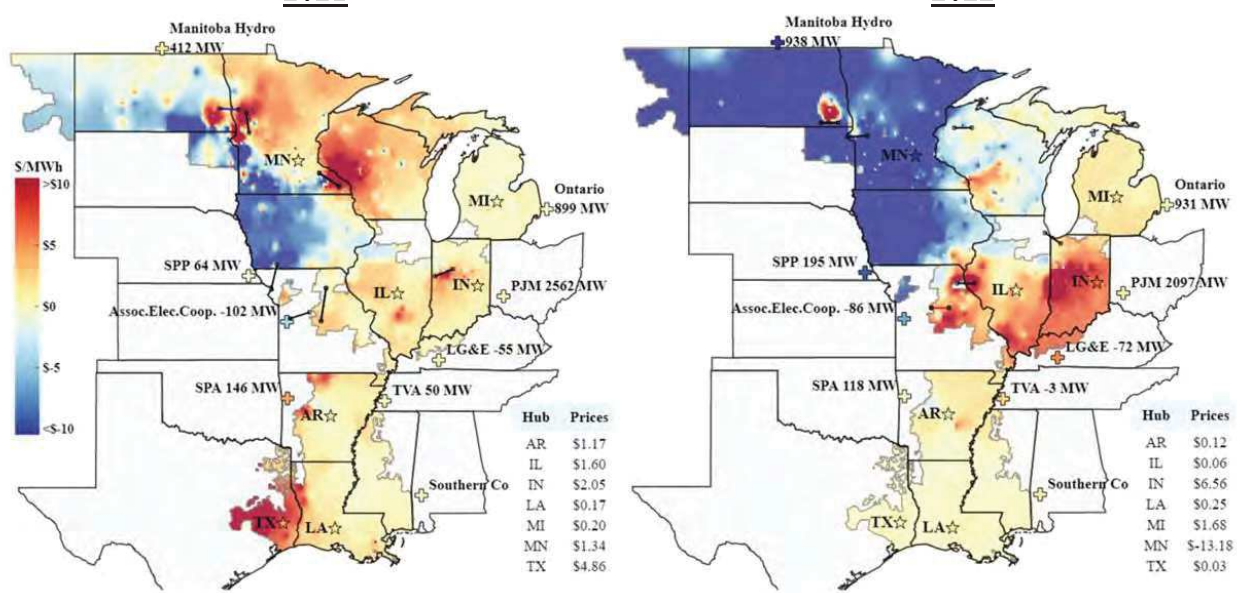
Transmission congestion costs arise on the MISO network when a higher-cost resource is dispatched in place of lower-cost ones to avoid overloading transmission constraints. These congestion costs arise in both the day-ahead and real-time markets. These costs are reflected in MISO's location-specific energy prices, which represent the marginal costs of serving load at each location given the marginal energy costs, network congestion, and losses. Because most transactions are settled through the day-ahead market, most congestion costs are collected in this market. The maps below show the changes in congestion patterns between 2021 and 2022.

Congestion Costs in 2022

The value of real-time congestion rose 30 percent in 2022 to $3.7 billion. The maps below show where the congestion became more severe in 2022.

Average Real-Time Congestion Components in MISO's LMPs

2021 **2022**



The substantial increase in real-time congestion was caused be the following factors:

- A substantial increase gas prices, beginning in the spring quarter, contributed to much of this increase because it raised the cost of re-dispatching natural gas-fired generation.
- Roughly $360 million of this increase was related to severe congestion that occurred during Winter Storm Elliott over just two days in December.
- Transmission constraints loaded by wind resources accounted for an increasing level of real-time congestion— exceeding $1.5 billion in 2022—because of the continued entry of new wind resources in MISO, SPP, and PJM that increase loadings on key constraints.
- Available relief on wind-related constraints has fallen in recent years because of the retirement of some key coal and gas-fired resources.
- Higher imports from Manitoba occurred in 2022, where in 2021 hydro output has been limited by drought conditions.

Not all of the $3.7 billion in real-time congestion cost is collected by MISO through its markets, primarily because there are loop flows caused by external areas and flow entitlements granted to PJM, SPP, and TVA under JOAs, resulting in uncompensated use of MISO's network. Hence, day-ahead congestion costs increased by 35 percent to $2.2 billion in 2022.

Day-ahead congestion revenues are used to fund MISO's FTRs. FTRs represent the economic property rights associated with the transmission system and serve as a hedge against day-ahead congestion costs. If the FTRs issued by MISO are physically feasible (do not imply more flows over the network than the limits in the day-ahead market), then MISO will always collect enough congestion revenue through its day-ahead market to "fully fund" the FTRs—to pay them 100 percent of the FTR entitlement. FTRs were fully funded in 2022.

Congestion Management Concerns and Potential Improvements

Although overall there have been improvements in MISO's congestion management processes, we remain concerned about a number of issues that undermine the efficiency of MISO's management of transmission congestion. Given the vast costs incurred annually to manage congestion, initiatives to improve congestion management are likely to be among the most beneficial. Hence, we encourage MISO to assign a high priority to addressing these issues.

Outage Coordination. Transmission and generation outages often occur simultaneously and affect the same constraints. Multiple simultaneous generation outages contributed to more than $1 billion in real-time congestion costs in 2022 – 30 percent of real-time congestion costs. We continue to recommend MISO explore improvements to its coordination of transmission and generation outages, including expanding its outage approval authority to include some form of economic criteria for approving and rescheduling planned outages.

Understated Transmission Ratings. Most transmission owners still do not actively adjust their facility ratings to reflect ambient temperatures or provide emergency ratings for contingent constraints (when the actual flow would temporarily approach this rating only after the contingency). As a result, MISO often uses lower fixed ratings, which reduces MISO's utilization of its transmission network. We estimate MISO could have saved over $540 million in congestion costs in 2022 by using temperature-adjusted and emergency ratings. In late 2020, FERC issued a proposed rule that would make this a requirement. We urge MISO to work with the TOs to provide such improved ratings in a more timely manner than required by the Rule.

Transmission Reconfiguration. It can often be highly economic to alter the configuration of the network (e.g., opening a breaker) to reduce flows on a severely-constrained transmission facility. This is done currently to mitigate reliability concerns under procedures established with the transmission owners impacted by the reconfiguration. Such procedures should be expanded to economically manage congestion. The report illustrates examples of constraints that generated tremendous amounts of congestion and compelled sizable and sustained wind curtailments.

Market-to-Market Coordination

There are many MISO constraints that are greatly affected by generation in PJM and SPP, and likewise constraints in these areas that are affected by MISO generation. Therefore, MISO coordinates congestion management on these constraints through the market-to-market (M2M) process with SPP and PJM. Congestion on MISO's M2M constraints nearly doubled to total $2 billion in 2022, which was more than 30 percent of all congestion in MISO. Because there are so many MISO constraints that are affected by generators in SPP and PJM, it is increasingly important that M2M coordination operate as effectively as possible.

We evaluate the M2M process by tracking the convergence of the shadow prices of M2M constraints. When the process is working well, the "non-monitoring RTO" (NMRTO) will continue to provide additional relief until the marginal cost of its relief (its shadow price) is equal to the shadow price of the "monitoring RTO" (MRTO), which is responsible for managing the constraint. Our analysis of M2M coordination provided the following findings:

- M2M coordination has generally contributed to shadow price convergence over time and lowered costs of managing congestion. However, we also find that coordination could be improved with three key changes and deliver substantial additional savings.
- *Relief request software*. Improving the software used to determine the amount of relief requested by the MRTO from the NMRTO will provide significant savings. The current process often produces suboptimal relief quantities that prevent the NMRTO from providing all available economic relief or can cause a constraint to oscillate from binding to unbinding. Based on our analysis of this issue with SPP, we believe improving the relief requests would generate well over $100 million in annual savings.
- *Five-percent test*: Constraints are identified as M2M constraints if the NMRTO has substantial market flows on the constraint or has a single generator with a GSF greater than five percent on the constraint. The five percent test has frequently resulted in constraints designated as M2M constraints for which the benefits of coordinating are extremely small. Hence, we recommend that MISO replace the current five-percent test with a test based on the NMRTO's relief capability on the constraint.
- *Automation of the M2M Processe*s. MISO has made progress in improving the M2M processes over the years, particularly in the area of testing new constraints in a timely manner. Given that much of this process continues to be implemented manually, there are still significant opportunities to improve the timeliness with which constraints are tested and activated by expanding the automation of the M2M processes.

Long-Term Economic Signals and Resource Adequacy

Capacity Levels and Summer Capacity Margins

The capacity surplus MISO had enjoyed prior to the 2022/2023 Planning Year dwindled in recent years as the retirements of baseload resources have mostly been replaced with intermittent renewable resources. In 2022:

- 4 GW of resources retired or suspended operations in MISO, comprised mostly of coal, gas steam, and nuclear resources. The continuing trend of suspensions and retirements into the 2022/2023 Planning Year resulted in a capacity shortage in the Midwest region.

- 2 GW of new unforced capacity entered MISO, including a 1.1 GW natural gas-fired combined-cycle in the Central region. 2.8 GW (nameplate) of wind resources were added in 2022, providing 380 MW of unforced capacity. 600 MW of solar unforced capacity entered, primarily in the North and Central regions.

MISO was not short of capacity in the 2023/2024 PRA as its load forecast and requirements fell and some new capacity resources entered. Nonetheless, we expect the retirement trends above to continue and for MISO to continue to struggle to maintain adequate resources if it does not improve the price formation in its capacity market. These price formation issues discussed above substantially affect the net revenues available to new and existing resources in MISO, which is discussed in the next subsection.

Long-Term Signals: Net Revenues

Market prices should provide signals that govern participants' long-run investment, retirement, and maintenance decisions. These signals can be measured by the "net revenues" generators receive in excess of their production costs. We evaluate these signals by estimating the net revenues that different types of new resources would have received in 2022.

We find net revenues rose in almost all regions in 2022 as rising natural gas prices contributed to higher energy and ancillary services prices throughout MISO. High capacity prices and congestion caused net revenues for new combustion turbines and combined-cycle resources to generally exceed their cost of new entry in most of the Midwest region. This is not likely to be sustained given the falling capacity prices and natural gas prices in early 2023. In other areas, including all of the South, net revenues were well short of those needed to support investment in new resources. This is largely a result of the market design issues described above.

PRA Market Design

MISO has implemented two significant changes in its capacity market to more effectively and efficiently satisfy its resource adequacy requirements – (i) a seasonal capacity market; and (2) an availability-based accreditation for thermal resources. We provided extensive feedback and analyses to MISO in the implementation of these changes. The first PRA with these changes occurred in early May and while it could have gone more smoothly, the results were consistent with the design of the market. We have identified elements of these new designs that could be improved in the future and will continue to discuss them with MISO and its participants.

We have also recommended several other improvements to the PRA. A number of these changes involve improving the accuracy of the supply and demand in the PRA, including:

- Disqualifying energy efficiency from selling capacity in the PRA or improving Tariff provisions to help ensure that they provide some value to MISO;
- Improving the accreditation rules for emergency-only resources in the PRA; and

- Modeling constraints in the PRA by assigning a zonal shift factor for each modeled constraint that reflects how the resources in each zone affect the flow on the constraint.

We will continue to discuss these improvements with MISO along with the high-priority changes to the capacity demand curve and accreditation methodologies that will allow the MISO region to remain reliable as its generation fleet transitions.

Long Range Transmission Planning

In July of 2022 the MISO Board approved $10.3 billion of Long Range Transmission Plan (LRTP) projects. The LRTP Tranche 1 evaluation focused on the most clearly beneficial projects as well as projects that could use existing rights-of-way. As MISO moves towards evaluating Tranche 2 of the LRTP, it will be increasingly important to accurately evaluate the costs and benefits of the transmission investments to avoid costly, inefficient investments. This is critical because inefficient investment in transmission can undermine incentives that govern other long-term decisions, some of which can address congestion at a fraction of the costs of the transmission upgrades. These long-term decisions include generation investment and siting decisions, retirement decisions, energy storage and grid-enhancing technologies investment.

The report identifies concerns regarding the methodologies and assumptions for identifying expected long-term resource changes and for estimating benefits of new transmission projects. We recommend changes to address these concerns in the evaluation of future LRTP tranches.

External Transaction Scheduling and External Congestion

As in prior years, MISO remained a substantial net importer of power in 2022, importing an average of 4.2 GW per hour in real time, down from 4.6 GW in 2021. MISO's imports from PJM in 2022 averaged 2.2 GW per hour, down 20 percent from 2021. Price differences at the interfaces between MISO and neighboring areas create incentives to schedule imports and exports between areas. We evaluate interface pricing in this report because of the key role it plays in facilitating efficient external transaction scheduling. We also assess the coordination of interchange with PJM. Efficient interchange is essential because poor interchange can reduce dispatch efficiency, increase uplift costs, and sometimes create operating reserve shortages.

Interface pricing. To calculate an accurate congestion price at the interface, an RTO must assume the sources or sinks in the neighboring area (referred to as the "interface definition"). Ideally, RTOs would assume sources and sinks throughout each RTO's footprint since this is what happens in reality. Unfortunately, MISO agreed to adopt a "common interface" definition for the PJM interface in June 2017 consisting of 10 generator locations near the PJM seam. This has increased interface price volatility, resulted in less efficient imports and exports, and raised costs for customers in both regions. Hence, we encourage MISO to consider revising its interface pricing with PJM to match our recommended pricing for the SPP interface.

At the SPP interface, we have verified that redundant congestion pricing is occurring based on their overlapping interface definitions. In other words, when an M2M constraint binds in both markets, both RTOs will settle with an importer/exporter at the full congestion value of the constraint in each respective market. This results in duplicative payments/charges and inefficient incentives to schedule imports or exports. We encourage MISO to adopt an efficient interface pricing method at the SPP interface and its other interfaces by removing all external constraints from its interface prices (i.e., pricing only MISO constraints). If SPP does the same, the redundant congestion issue will be eliminated, and the interface prices will be efficient.

Interchange Coordination. Coordinated Transaction Scheduling (CTS) is the most promising means to improve interchange coordination. CTS allows participants to submit offers to transact within the hour if the forecasted spread in the RTOs' real-time interface prices is greater than the offer price. MISO worked with PJM to implement CTS on October 3, 2017. The participation in CTS has been minimal because of high transmission charges and persistent forecast errors have likely deterred traders from using CTS. Hence, it has produced very little of the sizable savings it could generate. To improve the CTS process, we recommend that MISO:

- Eliminate all transmission and other charges applied to CTS transactions, while encouraging PJM to do the same;
- Modify the CTS to clear transactions every five minutes through the real-time dispatch model based on the most recent five-minute prices in the neighboring RTO area; and
- Implement a CTS process with SPP based on this type of five-minute clearing process.

Our analysis of the benefits of this change in Section VII.B of this report shows that it would have raised the production cost savings in 2022 of the CTS process with PJM from actual savings of $3 million under the current approach to more than $100 million under the 5-minute adjustment approach. We estimate savings of $63 million for a similar approach with SPP. This would also improve incentives for participants to utilize CTS because profits would have exceeded $60 million versus only $76,000 under the current approach at the PJM interface.

Demand Response and Energy Efficiency

Demand response is an important contributor to MISO's resource adequacy. MISO had 12 GW of DR resources in 2022, which included 4.2 GW of behind-the-meter generation. Most of its DR capability is in the form of interruptible load developed under regulated utility programs. DR resources are registered in three primary MISO programs depending on their capabilities.

Load-Modifying Resources (LMRs). Almost 95 percent of MISO's DR resources are LMRs that can only be accessed after MISO has declared an emergency. MISO has recently made several changes to improve the accessibility and information on the availability of LMRs. These changes are discussed in Section IX.A. Although they are clear improvements, we still have concerns that LMRs are not as accessible or as valuable as generating resources from a reliability perspective. Hence, we recommend MISO make further accreditation improvements for LMRs.

Demand Response Resources (DRRs). DRRs are a category of DR that can participate in the energy and ancillary services markets because they are assumed to be able to respond to MISO's real-time curtailment instructions. DRRs are divided into two subcategories:

- Type I: These resources can supply a fixed quantity of energy or reserves by interrupting load. These resources can qualify as FSRs and set price in ELMP;[3] and
- Type II: These resources can supply varying levels of energy or operating reserves on a five-minute basis and are eligible to set prices, just like generating resources.

DRR schedules and the associated payments fell 34 percent 2022 as resources we previously identified as engaging in problematic conduct ceased participation in MISO. Almost all of the payments to these resources produced no meaningful demand curtailments and were largely the result of opportunistic conduct. To address this issue, we recommended two potential improvements to provide more efficient incentives and ensure all payments are justified:

- DRRs should be obligated to submit their anticipated consumption absent any curtailments, which could be the basis of legitimate settlements. This could be monitored to identify when a participant has submitted inaccurate data to inflate their settlements.
- MISO should establish a price floor that is significantly higher than typical LMPs, which would effectively preclude the strategies we detected. This is reasonable because a load could just not consume at the current price rather than offer curtailments as a price-taker.

Emergency Demand Response Resources (EDRs). These are called in emergencies, but not obliged to offer and do not satisfy capacity requirements unless cross-registered as LMRs.

Energy Efficiency (EE). MISO also allows energy efficiency to qualify to provide capacity. It is important that payments to EE be justified, and that the accreditation of EE is accurate. We have concerns in both regards, finding that:

- Making capacity payments for assumed load reductions provides compensation that is redundant to customers' retail electricity bill savings and is, therefore, not efficient;
- MISO must be able to accurately calculate how much the load has been reduced by EE in peak hours, which is inevitably based on an array of speculative and highly uncertain assumptions; and
- The existing program can result in sizable cost shifting by causing other LSEs to pay for EE capacity payments that are benefiting one LSE.

To evaluate the accuracy of the claimed savings, the IMM performed an audit of EE capacity that had been sold in the PRA in prior years. Based on this audit, we found that (a) The EE resources audited did not actually reduce MISO's peak demand, (b) virtually all of the claimed savings were associated with product purchases by others that would have occurred without the EE resource, and (c) the claimed savings were not reasonably verified as the Tariff requires.

[3] A resource can qualify as a Fast-Start Resource provided the DRR Type I resource can curtail demand within 60 minutes and offers a minimum run time of less than or equal to one hour.

These findings are unfortunate because MISO's customers paid more than $17 million to these resources in a prior PRA and received virtually nothing in return. Since MISO's EE program is not addressing a known inefficiency and the quantities are difficult to accurately estimate or verify, we have recommended that MISO disqualify EE from selling capacity. Alternatively, MISO should make Tariff changes to ensure that any payments to EE resources are justified.

Table of Recommendations

Although the markets performed competitively in 2022, we make 31 recommendations in this report intended to further improve their performance. Five are new this year, while 23 were recommended previously. MISO addressed three of our recommendations since our last report.

The table below shows the recommendations organized by market area. They are numbered to indicate the year in which they were introduced and the recommendation number in that year. We also indicate whether each would provide high benefits and can be achieved in the near term.

SOM Number	Recommendations	High Benefit	Near Term
Energy and Operating Reserves and Guarantee Payments			
2021-2	Evaluate reintroducing LMR curtailments as STR demand in pricing models and UDS.		
2021-5	Modify the Tariff to improve rules related to demand participation in energy markets.		✓
2020-1	Develop a real-time capacity product for uncertainty.		
2016-1	Improve shortage pricing by adopting an Operating Reserve Demand Curve reflecting the expected value of lost load.	✓	✓
2012-3	Remove external congestion from interface prices.		✓
2012-5	Introduce a virtual spread product.		
Transmission Congestion			
2022-1	Expand the TCDCs to allow MISO's market dispatch to reliably manage network flows.	✓	✓
2021-1	Work with TOs to identify and deploy economic transmission reconfiguration options.	✓	✓
2019-1	Improve the relief request software for market-to-market coordination.		
2019-2	Improve the testing criteria defining market-to-market constraints.		
2019-3	Develop improved capabilities to receive and validate current and forecasted dynamic ratings from transmission facilities.	✓	
2016-3	Enhance authority to coordinate transmission and generation planned outages.		

SOM Number	Recommendations	High Benefit	Near Term
2014-3	Seek joint operating agreements with the control areas around MISO to improve congestion management and coordination during emergencies.		
Market and System Operations			
2022-2	Improve the real-time wind forecast by adopting enhancement to its current persistence forecasting methodology.	✓	✓
2022-3	Improve excess and deficient energy penalties to improve generators' incentives to follow MISO's dispatch instructions		
2021-3	Evaluate and reform the unit commitment processes.	✓	✓
2021-4	Develop a look-ahead dispatch and commitment model to optimally manage fluctuations in net load and the use of storage resources.	✓	
2020-2	Align transmission emergency and capacity emergency procedures and pricing.		✓
2019-4	Clear CTS transactions every five minutes through the UDS based on the RTOs' most recent five-minute prices.	✓	
2018-4	Clarify the criteria and improve the logging for declaring emergencies and taking emergency actions.		✓
2017-2	Remove transmission charges from CTS transactions.	✓	✓
2017-4	Improve operator logging tools and processes related to operator decisions and actions.		
2016-6	Improve the accuracy of the LAC recommendations and record operator response to LAC recommendations.		✓
Resource Adequacy and Planning			
2022-4	Improve the LRTP processes and benefit evaluations.	✓	✓
2022-5	Implement jointly optimized annual offer parameters and improve outage penalty provisions in the seasonal capacity market.		
2020-4	Develop marginal ELCC methodologies to accredit DERs, LMRs, battery storage, and intermittent resources.	✓	
2019-5	Improve the Tariff rules governing Energy Efficiency and their enforcement.		✓
2017-7	Establish PRA capacity credits for emergency resources that better reflect their expected availability and deployment performance.		
2015-6	Improve the modeling of transmission constraints in the PRA.		
2014-6	Define local resource zones based on transmission constraints and local reliability requirements.		
2010-14	Improve the modeling of demand in the PRA by implementing reliability-based demand curves.	✓✓	✓

I. Introduction

As the Independent Market Monitor (IMM) for MISO, we evaluate the competitive performance and operation of MISO's electricity markets. This annual report summarizes this evaluation and provides our recommendations for future improvements.

MISO operates wholesale electricity markets that are designed to efficiently satisfy the needs of the MISO system, which encompasses parts of 15 states in the Midwest and South. The MISO markets include:

Day-Ahead and Real-Time Energy Markets – that utilize the lowest-cost resources to satisfy the system's demands and manage flows over the transmission network, while providing economic signals to govern short- and long-run decisions by participants.

Financial Transmission Rights (FTRs) – that are funded by the congestion revenues collected through the MISO markets and allow participants to hedge congestion costs by entitling holders to the day-ahead congestion costs paid between locations.

Ancillary Services Markets (ASM) – that include contingency reserves and regulation that are jointly optimized with the energy market to schedule resources and price shortages efficiently.

Capacity Market – that is implemented through the Planning Resource Auction (PRA) to compensate resources for meeting resource adequacy. The capacity market requires reform to facilitate efficient investment and retirement decisions.

The energy and ancillary services markets provide a robust foundation for the long-term challenges that lie ahead. Our evaluation of the markets' performance in 2022 reveals that the markets performed competitively with no substantial evidence of market manipulation or market power abuses. Nonetheless, we identify a number of potential improvements in the design and operation of the markets that would allow them to operate more efficiently and provide better economic signals to market participants.

MISO continued to respond to our past recommendations, allowing the markets to evolve to meet the changing needs of the system. Key changes or improvements during 2022 included:

- Critical changes to MISO's Resource Adequacy construct include moving toward a seasonal market and availability-based accreditation. The first auction under this new framework ran in the Spring of 2023.

- Changes to the demand curves for the Short-Term Reserve (STR) product and the Ramp-Up Capability product.
- The implementation of some changes in the reliability commitment process in late 2022 and early 2023 to reduce unnecessary commitments of resources and associated RSG.

These changes should improve the performance of the markets and the operation of the system. We discuss these improvements in more detail throughout the remaining sections of this report. While these improvements are valuable, we also identify and continue to recommend essential changes to MISO's shortage pricing, capacity market design, and congestion management. MISO is currently working on each of these changes, as they promise to provide substantial short-term benefits. More importantly, they will position MISO to successfully navigate the transition of its fleet to much higher reliance on intermittent and energy storage resources.

These and our other recommendations are listed and discussed in Section X of the report, which describes the status of each existing recommendation and identifies recommendations that have been addressed by MISO over the past year.

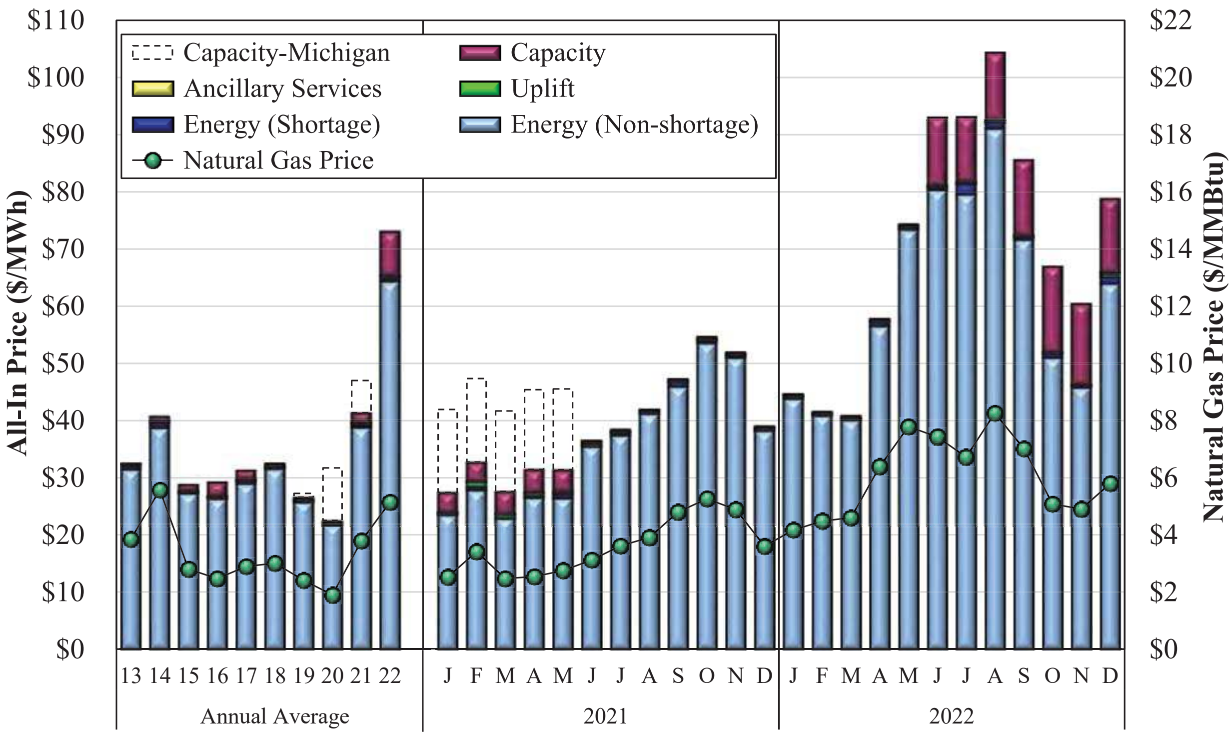
II. PRICE AND LOAD TRENDS

MISO's wholesale electricity markets in the day-ahead and real-time timeframes facilitate the efficient commitment and dispatch of resources to satisfy the needs of the MISO system. The resulting prices also play a key role in providing short- and long-term incentives for MISO's participants. This section reviews overall prices, generation, and load in these markets.

A. Market Prices in 2022

Figure 1 summarizes changes in energy prices and other market costs by showing the "all-in price" of electricity, which is a measure of the total cost of serving load from MISO's markets. The all-in price is equal to the load-weighted average real-time energy price plus capacity, ancillary services, and real-time uplift costs per MWh of real-time load.[4] We separately show the portion of the all-in price that is associated with shortage pricing, as well as the higher all-in price components associated with the much higher capacity price in Michigan in the 2020/2021 planning year in the transparent bars. Figure 1 also shows average natural gas prices to highlight the trend in the relationship between natural gas and energy prices.

Figure 1: All-In Price of Electricity
2021–2022



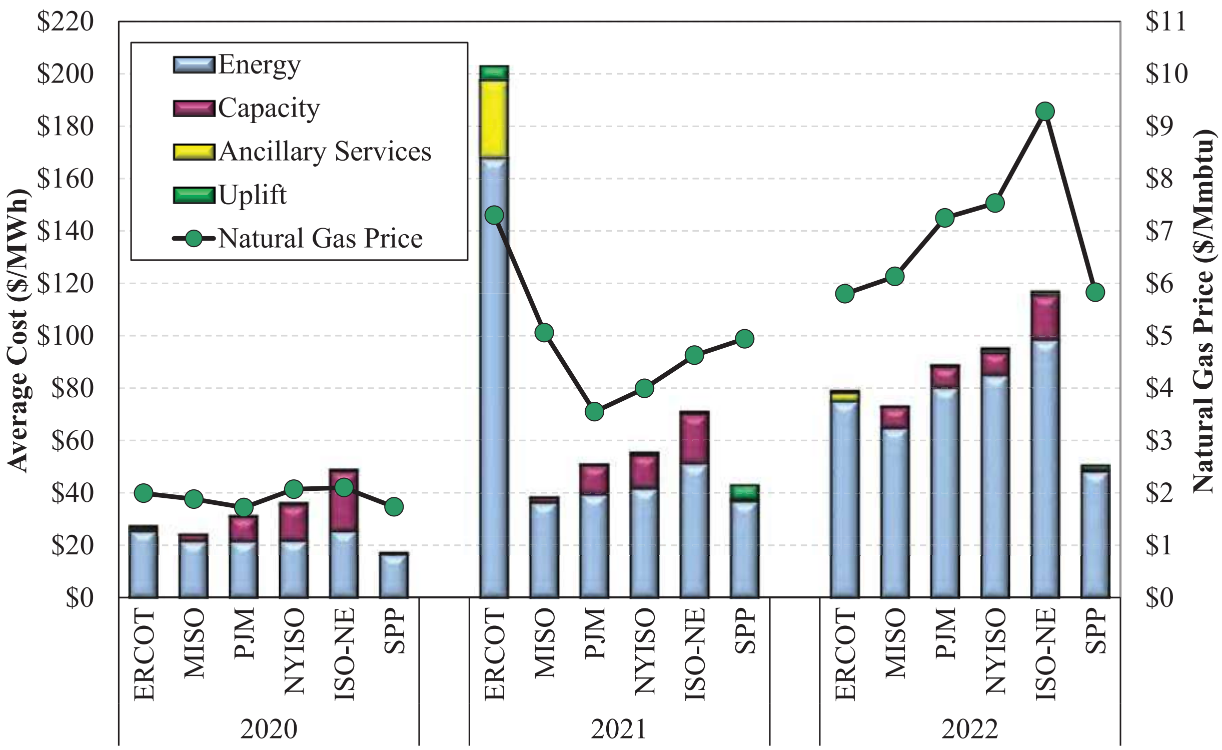
4 The non-energy costs are shown on a per MWh basis by dividing these annual costs by real-time load.

The all-in price rose 77 percent in 2022 to an average of $73 per MWh. This increase was largely caused by rising fuel prices and the effects of the Winter Storm Elliott.

- Energy prices rose 65 percent to the highest level in the last ten years as natural gas prices increased 36 percent. Coal supply chain limitations contributed to higher prices because coal conservation measures raised the costs of a large share of the coal fleet.
- Shortage pricing rose 57 percent over last year partly because MISO eliminated the $200 per MWh step on the Operating Reserve Demand Curve (ORDC) in late 2021.
- The ancillary services component contributed only $0.16 per MWh.
- The capacity component of the all-in price rose nearly five times over 2021 because the Midwest region cleared at CONE in the 2022/2023 capacity auction.
- The uplift component of the all-in price fell 34 percent to $0.21 per MWh.[5]

The figure indicates that natural gas prices continued to be a primary driver of energy prices. This correlation is expected because fuel costs are the majority of most suppliers' marginal production costs. In competitive markets, suppliers have strong incentives to offer at their marginal costs, so fuel price changes result in comparable offer price changes. To compare these results to other RTOs, Figure 2 shows the all-in prices in the Eastern RTOs and ERCOT.

Figure 2: Cross Market All-In Price Comparison
2020–2022



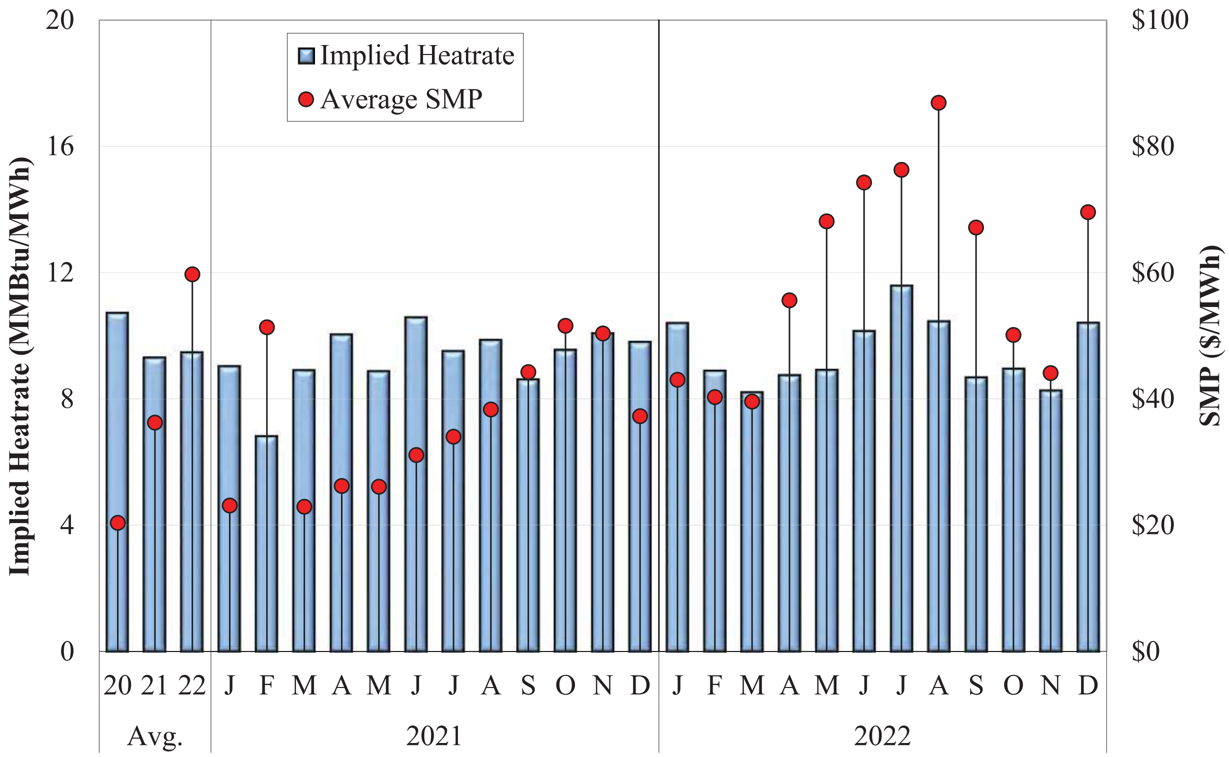
5 Uplift payments include Revenue Sufficiency Guarantee (RSG) payments made to ensure resources cover their as-offered costs, and Price Volatility Make-Whole Payments (PVMWPs).

Each of these RTO markets have converged to similar market designs, including nodal energy markets, operating reserves and regulation markets, and capacity markets (with the exception of ERCOT). However, the details of the market rules can vary substantially. The market prices and costs in different RTOs can be affected by the types and vintages of the generation, the input fuel prices and availability, and differences in the transmission capability of the network.

In Figure 2, MISO exhibits among the lowest all-in prices because of its low natural gas prices and weak shortage pricing, even though the capacity market cleared in shortage in June 2022. ERCOT lacks a capacity market entirely but has much stronger shortage pricing. ISO New England's high capacity prices were largely due to load being over-forecasted in its 3-year ahead forward capacity market. Its relatively high energy prices are caused by higher gas prices that reflect pipeline constraints.

To estimate the effects on prices of factors other than the change in fuel prices, we calculate an "implied marginal heat rate". This is calculated by dividing the real-time energy price by the natural gas price. Figure 3 shows the monthly and annual average implied marginal heat rates in recent years.[6]

Figure 3: Implied Marginal Heat Rate
2021–2022



While the nominal SMP in 2022 increased by 65 percent relative to 2021, the implied marginal heat rates were virtually unchanged from 2021 to 2022. The slight increase in 2022 is largely

6 See Section II.A of the Appendix for a detailed explanation of this metric.

due to the higher level in December that is attributable to the Winter Storm Elliott event. Most of the other differences in system marginal prices were caused by changes in fuel prices. In the future, implied heat rates are likely to become less predictable as the generating fleet transitions.

B. Fuel Prices and Energy Production

As natural gas prices rose to the highest levels in years, this improved the operating margins for non-gas-fired resources. One would have expected this to lead to higher coal-fired output and lower gas-fired output, which did not occur for reasons discussed in this subsection. Additionally, the resource mix continued to evolve in 2022. MISO lost 4 GW of Unforced Capacity (UCAP) from retirements and suspensions and added 2 GW of new resources. These included a new 1.1 GW natural gas-fired combined-cycle resource in the Central region and over 600 MW of new solar. While approximately 2.8 GW of new installed wind capacity entered MISO in 2022, this only constitutes a few hundred MW of new Unforced Capacity.

Table 1 below summarizes the share of capacity (in UCAP), energy output, and how frequently different types of resources were marginal in setting system-wide energy prices and locational energy prices in 2021 and 2022.

Table 1: Capacity, Energy Output, and Price-Setting by Fuel Type

	Unforced Capacity				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)		LMP (%)	
	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022
Nuclear	11,701	10,870	9%	9%	16%	15%	0%	0%	0%	0%
Coal	43,123	39,544	34%	31%	40%	34%	35%	24%	77%	63%
Natural Gas	59,901	61,032	47%	48%	29%	33%	64%	75%	96%	90%
Oil	1,474	1,523	1%	1%	0%	0%	0%	0%	1%	0%
Hydro	3,695	4,228	3%	3%	1%	1%	1%	1%	1%	2%
Wind	4,454	4,709	3%	4%	13%	16%	0%	0%	62%	68%
Solar	1,037	1,808	1%	1%	0%	0%	0%	0%	1%	3%
Other	2,734	2,599	2%	2%	1%	2%	0%	0%	8%	5%
Total	**128,120**	**126,312**								

Energy Output Shares. The lowest marginal cost resources (coal and nuclear) became more profitable as energy prices rose. Fuel supply issues and other supply chain problems led many coal resources to restrict their operations to conserve coal,[7] leading to a reduction in their share of energy output. This caused the share of energy produced by natural gas resources to rise even though they were less economic. As wind capacity continued to grow, their share of output rose to 16 percent in 2022. Nuclear output fell slightly as an 800 MW nuclear unit retired in May.

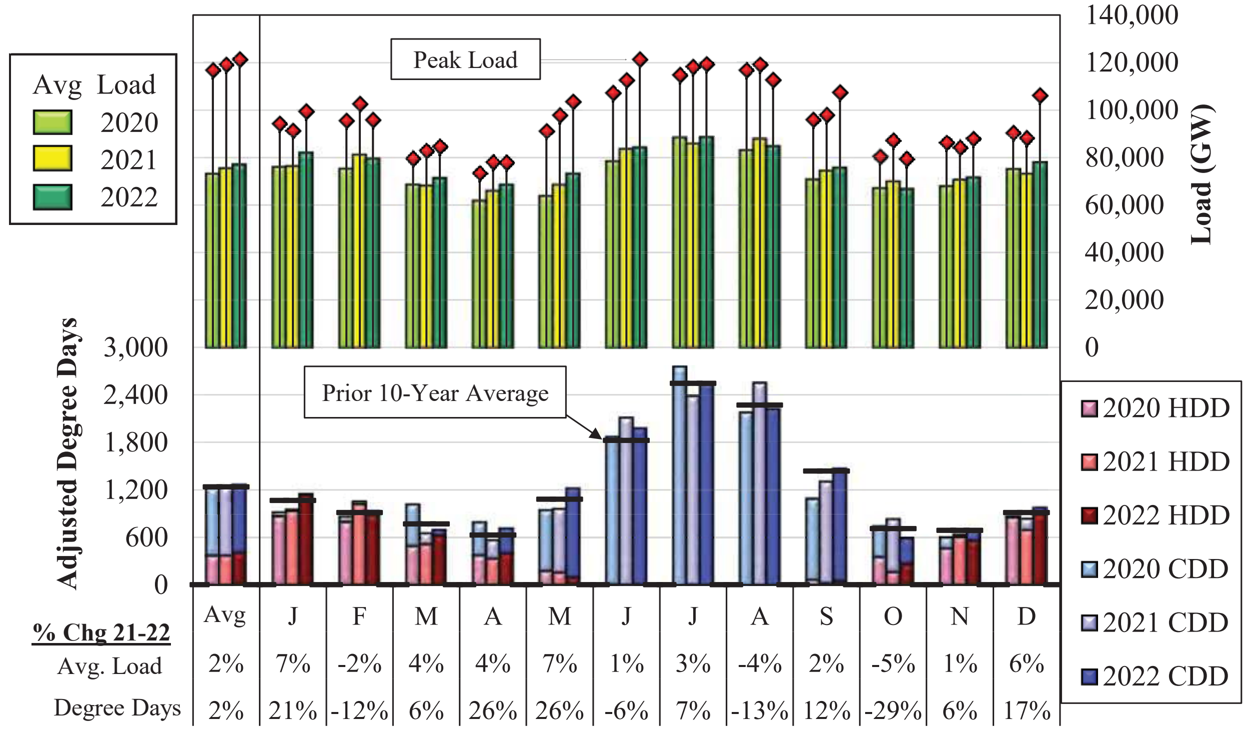
7 These issues and others related to the operation of MISO's coal resources are discussed in Section IV.H.

Price-Setting. Coal resources set system-wide prices in just 24 percent of hours, generally in off-peak periods. This is down from 35 percent in 2021 as they produced less energy and were more deeply inframarginal. Although natural gas-fired units produced only 33 percent of the energy in MISO, they set the system-wide energy price in 75 percent of all intervals, up from 64 percent and including almost all peak hours. In addition, congestion often causes gas-fired units to set prices in local areas (90 percent of intervals) when lower-cost units are setting the system-wide price. Likewise, wind units set prices in more than two-thirds of all intervals as growing wind output has resulted in increasingly frequent congestion.

C. Load and Weather Patterns

Long-term load trends are driven by economic and demographic changes in the region, but short-term load patterns are generally determined by weather. Figure 4 indicates the influence of weather by showing the heating and cooling needs together with the monthly average load over the past two years. The top panel shows the monthly average load in the bars and the peak monthly load in the diamonds. The bottom panel shows monthly Heating Degree Days (HDD) and Cooling Degree Days (CDD) summed across six representative locations in MISO.[8]

Figure 4: Heating and Cooling Degree Days
2020–2022



8 HDDs and CDDs are defined using aggregate daily temperatures relative to a base temperature (65°F). To normalize the load impacts of HDDs and CDDs, we inflate CDDs by 6.07 (based on a regression analysis).

In 2022, both the average load and the number of degree days rose 2 percent over 2021. Some notable cold and hot weather episodes occurred throughout 2022, including:

- Warmer than normal temperatures in May and June led to higher cooling demand.
- Above-normal temperatures in September increased cooling demand and the seasonal peak load of 108 GW occurred on the first day of the Fall quarter.
- Between December 23 and 25, arctic temperatures in the central U.S. caused emergencies that are discussed below in subsection E. Average and low temperatures were 15 to 35 degrees below normal and led to unusually high peak loads above 100 GW.

MISO's annual peak load of 122 GW occurred on June 21, as higher than normal footprint-wide temperatures led to high peak cooling demand. Peak load was 1.6 percent lower than the 50/50 forecasted peak of 124 GW from MISO's *2022 Summer Seasonal Assessment.*

D. Ancillary Services Markets

Since their inception in 2009, co-optimized ancillary services markets have produced significant benefits, leading to improved flexibility and lower costs of satisfying the system's reliability needs. These markets have also facilitated more efficient energy pricing that reflects the economic trade-off between reserves and energy, particularly during shortage conditions.

Supplemental (offline) reserves only meet the market-wide Contingency Reserve requirement (i.e., 10-minute operating reserves). Spinning reserves can satisfy both the Contingency Reserve and the spinning reserve requirements, so the spinning reserve price will always be equal to or higher than the Contingency Reserve price. Similarly, regulation prices will include components associated with spinning reserve and Contingency Reserve shortages.[9] Likewise, energy prices include all ASM shortage values plus the marginal cost of producing energy. MISO's demand curves specify the value of each of its reserve products. When the market is short of a reserve product, the demand curve for the product will set its market clearing price and affect the prices of higher-valued reserves and energy through the co-optimized market clearing.

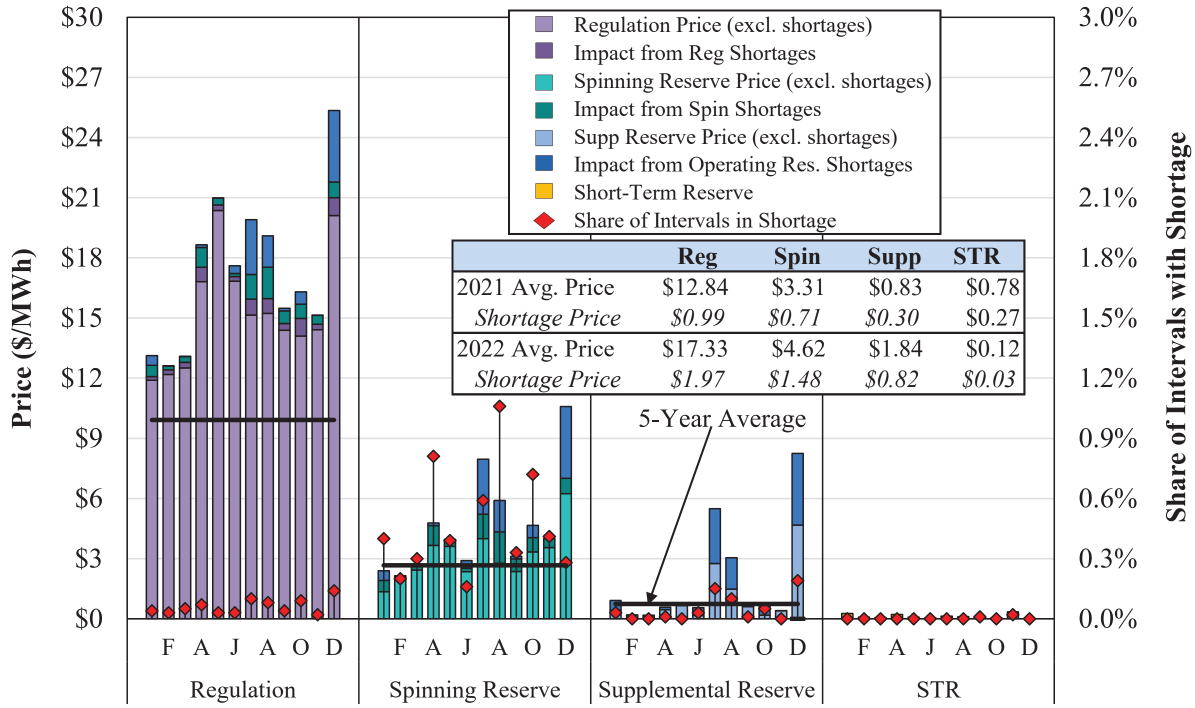
Ancillary Services Prices in 2022

For each product, Figure 5 shows monthly average real-time prices, the contribution of shortage pricing to each product's price and the share of intervals in shortage. The figure also shows the 5-year average price of the reserve products, except for Short-Term Reserves (STR) that were implemented in December 2021. The average clearing prices rose significantly for all reserve products in 2022, primarily because of changes in natural gas prices and the effects of Winter

9 The demand curve for regulation, which is indexed to natural gas prices, averaged $289.41 per MWh in 2022, up from $280.24 per MWh in 2021. The spinning reserve penalty price was unchanged at $65 per MWh (for shortages < 10% of the reserve requirement) and $98 per MWh (for shortages > 10%).

Storm Elliott in December discussed later in this section. Higher opportunity costs caused by higher natural gas prices contributed to the 40 percent increase in spinning reserve prices.

Figure 5: Real-Time ASM Prices and Shortage Frequency
2022



Short-Term Reserves. Based on our recommendation, MISO implemented a 30-minute reserve product (short-term reserves or "STR") in December 2021. We had recommended the requirements be applied locally to zones with VLR requirements, but they are currently only applied to MISO and its two subregions. STR prices have averaged close to zero in the day-ahead and real-time markets (under $1 per MWh), excluding the effects of Winter Storm Elliott.

MISO enforces STR requirements in its two subregions by enforcing reserve procurement enhancement (RPE) constraints over the Regional Directional Transfer (RDT) constraint. The RPE binds when headroom on the RDT plus the available STR in the importing subregion is limited. Although the STR product is producing benefits for MISO, we recommended two key changes to improve its performance, one of which MISO implemented late in 2022:

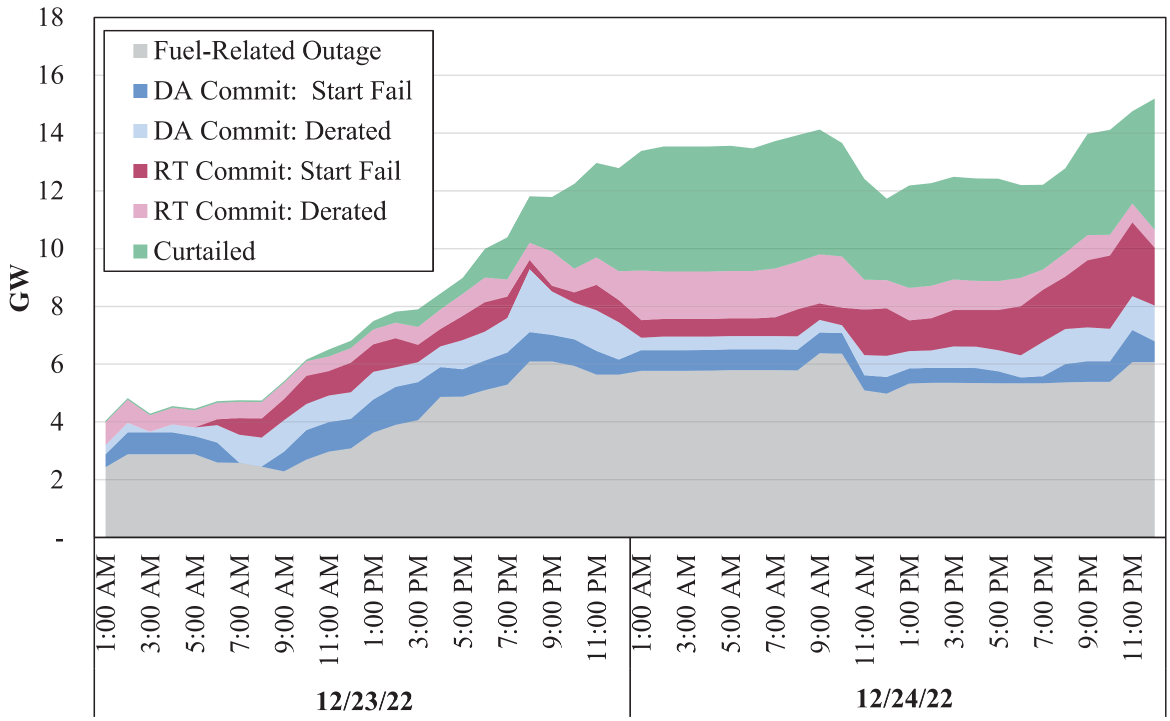
- Application of appropriate demand curves to price STR shortages efficiently. In November 2022, MISO implemented a multi-step curve that reached a high step of $500 per MWh, replacing its previously set curve set at $100 per MWh.
- Expansion of the RPE constraints to enforce STR requirements in local reserve zones that have VLR requirements that cause large amounts of uplift costs. Enforcing local STR requirements will provide efficient incentives for suppliers to invest in fast-start units that can satisfy the VLR requirements.

E. Winter Storm Elliott and Market Outcomes

In 2022, MISO experienced a significant event at the end of the year—Winter Storm Elliott—that stressed its ability to maintain reliability and assist its neighbors. In this subsection, we provide a description of the event, the impacts on the markets, and recommendations we identified to improve operation of the system under emergency conditions.

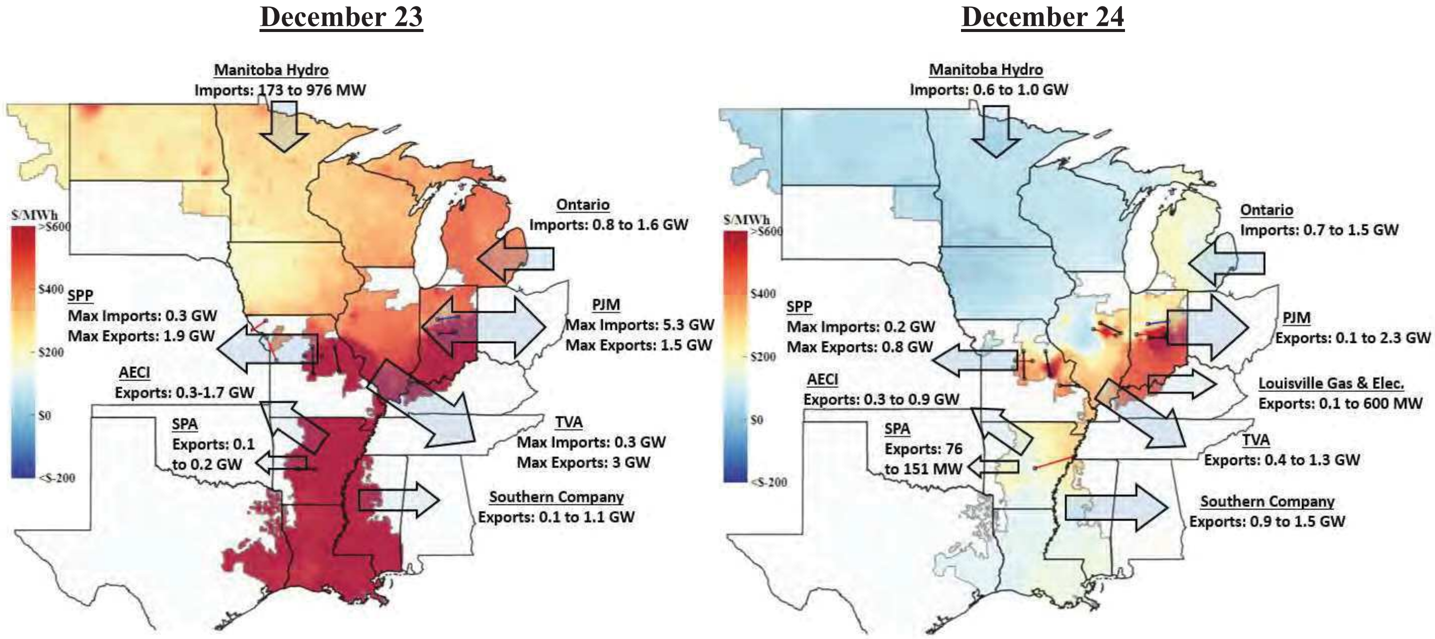
On December 23, temperatures throughout MISO ranged from 20 to 35 degrees below normal as a bomb cyclone hit much of the central United States. MISO and most neighboring control areas experienced large load forecasting errors, causing capacity shortfalls in a number of these areas. Tight gas supply conditions contributed to the capacity shortages. Many gas-fired resources committed after the day-ahead market were unable to procure gas and several others ran out of fuel. This contributed to 15 GW of fuel-related outages and derates by the end of the day on December 24 as shown in Figure 6. The fuel supply issues were partly due to frozen wells in the Marcellus shale area and issues with compressors that caused pipeline pressure issues.

Figure 6: Gas-Fired Generation Outages
December 23–24, 2022



The most serious reliability issues were experienced by TVA, which implemented rolling blackouts throughout the day on December 23. MISO provided extensive support to TVA and other neighboring LBAs, including Southern Company, AECI, SPP, and PJM. Figure 7 illustrates the unusually large exports and wheels that were scheduled and contributed to more than $350 million in real-time congestion between December 23 and 24, as shown by the average LMPs on those days.

Figure 7: Winter Storm Elliott Power Flows and Locational Prices



On December 23, MISO imported from Manitoba, Ontario, and PJM, and exported to TVA, Southern Company, AECI and SPP. On December 24, fuel supply issues in PJM caused typical import flows to reverse overnight and become large export flows throughout the day. The large and unusual exports caused severe congestion in MISO.

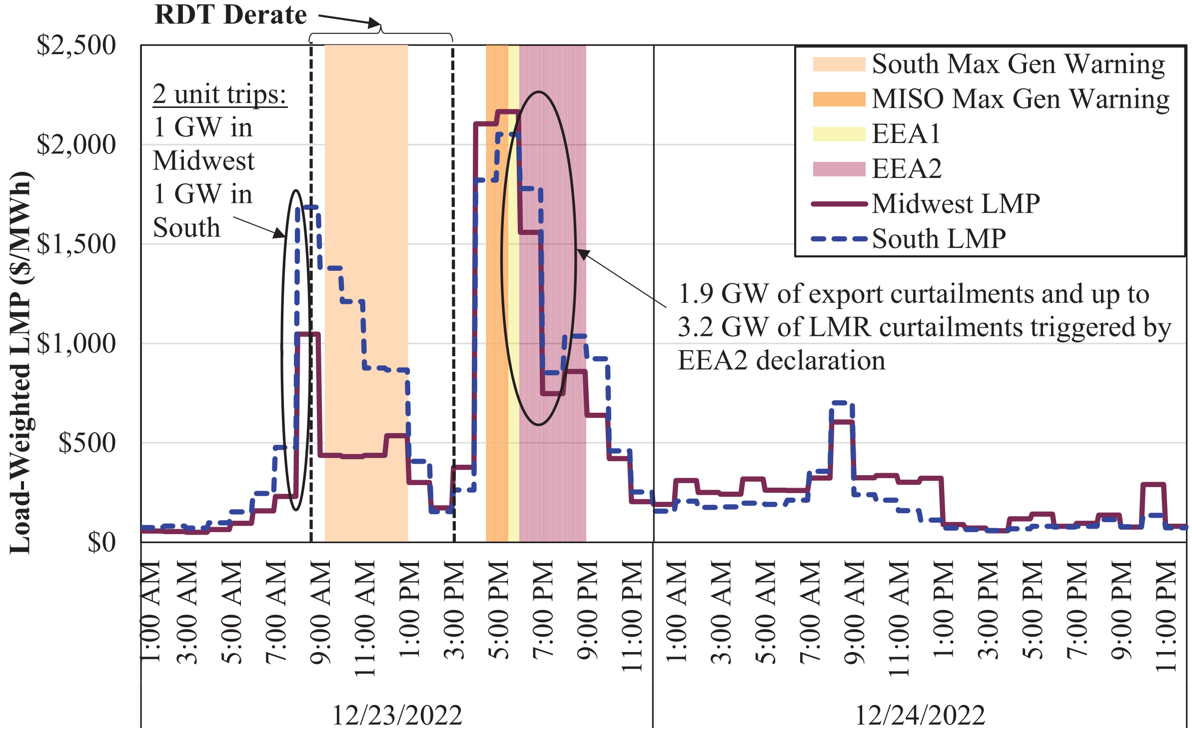
Real-Time Pricing and Emergency Declarations During Elliott

Figure 8 shows prices and the emergency declarations by MISO during the event. On the morning of December 23, SPP and TVA requested that MISO derate the RDT from 3000 to 1500 MW, which triggered a violation of the RDT and prompted MISO to declare a Maximum Generation Warning in the South. Additionally, two large units tripped off shortly before the derate. Together, these events caused prices to spike up, particularly in the South.

MISO's emergency procedures would call for it to curtail non-firm exports under MISO-wide or subregional emergency declarations. At the time of the Maximum Generation Warning in the South, MISO had almost 3 GW of non-firm exports to Southern Company, TVA, SPP and AECI that could have been curtailed to relieve the RDT violation and the subregional emergency, but MISO choose not to curtail the vast majority of these exports.

Later that afternoon, as imports from PJM were falling and exports to TVA were growing, MISO moved through its emergency procedures to an EEA2. MISO was not forecasting a capacity shortage and still had large quantities of non-firm exports available to cut prior to these emergency declarations. However, MISO took these actions in order to sustain the exports to its neighbors, particularly to TVA that was shedding load.

Figure 8: Winter Storm Elliott Emergency Declarations and Prices
December 23–24, 2022



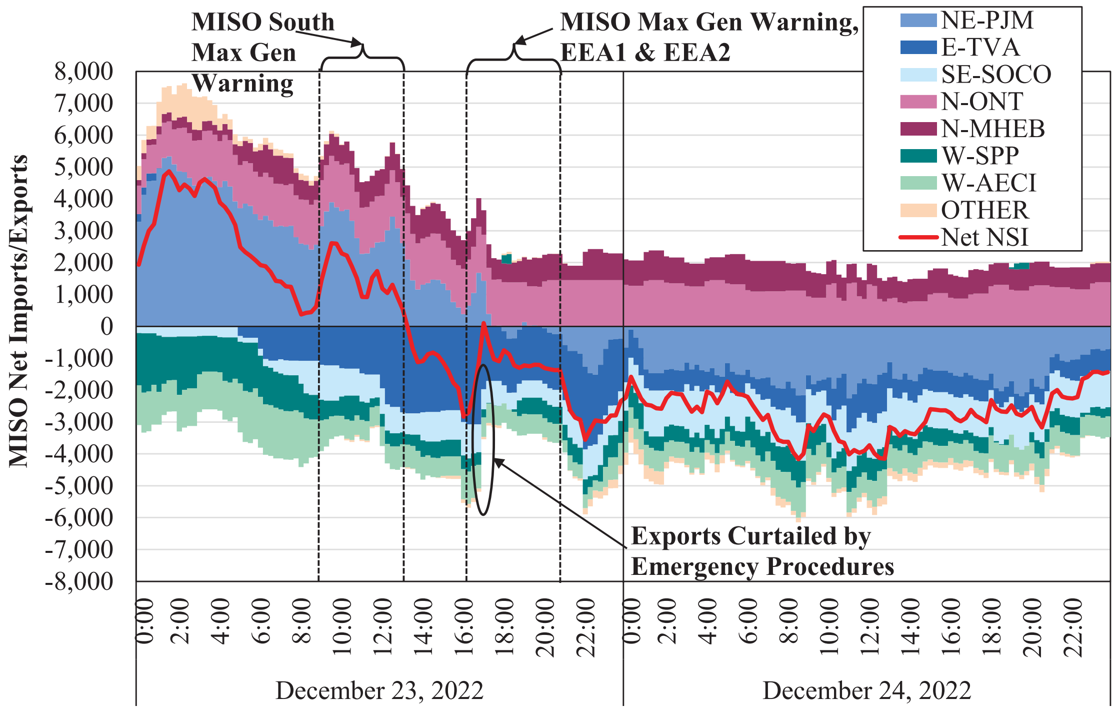
MISO ultimately declared the EEA2 to access LMRs in order to provide additional exports to TVA. Unfortunately, the EEA2 procedures also require cuts to non-firm exports. As a result, instead of providing the additional 1.5 GW TVA requested, the EEA2 led MISO operators to curtail 1.4 GW of exports to TVA and additional amounts to other areas.

Import and Export Trends During Elliott

Figure 9 shows the net imports (positive values) and exports (negative values) on December 23 and 24, with the red line indicating the net scheduled interchange across those days. Maroon shaded areas are imports/exports over northern interfaces, while the blue shaded areas show the eastern interfaces and green shaded areas show the western interfaces.

On December 24, MISO's total net exports grew as net imports from PJM on December 23 fell and became substantial net exports. Although no MISO capacity emergencies or shortages occurred on December 24, MISO took unprecedented actions to maintain exports to its neighbors. MISO committed many resources to sustain the exports, even as the congestion caused an increasing number of resources to be "stranded" behind constraints. These commitments generated more than $11 million in RSG.

Figure 9: Net Scheduled Interchange During Winter Storm Elliott



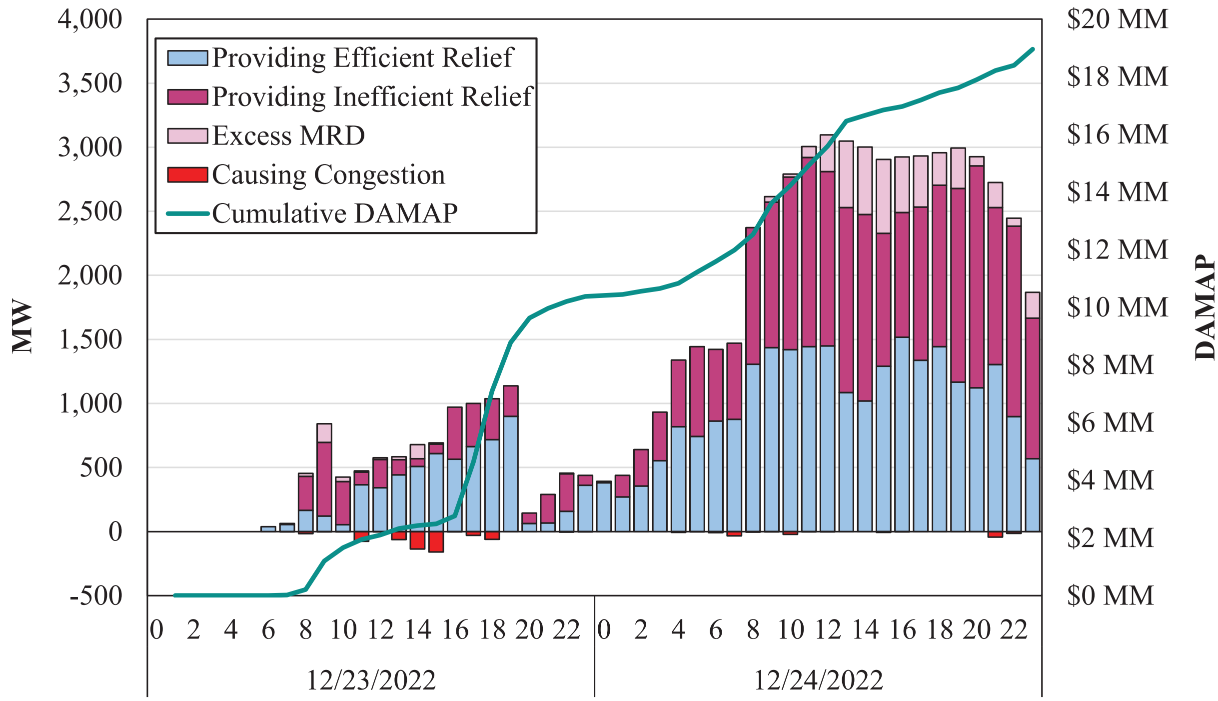
Manual Redispatch During Elliott

MISO responded to a number of transmission violations by using manual redispatch (MRD). MRD directs a unit's output to a fixed amount and is necessary when the value of managing the flows on a transmission constraint is not high enough for the real-time dispatch to move the resources needed to manage the flows. MRD is not ideal because it prevents the market from properly pricing the congestion, is often not efficient, and can generate large uplift costs.

Figure 10 shows the increasing levels of MRDs implemented on December 23 and 24 along with the Day-Ahead Margin Assurance Payments (DAMAP) paid to MRD units. To determine how efficient these manual dispatch actions were, we conducted a simulated dispatch analysis for December 23 and 24. We removed all the resource MRDs and adjusted the TCDCs on the relevant constraints to a maximum of $10,000 per MWh of flow. Increasing the TCDC allowed the dispatch model to recognize the value of moving the resources and keeping the flows below the limits of the constraints. The simulation allowed us to divide the MRD actions taken by MISO into the following categories:

- Efficient: the simulation dispatched the units to the MRD level;
- Inefficient: other, less costly resources would have been dispatched for the constraint;
- Excessive: the MRD provided more relief than necessary to manage the constraint; and
- Harmful: the MRD caused congestion by increasing the flows on a constraint.

Figure 10: Manual Re-Dispatch and Associated DAMAP
December 24, 2022



Our analysis shows that less than half the MRDs during Winter Storm Elliott were efficient. On December 24, a substantial amount of MRDs were excessive, particularly in the peak hours. This indicates why manually dispatching resources is not preferred and should be avoided if possible. Even when the same dispatch would result, MRDs: (a) prevent prices from reflecting the marginal costs of the resources being moved, and (b) require MISO to make the resource whole to the inaccurate price by paying unjustified DAMAP.

Our evaluation of this event highlights the following opportunities for operational improvements:

4. To avoid MRDs in the future, we recommend that MISO:
    a. Add higher-priced steps to the Transmission Constraint Demand Curves (TCDC).
    b. Improve its procedures to increase TCDCs as needed to ensure that the dispatch model will reasonably manage network flows and violations under all conditions.
5. Strengthen the operating controls and logging to minimize deviations from its operating procedures.
6. To the extent that operating actions will be taken in the future primarily to support neighboring areas, MISO should:
    a. Modify its operating procedures to specify these actions and the requisite criteria for taking each action; and
    b. Establish operating agreements with neighboring areas to better coordinate during emergencies and to establish equitable provisions to allocate the associated costs.

III. FUTURE MARKET NEEDS

The MISO system is changing rapidly as the generating fleet transitions and new technologies enter the market, which will require MISO to adapt to new operational and planning needs. MISO has been grappling with these issues through several initiatives, including the Renewable Integration Impact Assessment (RIIA), the Regional Resource Assessment (RRA), and the publication of the *MISO Futures Report*.

With the exception of its capacity market, MISO's markets are well-suited to facilitate this transition and fundamental market changes will not be needed. However, a number of key improvements will be critical as MISO proceeds through this transition. We discuss the key issues in this section that MISO will be facing in the coming decades and recommend both principles and specific market improvements MISO should consider as it moves forward.

We begin the chapter with a discussion of the remarkable changes anticipated in MISO's generation portfolio and the implications of these changes. We then identify the key market and non-market issues and improvements that will allow MISO to successfully navigate this transition.

A. MISO's Future Supply Portfolio

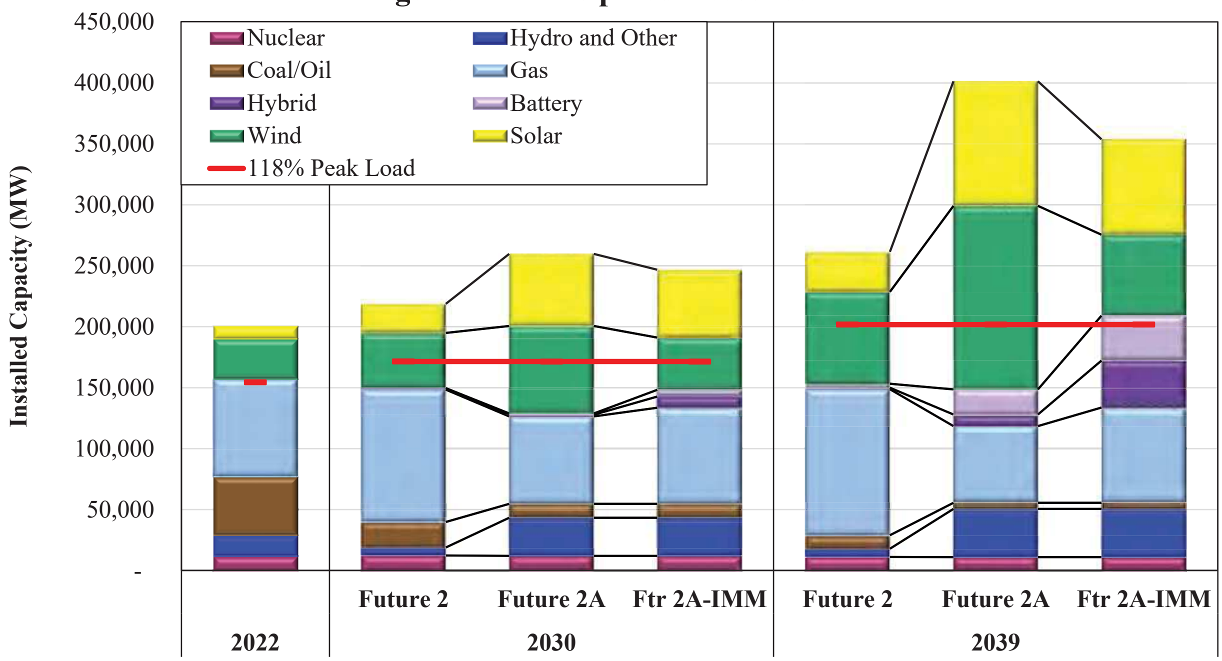
Over the past decade, the penetration of wind resources in the MISO system has consistently increased as baseload coal resources have gradually retired. To date, MISO has effectively managed the operational challenges of integrating wind and solar resources while losing conventional resources. However, the trend of increased intermittent resource penetration and retirement of conventional resources is expected to accelerate as large quantities of solar and battery storage resources join new wind resources in the interconnection queue. Currently, MISO's interconnection queue is comprised almost entirely of renewable resources, sometimes combined with batteries to form "hybrid" facilities. MISO has more than 1400 active projects in the interconnection queue, totaling over 240 GW. More than half of these are solar projects or hybrid solar projects and another 10 percent are wind projects or hybrid wind projects. Distributed energy resources may also grow and play a more substantial role in the future.

Changes are also anticipated on the demand side. MISO's Transmission Expansion Planning (MTEP) study includes a scenario that examines a significant electrification of the transportation sector with the widespread adoption of electric vehicles (EVs). Such a transition may substantially change typical load profiles and congestion patterns. Nonetheless, the most significant changes are likely the supply-side changes discussed above.

Figure 11 shows the anticipated mix of resources based on MISO's prior and updated "Future 2" Scenario that are used for its planning studies (Future 2 and 2A). The Future 2 scenarios are an intermediate scenario between Future 1 that shows a slower clean energy transition and Future 3 that shows a faster transition and substantial assumed electrification of both the transportation sector, (primarily EVs) and residential heating/cooling (advanced heat pumps).[10]

Figure 11 shows that MISO's expectations have changed substantially over the past two years since Future 2 was published. Future 2A shows a roughly 50 percent reduction in coal in 2030 and 2039 from Future 2, some of which is due to a more aggressive age-based retirement assumption (36 years). We find this assumption questionable, particularly in states with no announced decarbonization plans. Future 2A also shows reductions in gas-fired generation of 34 and 48 percent from the Future 2 levels in 2030 and 2039, respectively. We likewise find this questionable given the system's need for the attributes that these resources provide.

Figure 11: Anticipated Resource Mix



Finally, Future 2A also shows much faster growth of intermittent solar and wind resources, which are 90 percent and 134 percent higher in 2030 and 2039 respectively. This growth is driven by two factors: (1) announced plans of states and utilities, and (2) projections made by the EGEAS model to build new resources to satisfy MISO's PRM. In reviewing this case, we are concerned about the intermittent resources assumed from the EGEAS model. Our largest concern relates to the assumed accreditation levels for intermittent resources in its EGEAS model.[11] These levels are much higher than their marginal reliability value, particularly after 2030 when large quantities of both types of resources are assumed to have been built.

10 MISO Futures Report, April 2021 (updated December 2021), https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf.

11 Fixed 17% for wind resources and 50% for solar resources, which falls to 41% and 2030 and 20% by 2039.

By overstating accreditation levels, the EGEAS model will find them attractive to build to satisfy MISO's reliability requirements (i.e., its PRM) given the Federal production incentives. If the model understood that their contribution to reliability will be close to zero by 2030, it would likely select other types of resources to satisfy MISO's PRM. Natural gas resources in states without decarbonization mandates would likely be selected because their attributes cause them to have the highest reliability value. These resources in the future could be fired by fuel produced from renewable sources. Hybrid resources and batteries are also likely alternatives because: (i) their storage can be used to manage congestion and greatly increase their energy and ancillary service market revenues, (ii) they contribute much more to energy adequacy than intermittent resources do, and (iii) they are zero-carbon resources.

Figure 11 includes an alternative to a case that accepts MISO's assumptions on "committed resources" but assumes the EGEAS model will select a combination of gas resources, hybrid resources, and batteries storage to meet MISO's energy and resource adequacy requirements.[12] Importantly, these resources provide much higher marginal reliability to the system so they can satisfy MISO's reliability requirements with a smaller amount of this capacity than the assumed intermittent resources. The total capacity levels would fall further than shown if some of the assumed intermittent resources in the outyears are converted to hybrid configurations or are replaced by dispatchable carbon-free resources that are currently under development. We consider the IMM-modified 2A case to be much more likely and importantly, it would likely have different implications on MISO's long-range transmission plans discussed below. Therefore, we recommend MISO re-evaluate its futures cases to address these issues.

Nonetheless, all cases forecast substantial penetration of solar resources in the coming years, which is consistent with large quantities shown in the interconnection queue, further expansion of wind resources, and higher reliance on battery storage and hybrid resources. Regardless of the ultimately quantity of these, it will be critical for the markets to optimize the dispatch of both dispatchable and storage resources to complement the fluctuations in the intermittent resources. This will likely require MISO to develop a look-ahead dispatch and commitment model that optimizes multiple hours, which we recommend MISO begin evaluating.

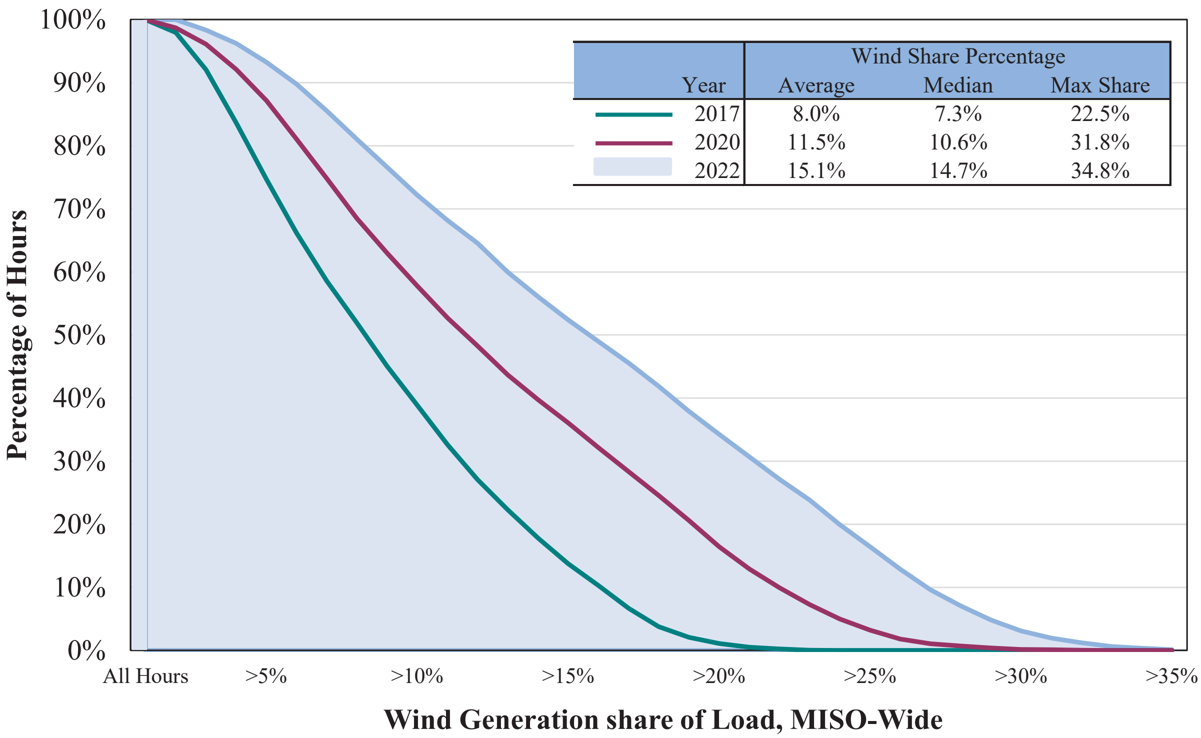
Expansion of Wind Resources

Average hourly wind output continued to grow in 2022, rising 23 percent over 2021 to 11 GW. Hence, wind resources continue to produce increasing shares of the total generation in MISO, increasing from 13 percent of all energy in 2021 to 16 percent in 2022. However, wind generation varies substantially from day to day and often from hour to hour. In some hours, wind generation served over one third of the load in MISO in 2022, which presents increasing

12 We do this by calculating the amount of accredited capacity MISO assumed that the new intermittent resources would provide, subtract the accurate amount of accredited capacity from "committed" intermittent resources and replace the balance of the accredited MW with natural gas, hybrid, and battery resources.

operational challenges that MISO must confront. Figure 12 below shows the cumulative share of MISO's load served by wind, and how this share has changed over the past five years. The x-axis represents the percentage of load served by wind. The y-axis shows the percentage of hours during the year when wind output exceeded that share of load. So, for example, in 2022, in 52 percent of the hours, over 15 percent of the load was served by wind.

Figure 12: Share of MISO Load Served by Wind Generation
2017–2022

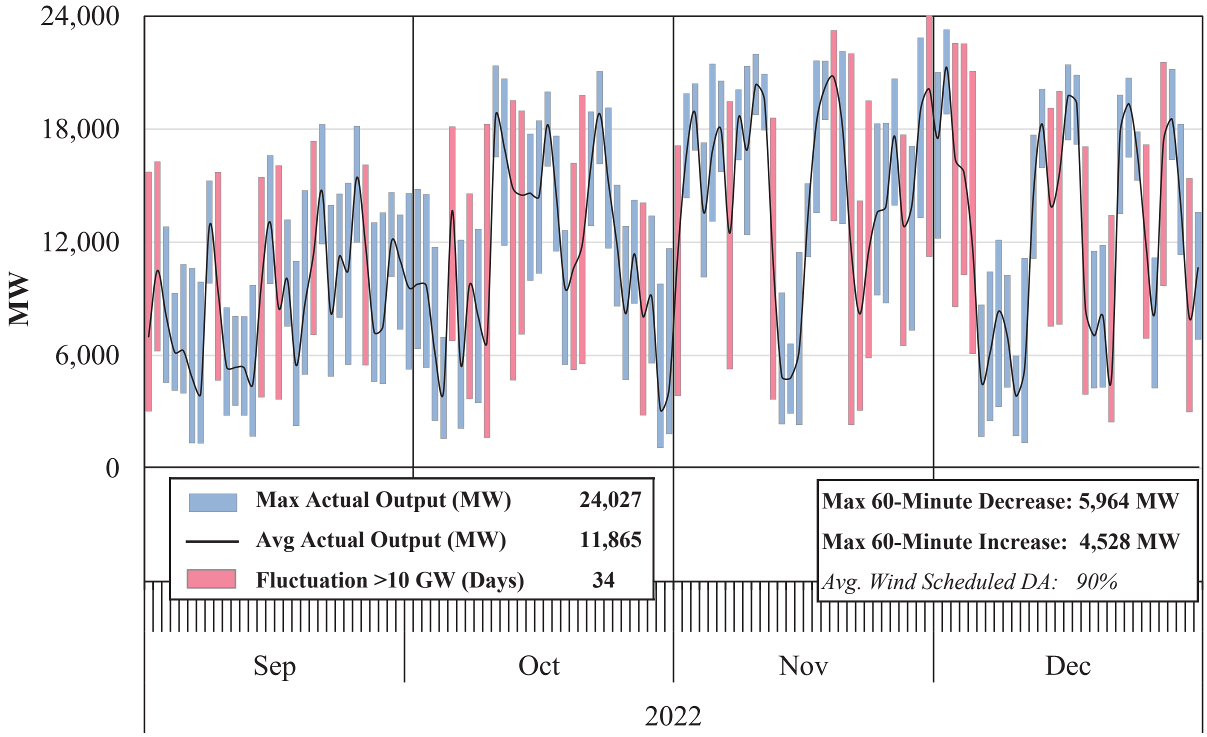


This figure shows that wind output as a share of load in MISO has been growing rapidly. To see the changes over time, notice in the figure that for half of the hours of the year, wind was serving more than 7 percent of the load in 2017, 11 percent in 2020, and roughly 15 percent of the load in 2022. We expect this trend to continue and, as wind generation increases, the operational challenges of managing this generation will increase.

Wind Fluctuation. The operational challenges associated with managing wind generation arise because of the substantial uncertainty of the wind output. As uncertainty grows, so do the errors in forecasting the wind output. To illustrate these challenges, Figure 13 shows the daily range in wind output along with the average wind output each day from September through December 2022, a period during which wind output was relatively high. This period included a new all-time peak wind output of more than 24 GW on November 30, a day when wind served more than 30 percent of the demand in MISO.

On the days colored pink in the figure, wind output fluctuated by more than 10 GW. MISO has generally been able to manage these increasingly large fluctations in wind output. They will continue to be more challenging and can lead to operational issues when the fluctuations are not forecasted accurately. Sharp changes in output can be more difficult to manage because MISO is limited in how quickly it can move other resources. As the figure reports, wind dropped by as much as 6,000 MW in one hour during this period. As wind penetration increases, the need to have other flexible resources available to manage the intermittent output will rise.

Figure 13: Daily Range of Wind Generation Output
September – December 2022



Often the highest output from wind resources occurs in overnight hours. As wind capacity continues to grow, this may place increasing pressure on older, uneconomic baseload resources to cycle off overnight. It also will increase the value of having dispatchable conventional resources that can cycle on and off for much shorter periods. Finally, Figure 13 also shows that MISO continues to experience periods when wind output is close to zero. This underscores the importance of having sufficient dispatchable resources available to satisfy the system demands when intermittent generation is not available.

Transmission Congestion Caused by Wind. In addition to the issues caused by the uncertainty of wind output, the concentration of wind resources in the western areas of MISO's system has created growing network congestion in some periods that can be difficult to manage. MISO's Dispatchable Intermittent Resource (DIR) type has been essential in allowing MISO to manage congestion caused by wind output. DIR participation by wind resources increases MISO's control over wind resources by allowing them to be dispatchable (i.e., to respond economically to dispatch instructions). In the longer term, innovative management of the transmission system, including integration with other controllable network facilities (e.g., HVDC, PARs, switches, and battery facilities) will be pivotal in integrating much larger quanitities of wind resources. We discuss possible approaches in the next subsection.

Penetration of Solar Resources

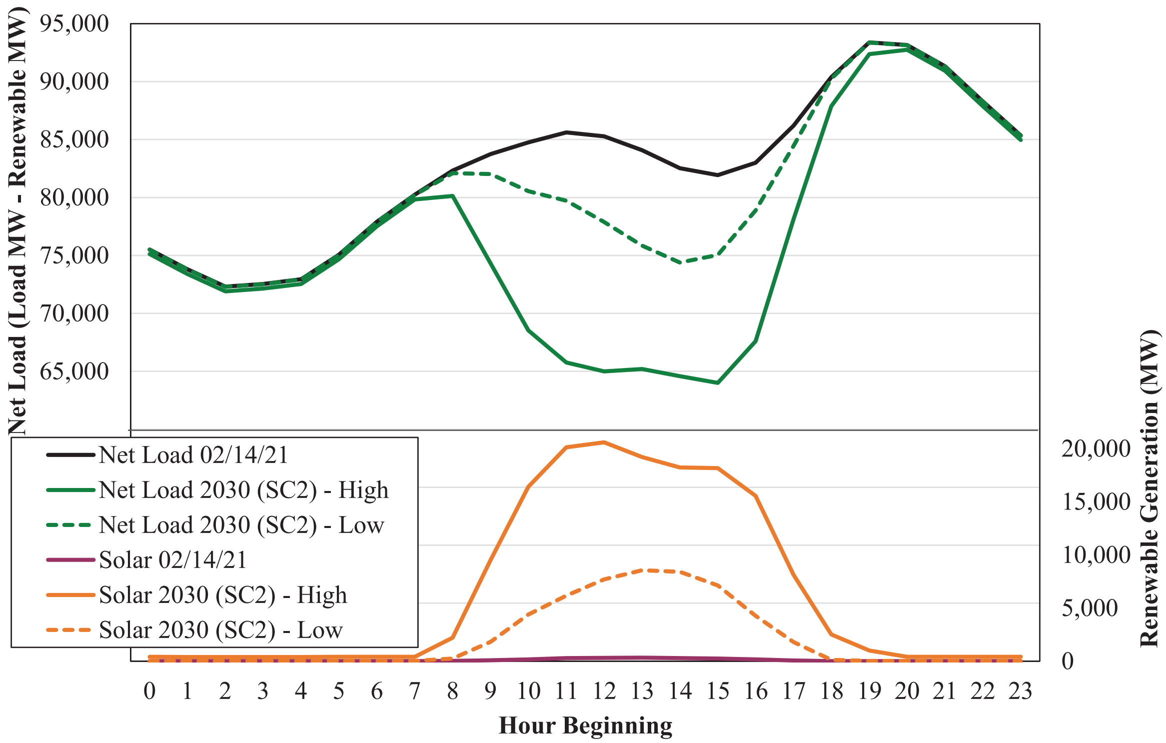
Scenario 1 of Figure 11 shows that solar resources are forecasted to grow more rapidly than any other resource type in the next 20 years. This expectation is likely driven by the fact that solar resources dominate the interconnection queue, a large share of which may not ultimately enter the MISO market. Nonetheless, the penetration of solar resources will likely be substantial and present new challenges for MISO's operators and its markets. Currently, solar resources with a peak output of 2,500 MW are online in MISO, the vast majority of which entered in 2022.

Given the expected operating profile of solar resources, a large influx of these resources will lead to significant changes in the system's ramping needs. The morning ramp demand occurs between 6 a.m. and 8 a.m. will continue to primarily be served by conventional resources. Once solar resource output spikes in the late morning and through the afternoon, the conventional resources will likely need to ramp down to balance the solar output. As solar output falls off sharply in the evening hours, a second ramping demand of conventional resources will occur. These patterns are particularly challenging in the winter season because MISO's load peaks in the early morning and in the evening when solar output is lowest. These ramp management challenges have already been observed in solar-rich western markets.

Figure 14 shows the "net load" that must be served by conventional resources in MISO under different solar penetration scenarios. In this figure, net load is the system load minus the output of intermittent resources. This curve has been referred to as the "duck curve" because of its shape. This figure is based on the load on a relatively cold winter day—February 14, 2021. Data for modeling solar resources is from the Futures Scenario 2 from MISO's MTEP and RIIA processes, which is an intermediate case. Because solar output from a fixed set of resources can vary substantially, the figure shows a high solar and low solar case under this Futures Scenario.

This figure shows the typical dual peak in load that often occurs in the winter, one in the morning and one in the evening. Because the solar output rises, peaks, and then falls between these two daily peaks, it increases the need for the conventional generation fleet to ramp. In the high solar case, the net load falls sharply after the morning peak as solar output increases.

Figure 14: Net Load in MISO on a Representative Winter Day



Likewise, the net load increases sharply from 4 p.m. to 10 p.m. as evening sets in. The net load that would be served by conventional resources in this case would rise by more than 25 GW. This ramp could be even larger if wind happens to be falling in these hours. This underscores the importance of having generation available and flexible enough to satisfy these needs.

Distributed Energy Resources

Another developing area that MISO is addressing is Distributed Energy Resources (DERs) and Energy Storage Resources (ESRs). MISO has begun discussing the challenges that are anticipated to arise from these resources, especially with visibility and uncertainty around operation of these resources. They are generally going to be located and operated on the distribution system, yet FERC has ordered that DERs be able to participate in all aspects of the RTO markets, which creates RTO challenges.[13]

According to the 2022 OMS DER Survey, 11.5 GW of DER currently exists in MISO, and only around 60 percent is registered. Almost a third of this is solar PV, approximately half is demand response, and the rest is other DER types that include battery storage and small-scale generation. We do not anticipate large-scale entry of DER resources, but MISO should be prepared because

13 Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, Order No. 2222, 172 FERC ¶ 61,247 (2020).

technologies and business models can change rapidly. DERs will present the following unique challenges for MISO's markets and operations:

- *Operational Visibility*: The output level and location of DERs may be uncertain in the real-time market, leading to challenges managing network congestion and balancing load.
- *Operational Control*: Unlike conventional generation, most DERs will not be controllable on a five-minute basis. This has important implications for how DERs are integrated operationally through the MISO markets.
- *Economic Incentives*: To the extent that DERs participate in or are affected by retail programs or utility rates, wholesale market rules and settlements may result in inefficient incentives to develop and operate the DERs.

In the next subsection, we recommend guiding principles and objectives for MISO's effort to accommodate DERs to address these challenges.

Energy Storage Resources

Order No. 841 required MISO to enable ESRs to participate in the market, recognizing the operational characteristics of ESRs. Figure 11 above shows that MISO forecasts only moderate growth in ESRs over the next decade. Based on the trends we are observing in other markets, we believe this forecast is likely conservative. Installation costs of ESRs are likely to fall as they proliferate. This trend, along with the increases in intermittent resource price volatility discussed above, are likely to increase the economic value of ESRs. This is particularly true if MISO adopts the shortage pricing improvements described below, which would efficiently compensate ESRs for the value they provide in mitigating or eliminating transitory shortages.

Although ESRs can provide tremendous value in managing the fluctuations in intermittent output and maintaining reliability, ESRs are not fully substitutable for conventional generation. This is particularly true as the quantities of ESRs rise, which causes the marginal value of ESRs to fall. Therefore, it will be critical to adopt an accurate accreditation methodology for ESRs along with other new technologies as we discuss in the following subsection.

B. The Evolution of the MISO Markets to Satisfy MISO's Reliability Imperative

MISO has managed the growth in intermittent resources reliably. Some have suggested that fundamental changes in MISO's markets are needed in response to the dramatic change in its future generation portfolio. Fortunately, this is not true. MISO's markets are robust and are fundamentally well-suited to accommodate the transition in MISO's generating fleet, although incremental improvements will be needed. MISO has already begun the process of making necessary changes to accommodate higher levels of intermittent resources, including:

- Introducing a ramp product to increase the dispatch flexibility of the system;
- Developing the DIR capability to improve its ability to control its wind resources; and
- Improving its wind forecasting and incentivizing suppliers to use MISO's forecasts.

As the resource fleet transitions, some needs may arise that are not currently satisfied by the markets, such as increased needs for voltage support in some locations or system-wide needs for inertial support.[14] We support MISO's continuing evaluation of these issues and will work with MISO to determine, to the extent they arise, whether they would be best addressed through the markets, through non-market settlements, or through interconnection requirements. However, the vast majority of issues that will arise over the next decade can be addressed with the following improvements to the MISO markets in three key areas:

1. Improvements in the Energy and Ancillary Services Markets
   - Introduction of an uncertainty product to reflect MISO's need to commit resources to have sufficient supply available in real time to manage uncertainty;
   - Introduction of a look-ahead dispatch and commitment model in the real-time market;
   - Shortage pricing reforms to compensate resources that are available and flexible and that allow MISO to maintain reliability when shortages arise; and
   - Development of rules and processes for integrating DERs that will satisfy essential reliability and efficiency objectives.
2. Improvements in the Operation and Planning of the Transmission System
   - Introduction of new processes to optimize the operation of the transmission system and improve its utilization; and
   - Improvements to the transmission planning processes and benefit-cost analyses.
3. Improvements in the Capacity Market
   - Reforming capacity accreditation so that resource capacity credits under Module E accurately reflect reliability values; and
   - Introducing a reliability-based demand curve in the capacity market that will align with the marginal reliability value that capacity provides.

1. Improvements in the Energy and Ancillary Services Markets

Energy and ancillary services markets will be key in the transition to a cleaner generation portfolio because they will ensure that MISO fully utilizes its supply and demand resources to efficiently maintain reliability, while also providing critical incentives that govern the development and operation of its resources. The following are key improvements in this area.

Uncertainty Product and Look-Ahead Dispatch

As MISO transitions to a fleet that is far more dependent on intermittent resources, supply uncertainty will increase markedly, affecting MISO's planning and operations. MISO has correctly concluded that the availability and flexibility of its non-intermittent resources will be

14 Recent studies have determined that inverter-based resources (IBR) such as intermittent solar and wind, can provide many of the grid-forming benefits provided by conventional resources with the necessary configuration and investment in power electronics. See: https://www.nrel.gov/news/program/2021/landmark-demonstration-shows-wind-turbine-can-provide-fundamental-grid-stability.html.

paramount to ensuring it can maintain reliability. Figure 15 shows the "net uncertainty" that MISO currently faces in the operating horizon. This is calculated using historical data on the combined impact of generation resource forced outages and forecast errors from load and renewables. We calculate the uncertainty typically faced on the system (the 50th percentile) and in the hours when uncertainty is higher (higher percentiles). The figure shows the uncertainty one hour ahead and four hours ahead (blue bars). The red, green, and purple lines indicate the underlying contributing factors of load forecast error, renewable forecast error, and generating resource trips and derates in 2022.

Figure 15: Uncertainty and MISO's Operating Requirements
January 2021 to December 2022

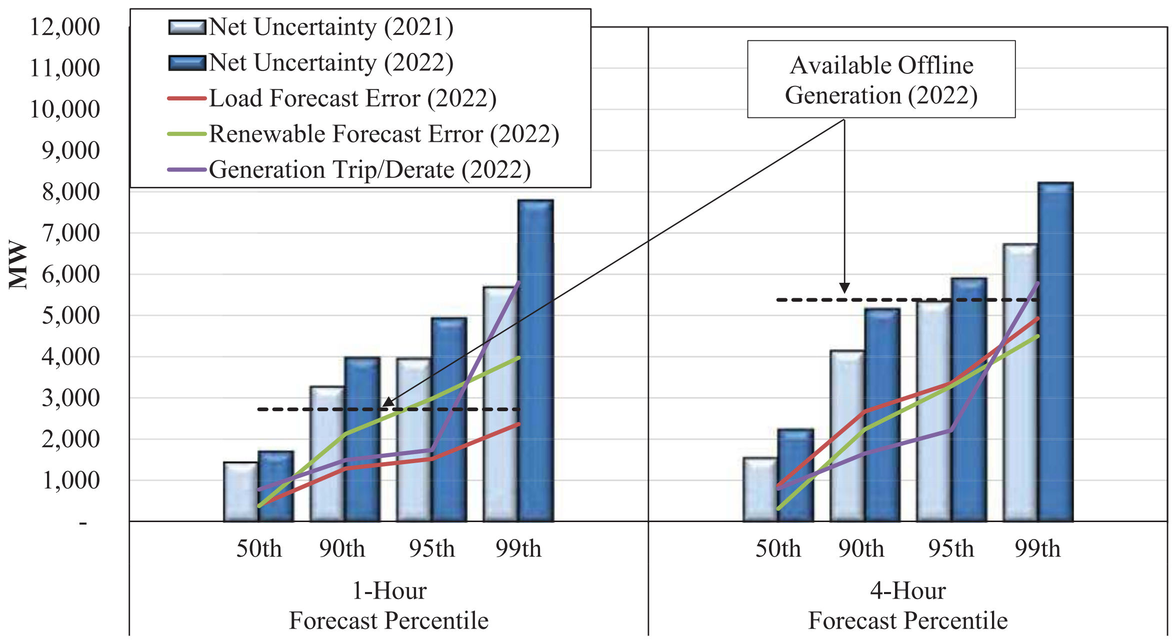


Figure 15 shows that the factors contributing to uncertainty increased in 2022. MISO continues to routinely commit resources outside of the market to ensure it will have sufficient generation available to satisfy the system's needs and respond to uncertainty. These requirements cause RSG costs to be incurred almost every day. If these requirements were reflected in a market product, prices would more efficiently reflect these requirements, less out-of-market intervention by MISO's operators would be needed, and the associated RSG costs would largely disappear.

As intermittent generation increases, these operational needs and out-of-market costs are likely to rise substantially. Hence, we recommend that MISO develop a spot capacity product for the day-ahead and real-time markets to account for increasing uncertainty associated with load, intermittent generation, NSI, and other factors. The product should be co-optimized with energy and other ancillary services products. Clearing such a product on a market basis would allow MISO's prices to reflect the need for this capacity to address uncertainty, reduce RSG, and reward the flexible resources that can meet this need.

In the longer term, we recommend MISO consider implementing this product along with other existing products through a look-ahead dispatch and commitment model that would optimize the dispatch of resources in future periods of up to four hours. Adding tools such as a look-ahead dispatch and commitment model will enable more efficient management of increased storage and DERs, which will be important as the penetration of these resource types in MISO grows. Currently, MISO may not be able to optimize these types of resources over its current 5-minute dispatch interval.

Shortage Pricing in the Energy and Ancillary Services Markets

Virtually all shortages in energy and ancillary markets are of reserve products (i.e., less reserves will be held than required). When an RTO is short of reserves, the value of the foregone reserves should set the clearing price for reserves and be embedded in all higher-value products, including energy. The shortage value is established in the reserve demand curve for each reserve product, so efficient shortage pricing requires properly valued reserve demand curves.

Efficient shortage prices play a key role in establishing economic signals to guide investment and retirement decisions in the long term, facilitating optimal interchange and generator commitments in the short-run, and efficiently compensating flexible resources. Compensating flexible resources efficiently will be increasingly important as the penetration of renewable resources increases. The output of most renewable resources is intermittent and increases supply uncertainty, which will likely increase the frequency of reserve shortages.

The most highly valued reserve demand curve in MISO is the total Operating Reserve Demand Curve (ORDC). Shortages of total operating reserves are the most severe reserve shortages and the most likely to impact pricing during capacity emergencies. An efficient ORDC should: a) reflect the marginal reliability value of reserves at each shortage level; b) consider all supply contingencies, including multiple simultaneous contingencies; and c) have no artificial discontinuities that can lead to excessively volatile outcomes. The marginal reliability value of reserves at any shortage level is equal to the expected value of lost load. This is equal to the following product at each reserve level:

Net value of lost load (VOLL) * the probability of losing load

MISO's current ORDC does not efficiently reflect the value of reserves and is based on an understated VOLL. Hence, we recommend that MISO improve its shortage pricing by improving its VOLL and the slope of its ORDC as described below.

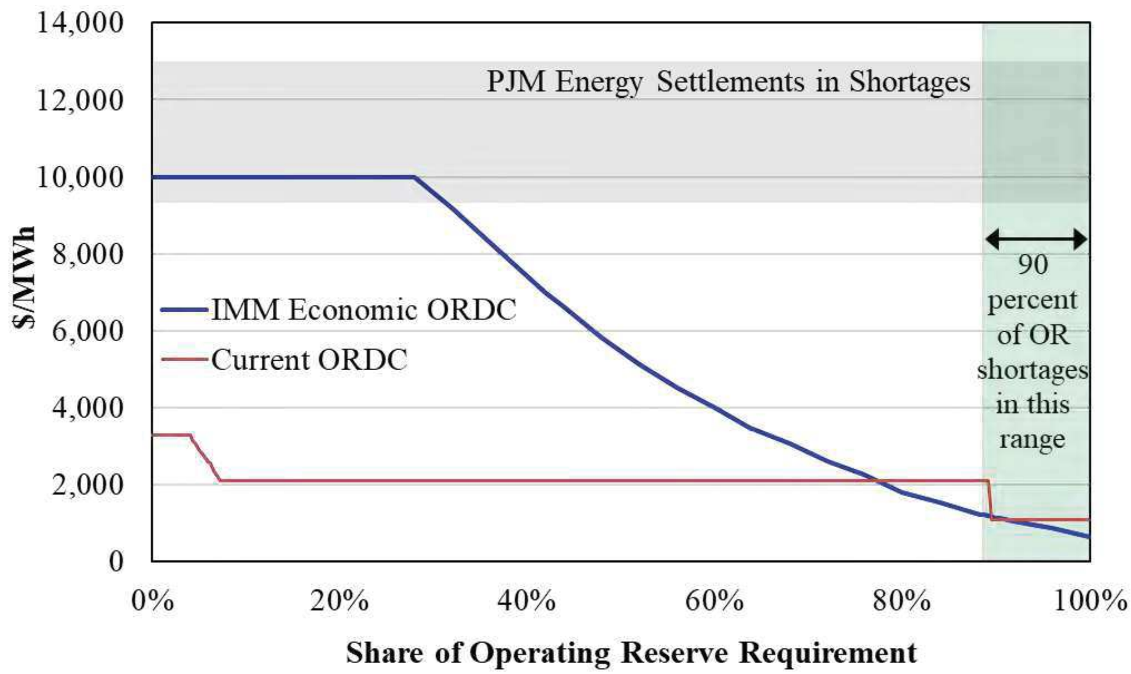
Improving the VOLL. We conducted a literature review and utilized a model developed by Lawrence Berkeley National Laboratory to estimate an updated VOLL for MISO. This study, as well as a number of others, estimated a much different VOLL for residential customers and for commercial/industrial customers with the latter being much higher. Using the Berkeley Model and 2018 data for MISO, we estimated VOLL for residential customers ranging from $4,200 to

$4,600 per MWh, and for commercial customers ranging from $36,000 and $84,000 per MWh.[15] Weighting these values based on the 2021 load data in MISO yields an average VOLL of $25,000 per MWh. We recommend MISO adopt this VOLL or a comparable value.

Improving the Slope of the ORDC. The slope of the ORDC is determined by how the probability of losing load changes as the level of operating reserves falls. The probability of losing load depends on accurately estimating the vast combinations of random contingencies and conditions that could occur when MISO is short of reserves. To model these random factors, we estimated the probability of losing load using a Monte Carlo simulation.[16] This simulation includes generation contingencies, wind forecast errors, load forecast errors, and NSI uncertainty.

Combining our recommended VOLL with our estimate of the ORDC slope gives the IMM Economic ORDC shown in Figure 16 (royal blue line). The figure also shows MISO's current ORDC, which is significantly understated for almost all shortage quantities.

Figure 16: Comparison of IMM Economic ORDC to the Current ORDC



Our proposed ORDC plateaus at $10,000 per MWh for three primary reasons: (i) very few shortages would be priced in this range as the figure shows; (ii) pricing shortages at prices exceeding $10,000 per MWh could result in inefficient interchange because most of MISO's neighbors price shortages at lower prices; and (iii) pricing at higher price levels could cause MISO's dispatch model to make inefficient trade-offs between retaining reserves and managing flows on network constraints.

15 The calculation of these values is described in more detail in Section III.B of the Analytic Appendix.

16 The simulation estimated the conditional probabilities across 10,000 iterations, which is described in Section III.B of the Analytic Appendix.

In conclusion, an economic ORDC aligns shortage pricing with the marginal reliability value of the foregone reserves. Adopting this will result in more efficient economic signals that govern both short-term and long-term decisions by MISO's participants.

Objectives for Accommodating Distributed Energy Resources

In response to FERC Order 2222, MISO is engaging stakeholders to identify technical, market, and reliability issues associated with alternative DERs. There are a wide range of possible DER models with varying roles between MISO, the LSEs, DER aggregators, and individual DERs. As MISO develops new market rules and processes, it should seek to ensure that DERs will support reliability and provide efficient incentives for DERs and non-DERs. To achieve these two goals, we recommend that MISO address the following primary objectives:

- *Comparable and Verifiable Performance*. DERs participating in energy markets should have comparable performance and verification requirements to other types of units.
- *Distinguish Between Controllable and Uncontrollable*. DERs that are not controllable (e.g., rooftop solar, energy efficiency) present additional forecasting challenges and do not support reliability in the same manner as controllable DERs.
- *Operate and settle DERs locationally*. The locational effects of DERs must be reflected in MISO's operations and settlements in order to provide efficient investment incentives and to utilize them effectively. Hence, accurate locational metering will be essential.
- *Avoid Duplicative Payments*. In many cases DERs will already be participating in non-wholesale markets or distribution programs. Duplicative payments will provide inefficient investment and operating incentives and should be avoided if possible.
- *Account for DERs in the Planning Process*. This includes the use of accurate operational and locational information about DERs that will need to be provided by DER owners.
- *Develop accurate accreditation methods for DERs*. Most DERs will be less accessible and controllable than conventional resources. Accurate accreditation is essential to provide efficient incentives to invest in DERs and other resources needed for reliability.

DERs may present new challenges. The evolving rules should provide efficient incentives to be controllable and require visibility and verification. This will be key to integrating DERs reliably.

2. Improvements in the Operation and Planning of the Transmission System

As intermittent output grows and the variability of the flows over the transmission network increases, critical bottlenecks are likely to emerge that will continue to increase congestion and lead to growing levels of output curtailments. Therefore, maximizing the utilization of the transmission network and facilitating efficient transmission upgrades will be key. MISO's work with transmission owners to submit ambient-adjusted and emergency ratings is the first essential step toward greater utilization of the network and other key improvements are discussed below.

Transmission Optimization

One of MISO's core functions is ensuring the transmission system can reliably support the MISO markets. New challenges will emerge with the accelerating growth of renewables and likely increased distances will occur between load centers and generating resources. These challenges will arise partially because large fluctuations in intermittent output can cause substantial changes in transmission flows, potentially resulting in more erratic and severe congestion patterns that are more difficult to forecast. Additionally, much heavier reliance on intermittent and inverter-based resources may raise issues related to other system attributes that are currently provided by conventional resources, such as inertial support, voltage and current stability, and reactive power.

MISO is actively engaging stakeholders in studying potential future scenarios and challenges to the bulk electric system and grid operations through both the MTEP and RIIA studies. These studies allow MISO to identify the investments and processes that may be necessary to address the needs of the system. This may include technologies and processes that will allow MISO to optimize the operation of network by redirecting flows to minimize congestion, or by using dynamic line ratings for transmission facilities to recognize factors other than temperatures.

These technologies may enable large cost savings with little or no impact on reliability. These technologies have been referred to as "grid-enhancing technologies" and the processes are referred to as "grid optimization". In addition to reducing network congestion, these processes and technologies may improve MISO's ability to plan for and manage transmission and generation outages, as well as fluctuations in flows caused by loads and intermittent generation.

In 2020, FERC convened a technical conference to discuss the opportunities and barriers to the utilization of such technologies.[17] Realizing the benefits of such technologies and process improvements will require that MISO devote resources in the coming years to integrating such technologies into its operations and market systems. These efforts are likely to be synergistic with integration and utilization of new resource types, including energy storage and DERs. We recommend that MISO anticipate these needs in the near term because the benefits of such improvements are likely to grow substantially as MISO's generating fleet transitions.

Long-Range Transmission Planning

An important component of the transition of MISO's generation portfolio is the evolution of its transmission network to facilitate the delivery of its clean resources to the loads in MISO. The evolution of the transmission network is guided by MISO's planning studies to identify constraints that will bind as MISO's renewable resource portfolio expands and the transmission investments that would mitigate these constraints.

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17 See Docket No. AD19-19. In February 2022, FERC issued an NOI (see AD22-5) on Dynamic Line Ratings that may lead to a rulemaking that may include requirements for enabling and integrating these technologies.

Most of these investments are identified through the Long-Range Transmission Planning (LRTP) process, which identifies projects in four tranches. Tranche one was approved in July of 2022 to address key constraints throughout MISO and is now under review in state regulatory proceedings. Tranche 1 included more than $10 Billion in network investments. Tranche 2 is intended to identify additional transmission upgrades in the Midwest region assuming greater intermittent penetration (Future 2A), while Tranche 3 is intended to identify transmission upgrades in the South region. Tranche 4 will identify projects to enable interregional transfers.

As MISO moves towards developing and evaluating Tranche 2, it will be increasingly important to evaluate the costs and benefits of the alternative transmission investments in a manner that ensures that the investments are economically efficient. This is important not only because inefficient investments can generate substantial costs for MISO's customers, but also because inefficient transmission investments can undermine the performance of MISO's markets. It can fundamentally alter incentives of developers and existing suppliers to make long-term generation investment and retirement decisions that would allow MISO to manage congestion at costs that are a fraction of the costs of investing in transmission upgrades.

To ensure that future cost-benefit analyses are as accurate as possible, it is first important to adopt reasonable future resource addition and retirement assumptions. Our evaluation of Future 2A (the basis for Tranche 2) raises concerns that it includes unrealistically high levels of intermittent resources and unrealistically low levels of dispatchable, hybrid, and battery storage resources. The changes shown in our modified Future 2A case would substantially change future transmission needs, so we recommend that it reconsider its Future 2A to address these concerns.

Additionally, to maximize the accuracy and validity of the estimated costs and benefits of the potential transmission projects, we the analyses satisfy the following principles:

1. Congestion and reliability constraints are substantially affected by suppliers' resource siting and retirement decisions. Hence, forecasted siting and retirement assumptions should be based on the economic incentives provided by the market. This can be done by employing a locational capacity expansion model that optimizes these decisions.
2. Storage resources can often resolve transmission and reliability constraints caused by fluctuations in intermittent output at a fraction of the cost of building new transmission. The same may be true in the future of grid-enhancing technologies. Hence, future studies should include such alternatives when evaluating the benefits of new transmission.
3. Valid cost-benefit analyses must ensure logical consistency between all base cases and all LRTP cases. All estimated benefits should include all costs incurred to realize the benefits. Likewise, all foregone costs deemed to be benefits must include the foregone benefits of such actions as an offsetting cost in the analysis. This will ensure that benefit-cost ratios are valid and are a sound basis for the sizable investments proposed.
4. All "but for" base cases must reflect an accurate forecast or assumption regarding market participant actions and investments that would take place absent the LRTP investments.

Although it is highly likely that the Tranche 1 investments evaluated by MISO and approved by the Board of Directors will produce benefits that are substantially higher than their costs, the Tranche 1 analysis was not consistent with some of the factors listed above. Therefore, we are recommending that MISO upgrade its analysis to address these factors in its future analyses of LRTP Tranches 2, 3, and 4 and other future MVP initiatives. This will help ensure that the resulting transmission upgrades are economic and do not undermine the performance of the MISO markets and decisions of its participants.

3. Improvements in the Capacity Market

As in other RTO markets, the capacity market plays a key role in facilitating efficient investment and retirement decisions. Although most of the participants in the MISO markets are vertically-integrated regulated utilities, efficient capacity market outcomes will nonetheless provide key incentives that influence these long-term decisions and resource planning processes. Additionally, MISO has a number of merchant generators and other types of unregulated market participants. Therefore, we believe the improvements discussed below are essential changes to facilitate MISO's transition of its generating portfolio.

Reliability-Based Capacity Market Demand Curve

One of the most essential changes to the MISO markets that will be needed to satisfy the reliability imperative is reforming the capacity market to provide efficient economic incentives. These reforms will generally benefit MISO's regulated utilities that have historically shouldered most of the burden of ensuring resource adequacy.

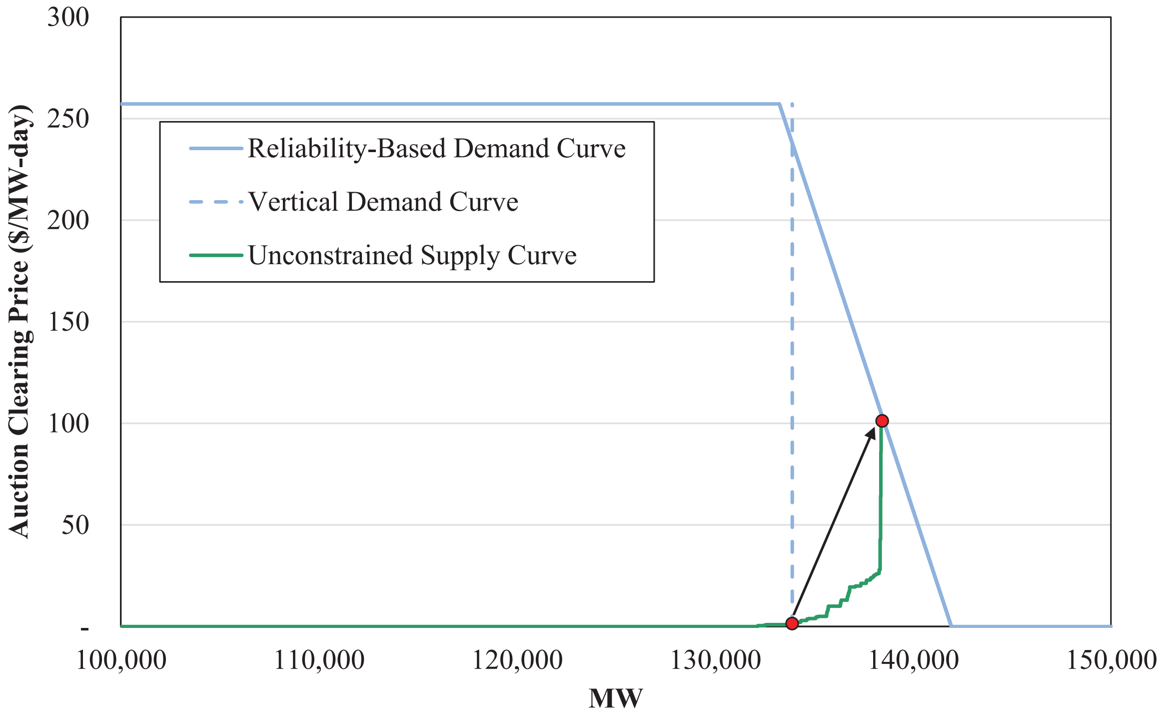
The problem with MISO's current capacity market is that the demand for capacity does not reflect the true reliability value of capacity. The fixed quantity of required demand subject to a deficiency price represents a vertical demand curve for the market. The implication of a vertical demand curve is that the last MW of capacity needed to satisfy the minimum requirement has a value equal to the deficiency price, while the first MW of surplus has no value. In reality, each unit of surplus capacity above the minimum requirement increases system reliability and lowers energy and ancillary services costs, although these effects diminish as the surplus increases.

The true marginal contribution of surplus capacity to reliability can only be captured by a sloped reliability-based demand curve. Implementing a reliability-based demand curve will:

- Establish stable and efficient capacity prices to facilitate efficient market incentives that govern not only new investment decisions, but also resource retirement decisions;
- Ensure that participants supplying more than their share of the required capacity receive capacity revenues that reflect their contribution to the system's reliability needs; and
- Provide incentives for load-serving entities that do not own sufficient capacity to plan efficiently by contracting for existing capacity or building new capacity.

To demonstrate the significance of this improvement, we simulated the clearing price in MISO that would have prevailed in the 2021/2022 PRA had MISO employed sloped demand curves in the PRA (Appendix Section III.C describes the assumptions underlying this curve). Figure 17 provides a representation of the sloped demand curve for all of MISO. The blue dashed line in the figure represents the vertical demand curve actually used in the auction. The solid green line is the capacity supply curve, reflecting resource offer prices and quantities. Resources that are self-supplied in accordance with Fixed Resource Adequacy Plans are represented with $0 offers.

Figure 17: Supply and Demand in 2021/2022 PRA



This illustrative example shows that the reliability-based demand curve would have increased prices from close to $0 to $100 per MW-day. In the actual 2021/2022 MISO PRA, prices were close to zero in both subregions. However, because the transfer constraint was binding, prices under a reliability-based demand curve would vary between the subregions, clearing at $150 per MW-day in the Midwest and $13 per MW-day in the South. Although this remains well below the cost of new entry of roughly $250 per MW-day, this price would support revenues for existing resources that are needed to maintain reliability and ensure they remain in operation.

Unfortunately, because the PRA sets prices far below efficient levels (close to zero) by design, our resource adequacy concerns that we have raised for almost 15 years materialized. MISO's inefficiently low capacity prices led to a sustained trend of retirements in recent years. A substantial share of these retiring resources would have been economic to remain in operation had MISO priced capacity efficiently in the PRA. Most of the inefficient retirements over the past four years—almost 5 GW—were made by merchant generators who rely on market signals to make long-term investment and retirement decisions. Captive retail ratepayers subsidize resources owned by vertically-integrated utilities and shield those resources from the inefficient capacity market signals. MISO's poor capacity auction design has driven economic resources into retirement and ultimately led MISO to be short of resources in the Midwest region. These issues are likely to persist unless and until MISO addresses the problems caused by its poor representation of capacity demand.

Short-Term Effects of PRA Reform on Different Types of Participants

The next analysis estimates how improving the design of the PRA would have affected various types of market participants in the 2021/2022 PRA. We calculated the simulated settlements for each participant based on its net sales. We then aggregated the participant-level results into four categories: competitive suppliers (merchant generators), competitive retail LSEs, municipal and cooperative entities, and vertically-integrated utilities. The results are shown in Table 2.

Table 2: Effects of Sloped Demand Curve by Type of Participant
2021–2022 PRA

Type of MP	Net Revenue Increases	Net Revenue Decreases	Total
Vertically Integrated LSEs	$148.4M	-$27.3M	$121.1M
Municipal/Cooperative	$67.2M	-$81.2M	-$14.0M
Merchant	$59.3M		$59.3M
Retail Choice/Competitive LSEs		-$166.4M	-$166.4M

This table shows that the vertically-integrated utilities would have benefited in aggregate by more than $120 million from the use of the sloped demand curve, and 70 percent of participants in that category would have realized almost $150 million in increased revenues. The effects on the vertically-integrated utilities were significant because they tend to have surplus capacity. Hence, vertically-integrated utilities would realize significant benefits from a sloped demand curve because it would allow them to sell their excess capacity at prices that reflect its value.

While some municipal and cooperative entities also would have benefitted from the adoption of a sloped demand curve in the 2021–2022 auction, on net the costs to municipal and cooperative entities would have increased by $14 million because many of them do not own sufficient resources to meet their own requirements. Improving pricing in the PRA would provide stronger and more efficient incentives for them to plan and contract for resources to satisfy their needs.

The effects on the competitive participants are more important because the economic price signals from the wholesale market guide key decisions by the unregulated participants in MISO, including competitive suppliers and competitive retail LSEs.

- Merchant generators would have received almost $60 million more in capacity revenue, providing more efficient signals to maintain existing resources and build new resources. This revenue would have been key in maintaining economic resources that have retired over the past few years that caused MISO to now be short of resources in the Midwest.

- Costs borne by competitive retail load providers would have risen by $166.4 million per year. This is desirable because it provides incentives for these LSEs to arrange for their capacity needs and contribute to satisfying resource adequacy in MISO.

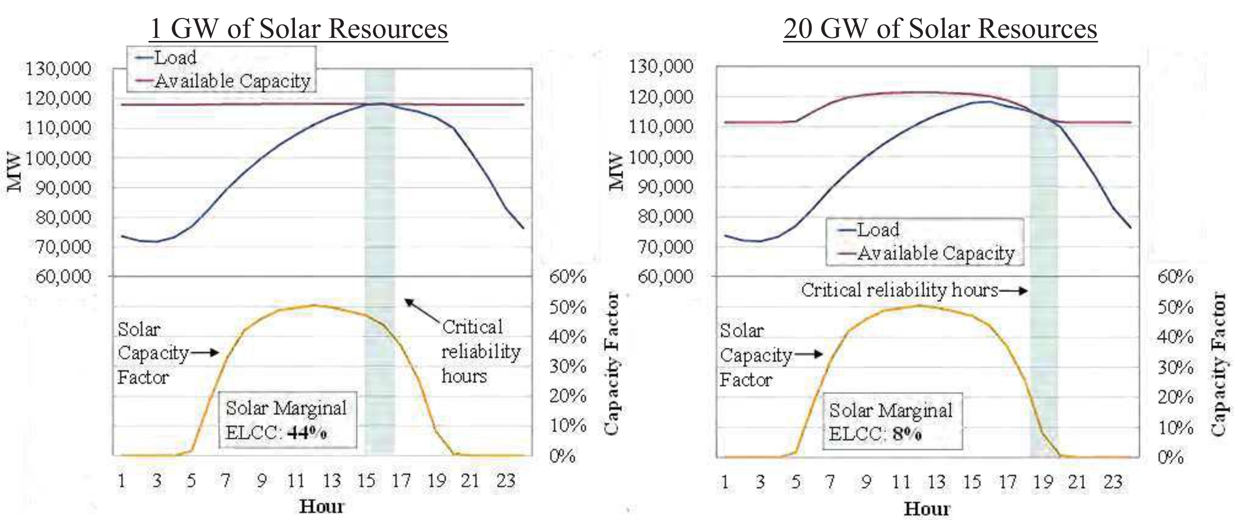
Non-Thermal Capacity Accreditation

A resource's true reliability value is its expected availability to provide energy or reserves when the system is at risk of load shedding. This value depends on (a) the timing of the system's hours of greatest need and (b) the factors that affect the availability of a resource in those hours. Importantly, the hours of greatest need are affected by the portfolio of generation and the output profile of the portfolio. Because the value of each additional MW is determined in part by the portfolio of existing generation, this value can be characterized as a "marginal value". For resources to be accredited accurately, RTOs must utilize methods that determine the marginal value of different types of resources.

MISO's recently implemented availability-based accreditation is generally consistent with this principle because it measures resources' availability during the tightest hours, which are determined by the operating characteristics of the existing generation portfolio. Intermittent resources are generally accredited using methods that predict the expected output of the resources under different conditions. One such method is the Expected Load Carrying Capability (ELCC) used by MISO, although its current approach is not marginal.

The following figure shows how the increasing penetration of one type of resource with similar output profile can affect the critical reliability hours and alter the marginal ELCC of the resources. This figure shows an illustrative example of the marginal ELCC value of solar resources in MISO based on a hypothetical peak summer day based on two different levels of solar resource penetration (1 GW and 20 GW).

Figure 18: Marginal Reliability Value of Solar Resources
Under 1 GW and 20 GW Penetration Scenarios



This figure shows that in a system with relatively low solar penetration (left panel), critical reliability hours occur in late afternoon when load is peaking and solar output is relatively high. Under these conditions, we estimate a marginal ELCC of 44 percent.

With high solar penetration (right panel), there is abundant available generation in the afternoon, which shifts the timing of critical hours towards the evening. The marginal value of solar falls under these conditions to a marginal ELCC of 8 percent because additional solar generation provides less reliability benefit when critical hours mostly occur in the evening.

The same principles apply to other types of generation, such as natural gas-only resources in the winter. Increasingly, critical reliability hours in the winter are likely to occur when natural gas availability is limited, causing natural gas-only resources that rely on non-firm fuel purchases to provide diminishing levels of reliability to the system. These changes must be reflected in the capacity accreditation framework to ensure that the market will perform well and maintain resources with attributes that are needed to maintain reliability.

If MISO fails to accredit resources based on their marginal value, the inflated accreditation to low-value (over-saturated) resources will substantially increase costs to consumers and undermine incentives to the high-value resources the system needs. Additionally, accurate accreditation will inform the states' integrated resource planning processes and ensure that these processes produce resource plans that will satisfy the reliability needs of the MISO region.

Marginal capacity accreditation is consistent with the principles that underlie MISO's market design. All of MISO's market products are priced based on marginal value and marginal cost. In MISO's capacity market, all sellers are paid a marginal clearing price. Hence, it is appropriate and necessary to determine capacity credit values such that an additional unit of capacity from any source provides the same amount of incremental reliability. This is accomplished by a marginal accreditation approach, and we continue to believe that the adoption of such an approach for all non-thermal resources is essential for satisfying MISO's reliability imperative.

IV. Energy Market Performance and Operations

MISO's electricity markets operate together in a two-settlement system, clearing in the day-ahead and real-time timeframes. The day-ahead market is financially binding, establishing one-day forward contracts for energy and ancillary services.[18] The real-time market clears based on actual physical supply and demand, settling any deviations from day-ahead contracts at real-time prices.[19] The performance of both markets is essential.

Day-ahead market performance is important because:

- Most resources in MISO are committed through the day-ahead market, so good market performance is essential to ensure efficient commitment of MISO's resources;[20]
- Most wholesale energy bought or sold through MISO's markets is settled in the day-ahead market -- 98.5 percent in 2022 (net of virtual transactions); and
- The value of entitlements of firm transmission rights are determined by day-ahead market outcomes (i.e., payments to FTR holders are based on day-ahead congestion).

Real-time market performance is also crucial because it governs the optimal physical dispatch of MISO's resources, while also establishing prices that indicate the real-time value of energy and ancillary services. These prices send economic signals that facilitate scheduling in the day-ahead market and longer-term investment and retirement decisions. This section evaluates the performance of the day-ahead and real-time markets in key areas, as well as how they were operated by MISO.

A. Day-Ahead Prices and Convergence with Real-Time Prices

The day-ahead energy prices tracked the real-time price trends described in Section II.A, rising substantially in 2022 as natural gas and coal prices increased. Average day-ahead energy prices across MISO increased 74 percent from 2021 to $65 per MWh. Congestion caused day-ahead prices at MISO's hubs to range from $47 per MWh at the Minnesota Hub to roughly $74 per MWh at the Indiana Hub.

An important difference between the day-ahead and real-time markets is that the day-ahead market clears hourly schedules while the real-time market clears on a five-minute basis. This creates some issues in managing MISO ramp demands—i.e., the need to schedule generation to

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18 In addition to day-ahead market commitments, MISO utilizes the Multi-Day Forward Reliability Assessment Commitment process to commit long-start-time resources to satisfy reliability needs in certain load pockets.

19 In addition, deviations that are due to deratings or outages are subject to allocation of uplift payments. Virtual and physical transactions scheduled in the day-ahead market are also subject to these charges.

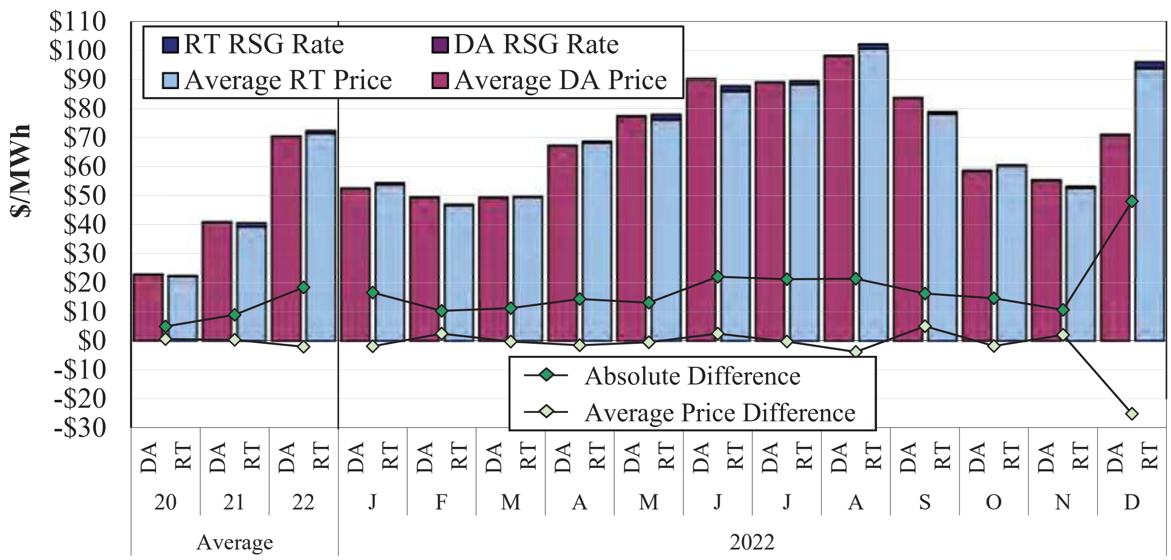
20 After the day-ahead market, MISO runs its Forward Reliability Assessment Commitment (FRAC) and Look-Ahead Commitment (LAC) process that may cause MISO to make additional commitments.

rise or fall gradually as load and other conditions change over the day. Since large changes in supply tend to occur at the top of the hour when day-ahead schedules change, prices tend to spike at these times. We have recommended MISO evaluate the feasibility of transitioning to a 15-minute day-ahead market to improve the operation of the system.

The primary measure of performance of the day-ahead market is how well its prices converge to the real-time market prices. The real-time market clears actual physical supply and demand for electricity, and participants' day-ahead market bids and offers should reflect their expectations of market conditions for the following day. However, several factors can cause real-time prices to be significantly higher or lower than anticipated in the day-ahead market, such as wind or load forecast error, real-time output volatility, and forced generation or transmission outages. While these factors may limit convergence in a well-performing market on an hourly basis, prices should converge over longer timeframes (monthly or annually).

Figure 19 shows monthly and annual price convergence statistics. The upper panel shows the monthly average prices plus the allocated RSG costs for the Indiana Hub. The real-time RSG charges (allocated partly to real-time deviations from day-ahead schedules) tend to be much larger than day-ahead RSG charges (allocated to day-ahead energy purchases). The lines show two measures of the difference between day-ahead and real-time prices. The bottom table shows the average difference (as a percentage) between day-ahead and real-time prices for six hub locations in MISO, accounting for the allocated RSG costs.

Figure 19: Day-Ahead and Real-Time Prices at Indiana Hub
2020–2022



Average DA-RT Price Difference Including RSG (% of Real-Time Price)

Indiana Hub	2	1	-3	-3	5	-1	-2	-1	3	0	-4	6	-3	4	-26
Michigan Hub	1	1	-1	-3	6	3	-3	5	6	-1	-3	7	1	4	-21
Minnesota Hub	-2	-1	0	3	8	8	2	-1	10	-2	-5	7	0	4	-17
Arkansas Hub	1	-3	-2	-2	3	3	3	6	3	-5	-7	4	-3	-3	-18
Louisiana Hub	2	-1	-1	-3	5	4	4	8	5	0	-7	3	-1	-1	-23
Texas Hub	6	-2	-1	-4	4	4	1	9	4	-2	-7	4	-1	-2	-24

These results indicate that price convergence was good overall. Day-ahead prices were about three percent lower than real-time prices after adjusting for the real-time RSG costs, which averaged $0.99 per MWh. Divergence between day-ahead and real-time prices occurred primarily because of transient conditions in 2022. The most significant source of divergence occurred during Winter Storm Elliott in December. During this event, MISO experienced extended periods of shortage pricing that was particularly significant in the South.

B. Virtual Transactions in the Day-Ahead Market

A large share of the liquidity that facilitates good day-ahead market performance is provided by virtual transactions. Virtual transactions are financial purchases or sales of energy in the day-ahead market that do not correspond to physical load or resources. The buyer (or seller) enters the real-time long (or short). Since they do not produce or consume physical energy, virtual transactions positions settle against real-time prices. Virtual transactions are essential facilitators of price convergence because they are used to arbitrage price differences between the day-ahead and real-time markets. Figure 20 shows the average offered and cleared virtual supply and demand. The figure separately shows financial-only participants and physical participants.

Figure 20: Virtual Demand and Supply in the Day-Ahead Market

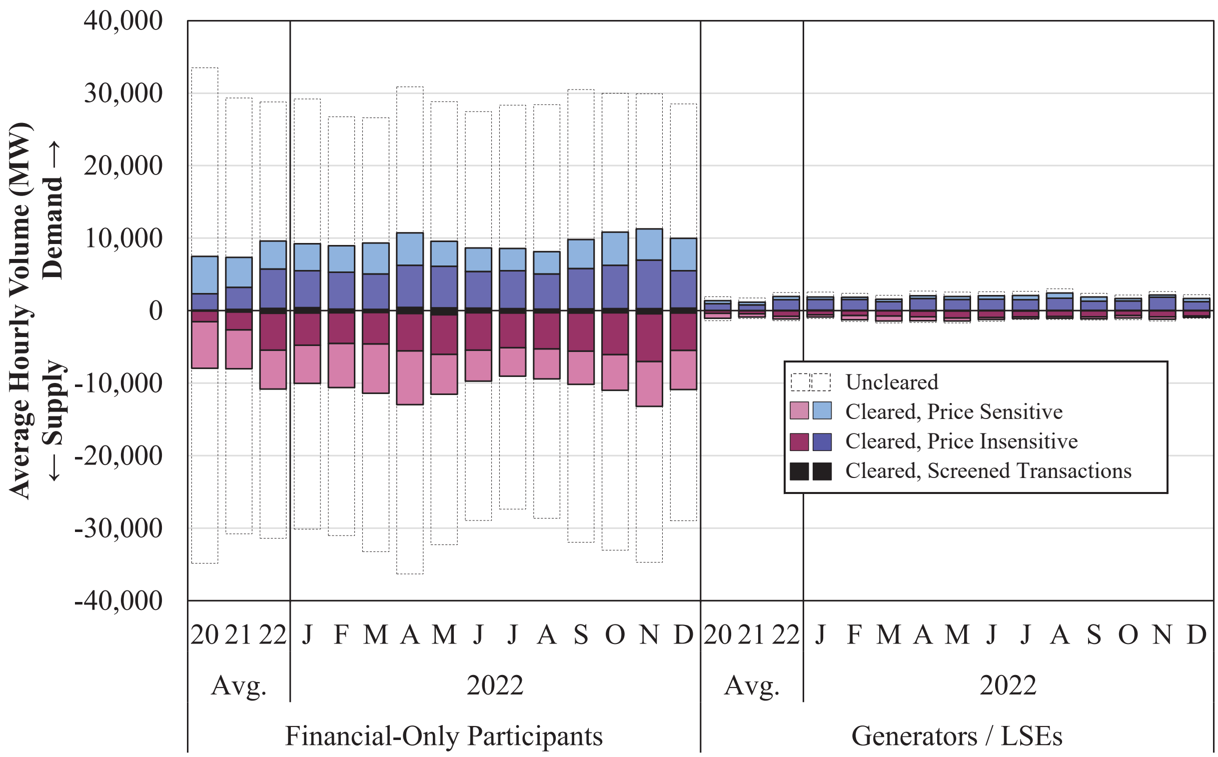


Figure 20 shows that financial participants continue to account for the vast majority of virtual transactions, although the limited quantities scheduled by physical participants grew roughly 50 percent. In total, cleared transactions increased by 35 percent, driven by increases in cleared virtual activity of 36 percent in the Midwest and of 15 percent in the South.

Figure 20 indicates the following additional key findings:

- Financial participants offer more price-sensitively and provide day-ahead market liquidity.
- Several participants submit "backstop" bids and offers that are priced well below (for demand) or above (for supply) the expected price range. Backstop bids and offers clear less than one percent of the time, but they are substantially profitable when they do clear. They are beneficial because they mitigate particularly large day-ahead price deviations.
- Bids and offers that are price-insensitive (i.e., offered at prices making them very likely to clear) constitute a significant share of all virtual transactions. They provide less liquidity to the market and can raise manipulation concerns.
  - Most price insensitive transactions are used to arbitrage congestion-related price differences by allowing participants to establish an energy-neutral position between two locations (offsetting virtual supply and demand positions at two locations). We refer to these transactions as "matched" transactions.
  - Matched transactions avoid RSG deviation charges and carry no energy price risk. Their average hourly volume increased by 90 percent from 2021 to 2,063 MW.
  - We continue to recommend MISO implement a "virtual spread product" that would allow participants to engage in such transactions price-sensitively. Comparable products exist in both PJM and ERCOT.
- Price-insensitive transactions that cause congestion *divergence* between the day-ahead and real-time markets (labeled "Screened Transactions") raise potential manipulation concerns. They were only 3.1 percent of all transactions and raised no concerns in 2022.

Virtual Activity and Profitability

Gross virtual profitability rose 14 percent in 2022 to average $1.37 per MWh, up from $1.20 per MWh in 2021. Both virtual demand and virtual supply profitability increased substantially. Some of this increase was due to high profits during Winter Storm Elliott in December, when real-time price spikes raised virtual demand profitability to average almost $14 per MWh.

In general, gross profits are higher for virtual supply because more than half of these profits are offset by real-time RSG costs allocated to participants with net virtual supply positions. This allocation eliminates the incentive for virtual suppliers to pursue low-margin arbitrage opportunities. Virtual demand does not bear capacity-related RSG costs because they reduce the need for real-time capacity commitments. Virtual transactions by financial participants remained generally more profitable than transactions submitted by physical participants, averaging $1.45 per MWh compared to $0.83 per MWh.

To provide perspective on the virtual trading in MISO, Table 3 compares virtual trading in MISO to trading in NYISO, ISO New England, SPP, and PJM. This table shows that virtual trading is generally more active in MISO than in other RTOs, even after adjusting for the much larger size of MISO. This is partly due to the more efficient allocation of RSG costs that MISO uses. The table also shows that liquidity provided by virtual trading in MISO translates to relatively low virtual profits. Virtual supply profits are higher than virtual load because of the RSG cost allocation discussed above.

Table 3: Comparison of Virtual Trading Volumes and Profitability
2022

Market	Virtual Load		Virtual Supply	
	MW as a % of Load	Avg Profit	MW as a % of Load	Avg Profit
MISO	14.9%	$1.00	15.5%	$1.73
NYISO	5.9%	$5.15	5.9%	$0.10
ISO-NE	3.1%	-$0.60	4.9%	$2.84
SPP	9.4%	$0.05	16.2%	$7.83
PJM	5.7%	$4.72	4.0%	-$0.19

Low virtual profitability is consistent with an efficient day-ahead market, which is important because the day-ahead market coordinates the daily commitment of MISO's resources. Although overall profitability is a positive indicator, the next subsection contains a more detailed analysis of virtual transactions to determine the share that improves day-ahead market outcomes.

Benefits of Virtual Trading

We studied the contribution of virtual trading to market efficiency in 2022. We determined that 60 percent of all cleared virtual transactions in MISO were efficiency-enhancing and led to convergence between the day-ahead and real-time markets. The majority of efficiency-enhancing virtual transactions were profitable based on congestion modeled in the day-ahead and real-time markets and the marginal energy component (system-wide energy price).

A small share of the efficiency-enhancing virtual transactions was unprofitable, which occurs when virtual transactions respond to a real-time price trend but overshoot. We did not include profits from un-modeled constraints or from loss factors in our efficiency-enhancing category because these profits do not increase day-ahead efficiency. A detailed description of our methodology can be found in the Appendix Section IV.G.

Virtual transactions that did *not* improve efficiency led to divergence and were generally those that were unprofitable based on the energy and congestion on modeled constraints. They can be profitable when they profit from un-modeled constraints or loss factor differences. Table 4 shows the total amount of efficient and inefficient virtual transactions by market participant type.

The table shows that 60 percent of all virtual transactions were efficiency-enhancing. Convergent profits were positive on net for all virtual transactions by $201.4 million, up from $133.2 million in 2021. However, this value significantly understates the net benefits of the virtual transactions because it measures the profits at the margin.

In other words, the total benefit is much greater than the marginal benefit, because:

- The profits of efficient virtual transactions become smaller as prices converge; and
- The losses of inefficient virtual transactions get larger as prices diverge.

Table 4: Efficient and Inefficient Virtual Transactions by Type of Participant in 2022

Transaction Category	Financial Participants			Physical Participants		
	MWh	Convergent Profits	Rent-Seeking	MWh	Convergent Profits	Rent-Seeking
Efficiency Enhancing (Profitable)	92,126,308	$1,771.9M	-$72.4M	12,031,077	$219.6M	$5.9M
Efficiency Enhancing (Unprofitable)	14,349,361	-$141.4M	$28.1M	2,235,921	-$21.0M	$3.5M
Not Efficiency Enhancing (Profitable)	5,422,658	-$42.7M	$93.8M	830,514	-$4.1M	$8.9M
Not Efficiency Enhancing (Unprofitable)	66,910,978	-$1,389.8M	$11.7M	12,056,649	-$191.2M	$.9M
Total	**178,809,305**	**$198.1M**	**$61.2M**	**27,154,161**	**$3.4M**	**$19.1M**

Although we are not able to rerun the day-ahead and real-time market cases for the entire year, this analysis provides a high degree of confidence that virtual trading was beneficial in 2022.

C. Real-Time Market Pricing

Efficient real-time market outcomes are essential because they provide incentives for suppliers to be available and to respond to dispatch instructions. They also inform forward price signals for day-ahead scheduling and long-term investment and maintenance. In this subsection, we evaluate whether real-time prices efficiently reflect prevailing conditions. However, we do not discuss pricing during energy or reserve shortages in this subsection because it is addressed in Section III.B, which discusses the future needs of the MISO markets. Efficient shortage pricing is essential for the market to perform well, especially as the reliance on intermittent resources rises.

Fast-Start Pricing by the ELMP Model

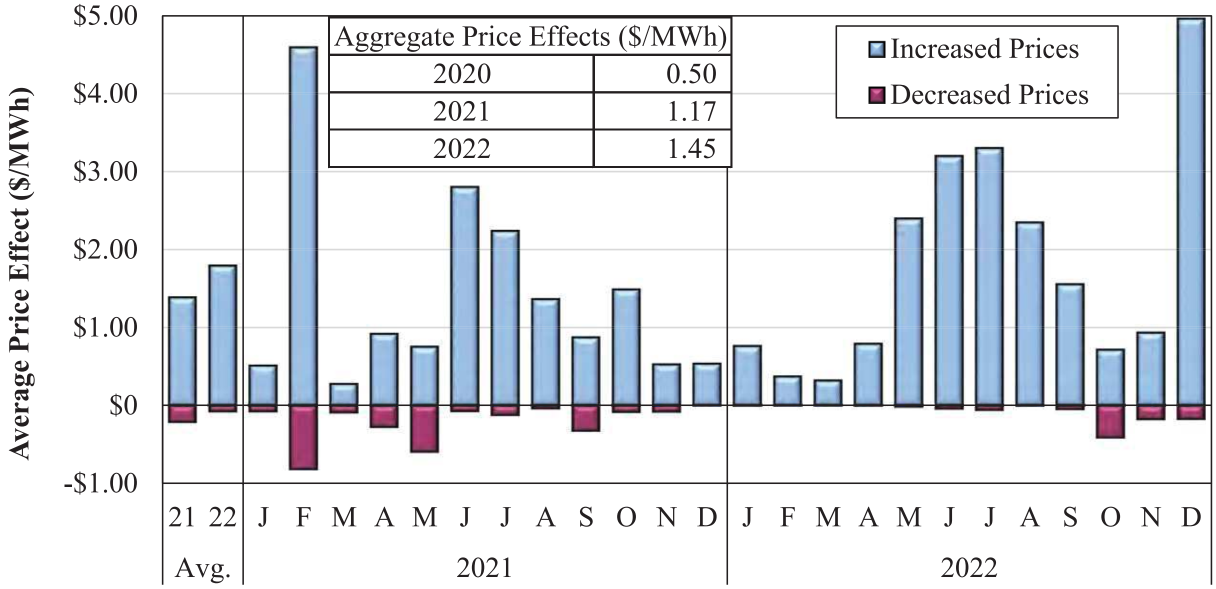
Beyond shortage pricing, a key element of MISO's real-time pricing is its Extended Locational Marginal Pricing (ELMP) algorithm that was implemented in March 2015. While MISO's dispatch model calculates "ex ante" real-time prices every five minutes, these real-time prices are re-calculated by the ELMP model and used for real-time settlements. ELMP is intended to improve price formation by establishing prices that better reflect the true marginal costs of supplying energy and ancillary services at each location. ELMP reforms pricing by allowing Fast-Start Resources (FSRs) and emergency resources to set prices when needed and economic to satisfy the system's needs.[21]

21 MISO had previously allowed offline fast-start resources to set prices under transmission and reserve shortage conditions, which was inefficient and was suspended in ELMP in October 2021.

When FSRs are not reflected efficiently in prices, the resulting understatement of prices leads to higher RSG costs and poor pricing incentives for scheduling generation and interchange. Although FSRs may not appear to be marginal in the five-minute dispatch, the ELMP model recognizes that peaking resources are marginal and should set prices to the extent they are needed to satisfy the system's needs.

Although the initial impacts from ELMP were small, MISO implemented a number of recommendations to improve its effectiveness from 2017 through 2019 that have improved price formation. MISO implemented a final key recommendation in September 2021 to address an issue that had prevented FSRs that were needed to satisfy the system demands from setting prices. Together, these changes have significantly improved real-time price formation in MISO. The following figure summarizes the effects of the ELMP pricing model in 2022.

Figure 21: The Effects of Fast Start Pricing in ELMP
2021–2022



% of Intervals Affected by > +/- $0.10

SMP Increase	56	57	36	57	44	61	54	68	61	60	54	66	61	52	56	49	42	54	58	60	59	51	75	58	63	55
SMP Decrease	2	1	3	6	2	3	5	1	1	1	1	1	1	0	0	0	0	1	1	4	1	1	2	0	4	1

As shown in Figure 21, the effects of ELMP on MISO's real-time energy prices rose 24 percent in 2022. This increase was due to a combination of the ELMP improvements described above, the high price effects in December, higher natural gas prices, and the elimination of offline ELMP pricing in the fall of 2021. We expect ELMP will continue to perform well because of the improvements MISO has made in recent years. As expected, ELMP had almost no effect in the day-ahead market because the supply is far more flexible and includes virtual transactions.

Emergency Pricing by the ELMP Model

In addition to FSRs, emergency actions and resources can set prices in ELMP during declared emergencies. In September 2021, MISO implemented recommended improvements to its ELMP emergency pricing. MISO expanded the set of resources that can set prices during an emergency[22] and established minimums on the Tier 1 and Tier 2 Emergency Offer Floor Prices applied to emergency resources at $500 per MWh and $1,000 per MWh, respectively.[23] In previous years, MISO's emergency offer floor prices were set inefficiently low. MISO updated the value of RPE constraints to $200 per MWh during emergencies. These changes have helped ensure that MISO's emergency pricing sets more efficient prices during emergencies.

Modifying the Market Pricing during LMR Deployments

While EEA2 events that prompt MISO to deploy LMRs have been rare, pricing during these events has not been efficient in many cases. The ELMP model that produces prices during emergency conditions determines whether emergency resources should set prices by attempting to dispatch them down and allow other resources to replace them. The theory is that if the ELMP model cannot ramp the resources to zero, then they are needed and should set real-time prices. While this is reasonable in most cases, it is not always reasonable for LMRs because they are usually deployed in large quantities (3 to 6 GWs). The ELMP model generally lacks the ramp capability on other resources to replace the LMRs in a single dispatch interval. Therefore, they often set prices long after they are no longer needed. This has resulted in:

- Elevated prices and excessive non-firm imports as participants respond to these prices;
- High prices extending beyond the emergency area to all of MISO once supply is adequate and the constraint into the area unbinds; and
- Large uplift payments in the form of price-volatility make-whole payments that must be made to resources that are held down to make room for the LMRs and non-firm imports.

We recommend MISO consider revising its emergency pricing model to reintroduce LMR curtailments as Short-Term Reserves, instead of energy demand, to produce more efficient emergency pricing and better align ex-ante and ex-post results. We previously validated the value of this approach by simulating the emergency that occurred on June 10, 2021. This simulation was described in the *2021 State of the Market Report* and showed that the actual prices set between $200 and $400 per MWh for almost two hours would have been less than $150 per MWh. This demonstrates the significantly improved pricing outcomes resulting from treating LMRs as Short Term Reserves demand in the ELMP pricing model.

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22 Resources offering up to four hours to start and a minimum run time up to four hours may now set the price during emergency conditions (Tier 0 Emergency Offer Floor Price) when MISO declares a Max Gen Alert.

23 Tier 1 Emergency Offer Floor Prices apply when MISO declares a Max Gen Warning, while Tier 2 applies when MISO declares a Max Gen Event Step 2.

D. Uplift Costs in the Day-Ahead and Real-Time Markets

Evaluating uplift costs is important because these costs are difficult for customers to forecast and hedge, and they generally reveal areas where the market prices do not fully capture the cost of system requirements. Most uplift costs are the result of guarantee payments made to participants. MISO employs two primary forms of guarantee payments to ensure resources cover their as-offered costs and provide incentives to be available and flexible:

- Revenue Sufficiency Guarantee (RSG) payments ensure the total market revenue for a unit committed economically or for reliability is at least equal to its as-offered costs over its commitment period; and
- Price Volatility Make-Whole Payments (PVMWP) ensure suppliers will not be financially harmed by following the five-minute dispatch signals.

Resources committed before or in the day-ahead market may receive a day-ahead RSG payment as needed to recover their as-offered costs. Resources committed by MISO after the day-ahead market receive a real-time RSG payment as needed to recover their as-offered costs. The day-ahead RSG costs for economic commitments are recovered on a pro-rata basis from all scheduled load. The real-time RSG costs are recovered via charges to participants that cause the costs, and the residual is charged to load. This allocation generates efficient incentives for participants.

Day-Ahead and Real-Time RSG Costs

Figure 22 shows monthly day-ahead RSG costs categorized by the underlying cause. Most RSG payments for Voltage and Local Reliability (VLR) are made in the day-ahead market because most VLR commitments are made before or during the day-ahead market process. Because fuel prices have considerable influence over suppliers' production costs, the figure shows RSG payments in both nominal and fuel-adjusted terms.[24] The maroon bars show all the RSG paid to units started for VLR before the day-ahead market cleared, except that the VLR costs incurred for the Western Op Guide (replaced by the Southeast Texas (SETEX) Op Guide in August 2022) is shown in the maroon striped bars. The blue part of the bars shows RSG incurred for commitments made to maintain system-wide capacity.

Nominal day-ahead RSG payments fell 25 percent in 2022 to total $65 million, although it fell only 9 percent if the effects of Winter Storm Uri in February 2021 are excluded. Almost all day-ahead VLR costs accrue in two load pockets in MISO South, but three new gas-fired combined-cycle units exceeding 3 GW in total came online in MISO South in the past 3 years that reduced the need for these VLR commitments. In August 2022, MISO implemented a new op guide to fully incorporate the impacts of the addition of a large, 1 GW combined-cycle facility in early 2021 in WOTAB. We encourage such updates to be implemented in a timelier manner to avoid unnecessary commitments.

24 Fuel-adjusted RSG payments are indexed to the average three-year fuel price of each unit.

Figure 22: Day-Ahead RSG Payments
2021–2022

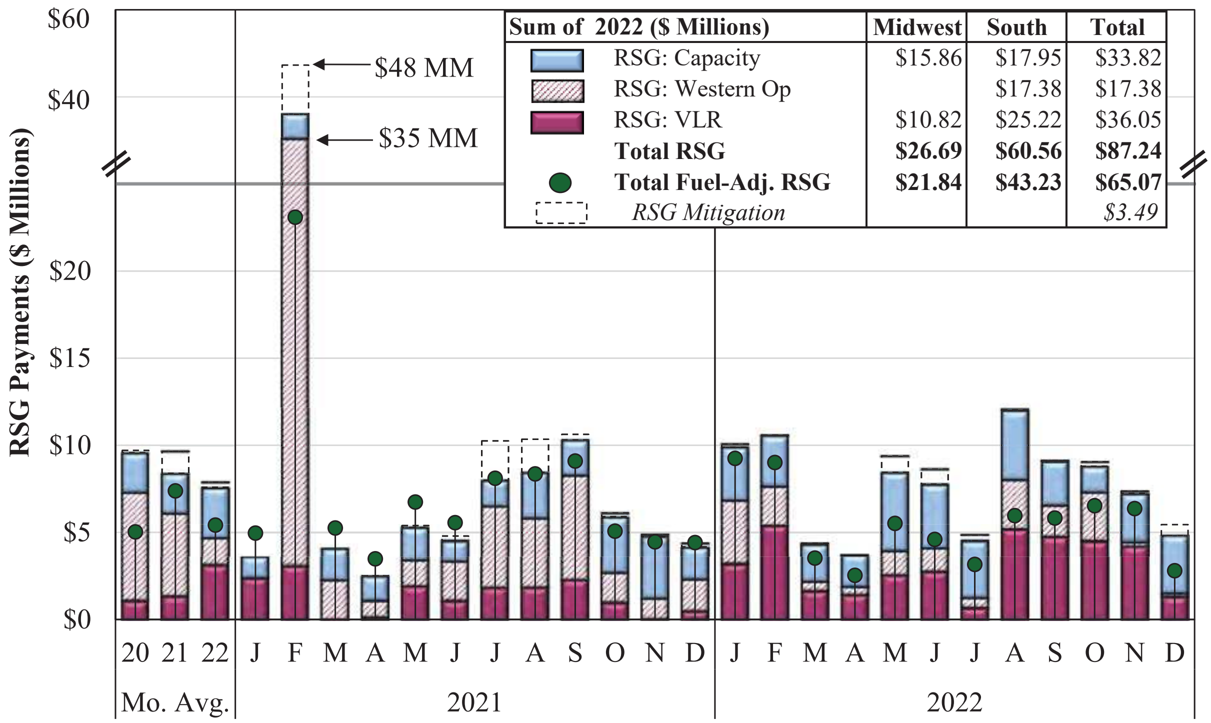
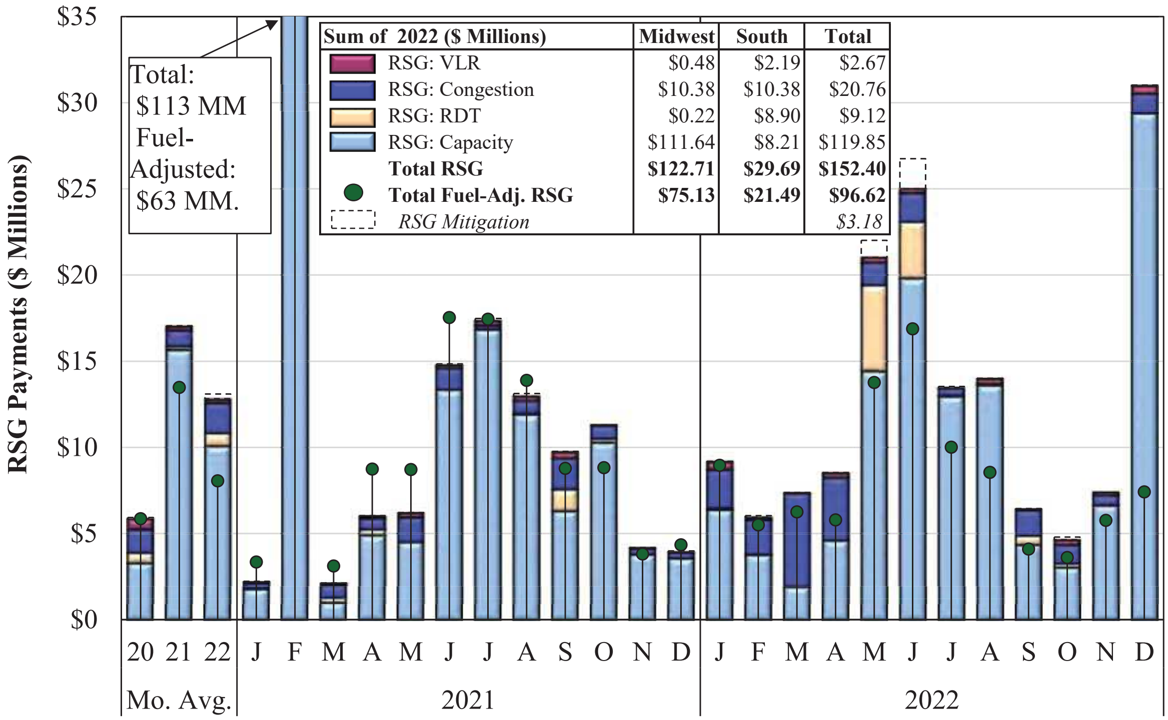


Figure 23 shows the same categories of real-time RSG payments, and includes RSG costs for units committed to: a) manage congestion, and b) manage RDT flows or create regional reserves.

Figure 23: Real-Time RSG Payments
2021–2022



The figure shows that real-time nominal RSG payments fell 40 percent in 2022, largely because real-time RSG was very high in 2021 during and after Winter Storm Uri. MISO incurred roughly $100 million during that event, compared to $24 million that MISO incurred during Winter Storm Elliott. Although RSG was lower on average, MISO incurred higher RSG between May and August in 2022 and commitment patterns played a key role. We evaluate and discuss the resource commitments in the next subsection.

Price Volatility Make-Whole Payments

PVMWPs address concerns that resources can be harmed by responding to volatile five-minute price signals. Hence, these payments provide suppliers the incentive to offer flexible physical parameters and come in two forms: Day-Ahead Margin Assurance Payments (DAMAP) and Real-Time Offer Revenue Sufficiency Guarantee Payments (RTORSGP). DAMAP payments are made when resources produce output at a level less than both the day-ahead schedule and the economic output level given its offer price. RTORSGP payments are made when a unit is operated higher than its economic output level. Table 5 shows the annual totals for DAMAP and RTORSGP, along with the price volatility at the system level (SMP volatility) and at the unit locations receiving the payments (LMP volatility). We separately indicate the amount of PVMWP MISO incurred excluding Winter Storm Uri in February 2021 and Winter Storm Elliott in December 2022.

Table 5: Price Volatility Make-Whole Payments ($ Millions)
2020–2022

	DAMAP		RTORSGP		Total	Avg. Market-Wide Volatility	Avg. Locational Volatility
	Midwest	South	Midwest	South			
2022	$69.9	$11.1	$5.2	$1.5	$87.7	15.2%	21.0%
WS Elliott	*$23.0*	*$0.7*	*$0.0*	*$0.1*	*$23.8*		
2021	$33.0	$14.2	$4.0	$2.1	$53.3	13.4%	14.3%
WS Uri	*$6.5*	*$6.9*	*$0.0*	*$1.3*	*$14.7*		
2020	$23.2	$4.5	$1.8	$0.5	$30.0	14.3%	19.2%

PVMWPs rose 65 percent over 2021. A large portion of the DAMAP in 2021 occurred in February 2021 when prices reached $3,500 per MWh for several hours during load shed conditions, while a large portion of the DAMAP in 2022 occurred in December when MISO experienced prolonged shortage pricing and emergency pricing. Some of the year-over-year increase was due to higher energy prices that resulted from higher fuel prices.

E. Real-Time Commitment Patterns

Excluding the very high RSG payments incurred during winter storm events (Uri in 2021 and Elliott in 2022), real-time fuel-adjusted RSG payments increased by 69 percent from 2020 to 2021 and 47 percent from 2021 to 2022. In 2021, we identified a pattern of increasing capacity-related commitments beginning in the summer months. Figure 24 shows monthly RSG costs in 2022 for resources committed in real time for capacity. We have evaluated these costs and categorize the RSG according to that which was:

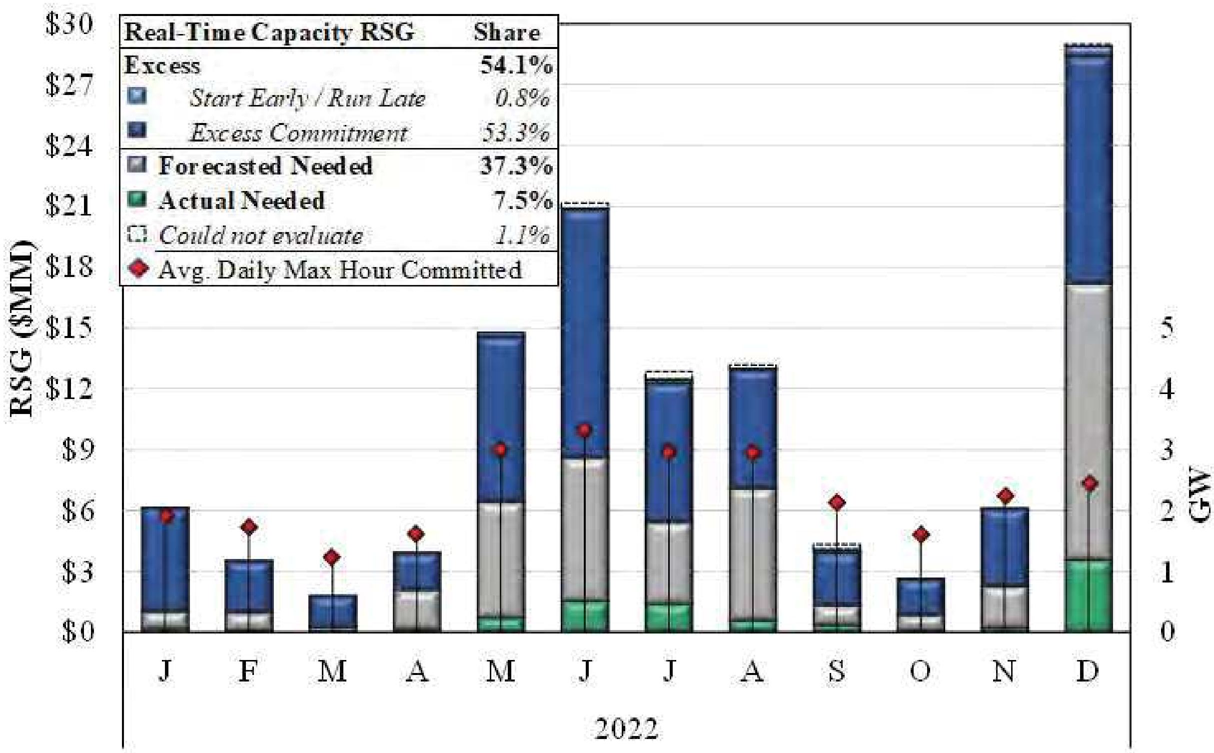
- Actually needed to cover load and reserves;
- Not needed based on actual load but that MISO forecasted as needed; and
- Not needed based on actual load or forecasted load (excess commitments).

The figure also shows the monthly GW average of the daily maximum commitment. For purposes of this evaluation, we accept the commitment criteria and capacity requirements that MISO employs. Accepting these requirements and targets, our evaluation finds that:

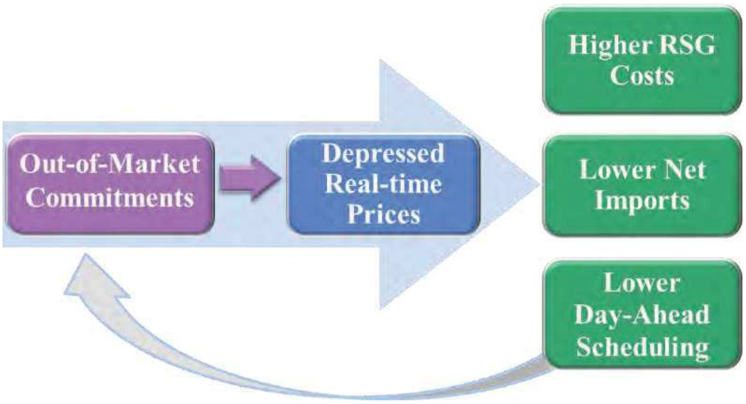
- Roughly 7.5 percent of the capacity-related RSG costs were actually needed, while another 37 percent appears to have been needed when commitment decisions were made.
- 54 percent of the capacity-related RSG costs were associated with commitments that were not needed or forecasted to be needed when they were made (i.e., excess).
- A small portion of the excess commitments was associated with resources being started earlier than needed or not being decommitted when no longer needed.

These results raise substantial concerns not only because of the costs they generate, but more importantly for the secondary adverse effects they have on MISO's market outcomes.

Figure 24: Monthly Real-Time Capacity Commitments and RSG Costs in 2022



Excess out-of-market commitments undermine the performance of the markets by creating a self-enforcing cycle of excess commitments. As the illustration below shows, they depress real-time prices, which increases RSG costs and reduces supply – increasing the need for out-of-market commitments. The lower real-time prices: a) decrease net supply scheduled in the day-ahead market (averaging 98 percent of peak real-time load in 2022), and b) reduce net imports in the real-time market.



We have been working with MISO to improve real-time commitment practices to reduce excessive commitments and prevent price suppression. We have recommended a number of improvements designed to reduce the frequency of unnecessary commitments, including:

- Eliminating the use of manual inputs to the LAC model to address uncertainty since they cause it to recommend unnecessary commitments, increasing STR requirements instead.
- Deferring commitments that do not need to be made immediately given resources' start-up times and decommitting them when no longer needed.
- Use reserve demand curves and TCDCs in the LAC and other commitment models that are more closely aligned with the market demand curves.

MISO has created a team to evaluate existing tools and operating practices and has begun working with the IMM to make recommended changes. Improving operator logging is also important because it will facilitate better understanding of the causes of excess commitments.

F. Regional Directional Transfer Flows and Regional Reliability

The scheduled transfers between the South and Midwest are limited to contractual limits. MISO has taken two actions to prevent exceeding these limits: (a) implementing a post-contingent constraint to hold headroom on the RDT, and (b) actively managing the RDT limit to avoid unmodeled exceedances. The latter involved MISO binding the RDT in real time at an average of 318 MW below its contractual limit.

Flows on the RDT averaged 807 MW in the South to North direction in 2022 but flows across the RDT in the North to South direction were generally correlated with wind output. Importantly, limiting interregional transfers that do not contribute to congestion on the SPP or the Joint Parties' systems is inefficient. To reduce these inefficiencies, we recommend that MISO explore better coordination and settlements on the constraints in adjacent areas that are affected by the transfers. This would increase MISO's ability to transfer power while reducing the congestion effects on its neighbors.

Currently, all wind resources in MISO are in the Midwest Region, so when MISO experiences high wind, the RDT flows tend to be in the North to South direction. Conversely, when wind falls sharply, flows tend to reverse to the South to North direction. The ability of the MISO market to shift the quantity and direction of flows by more than 5,000 MW provides tremendous value to the customers in both regions.

G. Real-Time Dispatch Performance

MISO issues dispatch instructions to generators every five minutes that specify the expected output at the end of the next five-minute interval. Good performance of MISO's generators is essential to efficiently managing congestion and maintaining reliability in MISO. Therefore, it is critical that MISO's markets provide adequate incentives for its generators to perform well in following MISO's dispatch instructions. Failing to meet the dispatch instruction is known as "dragging", and it can be measured in each 5-minute interval or summed over a longer period (e.g., 60-minutes). Table 6 shows the average 5-minute and 60-minute average hourly dragging in recent years in all hours and in hours when generation must ramp up or down rapidly in the morning and evening.

Table 6: Average Five-Minute and Sixty-Minute Net Dragging
2018–2022

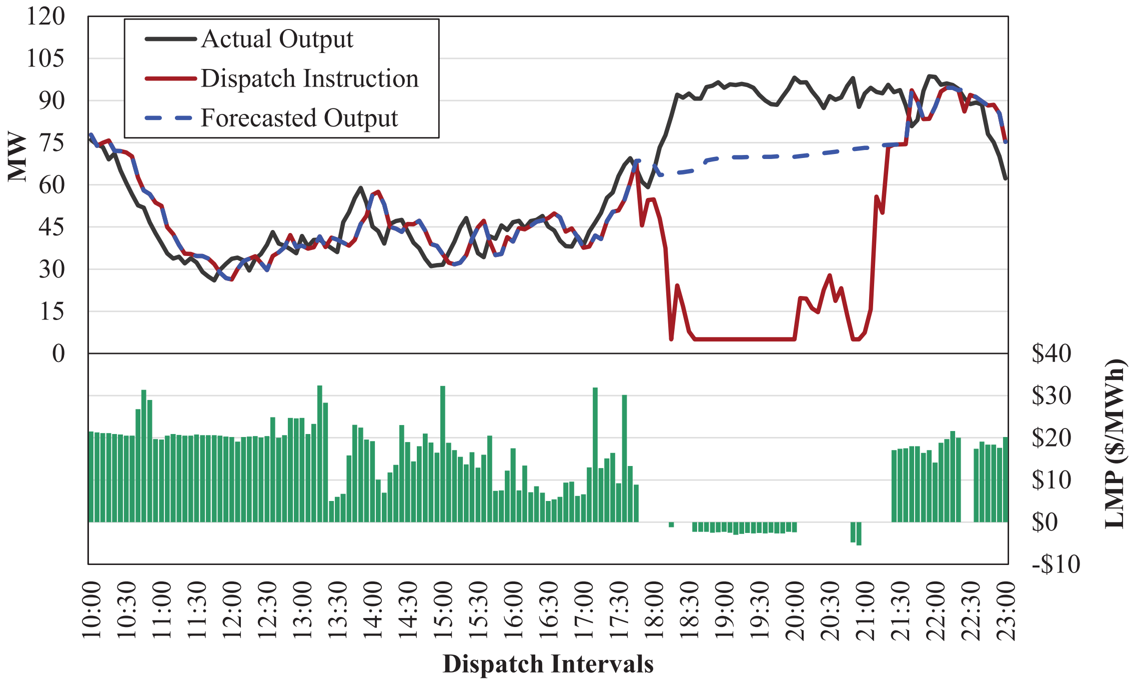
	5-min Dragging		60-min Dragging		Worst 10%	
	Ramp Hours	All Hours	Ramp Hours	All Hours	Ramp Hours	All Hours
2022	637	660	1,049	1,009	1,341	1,275
2021	611	629	956	908	1,338	1,290
2020	573	563	957	862	1,289	1,193
2019	525	526	851	787	1,163	1,078
2018	595	563	991	851	1,305	1,216

Table 6 shows that the 60-minute dragging in all hours increased 11 percent from 2021 to 2022. Dragging raises a substantial concern because capacity on resources that are not following dispatch instructions is effectively unavailable to MISO. Almost 20 percent of the 60-minute deviations are scheduled in MISO's look-ahead commitment model. This is troubling because MISO operators do not perceive this effective loss of capacity and, therefore, may not make economic or needed commitments. Some of these 60-minute deviations may indicate units that are derated and physically incapable of increasing their output. Because participants are obligated to report derates under the Tariff, we have referred the most significant "inferred derates" to FERC enforcement. Additionally, such conduct can qualify as physical withholding when no physical cause for the derate exists.

The failure to follow dispatch instructions generally creates the greatest adverse effects when the resource affects a binding transmission constraint. In this case, the real-time market dispatch will produce dispatch instructions and prices that assume the resource will follow the dispatch instructions. Figure 25 shows the actual output of a wind resource from 10 a.m. to 11 p.m. on a given day, along with the forecasted output, dispatch instruction, and the LMP at the resources' location. The forecast matches the dispatch instruction whenever the unit is not curtailed because: (a) the forecast is assumed to be the unit's economic maximum level and (b) the unit is offered at a negative price. Since MISO uses a persistence forecast, the forecast always equals the observed output of the unit roughly 10 minutes earlier, except when the unit is curtailed.

From approximately 6 p.m. to 9:15 p.m., the real-time dispatch model attempted to curtail this unit and generally set prices at zero or at a slightly negative price. These prices reflect the substantial congestion that the dispatch model recognized assuming this unit will follow the dispatch instruction. In reality, the congestion was more severe because the excess output from this unit increased the flow on the constraint by as much as 38 MW, violating the modeled limit for the constraint by as much as 9 percent.

Figure 25: Example of Wind Resource Failing to Follow Dispatch Instructions



These findings indicate the importance of improving generators' incentives to follow dispatch instructions and update to resources' real-time offers in a timely manner. We discuss below our recommendation for improving these incentives for units that overload transmission constraints.

Aligning Uninstructed Deviation Penalties with Congestion Impact

Current settlement rules are insufficient for generation deviations outside the uninstructed deviation (UD) tolerance bands and deviations that persist for less than 20 minutes are exempted from any financial penalty. The most significant penalty is the excessive energy price, paid at the lower of LMP and as-offered cost on excessive energy volumes. This provides a very weak incentive, particularly to renewable resources, which often set price at their cost when curtailed.

In these cases, the renewable resource is financially indifferent between following dispatch and producing excessive energy. This indifference is especially harmful when the excess energy causes transmission overloads that are difficult to manage.

To address this concern, which is bound to grow as more intermittent resources enter the system, we are recommending an improvement to the penalty structure that would be based on the marginal congestion component (MCC) of the resource's LMP. For excessive or deficient energy that loads a constraint, we recommend that MISO impose a penalty equal to an escalating share of the MCC beginning with 25 percent in the first interval and rising to 100 percent by the fourth interval. This MCC-based penalty is appropriate because it reflects the incremental congestion value of the deviation volumes and scales with the severity of congestion. The table below shows how this penalty would have affected different types of units in 2022.

Table 7: Proposed Uninstructed Deviation Penalties and Effective Rate in 2022

		Avg. Deviation Penalty ($/MWh)		Avg. Penalty ($/MWh of Output)	
Unit Type	**Total Penalty**	**Excessive**	**Deficient**	**Excessive**	**Deficient**
Gas Turbine	$405,553	$6.12	$5.43	$0.003	$0.003
Coal	$1,033,785	$11.58	$6.50	$0.003	$0.002
Combined Cycle	$489,974	$4.82	$4.02	$0.002	$0.002
Other	$645,519	$5.65	$4.77	$0.002	$0.003
Solar	$71,627	$10.01	$3.60	$0.009	$0.008
Wind	$3,298,440	$40.83	$1.81	$0.032	$0.001

There are several key takeaways from this table:

- The average penalty rate per MWh of output is extremely low at less than $0.01 for most conventional generation. Resources that follow dispatch instructions reasonably well should be minimally impacted by this proposal.
- The deviation penalty rate is material, averaging $17.02 and $4.23 for excessive energy and deficient energy, respectively. These rates vary based on the duration and congestion caused by different units' deviation. These penalties should promote better performance.
- The penalties and penalty rates are largest on excessive energy from wind resources. Nearly all wind resources – those that use the MISO forecast – are exempt from UD penalties Except when curtailed. Nonetheless, they would account for a disproportionate share of the penalties. Because they have such fast ramp rates, failure to follow dispatch can result in large deviations that cause serious constraint violations with little warning.

The proposed penalties will improve dispatch incentives for all resources, and particularly for those whose deviations cause the most serious reliability concerns.

Dispatch Operations: Offset Parameter

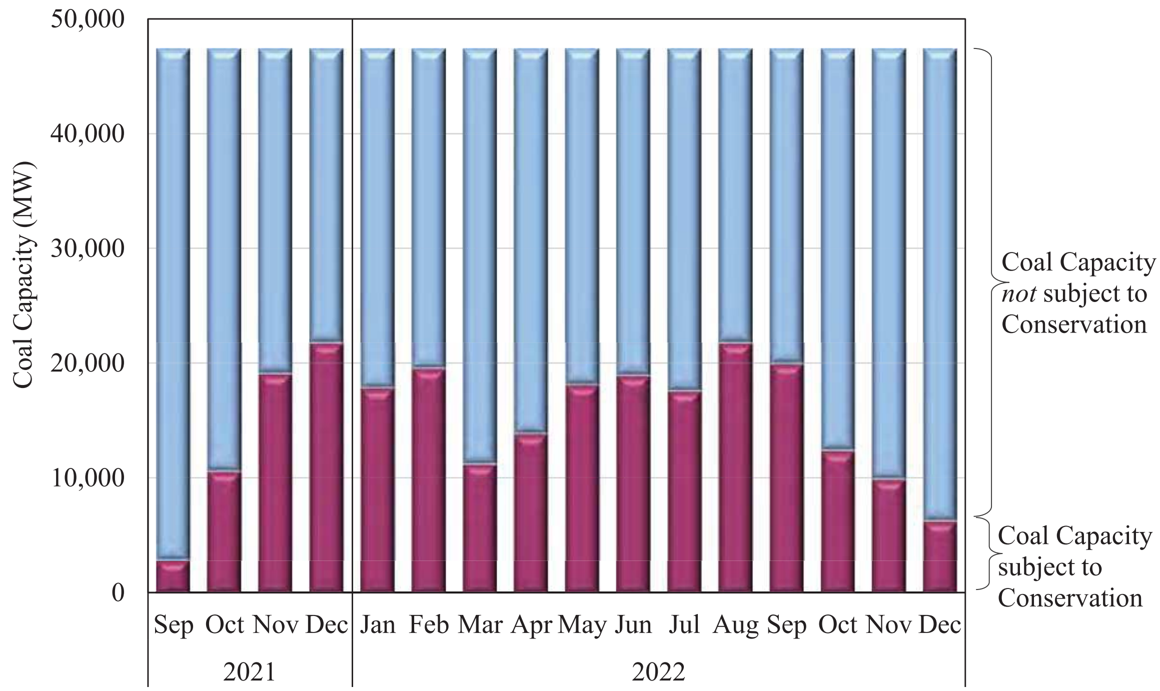
The offset parameter is a quantity chosen by the MISO real-time operators to adjust the modeled load to be served by the UDS. A positive offset value is added to the short-term load forecast to cause an increase in the generation output, while a negative offset decreases the load and the corresponding dispatch instructions. Offset values may be needed for many reasons, including: a) generator outages that are not yet recognized by UDS; b) generator deviations (producing more or less than MISO's dispatch instructions); c) wind output that is over or under-forecasted in aggregate; or d) operators believe the short-term load forecast is over or under-forecasted.

Large changes in offset values increase price volatility. This is not surprising because ramp capability—the ability of the system to quickly change output—is often limited, so large changes in the offset can lead to sharp changes in prices. Our analysis shows large offset increases sometimes lead to operating reserve shortages and associated price spikes. Conversely, offset reductions sometimes mute legitimate shortage pricing. MISO utilizes a tool that recommends offset values. We are concerned about some of the logic and calculations underlying these recommendations, which have sometimes led to poor offset selections. In response to these concerns, MISO has made some changes and agreed to work with us to resolve other concerns.

H. Coal Resource Operations

In the summer of 2021, as natural gas and energy prices rose during the summer months, the economic operating margins of MISO's coal-fired resources rose substantially and caused them to operate at higher capacity factors. However, multiple coal-fired resources began to experience COVID-related supply chain issues, transportation limitations, and shortages of reagents by the fall. These limitations led to coal conservation strategies that substantially reduced their output beginning in the fall of 2021. Figure 26 shows the quantities of resources conserving coal by month from the fall of 2021 through December 2022.

Figure 26: Coal Capacity Impacted by Coal Conservation Measures
2021–2022



This figure shows that by February 2022, lower-than-expected December gas prices and mild conditions allowed many resources to build up their coal inventories. At the end of the winter quarter, the number of resources conserving coal fell by 40 percent. Coal resources were utilized at higher rates through the summer of 2022, and coal conservation increased up through September. After September, coal supply constraints eased as railroads were able to provide more coal deliveries in MISO.

In Table 8, we summarize our analysis of coal resource operations, including how they are started and how profitably they operated. Because many of the regulated utilities operate differently than unregulated merchant generators, the table shows our results for them separately.

Table 8: Coal-Fired Resource Operation and Profitability
2017–2022

	2017-2020			2021			2022		
	Annual Starts	% of Starts	Net Rev. ($/MWh)	Starts	% of Starts	Net Rev. ($/MWh)	Starts	% of Starts	Net Rev. ($/MWh)
Regulated Utilities	1839		**$3.54**	1718		**$14.04**	1765		**$22.41**
Profitable Starts	1570	87%		1564	91%		1635	93%	
Offered Economically	*727*	*39%*		*885*	*52%*		*754*	*43%*	
Must-Run and profitable	*843*	*48%*		*679*	*40%*		*881*	*50%*	
Unprofitable (Must Run)	269	13%		154	9%		130	7%	
Merchants	187		**$5.05**	124		**$14.96**	84		**$30.42**
Profitable Starts	184	97%		124	100%		84	100%	
Offered Economically	*143*	*70%*		*124*	*100%*		*84*	*100%*	
Must-Run and profitable	*41*	*27%*		*0*	*0%*		*0*	*0%*	
Unprofitable (Must Run)	4	3%		0	0%		0	0%	

Table 8 shows that in 2022, coal resources were much more profitable than in recent years—their net revenues rose to almost $23 per MWh on average. These values are roughly six times higher than the average net revenues coal resources earned between 2017 and 2020. Although coal-fired resources were more economic in 2022, the fuel limitations and other supply chain issues limited the increase in their output.

Table 8 also shows that the share of resources running profitably increased significantly in 2022. This was likely due to the increasing energy prices. However, MISO's regulated utilities often continue to operate their resources as "must-run," running them regardless of the price. In contrast, MISO's unregulated merchant generators always offered economically in 2022 and ran profitably in 100 percent of their run hours.

I. Wind Generation

As discussed in Section III.A, wind capacity is continuing to grow in MISO. Accounting for over 29 GW of MISO's installed capacity, wind resources produced 16 percent of all energy in MISO in 2022. Section III.A also discusses the long-term challenges this will present and the market enhancements that we recommend. This subsection describes key trends related to wind output, wind scheduling, and wind forecasting. These results are summarized in Table 9.

Table 9: Day-Ahead and Real-Time Wind Generation

	Name Plate Capacity	Avg. Output (GW)			RT Seasonal Avg. Output (GW)			RT Top 5% Hourly Avg. Output (GW)			2 Hour Forecast Error (%)	
		RT	DA	%	Jan.-Apr.	May-Aug.	Sep.-Dec.	Jan.-Apr.	May-Aug.	Sep.-Dec.	Avg. Error	Abs. Avg.
2022	29,109	11.3	10.1	-10.8	13.7	8.4	11.9	21.6	18.0	21.6	2.3%	6.6%
*%**	*8%*	*23%*	*26%*		*37%*	*20%*	*11%*	*16%*	*18%*	*8%*		
2021	26,862	9.2	8.0	-13.0	10.0	7.0	10.7	18.6	15.3	19.9	-3.3%	6.7%
2020	24,450	8.1	6.6	-19.3	8.4	6.4	9.5	16.1	13.9	17.4	-2.0%	7.6%
2019	19,127	6.5	5.5	-15.9	7.2	4.7	7.5	14.4	11.4	14.6	-3.9%	7.8%

Note 1: 2019 Forecast Error calculated for 7/10-12/31.
Note 2: % Change between 2021 and 2022.*

Wind Output Trends

Average wind output has been growing rapidly, increasing 23 percent from last year and 74 percent over 2019, just three years ago. The table also reveals the seasonal wind output patterns, with output decreasing in summer months and at its highest levels in the spring and fall seasons. Both the average seasonal output and the output in the highest wind hours have been consistently rising over the past three years. We expect this trend to continue given the new wind projects in MISO's interconnection queue and the state and federal incentives available to wind resources.

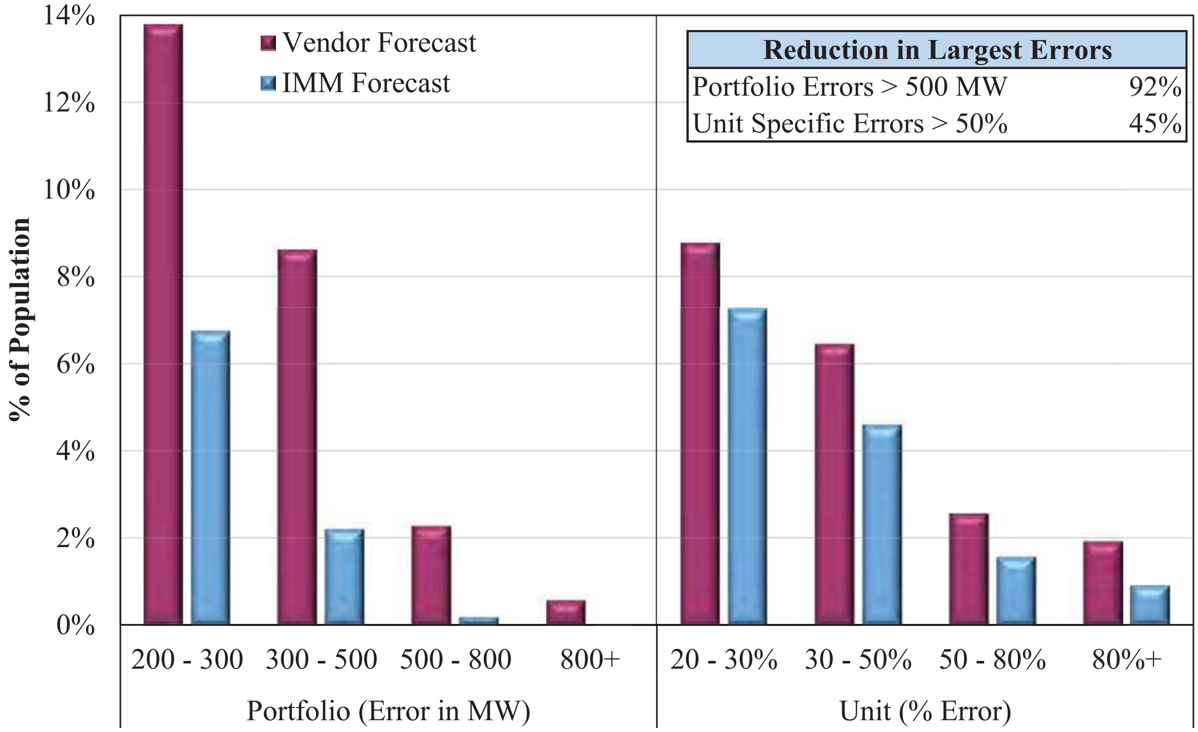
Wind Forecasting

The sharp rise in wind output has increased the operational challenges associated with managing the ramp demands resulting from the wind output fluctuations that are described in Section III.A. The accuracy of the wind forecasts plays a key role in managing these challenges. The wind forecasts are important because MISO uses them to establish wind resources' economic maximums in the real-time market. Because wind units offer at prices lower than other units, the forecasted output also typically matches the dispatch instruction, absent congestion. Wind suppliers can submit their own forecasts or rely on MISO's forecasts. MISO's settlement rules provide strong incentives for participants to use MISO's forecast and most wind resources do so.

MISO's Wind Forecasts. MISO implemented a change in early 2020 that reduced a relatively large bias in MISO's near-term forecast used in the real-time market dispatch. However, the forecast errors are still frequently large. MISO's near-term forecast is primarily a "persistence" forecast that assumes future wind resource output will match the most recent output observation. We developed a forecast methodology that is also persistence-based, but also incorporates the recent direction in output changes.

Figure 27 compares the IMM methodology to the current methodology employed by MISO's wind vendor. This figure shows that substantial improvement can be achieved by modestly changing the current persistence forecast – this change would reduce the frequency of the highest portfolio-level errors by more than 90 percent, while reducing the highest average unit-level errors by 45 percent.

Figure 27: Wind Forecast Methodology Improvement



Improving the forecast of wind units' output will be increasingly key for managing congestion and maintaining system reliability as the penetration of intermittent resources rises. We recommend that MISO develop and implement such a change in forecast methodology.

Market Participant Forecasts. Some of the bias and the remaining errors are due to a small number of wind suppliers that continue to submit less accurate forecasts than MISO's forecast. MISO modified its Tariff to clarify that submitting intentionally inaccurate forecasts is a violation of the MISO Tariff. We monitor this conduct on an ongoing basis and these Tariff changes should improve our ability to enlist FERC enforcement to deter it.

Wind Scheduling in the Day-Ahead Market

Table 9 shows that wind suppliers generally schedule less output in the day-ahead market than they actually produce in real time. Under-scheduling of wind averaged roughly 1,200 MW. This can be attributed to suppliers' contracts and financial risks related to RSG cost allocations when day-ahead wind output is over scheduled. Under-scheduling can create price convergence issues and uncertainty regarding the need to commit other resources, which is partially addressed by net virtual suppliers that sell energy in the day-ahead market in place of the wind suppliers.

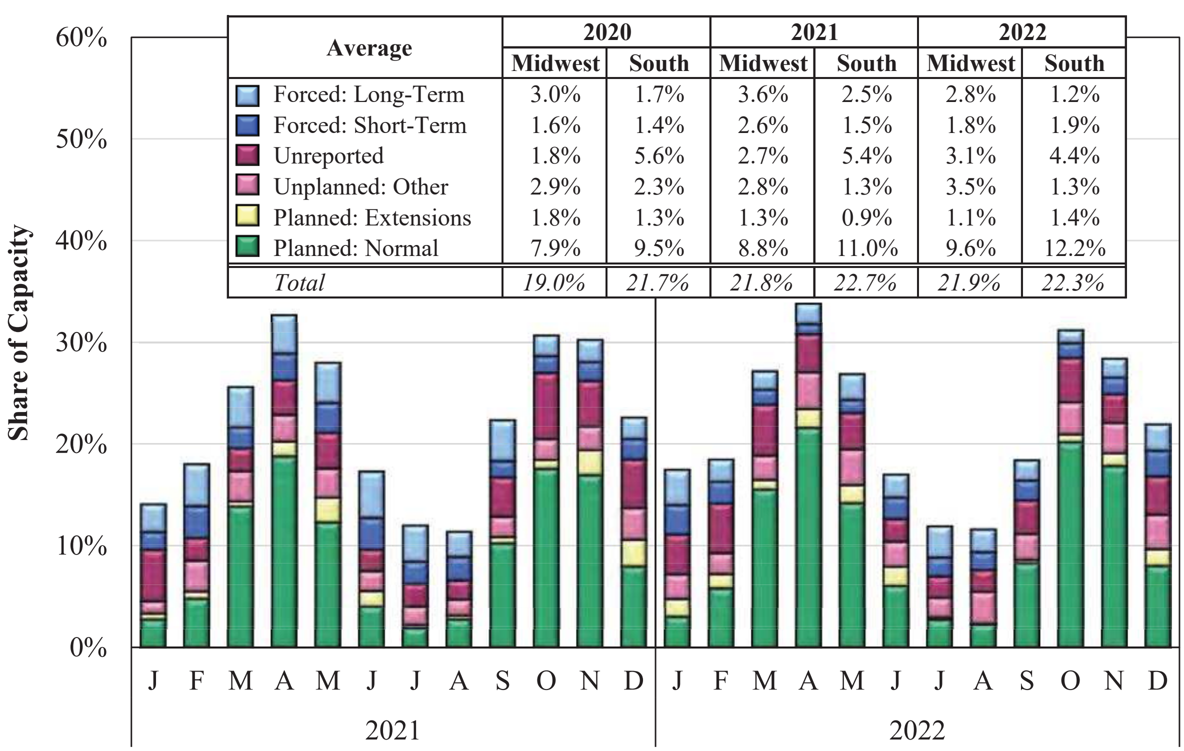
Since the most significant effect of under-scheduling wind in the day-ahead market is its effects on the transmission flows and associated congestion, we evaluated the extent to which virtual transactions offset the flow effects of wind under-scheduling. In evaluating these patterns, we found that virtual suppliers made approximately $193 million on a total of 402 wind-impacted constraints, with nearly 60 percent of the profits occurring on the ten constraints. The virtual activity serves a valuable role in facilitating more efficient day-ahead scheduling.

J. Outage Scheduling

Coordination of planned outages is essential to ensure that enough capacity is available if contingencies or higher than expected load occurs. MISO approves planned outages that do not violate reliability criteria but otherwise does not coordinate outages, which raises significant economic concerns and reliability risks. To evaluate the outages that occurred in 2022, Figure 28 shows MISO's outage rates in MISO Midwest and MISO South in 2021 and 2022.

Figure 28 shows that outage rates in 2022 were slightly lower than in 2021. As in prior years, true planned outages were relatively low for most of the summer. While the overall level of outages does not raise concerns, poorly coordinated outages do frequently raise concerns in local areas. In the *2016 State of the Market Report*, we recommended that MISO enhance its transmission and generation planned outage approval authority (see Recommendation 2016-3). We continue to believe that it is important for MISO to acquire the authority to deny or postpone outage requests that will create severe congestion or regional shortages. This is particularly important as many planned outages are scheduled or extended with very little advance notice. MISO has developed reports to assist participants in coordinating planned outages based on forecasted capacity margins, but our concerns regarding outage scheduling remain.

Figure 28: Generation Outages in 2021 - 2022



Average	2020		2021		2022	
	Midwest	South	Midwest	South	Midwest	South
Forced: Long-Term	3.0%	1.7%	3.6%	2.5%	2.8%	1.2%
Forced: Short-Term	1.6%	1.4%	2.6%	1.5%	1.8%	1.9%
Unreported	1.8%	5.6%	2.7%	5.4%	3.1%	4.4%
Unplanned: Other	2.9%	2.3%	2.8%	1.3%	3.5%	1.3%
Planned: Extensions	1.8%	1.3%	1.3%	0.9%	1.1%	1.4%
Planned: Normal	7.9%	9.5%	8.8%	11.0%	9.6%	12.2%
Total	*19.0%*	*21.7%*	*21.8%*	*22.7%*	*21.9%*	*22.3%*

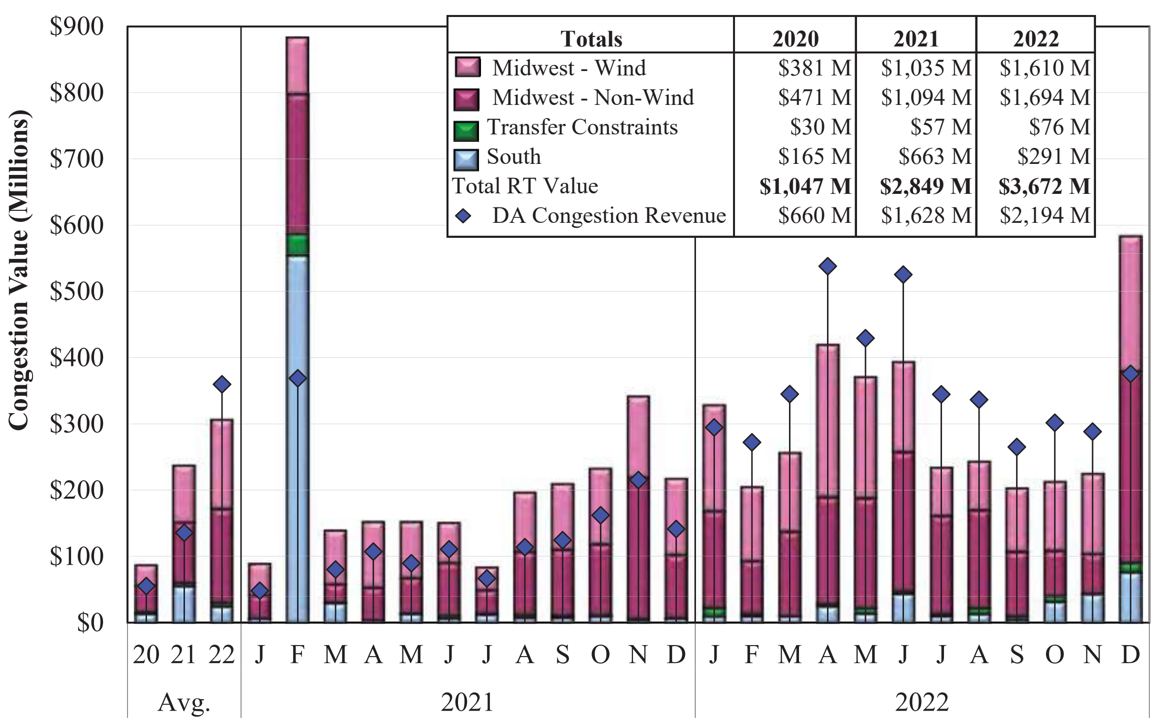
V. Transmission Congestion and FTR Markets

To avoid violating transmission constraints, the MISO markets establish resource dispatch levels and calculate associated transmission congestion costs that keep power flows within transmission operating limits. Transmission congestion arises when network constraints prevent MISO from dispatching the lowest-cost units to meet demand. The resulting "out-of-merit" costs incurred to avoid violating transmission constraints are reflected in the marginal congestion component (MCC) of the LMPs (one of three LMP components). The MCCs can vary widely across the system, they are higher (and raise LMPs) in "congested" areas where generation relieves the constraints and are lower (and lower LMPs) where generation loads the constraints. These create valuable locational price signals that reflect the efficient dispatch of generation to manage network congestion, and that provide economic signals that facilitate efficient investment and maintenance of resources.

A. Real-Time Value of Congestion in 2022

We begin by summarizing the value of real-time congestion, calculated as the product of physical flow over each constraint and the economic value of the constraint (i.e., the "shadow price"—the production cost savings from relieving the constraint by one MW). This is the value of congestion that occurs as MISO dispatches its system. Figure 29 shows the monthly real-time congestion value over the past two years along with day-ahead congestion revenue.

Figure 29: Value of Real-Time Congestion
2021–2022



Totals	2020	2021	2022
Midwest - Wind	$381 M	$1,035 M	$1,610 M
Midwest - Non-Wind	$471 M	$1,094 M	$1,694 M
Transfer Constraints	$30 M	$57 M	$76 M
South	$165 M	$663 M	$291 M
Total RT Value	**$1,047 M**	**$2,849 M**	**$3,672 M**
DA Congestion Revenue	$660 M	$1,628 M	$2,194 M

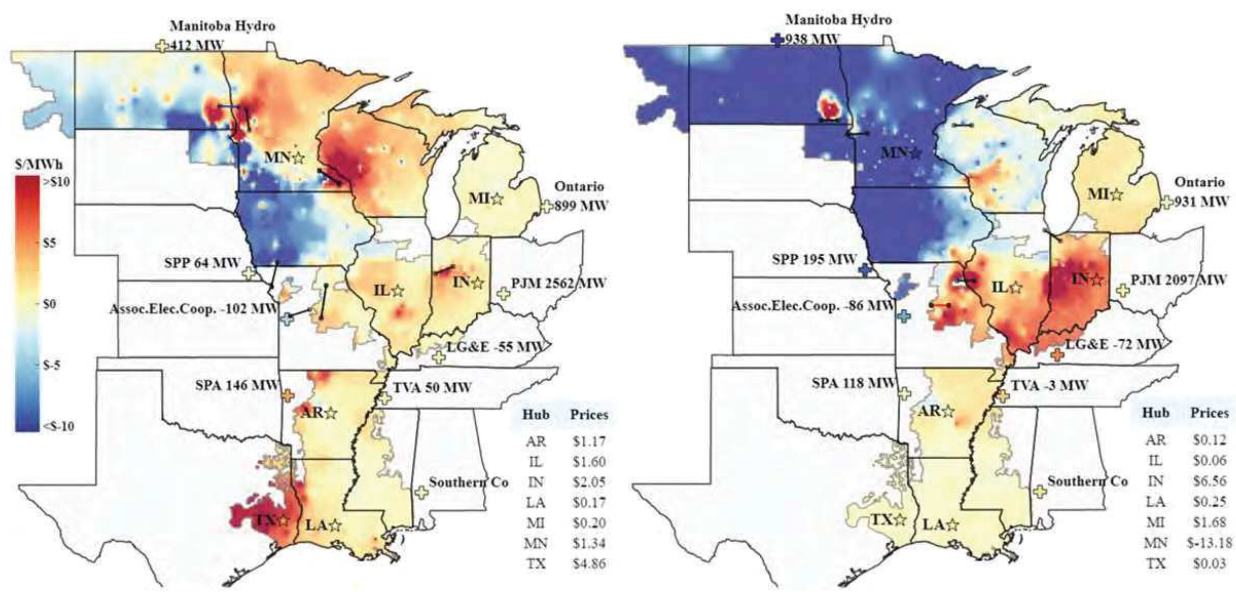
The value of real-time congestion continued to rise significantly in 2022 to total $3.7 billion. Increasing wind output and rising natural gas prices beginning in 2021 and continuing into 2022 together caused real-time congestion to triple from 2020 to 2021 and increase an additional 29 percent from 2021 to 2022. Extreme weather events also contributed to higher congestion. For example, Winter Storm Elliott contributed to more than $350 million in congestion in just two days in December 2022.

Wind-driven congestion continued to grow along with wind capacity in the Midwest subregion, accounting for about 44 percent of all real-time congestion compared to 36 percent in 2021. Continued expansion of nearby wind resources in SPP and PJM have contributed to the congestion on these constraints. Additionally, the retirement of some key coal and gas-fired resources in recent years that had provided relief on these constraints in the past also contributed to the increase in wind-related congestion.

Figure 30 illustrates the locational difference in average marginal congestion components of MISO LMPs between 2021 and 2022. The warmer colors indicate areas of MISO's footprint where prices were generally higher than the system marginal price, whereas cooler colors indicate areas of MISO's footprint where prices were generally lower than the system marginal price. The neutral shading indicates areas where there tended to be less congestion throughout the year.

Figure 30: Average Real-Time Congestion Components in MISO's LMPs

2021 **2022**



This figure shows that average imports from Manitoba increased in 2022 as drought conditions resolved in early 2022. This increase in imports contributed to the increased congestion in the North region along with the increased wind output.

The substantial increase in congestion over the past two years underscores the importance of improving the utilization of MISO's transmission network through improved transmission ratings, network reconfiguration, and strategic transmission investment. We have also identified operational improvements in how MISO manages congestion and administers the market-to-market coordination with SPP and PJM. Improvements in both areas will increase MISO's utilization of the transmission system and we are working with MISO to implement them.

B. Day-Ahead Congestion and FTR Funding

MISO's day-ahead energy market is designed to send accurate and transparent locational prices that reflect energy costs, congestion, and losses on the network. MISO collects congestion revenue in the day-ahead market from load based on the differences in the congestion component of the LMPs at locations where energy is produced and consumed. The resulting congestion revenue is paid to holders of Financial Transmission Rights (FTRs), which are economic property rights to power flows over particular elements of the transmission system.

A large share of the value of these rights is allocated to participants based on historical firm use of the transmission network. The rights to the remaining transmission capability are sold in the FTR market, with this revenue contributing to the recovery of the costs of the network. FTRs provide a means for market participants to hedge day-ahead congestion costs. If the FTRs issued by MISO are physically feasible, meaning that network flows sold as FTRs do not exceed flows scheduled in the day-ahead market, MISO will always collect enough congestion revenue through its day-ahead market to "fully fund" the FTRs (i.e., to pay them 100 percent of the FTR entitlements).

In addition to summarizing the day-ahead congestion, this subsection evaluates two key market outcomes that reveal how well the network is modeled in the day-ahead and FTR markets:

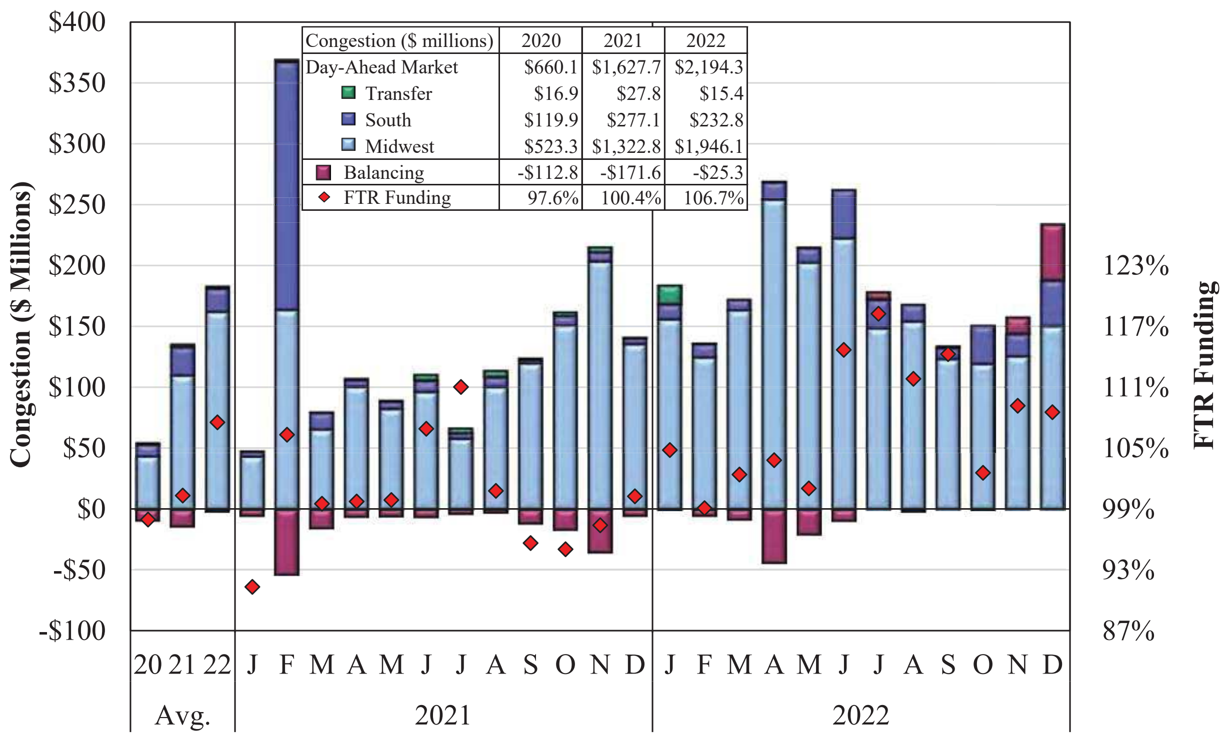
- *FTR Funding*: If MISO does not collect enough congestion in the day-ahead market to satisfy the FTR entitlements, FTR funding will be less than 100 percent, indicating that MISO issued more FTRs than the day-ahead network model could accommodate; and
- *Balancing Congestion*: If day-ahead schedules are not feasible in the real-time market, congestion will occur in real time to "buy back" the day-ahead flows. The cost of doing so is uplifted to MISO customers as "balancing congestion".

Figure 31 below summarizes the day-ahead congestion by region (and between regions), balancing congestion incurred in real time, and the FTR funding levels from 2021 to 2022.

Day-Ahead Congestion Costs

Day-ahead congestion costs increased by 35 percent to $2.2 billion in 2022. The day-ahead congestion costs collected through the MISO markets were about 60 percent of the value of real-time congestion on the system. The additional congestion in real time typically reflects loop flows across the MISO system caused by others who do not pay MISO and by entitlements on the MISO system granted to SPP and PJM.

Figure 31: Day-Ahead and Balancing Congestion and FTR Funding
2020–2022



Note: Funding surplus may be greater than the difference between day-ahead congestion and obligations to FTR holders because it includes residual revenue collections from the FTR auctions.

Day-ahead congestion costs increased in the Midwest because of the trends discussed earlier in wind production and natural gas prices, as well as the impacts of Winter Storm Elliott in December. Congestion fell in the South in 2022, largely because of the extraordinary congestion experienced in the South in February 2021 during Winter Storm Uri.

FTR Surpluses and Shortfalls

Overfunding and underfunding of FTRs is caused by discrepancies between the modeling of transmission constraints and outages in the FTR auctions and the day-ahead market. For example, if the flow on a binding day-ahead market constraint is below the flow scheduled in the FTR market, a congestion shortfall will occur. Conversely, a surplus will result when flow on a binding day-ahead constraint is higher than the flow sold in the FTR market.

In 2022, day-ahead congestion revenues exceeded FTR obligations by 7 percent. These FTR surplus revenues are distributed back to transmission customers. Some changes were made in the FTR modeling process in the 2021–2022 annual FTR auction and carried forward into the current FTR year. These changes include updating the constraints based on changes in the generation fleet and adopting conservative assumptions regarding outages and available transmission capability. These are intended to help ensure full funding of the FTR auction. During 2022, there was some variability in FTR funding month-to-month:

- FTR surpluses were unusually large, exceeding $160 million, during the summer months owing in part to changes in commercial flow assumptions. This surplus reflected an underselling of some paths in both the annual and monthly auctions.
- In October, the surplus was lower than adjacent months in part because a single TO failed to report known planned transmission outages before the annual auction, a Tariff requirement for TOs. In this instance, surplus collections were used to subsidize the shortfalls caused by the over-allocated FTRs. This is a serious concern, and we are working with MISO to improve its enforcement of the Tariff in this area.

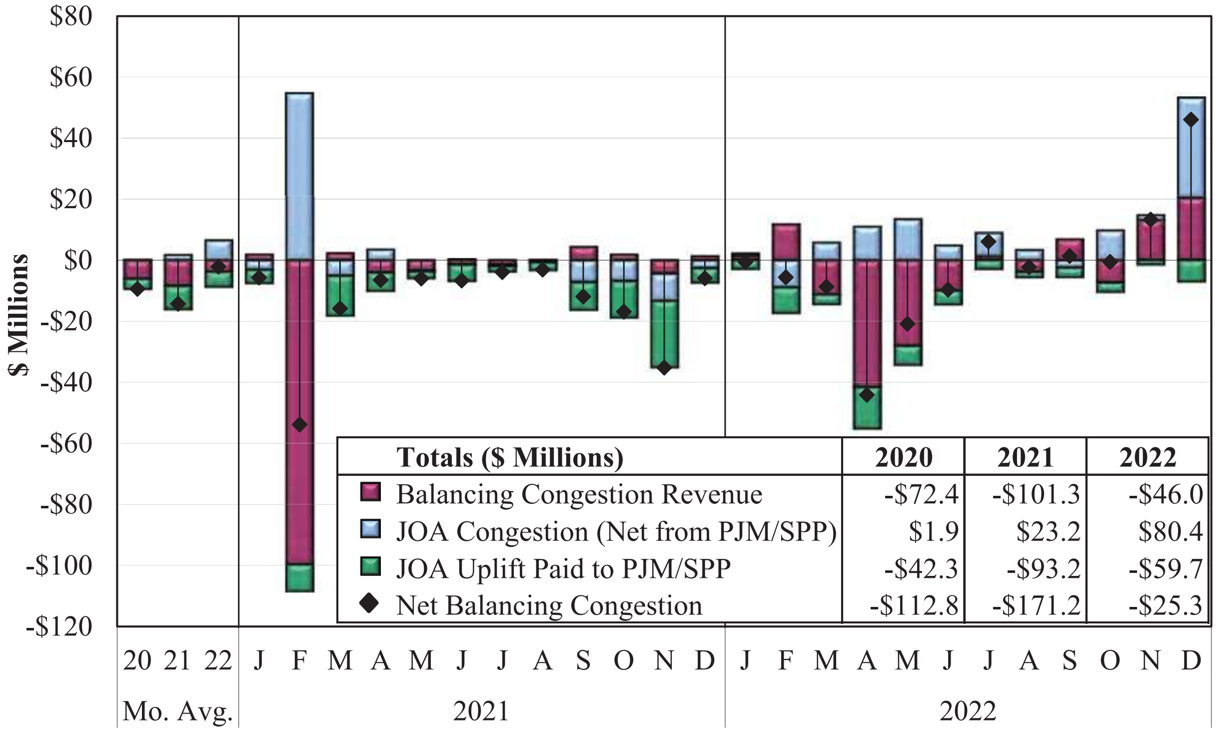
In the past, external constraints and low-voltage constraints tended to be underfunded because a higher proportion of their FTR flows were below the GSF cutoff applied in the day-ahead and real-time markets. This cutoff caused MISO to under collect day-ahead congestion revenues. FTRs impacted by SPP constraints coordinated under M2M, for example, were funded at 94 percent of the total obligation in 2021. In 2022, MISO responded to our recommendation by making several stepped reductions in the GSF cutoff. Those reductions contributed to full FTR funding on jointly-coordinated SPP constraints. In contrast, FTRs over the transfer constraints between the South and Midwest regions tend to be overfunded because they can bind in both directions. This causes them to not be fully subscribed and to generate substantial surpluses when the constraint binds.

Balancing Congestion

Balancing congestion shortfalls (negative balancing congestion revenue) occur when the transmission capability available in real time is less than the capability scheduled in the day-ahead market. In other words, negative balancing congestion is the cost of re-dispatching generation to reduce real-time flows on a constraint from day-ahead scheduled flow levels. Conversely, positive balancing congestion occurs when real-time constraints bind at flow levels higher than those scheduled in the day-ahead market.

Large amounts of negative balancing congestion costs typically indicate real-time transmission outages, derates, or loop flows that were not fully anticipated in the day-ahead market. Net negative balancing congestion must be uplifted to MISO's customers. These costs are collected from all real-time loads and exports on a pro-rata basis. While real-time forced outages and derates cannot be eliminated, persistent high levels of negative balancing congestion may indicate day-ahead modeling issues. Accordingly, RTOs should seek to minimize the shortfalls by achieving maximum consistency between the day-ahead and real-time market models. Figure 32 shows the 2021 through 2022 monthly balancing congestion costs incurred by MISO.

Figure 32: Balancing Congestion Revenues and Costs
2020-2021



Net balancing congestion decreased by $146 million from 2021 to 2022, primarily because of the unusually large net balancing congestion caused by Winter Storm Uri in February 2021. Regardless, the components of the total balancing congestion changed significantly in 2022, including balancing congestion revenue surpluses of $56 million and JOA congestion nearly quadrupling to $80 million. JOA congestion payments are transfer payments for market flows that exceed entitlements on coordinated M2M constraints. The most significant balancing congestion event in 2022 that resulted in sizable JOA congestion and balancing congestion surpluses occurred in December during Winter Storm Elliott. During that event, MISO experienced a number of substantial transmission violations as it supported extensive exports to its neighbors. These additional flows above transmission limits resulted in net balancing congestion surpluses exceeding $50 million in December.

FTR Market Performance

An FTR represents a forward purchase of day-ahead congestion. These are instrumental in allocating and pricing transmission rights. Because transmission customers pay for the embedded costs of the transmission system, they are entitled to its economic property rights. This is accomplished by allocating Auction Revenue Rights (ARRs) to transmission customers based on their network load and resources. ARRs give customers the right to receive the FTR auction revenues from the sale of the FTRs or to convert their ARRs into FTRs directly to receive day-ahead congestion revenues.

FTR markets perform well when they establish FTR prices that accurately reflect the expected value of day-ahead congestion, resulting in low FTR profits for the buyers (day-ahead congestion payments minus the FTR price). Even if the FTR prices represent a reasonable expectation of congestion, a variety of factors may still cause actual congestion to be much higher or lower than FTR auction values. These variations can be minimized if MISO uses the most up-to-date outage information in its FTR modeling processes. To facilitate the FTR process, market participants are required to report all known planned outages 12 months in advance even when specific dates have not been finalized. Longer notice is even better since the AAR allocation process begins 16 months before the FTR year.

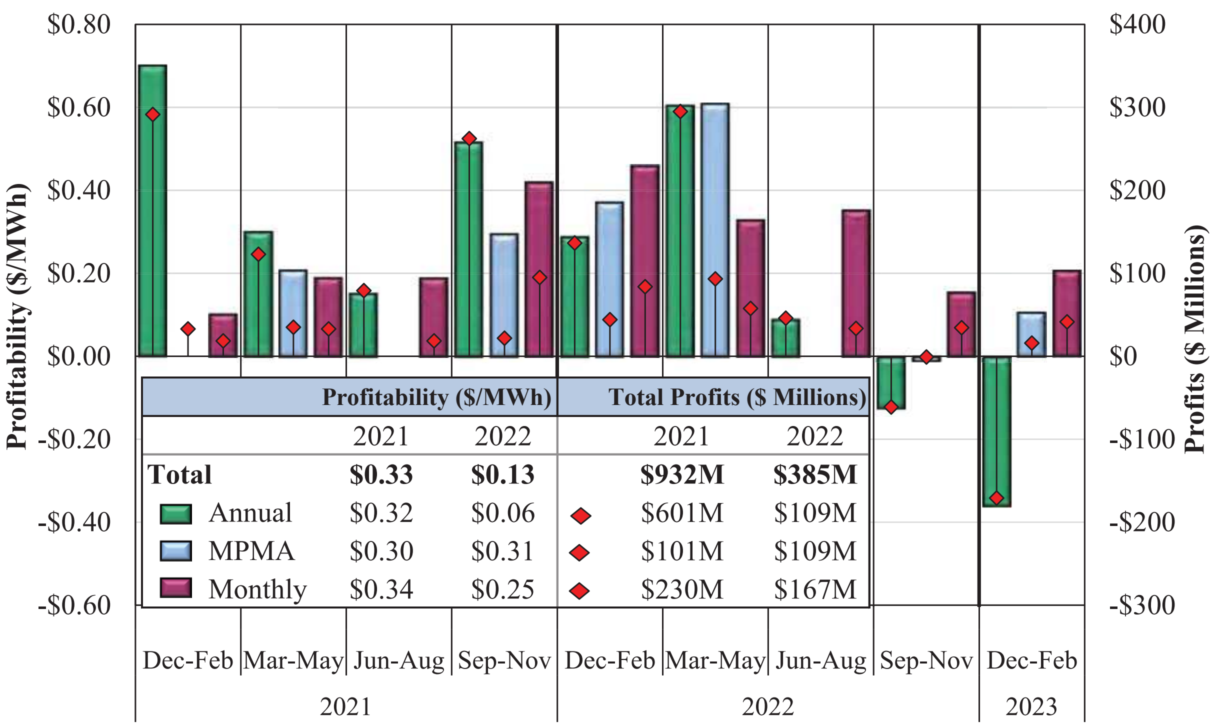
MISO currently runs two types of FTR auctions:

- An annual auction from June to May that includes seasonal and peak/off-peak resolution of bids, offers, and awards; and
- A Multi-Period Monthly Auction (MPMA) that yields monthly and seasonal peak/off-peak awards and facilitates FTR trading for future periods in the current planning year.

FTR Market Profitability

Figure 33 shows our evaluation of the profitability of FTRs in these auctions by showing the seasonal profits for FTRs sold in each market in the bars. The profit margin for each class of FTRs is shown in the red diamonds. For comparison purposes, profitability of monthly FTRs purchased in the MPMA are aggregated seasonally in this figure.

Figure 33: FTR Profits and Profitability
2021–2022

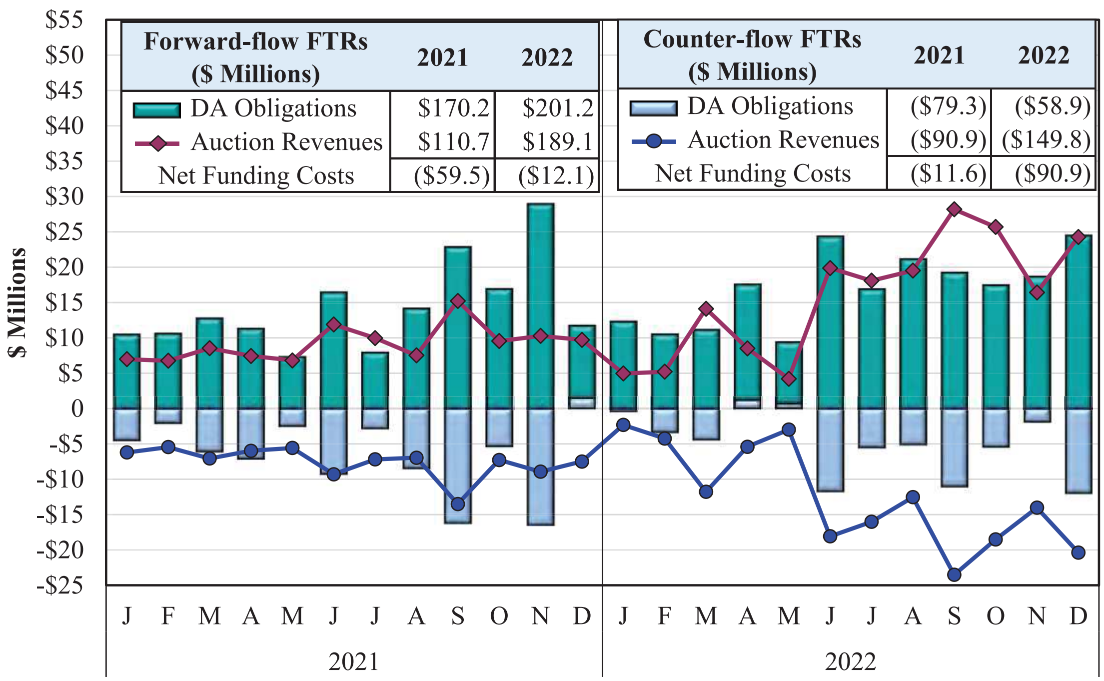


Annual FTR Profitability. Figure 33 shows that FTRs issued through the annual FTR auction were profitable overall, but fell sharply to roughly $100 million as FTRs acquired in the fourth quarter were substantially unprofitable. Some of this decrease was due to unusually high congestion and associated FTR profits in 2021 as natural gas prices rose unexpectedly throughout the year and Winter Storm Uri generated unanticipated congestion. In 2022, the higher natural gas prices were largely anticipated prior to the FTR auction and conditions moderated late in the year because of warmer weather, the easing supply concerns in Europe, and a significant LNG export facility outage. The unexpected drop in natural gas prices late in 2022 likely led participants to expect higher congestion in the fourth quarter than actually occurred.

FTR Profitability in the MPMA and Monthly Auction. Figure 33 shows that the FTRs purchased in the MPMA and prompt month auction were similar to last year, remaining close to $100 million and $200 million, respectively. In general, the MPMA and monthly markets should produce prices that are more in line with anticipated congestion because they are cleared much closer to the operating timeframe when better information is available to forecast congestion.

To evaluate MISO's sale of forward-flow and counter-flow FTRs, Figure 34 compares the auction revenues from the MPMA prompt month (the first full month after the auction) to the day-ahead FTR obligations associated with the FTRs sold. The figure separately shows forward-flow and counter-flow FTRs. The net funding costs shown in the inset tables represent the difference between the auction revenues and the day-ahead obligations. A negative value indicates that MISO sold forward-flow FTRs at a price less than their ultimate value or bought counter-flow FTRs at a price greater than their ultimate value.

Figure 34: Prompt-Month MPMA FTR Profitability
2021–2022



The analysis shows that the discount in the sale for forward-flow FTRs decreased from 35 percent in 2021 to just 6 percent in 2022, which translated into net funding costs (i.e., profits from these FTRs) of $12 million. These results indicate that the markets expected congestion costs to be relatively high.

In addition to selling forward-flow FTRs in the MPMA FTR auction, MISO often buys back capability on oversold transmission paths by selling counter-flow FTRs (i.e., negatively priced FTRs). In essence, MISO is paying a participant to accept an FTR obligation in the opposite direction to cancel out excess FTRs on a constraint.[25] Net funding deficits for counter-flow FTRs increased significantly in 2022, indicating that MISO substantially over-paid for these FTRs compared to the day-ahead congestion value.

Overall, these results indicate that the MPMA lacks the liquidity needed to erase the differences between FTR prices and congestion values. Barriers to participation should be identified and eliminated, which should improve convergence between the auction revenues and the associated day-ahead FTR obligations. If such improvements cannot be identified, it may be beneficial for MISO to examine its auction processes to determine whether to limit the sale of forward-flow FTRs at very low prices and/or the sale of counter-flow FTRs at unreasonably high prices.

C. Market-to-Market Coordination with PJM and SPP

MISO's market-to-market (M2M) process under Joint Operating Agreements (JOAs) with neighboring RTOs enables the RTOs to efficiently manage constraints affected by both RTOs. The process allows each RTO to utilize re-dispatch from the other RTOs' units to manage its congestion if it is less costly than its own re-dispatch.

Under the M2M process, each RTO is allocated Firm Flow Entitlements (or FFEs) on the coordinated constraint. The process requires the RTOs to calculate the shadow price on the constraint based on their own cost of relieving it and the RTO with the lower cost of relief reduces the flow to help manage the constraint. When the non-monitoring RTO (NMRTO) provides relief and reduces its market flow below its FFE, the monitoring RTO (MRTO) will compensate it for this relief by paying it the marginal value of the relief. Conversely, if the NMRTO's market flow exceeds its FFE, the NMRTO will pay the MRTO for the excess flow times the marginal costs incurred by the MRTO.

Summary of Market-to-Market Settlements

Congestion on M2M constraints within and outside of MISO increased overall in 2022:

- Congestion on MISO M2M constraints almost double over 2021 to total $2 billion.

25 For example, assume MISO issued 250 MW of FTRs over an interface that now can support only 200 MW of flow. MISO could sell 50 MW of counter-flow FTRs to reduce the FTR obligation to 200 MW.

- Congestion on external M2M constraints (those monitored by PJM and SPP) fell 12 percent year over year to $121 million.

Table 10 shows MISO's annual M2M settlements with SPP and PJM over the past two years.

Table 10: M2M Settlements with PJM and SPP ($ Millions)
2021–2022

	PJM	SPP	Total
2022	$180	-$149	$31
2021	$18	-$88	-$70

This shows that net payments generally flowed from PJM to MISO because PJM exceeded its FFEs on MISO's system. Twenty-five percent of PJM's payments to MISO occurred in December during Winter Storm Eliot. Another 28 percent occurred in March and April when wind generation was high, making it more difficult to manage M2M constraints significantly impacted by wind resources, which have fast ramp rates that create volatility and oscillation in relief request quantities from the non-monitoring RTO.

MISO generally makes M2M payments to SPP, partly because SPP enjoys relatively high FFEs on key constraints in both SPP and MISO. Some of the differences in the RTOs' FFE levels can be attributed to differences in the completeness of the historic transmission reservations included in the FFE calculations by SPP versus MISO. A substantial portion of MISO's historic transmission reservations are not included in the FFE calculations. We also question the wisdom of basing FFEs on *reservations* rather than *schedules*. Schedules are generally a fraction of the reservation quantities and schedules more accurately represent the historic use of the system. As wind output along the SPP seam grows and generator retirements reduce MISO's ability to relieve the wind-related constraints, we expect the payments to SPP to continue to grow.

Market-to-Market Effectiveness

One metric we use to evaluate the effectiveness of the M2M process is tracking the convergence of the shadow prices of M2M constraints in each market. When the process is working well, the NMRTO will continue to provide additional relief until the marginal cost of its relief (its shadow price) is equal to the marginal cost of the MRTO's relief. Our analysis shows that for the most frequently binding M2M constraints, the M2M process generally contributes to shadow price convergence and lowers the MRTO's shadow price after the M2M process is initiated.

However, we found that on some constraints, shadow prices fail to converge because the MRTO does not request sufficient relief to achieve convergence. This can occur because the current relief request software does not consider the shadow price differences between the RTOs. When the NMRTO's shadow price is sustained at a much lower level, the relief requested should increase to lower congestion costs and accelerate convergence. At other times, the software can request too much relief and cause constraints to bind and unbind in subsequent intervals, which is called "oscillation". To address these issues, we have recommended that MISO base relief requests on the RTOs' respective shadow prices and implement an automated means to control constraint oscillation. In the long term, MISO should use dynamic transmission constraint demand curves to reflect the actual relief provided by the NMRTO in the dispatch of the MRTO.

Evaluation of the Administration of Market-to-Market Coordination

Effective administration of the M2M process is essential because failing to identify or activate a M2M constraint raises two types of concerns:

- *Efficiency concerns*. The savings of coordinating with the NMRTO to relieve the constraint are not achieved and congestion costs are higher than necessary.
- *Equity concerns*. The NMRTO may vastly exceed its firm flow entitlements on the constraint with no compensation to the MRTO.

While the M2M process improves efficiency overall, we evaluated three issues that can reduce the efficiency and effectiveness of coordination:

- Failure to test all constraints that might qualify to be new M2M constraints;
- Delays in testing constraints after they start binding to determine whether they should be classified as M2M; and
- Delays in activating current M2M constraints once they are binding.

We developed a series of screens to identify constraints that should have been coordinated but were not because of these three issues. Table 11 shows the total congestion on these constraints. For the first two reasons (never classified and testing delay), we account for time needed to test a constraint by removing the first day a constraint was binding.

Table 11: Real-Time Congestion on Constraints Affected by Market-to-Market Issues
2020–2022

Item Description	PJM ($ Millions)			SPP ($ Millions)			Total ($ Millions)		
	2020	2021*	2022*	2020	2021*	2022*	2020	2021*	2022*
Never classified as M2M	$4	$17	$6	$34	$50	$55	$38	$68	$61
M2M Testing Delay	$2	$20	$7	$18	$55	$44	$20	$75	$51
M2M Activation Delay	$3	$2	$1	$2	$34	$6	$5	$36	$7
Total	$9	$39	$14	$54	$139	$105	$62	$179	$119

*We have excluded the Winter Storm Uri days (02/13-02/19/2021) and Winter Storm Elliott days (12/22-12/27/2022).

Historically, the highest congestion impacts occurred on constraints that MISO failed to test, prompting an IMM recommendation in 2016 for MISO to improve M2M identification and testing procedures. In December 2017, MISO implemented a tool to improve these procedures, which resulted in significant improvements in the process in 2018 and 2019. More recently, congestion associated with failure to test constraints or delays in testing constraints increased sharply in 2021 and 2022, partly because of the increase in natural gas prices and the volatility of wind-related congestion. However, based on these results, we encourage MISO to evaluate ways to improve its M2M processes and timeliness of the testing process, particularly with SPP.

Market-to-Market Test Criteria Software

Identifying the constraints to coordinate under the M2M processes is important to ensure both efficient and reliable coordination, to establish equitable settlements, and to improve the price signals in the NMRTO market. Currently, a constraint will be identified as a M2M constraint when the NMRTO has:

- A generator with a shift factor greater than 5 percent; or
- Market flows over the MRTO's constraint of greater than 25 percent of the total flows (for the SPP JOA) or 35 percent of the total flows (for the PJM JOA).

These two tests are not optimal in identifying constraints that would benefit from coordination because they do not consider the economic relief the NMRTO will likely have available.[26] The single generator test is particularly questionable because it ignores the size and economics of the unit—this test does not ensure that the NMRTO has any economic relief.

Our analysis of this area of the M2M process, presented in detail in Section V.E of the Analytic Appendix, shows that there are a number of M2M constraints for which the NMRTO has a very small portion of the economic relief and very little ability to assist in managing the congestion. If the NMRTO's market flows are also low on these constraints, then they should not be M2M constraints because the savings of coordinating are likely less than the administrative costs.

Based on this analysis we find that the current tests, particularly the five percent GSF test, often identify constraints for which the benefits of coordinating are very small—particularly high-voltage constraints where GSFs tend to be higher. Hence, we recommend the five percent test be replaced by two potential discrete tests based on the available relief controlled by the NMRTO:

- The share of available relief capability from the NMRTO (e.g., 10 percent); and/or
- The NMRTO relief as a percentage of the transmission limit (e.g., 10 percent).

Our analysis shows that implementing this recommendation would likely reduce the total number of M2M constraints. In other words, the five percent test is identifying more constraints that are not beneficial to coordinate (i.e., false positives) than the number of new constraints that would warrant coordination under the relief-based tests. This is important because the number of coordinated market-to-market constraints has been rising rapidly in recent years.

26 Economic relief is categorized as any redispatch relief that could be provided within five minutes time with a shadow price less than or equal to $200.

Other Key Market-to-Market Improvements

Our evaluation indicates two additional improvements that MISO should pursue that would improve the efficiency and effectiveness of the M2M coordination with SPP and PJM:

- Some of the costliest M2M constraints are more efficient for the NMRTO to monitor because it has most of the effective relief capability. MISO and SPP began using software in 2017 that enables the transfer of responsibility to the NMRTO, but it has rarely been used. PJM has postponed implementation of this software and currently only allows such transfers in limited circumstances. We recommend MISO continue working with SPP and PJM to improve the procedures to transfer the monitoring responsibility to the NMRTO when appropriate.
- In response to concerns about volatility caused by M2M coordination, MISO has developed software that is intended to allow the MRTO to control oscillations on constraints where both the MRTO and the NMRTO have fast-ramping resources responding to M2M price signals. SPP has agreed to use this software. Thus far the software has been very limited in use but in concept it should enable control of oscillations, at the risk of the NMRTO producing a higher shadow price than the MRTO for limited periods.
- Convergence of M2M constraints is much worse in the day-ahead market. MISO and PJM implemented a process coordinate and exchange FFEs in the day-ahead market, but do not actively use this process. Further, SPP was not modelling MISO's constraints in its day-ahead market until October 2022, which led to inefficient resource commitment in MISO. For instance, roughly 20 percent of the total congestion in winter 2022 accrued on two constraints impacted by a jointly owned resource that participates in MISO and SPP. Because SPP did not model MISO's constraints in its day-ahead market, the unit appeared economic in SPP's day-ahead market but not in MISO's. Since SPP began modeling some of the constraints in the fall of 2022, convergence has improved on some constraints. However, we recommend MISO continue to work with SPP and PJM to improve the day-ahead modeling and convergence of M2M constraints.

D. Congestion on Other External Constraints

In addition to congestion from internal and external M2M constraints, congestion in MISO can occur when MISO models the impact of its own dispatch on external constraints. MISO is obligated to activate these constraints and reduce its market flows when other system operators invoke Transmission Loading Relief (TLR) procedures. This results in MISO's LMPs reflecting the marginal cost of providing the requested relief and associated congestion costs being collected from MISO's customers. MISO receives relief requests that are often inefficient and inequitable for these constraints because:

- MISO receives relief obligations based on forward direction flows across the impacted flowgates, even if on net (when reverse-direction flows are included) its market flows are relieving the constraint; and

- Virtually all of MISO's flows over external constraints are deemed to be non-firm (and thus subject to curtailment before firm transactions) even though most of MISO's flows are associated with dispatching network resources to serve MISO's load.

As a result, MISO's relief obligations are often large and generate substantial congestion costs. Further, we have generally found that the external TLR constraints are often not actually physically binding when they are severely binding in MISO in response to a relief request. To address this, we have recommended that MISO pursue a JOA with the neighboring systems that call TLRs most frequently—TVA and IESO—which would allow MISO to coordinate congestion relief with them. Since TVA acts as the reliability coordinator for AECI, such a JOA would produce substantial benefits by allowing AECI resources to be utilized to provide significant economic relief on MISO's transmission constraints and vice versa.

In recent years, TLRs called by IESO have resulted in thousands of MWs of transaction curtailments from PJM to MISO and costly price spikes throughout MISO. There are many other actions that are less costly than curtailing vast quantities of PJM-to-MISO transactions. Unfortunately, the TLR process is indiscriminate and does not facilitate the most efficient relief. Therefore, we continue to recommend that MISO work with both TVA and IESO to develop JOAs that would reduce the costs of this external congestion.

E. Transmission Ratings and Constraint Limits

For the past several years we have estimated significant potential benefits from improved utilization of the transmission system, especially broader application of Ambient Adjusted Ratings (AARs) and emergency ratings. For most transmission constraints, the ability to flow power through the facility is related to the heat caused by the power flow. When temperatures are cooler than the typical assumption used for rating the facilities, additional power flows can be accommodated.[27] Therefore, if TOs develop and submit ratings adjusted for temperature or other relevant ambient conditions, they would allow MISO to operate to higher transmission limits and achieve substantial production costs savings. Most TOs do not provide ambient-adjusted ratings. We believe that at least one of the reasons for this is that there is little economic incentive to do so. In December 2021, FERC issued Order 881 that requires TOs to provide AARs and emergency ratings based on facility specific evaluations within three years.[28]

Estimated Benefits of Using AARs and Emergency Ratings

As in past years, we have estimated the value of operating to higher transmission limits that would result from consistent use of temperature-adjusted, emergency ratings for MISO's

27 Temperature is one common dynamic factor. In some regions, ratings are more dependent on other factors, such as ambient wind speed and humidity. Ratings used during night-time hours can be adjusted for the absence of solar heating. Our analysis evaluates only ambient temperature impacts.

28 MISO made a compliance filing on July 12, 2022 in ER22-2363 but FERC has yet to approve it.

transmission facilities.[29] This analysis is described in detail in Section V.D of the Analytic Appendix and summarized in Table 12.

Table 12: Benefits of Ambient-Adjusted and Emergency Ratings
2021–2022

		Savings ($ Millions)			# of Facilites for 2/3 of Savings	Share of Congestion
		Ambient Adj. Ratings	**Emergency Ratings**	**Total**		
2021	**Midwest**	$153.4	$94.89	$248.3	29	11.3%
	South	$27.3	$38.32	$65.6	1	10.0%
	Total	**$180.7**	**$133.2**	**$313.9**	**30**	**11.0%**
2022	**Midwest**	$326.4	$188.67	$515.1	22	15.3%
	South	$7.6	$19.11	$26.7	2	9.3%
	Total	**$334.0**	**$207.8**	**$541.8**	**24**	**14.9%**

Across the past two years, the results show average benefits of 13 percent of the real-time congestion value. The total potential savings in 2022 were over half a billion dollars. The benefits of temperature adjustments tend to accrue primarily in the non-summer months when static ratings are most understated. The benefits of using emergency ratings are more evenly distributed throughout the year. The Analytic Appendix details how these estimated benefits in 2022 are distributed in the areas served by transmission owners.

Recommended Improvements to Achieve the AAR Benefits

As MISO plans for compliance with Order 881, we encourage it to accelerate efforts to implement AARs and Emergency Ratings in real time, and MISO should enable forecasted ratings in the day-ahead market as soon as practicable. This should include beginning to collect the data and information necessary to validate transmission ratings consistent with the requirements of Order 881 and the TO Agreement.

This is particularly important because progress on implementing AARs has been extremely slow. We estimated the benefits that have been achieved by the TOs since they began working with MISO to implement new AARs prior to Order 881. This evaluation shows:

- The voluntary efforts by TOs to implement new AARs prior to 881 have largely stalled as MISO and TOs have discontinued organized efforts to expand use off AARs and Emergency ratings prior to Order 881 compliance.
- The MISO/TO voluntary program had been identifying facilities with the potential for significant congestion savings through use of AARs and Emergency ratings but very little had actually been implemented yet through the program.

29 We used temperature and engineering data to estimate the temperature adjustments. To estimate the effects of using emergency ratings, we assume that the emergency ratings are 10 percent higher than the normal ratings. This is consistent other facilities for which TOs submit emergency ratings. We then estimated the value of both of these increases based on the shadow prices of the constraints.

- The MISO/TO programs selection of candidate facilities for evaluation based on historical congestion failed to identify a large share of the binding facilities (i.e., a large amount of congestion occurs on facilities that were not significantly binding in prior quarters).
- A third of unrealized benefits from use of AARs and Emergency ratings occurs on transformers where TOs frequently provide only a single base rating for all transformers (without facility specific evaluations) for use in all conditions and for all contingencies.

F. Other Key Congestion Management Issues

MISO generally experiences significant real-time congestion each year—rising in 2022 to a record $3.7 billion. Hence, improvements aimed at the efficiency of its congestion management can deliver sizable savings. Many of these improvements we discussed above. We discuss four remaining improvements in this subsection.

Transmission Derates by MISO Operations

MISO generally derates transmission constraints by a few percent to account for the fact the actual flows often deviate from the flows modeled in the real-time dispatch. Such derates have been growing over the past two years. Prior to 2020, these transmission derates averaged about 5 percent but have grown to nearly 7 percent in in 2022 and early 2023. We are investigating these increases because the real-time value of the lost transmission capability is large. This lost value totaled $269 million in 2022 and the increase in derates from pre-2020 levels accounts for over $80 million of the lost transmission value.

To the extent that this increase reflects increased uncertainty regarding wind output and the poor performance of some wind resources in following dispatch signals, we are recommending improvements to address these issues. This includes implementing improved excessive and deficient energy penalties to improve suppliers' incentives to follow dispatch signals and improving real-time wind forecasting methodologies.

Generation Shift Factor Cutoff

MISO employs a GSF cutoff to limit the number of resources and loads that are deemed to affect the flows over a constraint in its market models. This is intended to allow the models to solve more quickly, but it also reduces the efficiency of the solutions. Previously, we recommended that MISO lower the GSF cutoff in both the day-ahead and real-time markets to manage flows on market-to-market constraints. Beginning in October 2021, MISO began the process of gradually reducing the GSF cutoff in both markets and continues to closely monitor market performance and market outcomes. Barring significant market or operational issues, the cutoff ultimately will be reduced to 0.5 percent or lower. This will produce substantial savings at little or no cost.

Coordinating Outages that Cause Congestion

Generators take planned outages to perform periodic maintenance, to evaluate or diagnose operating issues, and to upgrade or repair various systems. Similarly, transmission operators take planned outages to implement upgrades and planned maintenance on transmission facilities, which generally reduce the transmission capability of the system during the outages. When outage requests are submitted, MISO evaluates the reliability effects of the planned outages, including conducting contingency and stability studies.

Participants tend to schedule planned outages in shoulder months, assuming the opportunity costs of taking outages are lower because temperatures tend to be mild and demand relatively low. However, this is not always true. Multiple participants may schedule generation outages in a constrained area or transmission outages into an area without knowing what others are doing. Absent a reliability concern, MISO does not have the authority to deny or postpone a planned outage, even when it could have sizable economic benefits. Figure 35 summarizes the effects of uncoordinated planned outages on congestion by showing the portion of the real-time congestion value for 2021 and 2022 that occurred on internal constraints that were substantially affected (at least 10 percent of the constraints' flows) by two or more planned outages.

Figure 35: Congestion Affected by Multiple Planned Generation Outages
2021–2022

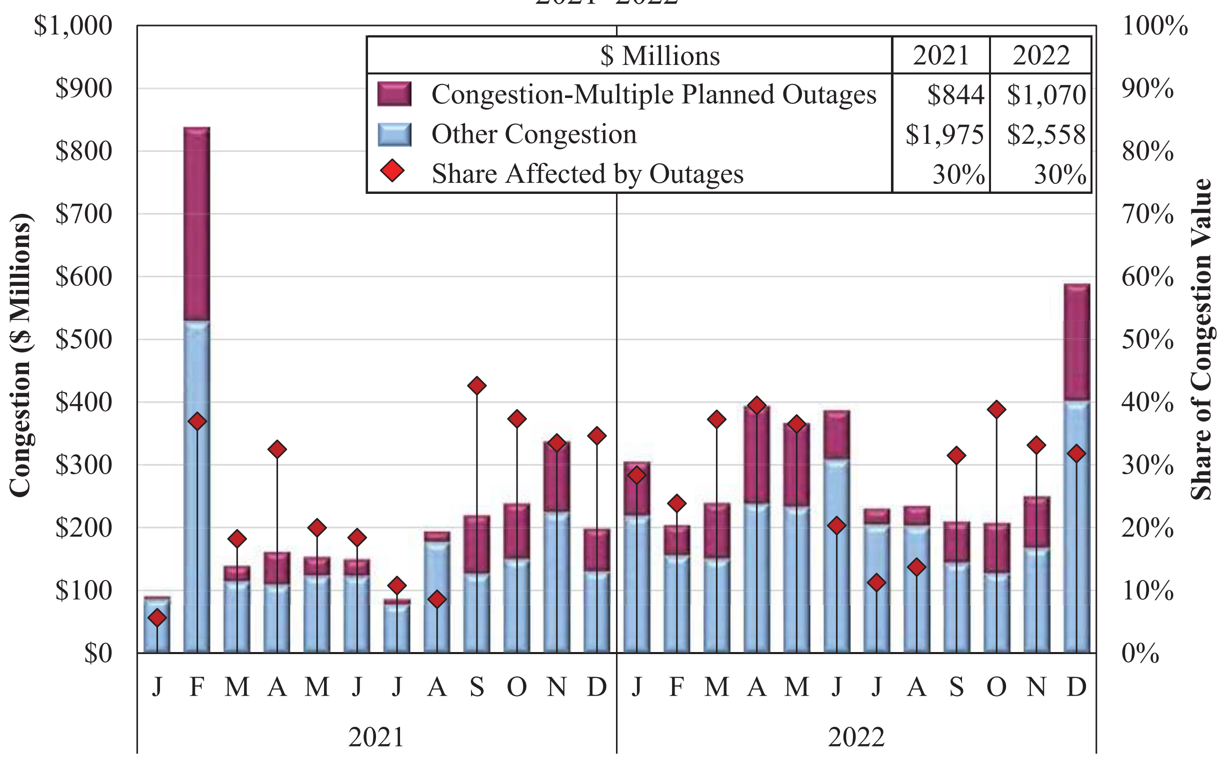


Figure 35 shows that 30 percent of the total real-time congestion on MISO's internal constraints in 2022 ($1.1 billion) was attributable to multiple planned generation outages. In several months, planned outages caused significant congestion, including almost a third of all congestion in a number of months. The large increase in outage-related congestion costs in 2022 was associated with the severe congestion costs during Winter Storm Elliott in December, higher natural gas prices throughout the year, and wind-related congestion. Figure 35 may understate the effects of planned generation outages on MISO's congestion because we do not include the effects of transmission outages that are scheduled at the same time as planned generation outages. We continue to recommend that MISO seek broader authority to coordinate planned generation and transmission outages in order to reduce unnecessary economic costs and enhance reliability.

Identification and Use of Economic Transmission Reconfigurations

In the *2021 State of the Market Report*, we highlighted the benefits of identifying and deploying network reconfigurations (e.g., opening a breaker) when such options are reliable and economic. This is done on a regular basis by Reliability Coordinators to address congestion-related reliability concerns, normally under the procedures established in Operating Guides in consultation with the TOs. However, tremendous benefits can be achieved by utilizing reconfiguration options economically to manage congestion.

To illustrate these benefits, we evaluated the costliest constraint during the summer of 2021, the Rochester-Wabaco 161 KV line, which generated over $57 million in congestion. Our study demonstrated that the reconfiguration immediately reduced the overall congestion that had occurred on Rochester-Wabaco by two thirds. After the immediate shift in congestion caused by the reconfigurations, the congestion on other nearby facilities tended to dissipate as generation moved to manage the congestion more efficiently on the other facilities. Hence, the benefits of the reconfiguration in mitigating the severe congestion on this facility are larger over time.

We have identified similar events in 2022 and we believe this case study is representative of the opportunities to develop economic reconfiguration options on other frequently binding constraints and deploying them as regular congestion management actions. Therefore, we continue to recommend that MISO work with TOs to develop tools, processes, and procedures to identify and analyze reconfiguration options and then employ them to reduce congestion, rather than only for reliability.

In 2022, MISO created the Reconfiguration for Congestion Cost Task Team to evaluate and implement reconfiguration requests. As of March 2023, two of seven reconfiguration requests were successfully implemented. However, MISO has no near-term plans to develop tools internally to suggest economic reconfiguration options, nor has it developed a process to ensure that evaluations of alternatives are timely. We recommend MISO pursue these enhancements.

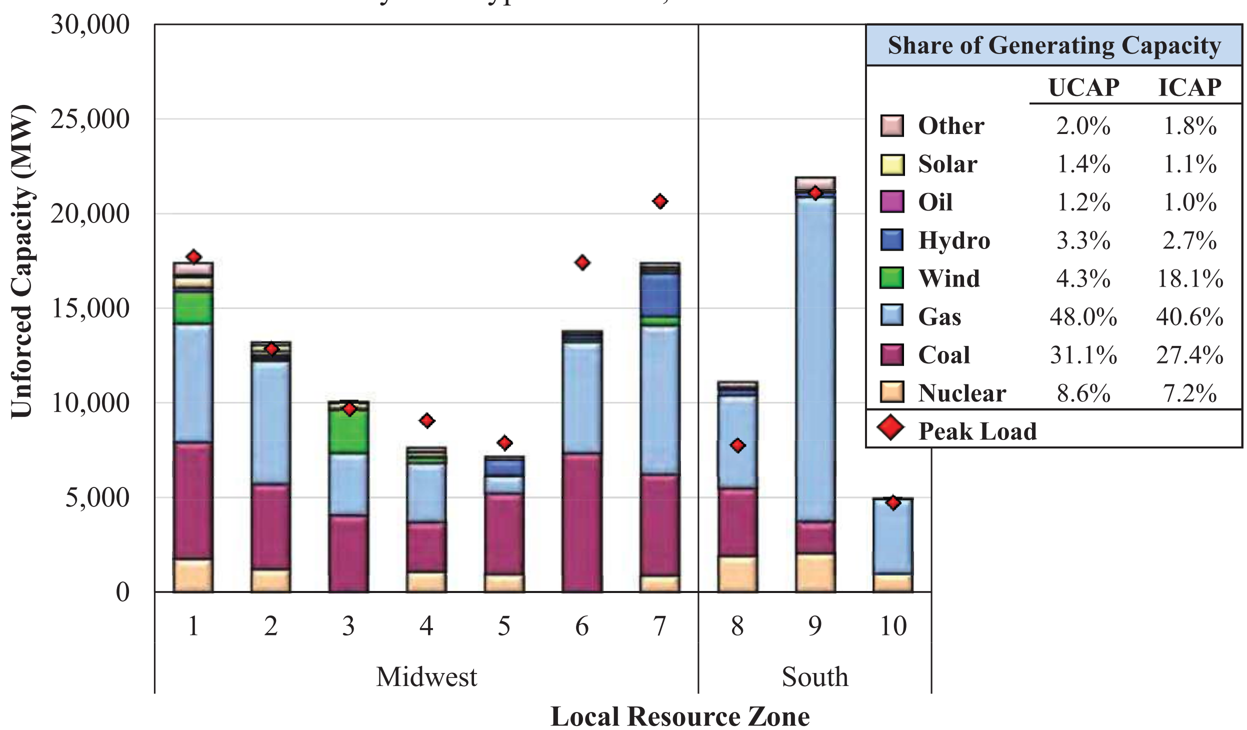
VI. RESOURCE ADEQUACY

This section evaluates the performance of the markets in facilitating the investment and retirement decisions necessary to maintain resources to meet system reliability. We assess the adequacy of the supply in MISO for the upcoming summer and discuss recommended changes that would improve the performance of the markets.

A. Regional Generating Capacity

This first subsection shows the distribution of existing generating capacity in MISO. Figure 36 shows the distribution of Unforced Capacity (UCAP) at the end of 2022 by Local Resource Zone (LRZ) and fuel type, along with the coincident peak load in each zone.[30] UCAP values account for forced outages and intermittency. Therefore, UCAP values for wind units are much lower than Installed Capacity (ICAP) values, as shown in the inset table. Hence, although wind is over 18 percent of MISO's ICAP, it is 4.3 percent of the UCAP.

Figure 36: Distribution of Existing Generating Capacity
By Fuel Type and Zone, December 2022



Share of Generating Capacity	UCAP	ICAP
Other	2.0%	1.8%
Solar	1.4%	1.1%
Oil	1.2%	1.0%
Hydro	3.3%	2.7%
Wind	4.3%	18.1%
Gas	48.0%	40.6%
Coal	31.1%	27.4%
Nuclear	8.6%	7.2%
Peak Load		

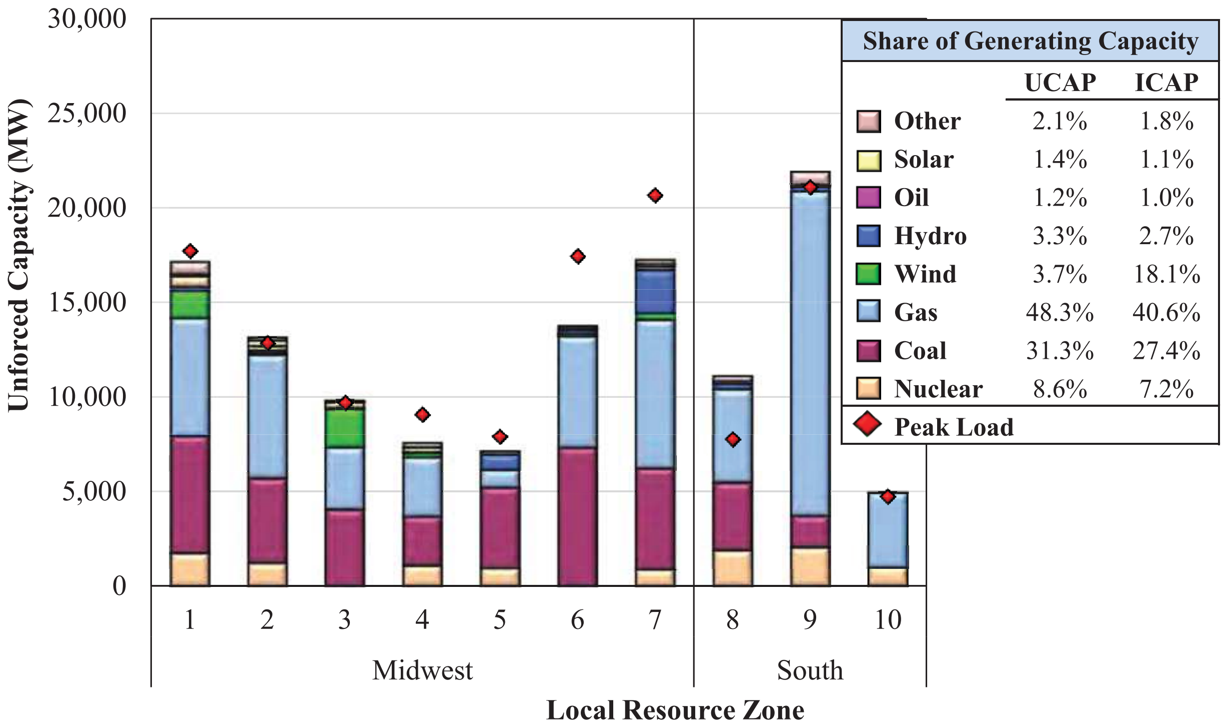
This figure shows that gas-fired resources account for a larger share of MISO's capacity than any other capacity type, including coal-fired resources. The figure also shows that the gas-fired capacity shares are largest in MISO South, which tends to result in large interregional flows from MISO South to the MISO Midwest when natural gas prices are low and outages are minimal.

30 UCAP was based on data from the MISO PRA for the 2021-2022 Planning Year and excludes LMR capacity.

B. Changes in Capacity Levels

Capacity levels have been falling in recent years because of accelerating retirements of baseload resources, which are being partially replaced with intermittent renewable resources. Figure 37 shows the capacity additions (positive values) and losses during 2022. The hatched bar indicates newly suspended resources, which rarely return to service. Per Section 38 of the Tariff, the distinction between suspension and retirement is based on interconnection rights rather than the status or future plans for the facility. A suspended resource may be disassembled, maintaining interconnection service to support a new facility at the same location. The status of the resource will eventually change from suspension to retirement if the interconnection rights are not being used. Figure 37 does not show retirements for resources in 2022 that were suspended in 2021.

Figure 37: Distribution of Additions and Retirements of Generating Capacity
By Fuel Type and Zone in 2022



Capacity Losses

In 2022, 4 GW of resources retired or suspended operations in MISO, consisting of primarily coal, gas steam, and nuclear resources. Some of the suspended unforced capacity is under consideration for partial replacement and could return as new generation (primarily solar and battery) in the next three years.[31] We expect baseload retirements to continue in the near term because of the weak economic signals provided by MISO's current capacity market.

31 See MISO Generator Replacement Requests: https://www.misoenergy.org/planning/generator-interconnection/GI_Queue/

Attachment Y to the MISO Tariff requires suppliers seeking to retire or suspend a unit to notify MISO at least 26 weeks in advance unless the unit is in outage. Based on a reliability study of the transmission system, MISO may designate a resource as a System Support Resource (SSR) and provide compensation. An SSR cannot retire or be suspended until a reliability solution (e.g., transmission upgrades) can be implemented or the reliability condition no longer exists. SSRs have been granted infrequently, and currently two resources in MISO are designated SSR.

New Additions

In 2022, 2 GW of unforced new capacity entered MISO. A 1.1 GW natural gas-fired combined-cycle resource entered MISO in the Central region. Approximately 2.8 GW (nameplate) of wind entered, although their total UCAP value is only 380 MW because they provide less reliability than conventional resources. Approximately 600 MW (UCAP) of solar resources also entered in 2022, primarily in the North and Central regions. Additional investment in wind resources is likely to occur given continued Federal subsidies and MISO state policies.

C. Planning Reserve Margins and Summer 2023 Readiness

This subsection summarizes capacity levels in MISO and their adequacy for satisfying the forecasted summer peak loads in 2023. Assumptions regarding the supply that will be available during the summer peak and the peak load can substantially change the planning reserve margins. Therefore, Table 13 presents a base case scenario and four additional scenarios that more realistically represent the range in MISO's summer peak reliability margin.

Base Scenario. We have worked closely with MISO to align our base scenario with MISO's assumptions in its *2023 Summer Resource Assessment,* including the 1,900 MW transfer limit assumption between MISO South and Midwest.[32] This scenario also assumes that: a) MISO will be able to access all demand response resources in any emergency, and b) the summer planned outages will be limited to those scheduled and approved by April 1, 2023. The planning reserve margin shown is 19.2 percent – which exceeds the installed capacity Planning Reserve Margin Requirement (PRMR) of 15.9 percent.

To report all values in the Summer Assessment on an ICAP basis, we: (a) replaced the UCAP-based PRM added to demand response resources with an ICAP-based PRM, and (b) converted the UCAP-based ELCC value for wind resources to an ICAP-based value by scaling it up based on the ratio of the ICAP and UCAP PRM values. As conventional resources retire, we expect MISO's summer margins to fall below the planning requirement.

32 We do not think this is a reasonable assumption based on real-time operations, but we include this assumption to align our Base Case with MISO's Base Case.

Realistic Scenario. Unfortunately, the assumptions in the base scenario are not very realistic, so we include a realistic scenario that assumes that:

- The transfer capability between MISO South and Midwest will be 2,300 MW, consistent with MISO operations;
- Planned and unreported outages and derates will be consistent with the average of the previous three years' summer peak months during on-peak hours; and
- MISO will only be able to access 75 percent of demand response resources in an emergency situation, consistent with historical observations.

Table 13: Summer 2023 Planning Reserve Margins

		Alternative IMM Scenarios*			
				High Temperature Cases	
	Base Scenario	Realistic Scenario	Realistic <=2HR	Realistic Scenario	Realistic <=2HR
Load					
Base Case	123,735	123,735	123,735	123,735	123,735
High Load Increase	-	-	-	7,040	7,040
Total Load (MW)	123,729	123,729	123,729	130,775	130,775
Generation					
Internal Generation Excluding Exports	132,837	132,837	132,837	132,837	132,837
BTM Generation	4,333	4,333	3,104	4,333	3,104
Unforced Outages and Derates**	-	(13,270)	(13,270)	(20,870)	(20,870)
Adjustment due to Transfer Limit	(2,067)	-	-	-	-
Total Generation (MW)	135,103	123,900	122,671	116,300	115,071
Imports and Demand Response* **					
Demand Response (ICAP)	8,304	6,228	3,108	6,228	3,108
Firm Capacity Imports	4,136	4,136	4,136	4,136	4,136
Margin (MW)	23,813	10,535	6,186	(4,110)	(8,459)
Margin (%)	**19.2%**	**8.5%**	**5.0%**	**-3.1%**	**-6.5%**
Expected Capacity Uses and Additions					
Expected Forced Outages****	(6,858)	(6,798)	(6,798)	(6,798)	(6,798)
Non-Firm Net Imports in Emergencies	4,708	4,708	4,708	4,708	4,708
Expected Margin (MW)	21,662	8,445	4,096	(6,201)	(10,549)
Expected Margin (%)	**17.5%**	**6.8%**	**3.3%**	**-4.7%**	**-8.1%**

* Assumes 75% response from DR.
** Base scenario shows approved planned outages for summer 2023. Realistic cases use historical average unforced outages/derates during peak summer hours. High temp. cases are based upon MISO's 2023 Summer Assessment.
*** Cleared amounts for the Summer Season of the 2023/2024 planning year.
**** Base scenario assumes 5% forced outage rate for internal and BTM generation. Alternative cases use historical average forced outages/derates during peak summer hours.

In this realistic scenario, the planning reserve margin falls to 8.5 percent. This planning reserve margin would raise concerns for many RTOs, but MISO has the unique advantage of having substantial import capability from virtually every direction. Only a small amount of this import capability is reserved on a firm basis and used to import capacity. The remaining capacity is available on a non-firm basis to be used to resolve shortages when they occur. Hence, the table includes additional imports that reflect the average amount of additional imports during emergency conditions.[33] This is conservative because the import levels would likely rise to much higher levels in response to shortage pricing in MISO. The table also shows the capacity that would be lost based on a historical average forced outage rate of around 5 percent. When offset by the non-firm imports, the realistic margin falls to 6.8 percent.

Unfortunately, even the realistic scenario is optimistic because it assumes all resources not in a forced outage will be available during an emergency. However, since emergencies are the result of unforeseen events, MISO has historically declared emergencies between 10 minutes and four hours in advance. Because a large quantity of emergency resources offer longer notification times (often up to 12 hours), the second realistic scenario assumes only emergency resources that can start in two hours or less will be accessible, which reduces emergency demand response and behind-the-meter generation. This lowers the planning reserve margin to 5.0 and further to 3.3 percent after accounting for expected forced outages and non-firm summer imports.

High Temperature Scenarios. We include two other variants of the realistic scenarios to include the effects of hotter than normal summer peak conditions. The high-temperature scenarios are important because hot weather significantly affects *both* load and supply. High temperatures can reduce the maximum output limits of many of MISO's generators when outlet water temperature or other environmental restrictions cause certain resources to be derated.[34] On the load side, we assume MISO's "90/10" forecast case (which should occur one year in ten).

The high-temperature cases using the realistic scenario and realistic plus limited emergency-only capacity both show that MISO's margin will be substantially negative (ranging from -3.1 to -6.5 percent). MISO will likely be well into emergency conditions in these cases because it must have a positive margin of 2,400 MW to satisfy its operating reserve requirements. We note, however, that the roughly 9 GW of firm and non-firm imports shown in the table is far less than the total import capability. Therefore, MISO would not likely need to shed load in most of these cases provided that its markets are effective in motivating high levels of imports.

Overall, these results indicate that the system's resources are adequate for summer 2023 but may run short if the peak demand conditions are much hotter than normal. Going forward, planning reserve margins will likely continue to decrease as fossil-fuel and nuclear resources retire and are replaced by renewable resources. Therefore, it remains important for the capacity market and shortage pricing to provide efficient economic signals to maintain adequate resources.

33 The additional imports are consistent with the non-firm external support assumptions in MISO's 2023-2024 LOLE study.

34 These high-temperature derates are highly variable, so we assume high-temperature conditions from the MISO high-temperature scenario from its 2020 Summer Assessment.

D. Capacity Market Results

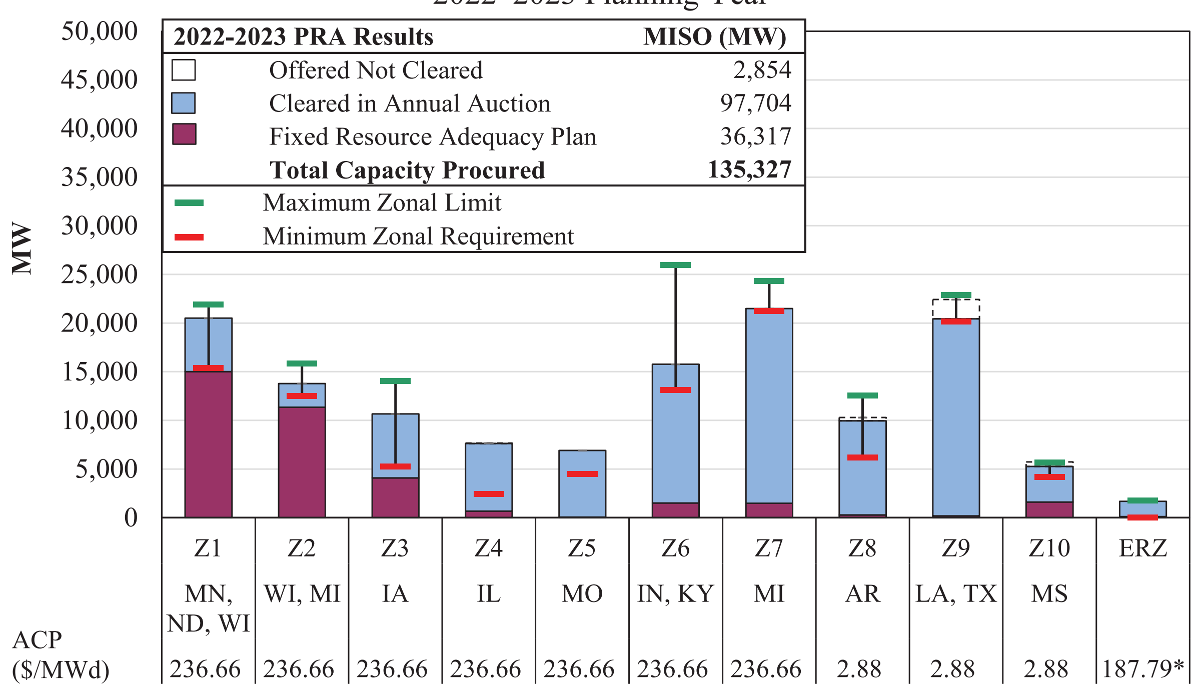
The purpose of capacity markets is to facilitate long-term resource decisions to satisfy RTOs' planning requirements in conjunction with their energy and ancillary services markets. The economic signals provided by these markets together inform long-term decisions to build new resources, make capital investments in or retire existing resources, and import or export capacity.

MISO's Resource Adequacy Construct allows load-serving entities (LSEs) to procure capacity to meet their Module E requirements either through bilateral contracts, self-supply, or the PRA. Resources clearing in MISO's PRA receive capacity revenues that, in addition to energy and ancillary services market revenues, should signal when new resources are needed.

PRA Results for the 2022–2023 Planning Year

Figure 38 shows the outcome of the PRA held in late March 2022 for the 2022–2023 Planning Year. The figure shows the minimum and maximum amount of capacity that can be purchased in the red and green lines. The stacked bars show the total amount of capacity offered. The stacked bars include capacity offered but not cleared (ghost bars), capacity cleared (blue bars), or self-supplied (maroon) in each zone. Zonal obligations are set by the greater of the system-wide planning reserve requirement or the local clearing requirement. The minimum amount is the local clearing requirement, equal to the local reliability requirement minus the maximum level of capacity imports. The maximum is equal to the obligation plus the limit on capacity exports.

Figure 38: Planning Resource Auctions
2022–2023 Planning Year



*Weighted Average Clearing Price

Prices. Zones 1 through 7 cleared at $236.66 per MW-day, the Cost of New Entry (CONE) for Zone 3, partially because of an increased load forecast and the retirements of multiple conventional resources that were replaced by the addition of renewable resources that are less reliable because of their intermittent nature. Zones 8 through 10 (MISO South) cleared at $2.88 per MW-day. MISO South Prices were extremely low and provided less than three percent of the revenues needed to cover the cost of new entry for a new peaking resource. External resource zones cleared at a weighted average price of $187.79 per MW-day.

We conducted an analysis that illustrates how capacity auction results in previous years contributed to the 2022–2023 Midwest capacity shortage. Since 2019, MISO has lost almost 5 GW of resources that would have been economic if MISO had employed a reliability-based (sloped) demand curve. Our estimated auction clearing prices in prior capacity auction years would have covered the net going forward costs of most of these resources, which would likely have allowed MISO to avoid the current capacity shortage. This is the predictable result of the flawed market design. If reliability is truly imperative, this flaw should be addressed by adopting a reliability-based demand curve. We discuss this further in Section III.B.

PRA Results for the 2023–2024 Planning Year

MISO substantially reformed its capacity market in 2022, adopting a seasonal market construct and an availability-based Seasonal Accredited Capacity (SAC) methodology for resources participating in the PRA.[35] These changes addressed two recommendations that we have made in recent *State of the Market* reports.[36] This new construct was introduced in the 2023–24 PRA held in April 2023. The results are summarized in Table 14.

Table 14: 2023–24 Planning Resource Auction Results

Season	Capacity Procured	Offered Not Cleared	LOLE Target	Prices ($/MW-Day) Rest of Market	Prices ($/MW-Day) Zone 9 (LA,TX)
Summer 23	132,891	6,483	0.10	$10.00	
Fall 23	125,795	10,587	0.01	$15.00	$59.21
Winter 23/24	128,104	11,378	0.01	$2.00	$18.88
Spring 24	124,389	10,049	0.01	$10.00	
PRA Year	127,795	9,624	0.13	$9.25	$24.52

Across the four seasons, market clearing prices average $9.25 per MW-day, with a low of $2 in the winter, a high of $15 in the fall, and $10 in the summer and spring. Prices separated in Zone 9 in the fall and winter with prices clearing at $59.21 and $18.88 per MW-day, respectively,

35 Docket No. ER22-495-000.

36 See Recommendations 2014-5 and 2018-5 from prior *State of the Market Reports*.

because of tight supply in this zone. Nonetheless, these prices are much lower than the prices that were set at CONE of $237 per MW-day in the Midwest (Zones 1 to 7) in the 2022–23 PRA.

This collapse in the prices was the result of a 6 GW increase in net capacity in the summer season of the 2023–2024 planning year and the vertical demand curves utilized in the market. The following factors contributed to this increase in net capacity in the Midwest:

- 2.1 GW decrease in PRMR from lower coincident peak forecasts and a lower PRM;
- 1.1 GW addition of new thermal capacity that more than offset 0.9 GW of retirements;
- 250 MW increase in accreditation of Midwest resources in the transition to SAC;
- 640 MW of new solar resources;
- 1.2 GW of additional wind: 450 MW of new wind resources and a 740 MW increase in existing wind capacity from procuring firm transmission to be deliverable; and
- 1.1 GW increase in LMRs, mostly from External Resources and demand response.

Most of the increase in net capacity is associated with reduced requirements and an increase in voluntary participation (e.g., LMRs and more converted wind deliverability). The change in requirements year-to-year is difficult to predict, but the change in participation is likely a reaction to the high prices the previous year. While there was a net gain in thermal capacity in this upcoming planning year, we expect continued retirements of aging coal and gas resources in future years. Rapid increases in solar and wind resources will also continue, but these resources are limited in the ability to satisfy MISO's reliability needs.

Unfortunately, MISO's capacity market is not designed to send efficient price signals to spur the development of new dispatchable resources. Addressing this inefficiency requires MISO to correct the representation of demand by adopting a reliability-based demand curve (RBDC). Under the sloped demand curve proposed by MISO, the summer capacity prices would have risen more than five-fold to more than $50 per MW-day. This price effect would have been much larger absent the sizable decrease in capacity requirements in this planning year.

Discussion of Other Issues Affecting the Performance of the PRA

Transfer Constraint. As part of the Settlement Agreement with SPP, MISO may dispatch up to 2,500 MW of energy transfers from MISO South to MISO Midwest. However, MISO limits the transfer capability in the South to North direction to 1,900 MW in the PRA. This reduction is made to account for firm interregional transmission reservations held by participants. Unfortunately, this reduction is not warranted because these reservations do not encumber MISO's utilization of the RDT. This constraint bound in the 2022–2023 PRA and caused the significant price separation between MISO South and MISO Midwest, contributing to the capacity shortage in the Midwest. Increasing the limit to an expected transfer capability closer to 2,500 MW would allow MISO to utilize its capacity more fully in MISO South. Hence, we recommend that MISO revise its transfer limit in future PRAs.

E. Long-Term Economic Signals

Price signals in MISO's markets play an essential role in coordinating commitment and dispatch of units in the short term, while providing long-term economic signals that govern investment and retirement decisions for generators and transmission facilities. This subsection evaluates the long-term economic signals produced by MISO's markets by measuring the net revenue a new generating unit would have earned in MISO's markets in 2022.

Net revenue is the revenue a unit earns above its variable production costs if it runs when it is economic to run. Well-designed markets should produce net revenue sufficient to support new investment at times when existing resources are not adequate to meet the system's needs. Figure 39 and Figure 40 show estimated net revenues for a new combustion turbine (CT) and combined-cycle (CC) generator for the last three years in the Midwest and South regions. For comparison, the figures also show the annual net revenue that would be needed for these investments to be profitable (i.e., the Cost of New Entry or "CONE"). We include in our analysis ghost bars that indicate the alternative net revenues that these resources would have received were MISO to have employed a sloped demand curve in its capacity market (as we discuss in Section III.B).

Figure 39: Net Revenue Analysis
Midwest Region, 2020–2022

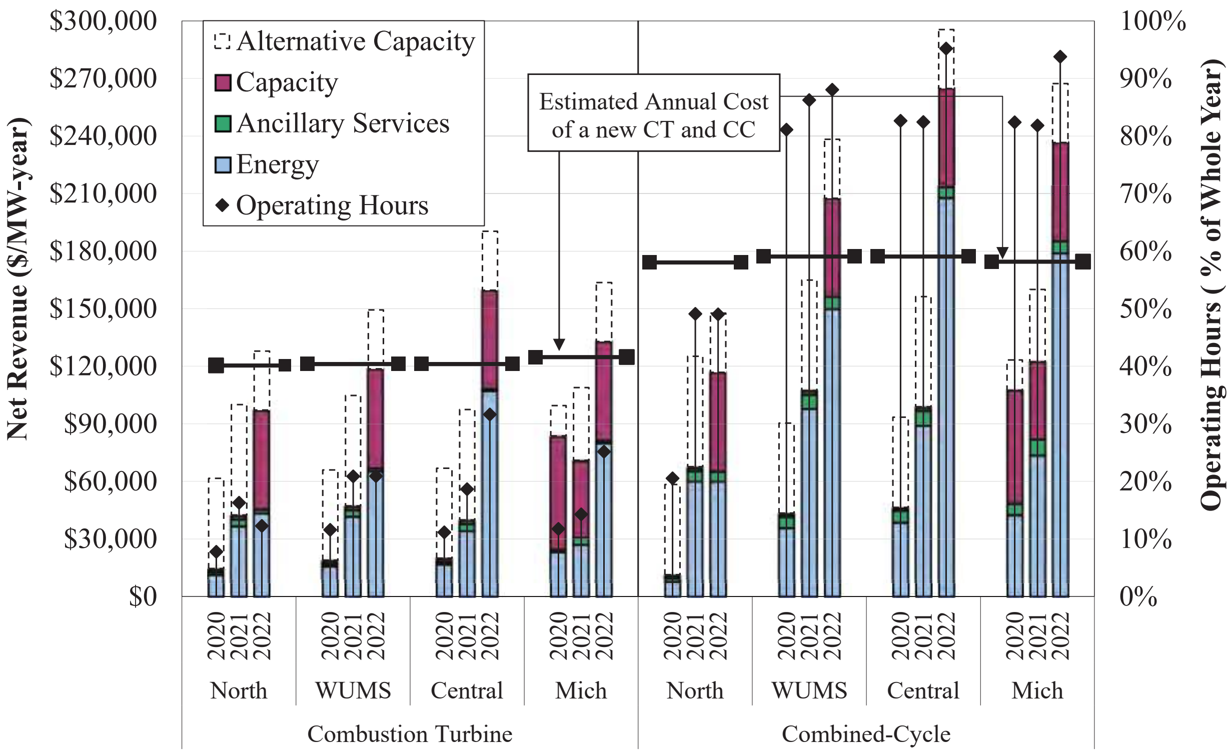
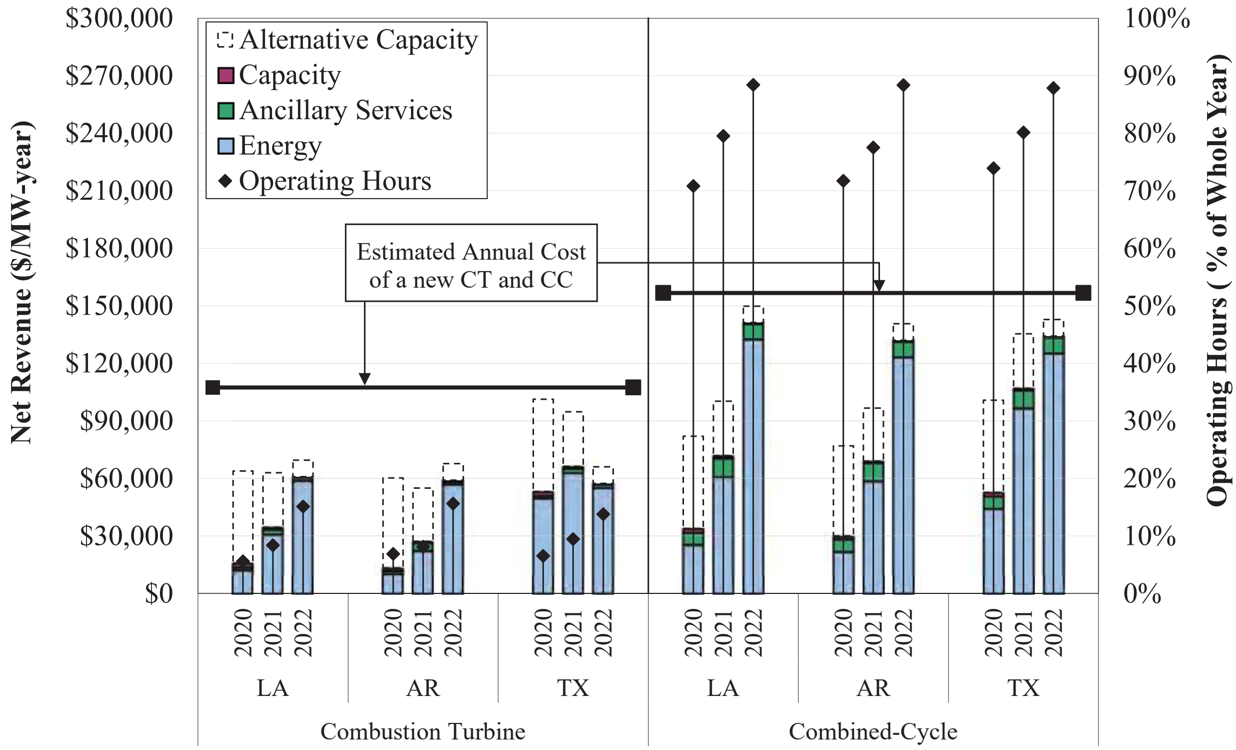


Figure 40: Net Revenue Analysis
South Region, 2020–2022



These figures show that net revenues rose substantially in all regions in 2022, partly because higher natural gas prices contributed to higher energy and ancillary services prices throughout MISO, and partly because MISO experienced a period of sustained high prices during Winter Storm Elliott in December. The capacity shortage and sharp increase in congestion caused net revenues to exceed the cost of new entry for combined-cycle and combustion turbine resources in eastern areas in the Midwest region. We do not expect this to continue given the reductions in natural gas and capacity prices that have occurred in early 2023.

Overall, MISO's economic signals continue to be undermined by capacity market design issues, including a poor representation of demand as a single quantity value (i.e., a vertical demand curve). Had MISO employed a reliability-based demand curve in the Planning Resource Auctions, the annual net revenues would have been significantly higher in recent years and sustained economic merchant resources that have been retiring prematurely. This raises particularly timely concerns as MISO's capacity surplus is dissipating and resources face substantial economic pressure. As noted above, this design flaw contributed to the capacity shortage in the Midwest Region in the 2022–2023 PRA and reduced MISO's overall reliability. This issue is discussed in more detail along with our recommendation to address it in Section III.

F. Existing Capacity at Risk Analysis

Since its inception, MISO has enjoyed a capacity surplus beyond the minimum requirement. MISO's capacity surplus has dwindled in recent years as older baseload units have entered long-term suspension or retired. This trend has largely been due to sustained low natural gas prices and the poor design of MISO's capacity market that results in understated capacity prices.

Well-designed markets should provide sufficient net revenues to cover the costs of remaining in operation (i.e., Going-Forward Costs or "GFCs") for resources that provide material reliability. When resources cannot recover their GFCs, they are at risk of suspending or retiring prematurely. Moreover, some resources may reduce maintenance expenditures, leading them to have more frequent forced outages and deratings.

We conducted an analysis to evaluate MISO's capacity at risk for long-term suspension or retirement for three types of technologies in MISO: coal, nuclear, and wind. Our analysis shown in Figure 41 compares the annual resource net revenues to the GFCs. The net revenues and GFCs are based on technology-specific heat rates, variable costs, capacity factors and Technology-Specific Avoidable Costs (TSACs). A detailed description of our analysis can be found in the Appendix Section VI.F.

Figure 41: Capacity at Risk by Technology Type
2022

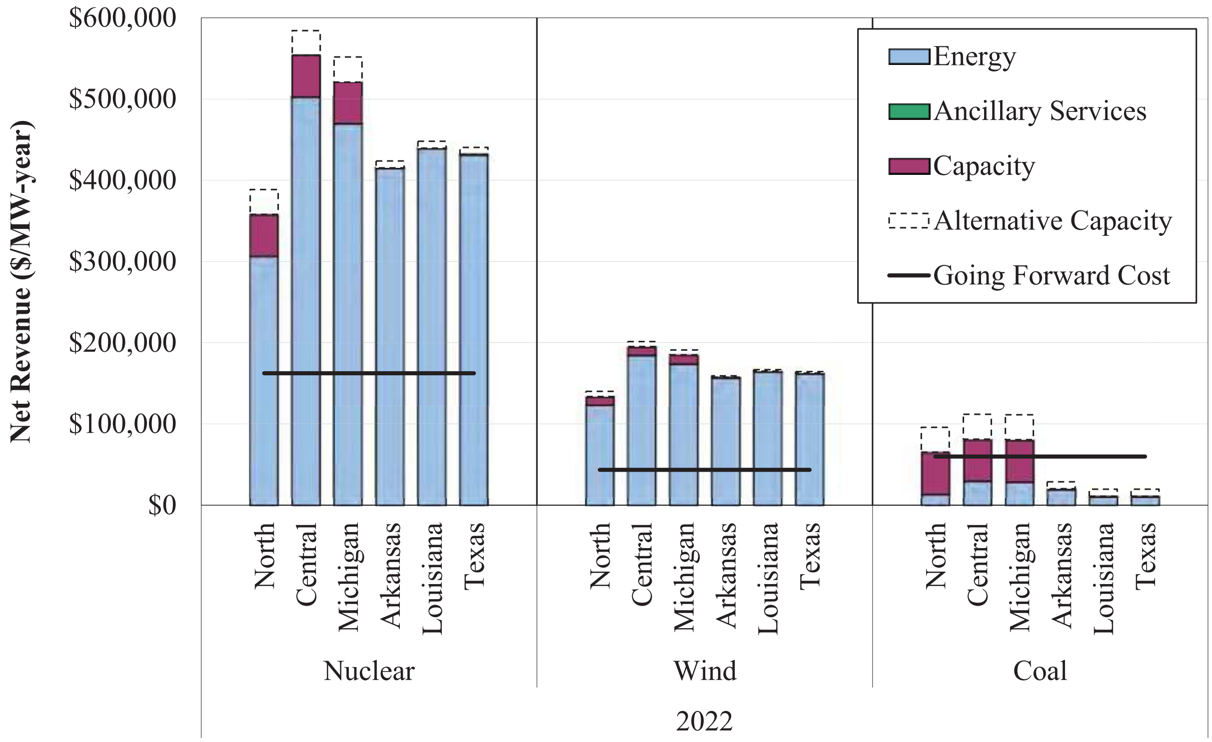


Figure 41 shows that while nuclear and wind resources are more than revenue adequate, even without including tax credits, typical coal resources exhibit revenue shortfalls under the current capacity construct. Even with the higher gas prices in 2022, many coal resources must rely on capacity auction revenue to cover their going-forward costs. Many coal-fired resources in MISO are owned by vertically-integrated utilities that have guaranteed returns on investment through cost-of-service rates. Barring out-of-market cost recovery and the capacity shortage pricing that occurred in the 2022–2023 PRA, most of these resources would be uneconomic to continue operating at the prices that prevailed in 2022. However, if MISO prices capacity efficiently (by adopting a reliability-based demand curve), typical coal resources would be able to recover their GFCs in the Midwest and avoid premature retirements. A more detailed analysis of the range of net revenues for existing individual coal resources by zone over the past two years is shown in Section VI.F of the Analytic Appendix.

G. Capacity Market Reforms

Although a reliability-based demand curve that we describe in Section III.B is the most important design improvement, followed by improving the accreditation of capacity resources, we have also recommended that MISO consider the following additional improvements to provide better long-term incentives to MISO's suppliers and ensure that MISO's resource adequacy needs are satisfied.

Improvements to the Seasonal Market

During MISO's SAC filing in 2022, we raised some issues concerning elements that we believed reduced the benefits of the two broad changes implemented by MISO (seasonal market and accreditation based on availability during tight hours):[37]

- The seasonal design has four seasons that clear simultaneously at the beginning of the planning year. We had recommended that MISO run prompt seasonal auctions so that participants could make auction decisions with less uncertainty and optimize their offers in the upcoming season given the results of the prior seasons; and

- The implemented design still generally overvalues inflexible resources, such as accrediting offline resources with 24-hour lead times comparably to online resources or fast-starting gas turbines.

We have also identified some additional issues with the design since the implementation of the new construct. Under the current design, if an MP does not replace ZRCs for a resource on planned outage for more than 31 days in a season, the Capacity Replacement Non-Compliance Charge (CRNCC) is assessed.

37 See *Motion to Intervene out of Time and Comments of the MISO IMM under ER22-495*.

The 31-day penalty threshold creates some inefficient incentives:

(1) It allows a resource on outage the entire season (over 90 days) to be profitably sold; and

(2) It creates incentives to schedule long-term planned outages that straddle seasons to avoid the CRNCC, which could degrade reliability.

We recommend that MISO reform this penalty structure to address these incentives concerns.

Other Recommended Improvements to the PRA

Accreditation of Emergency Resources. Emergency-only resources, including LMRs and Available Max Emergency (AME) resources, are only required to deploy during emergencies when instructed by MISO. If they are not available to mitigate capacity shortages during emergencies, then they are not providing the reliability value MISO assumes and for which they are compensated. Some emergency-only resources have long notification times (up to 12 hours) or long start-up or shutdown times that render them essentially unavailable in most emergencies, which tend to occur with less than two hours warning. Therefore, we recommend that MISO develop a reasonable methodology for accrediting emergency-only resources in the PRA.

MISO filed Tariff changes in March 2023 that restrict the use of emergency commitment status in energy offers, which will be effective June 2023.[38] MISO intends to make a follow-up filing effective June 2024 to account for restricted availability of AME in accreditation and allow operators to call on AME resources with more than 2-hour lead times in advance of emergency declarations.

Modeling Transmission Constraints in the PRA. MISO currently only models import and export limits for each zone and the RDT transfer constraint from South to North. It runs a power-flow model after the initial PRA solution to determine whether any constraints are binding. Although transmission constraints have not been prevalent in the past, this is a poor approach that will fail to efficiently price any constraints that arise. Instead, MISO should model these constraints in the PRA by assigning a zonal shift factor for each modeled constraint that reflects how the resources in each zone affect the flow on the constraint. This would allow the zonal prices to accurately reflect these constraints.

38 Docket No. ER23-1523-000.

VII. External Transactions

A. Overall Import and Export Patterns

Imports and exports play a key role in MISO because of its 12 interfaces with neighboring systems that have a total interface capability of 14 GW. Hence, the magnitude of the changes in imports and exports in response to prices can be large and significantly affect market outcomes. Interface price differences create incentives for physical schedulers to import and export between MISO and adjacent areas. MISO remained a substantial net importer in 2022:

- Day-ahead and real-time hourly net scheduled interchange (NSI) averaged 4.1 and 4.2 GW, respectively (positive NSI values reflect net imports).
- MISO's largest and most actively scheduled interface is the PJM interface. MISO was a net importer from PJM in 2022.
  - Hourly real-time imports from PJM averaged 2.2 GW, down 20 percent from 2021.
  - Some of the scheduling patterns between MISO and PJM were inefficient because of flaws in the RTOs' interface prices, as discussed below.

Scheduling that is responsive to interregional price differences captures substantial savings as lower-cost resources in one area displace higher-cost resources in the other area. Participants must schedule transactions at least 20 minutes in advance and, therefore, must forecast the price differences. The lack of RTO coordination of external transactions causes aggregate changes in transactions to be far from optimal. To evaluate the efficiency of external scheduling, we track the share of the transactions that were profitable (i.e., scheduled from the lower-priced market to the higher-priced market), which lowers the total production costs in both regions.

In 2022, nearly 60 percent of the transactions with PJM and over 60 percent of the transactions with SPP were scheduled in the profitable direction. Even though transactions are scheduled in the efficient direction more than half of the time, large untapped savings are available because it is often economic to schedule significantly more or less interchange. Many hours still exhibit large price differences that offer substantial production cost savings.

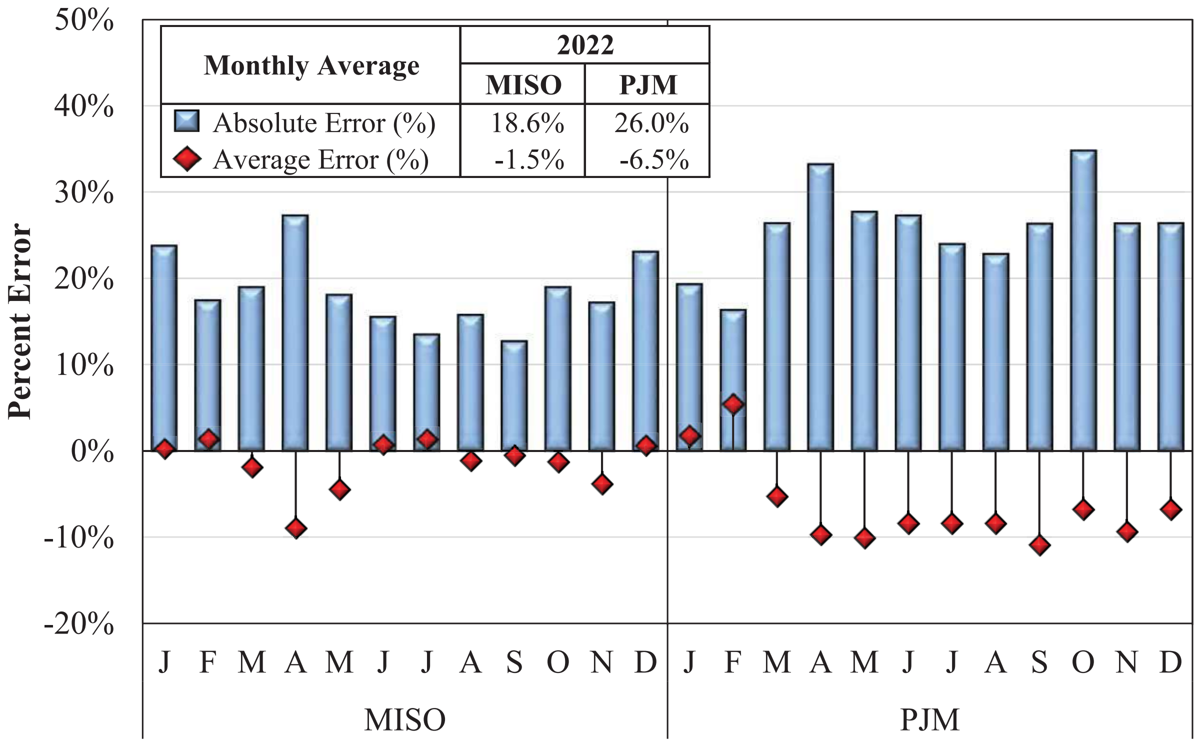
B. Coordinated Transaction Scheduling

On October 3, 2017, MISO and PJM implemented Coordinated Transaction Scheduling (CTS). CTS allows market participants to submit offers to schedule imports or exports between the RTOs within the hour. Offers clear if the forecasted spread between the RTOs' real-time interface prices 30 minutes prior to the interval is greater than the offer price. CTS transactions are settled based on real-time interface prices. In this subsection, we discuss the performance of the current CTS system and a fundamental reform to the CTS design that would allow it to perform much better.

Summary of CTS Performance

Up until early 2019, there had been almost no participation in CTS. In 2022, the hourly average quantity of CTS transactions offered and cleared remained extremely low at 50 MW and 23 MW, respectively. Over 99 percent of the transactions over the past two years have been in the import direction. CTS transactions remain a *de minimus* fraction of transactions at the PJM interface. We have previously shown that high transmission and energy charges have likely deterred traders from using CTS in lieu of traditional transaction scheduling. We have also concluded that persistent forecasting errors by MISO and PJM have likely hindered the use of CTS. We evaluated the forecasting errors for each RTO, measuring the percentage difference between the actual LMP and the forecasted price used for CTS. In Figure 42, we show the forecasting errors by month in both average and absolute average terms for both MISO (left-hand chart) and PJM (right-hand chart).

Figure 42: MISO and PJM CTS Forecast Errors
2022



This analysis shows significant inaccuracies in the forecast prices used for CTS, particularly in PJM where the forecasts are both large and biased. In 2022, the average difference between PJM's real-time LMPs and its forecast prices for the interface was -6.5 percent, and the average of the absolute difference was 26 percent.[39] For the same period, the average difference between MISO's real-time LMPs and its forecast prices for the interface was -1.5 percent, and the average

[39] PJM's forecast prices are from its intermediate term security-constrained economic dispatch tool (IT SCED).

of the absolute difference was 18.6 percent. When combined, these errors severely hinder the effectiveness of CTS in improving pricing at the interface because they create substantial risk for participants scheduling transactions through the CTS process. The poor forecasts suggest that CTS would likely clear many transactions that are uneconomic based on real-time spreads if participants submitted relatively low-cost CTS offers. These forecasts would also cause CTS to not clear many transactions that would otherwise be economic.

A comparable mechanism to CTS is in place between the New York ISO and ISO New England and is widely used, in part because the forecast prices are more accurate, and no charges are applied to these transactions. Hence, we continue to recommend that MISO eliminate all transmission and other charges applied to CTS transactions, while encouraging PJM to do the same. Additionally, we have concluded that it is unlikely for the RTOs to substantially improve their forecasts given the timing of the information used. Hence, we recommend the RTOs mitigate the adverse effects of the forecasts by modifying the CTS to clear transactions every five minutes through UDS based on the most recent five-minute prices in the neighboring RTO area. The following is an evaluation of this recommendation.

CTS with Five-Minute Clearing

We ran a simulation for 2022 of a CTS process that clears based on recent five-minute prices to evaluate the benefits of our recommendation. Instead of the markets clearing CTS offers on a 15-minute basis using forecasted prices from 30 minutes prior, the markets in our simulation clear CTS transactions every five minutes using interface price spreads from the previous interval. For each interval, we estimate an optimal clearing amount based on:

- The previous five-minute spread less cleared transaction fees;
- Assumed relationships of the price in PJM and MISO to changes in the transactions scheduled between them, which was based on a regression analysis we performed; and
- An assumed aggregate offer curve beginning at the level of the incremental charges and rising at a rate of $1 per MWh every 167 MW ($6 per 1000 MW).

We identify the optimal clearing amount, accounting for any changes in the actual scheduled NSI, by applying the following constraints: (1) maximum change between five-minute intervals of 500 MW (in either direction), and (2) maximum total CTS import and export limits of 5,000 MW. Based on the adjustments calculated for each five-minute interval, we are able to estimate the price changes, production cost savings, and profits of the CTS participants.

We also used this model to evaluate the benefits of a five-minute CTS with SPP, with tighter constraints since MISO has a smaller interface with SPP than PJM: (1) maximum 5-minute change of 250 MW (in either direction), and (2) maximum total CTS import and export limits of 2,000 MW. Table 15 summarizes the results for both markets.

This analysis shows that redesigning the CTS process to adjust NSI on a five-minute basis offers substantial savings that are not being captured under the current process. The recommended five-minute CTS with PJM would have achieved more than $40 million in production cost savings versus only $3 million under the current process. Although adjustments would have occurred in 88 percent of intervals, these savings do not require large adjustments—which average roughly 100 MW. A five-minute CTS with SPP would have achieved more than $56 million in production cost savings with a similar level of adjustments.

Table 15: CTS with Five-Minute Clearing Versus Current CTS
2022

	Percent of Intervals Adjusted	Production Cost Savings	Profits	Percent Unprofitable
PJM				
Current CTS	2.9%	$2,905,265	$76,892	12.2%
5-Minute CTS*	88.5%	$41,095,475	$20,663,002	23.0%
SPP				
5-Minute CTS*	95.2%	$56,130,144	$28,293,175	25.9%

* Results omit Dec 23-24 when MISO and PJM had very high prices from Winter Storm Elliott.

The improvement in the incentives for participants to utilize the CTS process is also notable. The CTS participants would have earned over $20 million from the cleared CTS transactions with PJM compared to profits in 2022 of just $77,000 under the current process. The poor price forecasts and high charges applied to any CTS offers leave little to no opportunity to profit by participating in the CTS. Five-minute CTS in SPP would have also been very profitable for participants, producing profits of over $28 million. Hence, using the most recent five-minute prices is a substantial improvement and leads to more efficient CTS adjustments. We recommend MISO pursue this form of CTS process with both PJM and SPP.

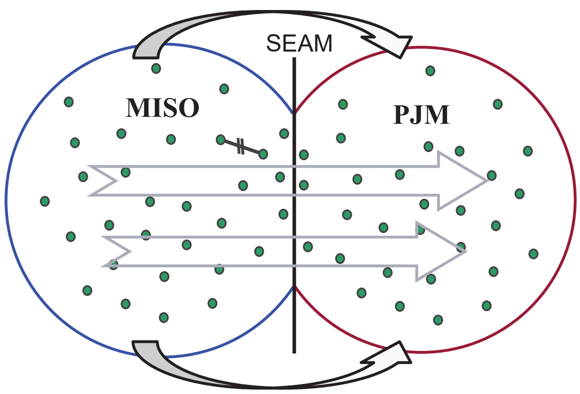
C. Interface Pricing and External Transactions

Each RTO posts its own interface price used to settle with physical schedulers wishing to sell to and buy power from the neighboring RTO. Participants will schedule flows between the RTOs to arbitrage differences between the two interface prices. Interface pricing is essential because:

- It is the sole means to facilitate efficient power flows between RTOs;
- Poor interface pricing can lead to significant uplift costs and other inefficiencies; and
- It is an essential basis for CTS to maximize the utilization of the interface.

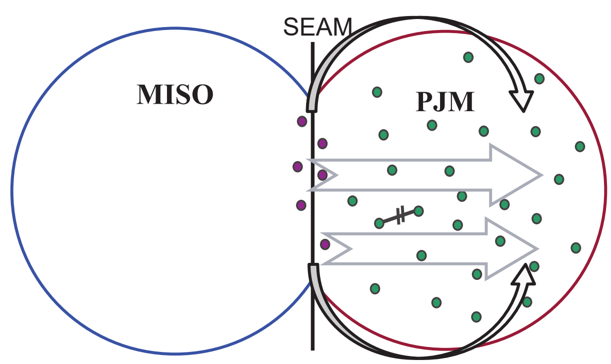
Establishing efficient interface prices would be simple in the absence of transmission congestion and losses—each RTO would simply post the interface price as the cost of the marginal resource on its system (the system marginal price, or "SMP"). Participants would respond by scheduling power from the lower-cost system to the higher-cost system until the SMPs equalize. However, congestion is pervasive on these systems, so the fundamental issue with interface pricing is estimating the congestion costs and benefits from imports and exports.

Like the LMP at all generation and load locations, the interface price includes: a) the SMP, b) a marginal loss component, and c) a congestion component. For generator locations, the source of the power is known and, therefore, congestion effects can be accurately calculated. In contrast, *the source of an import (or sink for an export) is not known*, so it must be assumed in order to calculate the congestion effects. This is known as the *"interface definition"*. If the interface definition reflects the actual source or sink of the power, the interface price will provide an efficient transaction scheduling incentive and lower the costs for both systems.



In reality, when power moves from one area to the other, generators ramp up throughout one area and ramp down throughout the other area (marginal units), as shown in the figure to the left. This figure is consistent with MISO's interface pricing before June 2017, which calculated flows for exports to PJM based on the power sinking throughout PJM. This is accurate because PJM will ramp down all its marginal generators when it imports power.

Because both RTOs price congestion on M2M constraints, some congestion had been redundantly priced by MISO and PJM and by MISO and SPP. To address this concern, PJM and MISO agreed to implement a "common interface" that assumes the power sources and sinks from the border with MISO, as shown in the second figure to the right. This common interface" consists of 10 generator locations near the PJM seam with five points in MISO's market and five in PJM. This approach tends to exaggerate the flow effects of imports and exports on constraints near the seam because it underestimates the amount of power that will loop outside of the RTOs.

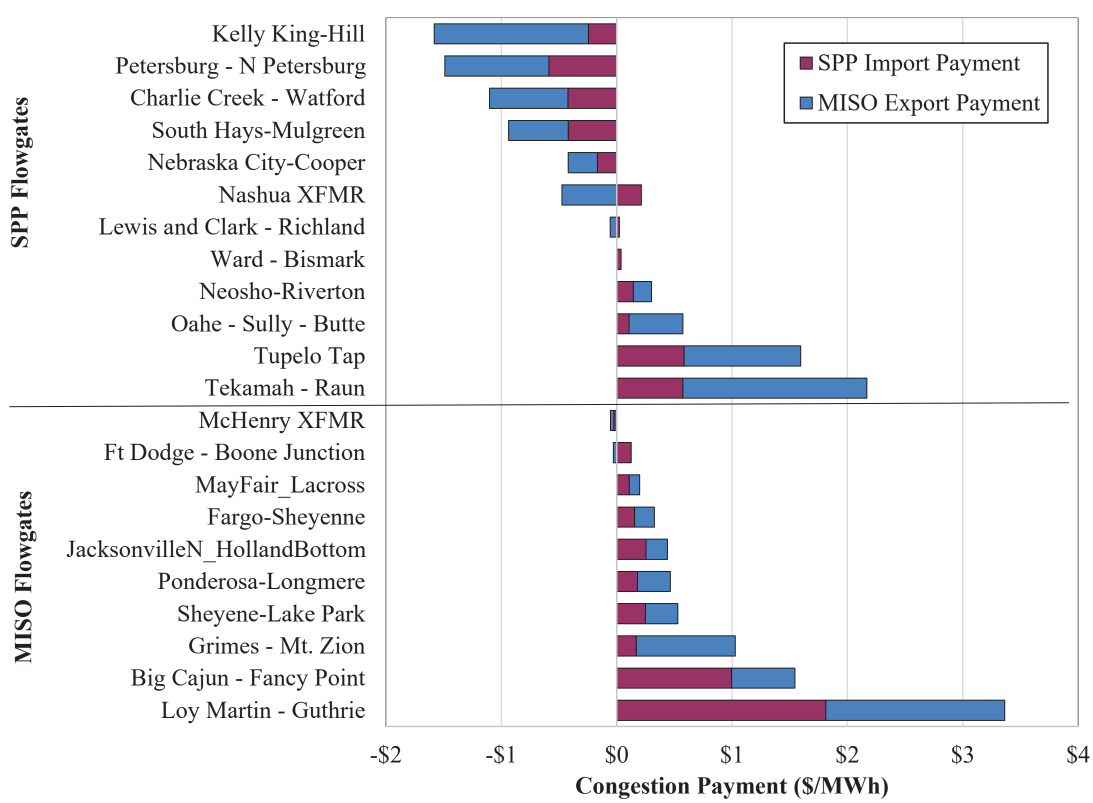


We have identified the location of MISO's marginal generators and confirmed that they are distributed *throughout* MISO, so we are concerned that the common interface definition sets inefficient interface prices. Our interface pricing studies show that in aggregate, the common interface has led to larger average errors and volatility at the interface. These results indicate that this approach was a mistake. Fortunately, MISO only uses this type of interface definition at the PJM interface, whereas PJM uses this approach on all its interfaces.

We have recently studied interface pricing at the MISO-SPP interface and verified that redundant congestion pricing is still occurring based on their overlapping interface definitions. In other words, when a M2M constraint binds, both RTOs price and settle with external transactions based on their respective estimates of the entire congestion effects of the transaction. Since both RTOs have relatively good models, their estimates are typically very similar, resulting in a rough doubling of the congestion settlement.

To show how this occurs, we have calculated the average interface pricing component associated with selected individual M2M constraints. These coordinated constraints had congestion value exceeding one million dollars between June 2018 and May 2019. Figure 43 shows the congestion component calculated by both SPP and MISO for each constraint, separately showing MISO constraints and SPP constraints. The congestion payments are displayed as the settlement of an export transaction from MISO to SPP. A negative value indicates that the participant would be charged the corresponding amount; whereas a positive value indicates that the participant would be paid for congestion relief.

Figure 43: Constraint-Specific Interface Congestion Prices



Even though their interface definitions differ somewhat, this figure shows that both RTOs estimate very similar effects on each of the jointly managed constraints. Unfortunately, this results in congestion payments and charges that are roughly double the efficient level—the payment made by the MRTO. Although these payments may appear small, it is because they are averages of many intervals. In some intervals, the distortions exceed $30 per MWh.

This is important because it results in poor incentives for participants to schedule imports and exports when M2M constraints are binding significantly. It also results in additional costs for the RTOs. When SPP makes a payment for an external transaction because it would relieve a MISO constraint, this payment is not recouped through the M2M process. In other words, if both RTOs pay $20 per MWh for congestion relief to the same participant ($40 per MWh), MISO would receive some relief for having made the payment, while SPP as the NMRTO would receive no credit and would generally recover the costs of its payment through an uplift charge to load. Of course, these effects would be reversed if MISO pays a participant to schedule a transaction that relieves an SPP M2M constraint. Hence, this is an issue that hurts both RTOs while leading to inefficient transaction schedules and higher costs.

Given our findings regarding the common interface approach adopted with PJM, this approach should not be considered at the SPP interface. We encourage MISO and SPP to adopt an alternative approach to settle interchange congestion accurately. Hence, we recommend that the RTOs employ their current interface definitions, but that M2M constraints modeled by both RTOs only be included in the MRTO's interface price.

Interface Pricing for Other External Constraints

In addition to PJM and SPP M2M constraints, MISO also activates constraints located in external areas when neighboring system operators call TLRs and MISO re-dispatches its generation to meet its TLR flow obligation. It is appropriate for external constraints to be reflected in MISO's market models and internal LMPs, which enables MISO to respond to TLR relief requests efficiently. However, MISO is not obligated to pay importers and exporters that may relieve constraints in external areas. In fact, the effects of real-time physical schedules are excluded from MISO's market flow, so MISO gets no credit for any relief that its external transactions may provide and no reimbursements for the millions of dollars in costs it incurs each year. Hence, it is inequitable for MISO's customers to bear these costs.

In addition to the inequity, these congestion payments motivate participants to schedule transactions inefficiently for two reasons:

- In most cases, beneficial transactions are already being fully compensated by the area in which the constraint is located. MISO's additional payment is excessive and inefficient.
- MISO's pricing of the external TLR constraints is generally vastly overstated and provides inefficient scheduling incentives.

Fortunately, this issue is not difficult to address. We have recommended since 2012 that MISO simply remove the congestion related to external constraints from each of its interface prices. This change would resolve the interface pricing issue associated with external constraints on all of MISO's other interfaces (excluding the PJM and SPP interfaces).

VIII. Competitive Assessment and Market Power Mitigation

This section contains our competitive assessment of the MISO markets, including a review of market power indicators, an evaluation of participant conduct, and a summary of the use of market power mitigation measures in 2022. Market power in electricity markets exists when a participant has the ability and incentive to raise prices. Market power in electricity markets can be indicated by a variety of empirical measures, which we discuss in this section.

A. Structural Market Power Indicators

Economists and antitrust agencies often utilize market concentration metrics to evaluate the competitiveness of a market. The most common metric is the Herfindahl-Hirschman Index (HHI), which is calculated as the sum of the squared market shares of each supplier. An HHI of less than 1000 is generally considered low, while an HHI higher than 1800 is considered high. Market concentration is low for the overall MISO area (624) but very high in some local areas, such as WUMS (3944) and the South Region (3997), where a single supplier operates more than 60 percent of the generation. However, the HHI metric does not include the impacts of load obligations, which affect suppliers' incentives to raise prices. HHI also does not account for the difference between total supply and demand, which is important because excess supply results in more competitive markets. Hence, the HHI is limited as an indicator of overall competitiveness.

A more reliable indicator of potential market power is whether a supplier is "pivotal". A supplier is pivotal when its resources are necessary to satisfy load or to manage a constraint. Our regional pivotal supplier analysis indicates that the frequency with which a supplier is pivotal rises sharply with load. This is typical in electricity markets because electricity cannot be economically stored. Hence, when load increases, excess capacity will fall, and the resources of large suppliers may be required to meet load.

We also evaluate local market power by identifying pivotal suppliers for relieving transmission constraints into constrained areas, including the five Narrow Constrained Areas (NCAs) and all Broad Constrained Areas (BCAs). NCAs are chronically constrained areas that raise more severe potential local market power concerns where tighter market power mitigation measures are employed. A BCA is defined when non-NCA transmission constraints bind. The BCA includes all generating units with significant impact on power flows over the constraint. Our results showed that a supplier was frequently pivotal in both types of constrained areas:

- On average, 57 percent of the active BCA constraints had at least one pivotal supplier.
- Over 90 percent of the binding constraints into both the MISO South NCAs and the Midwest NCAs had at least one pivotal supplier.

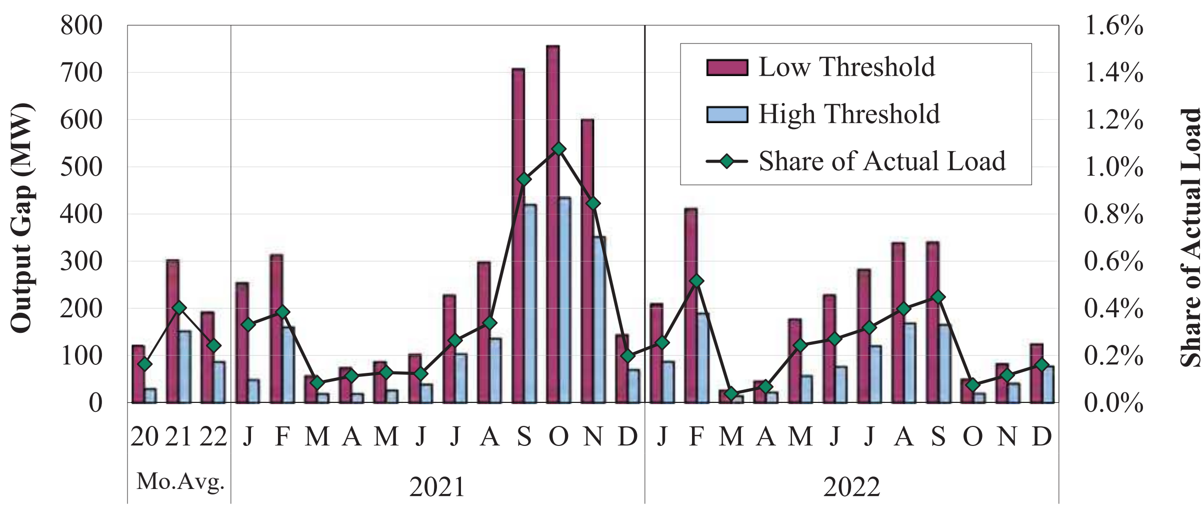
Overall, these results indicate that local market power persists, with respect to both BCA and NCA constraints, and that market power mitigation measures remain critical.

B. Evaluation of Competitive Conduct

Despite these indicators of structural market power, our analyses of participant conduct show little evidence of attempts to physically or economically withhold resources to exercise market power. This is confirmed in aggregate measures of overall market competitiveness, including a "price-cost mark-up". This measure compares the system marginal price based on actual offers to a simulated system marginal price assuming all suppliers submitted offers at their estimated marginal cost. We found an average system marginal price-cost mark-up of -0.5 percent in 2022. The mark-up was negative because the monthly mark-up was negative in a number of months. Coal conservation measures, which were in place throughout the year and impacted coal resource references, may have contributed to the decrease in mark-up.

Figure 44 shows the "output gap" metric, which we use to detect instances of potential economic withholding. The output gap is the quantity of power not produced from resources whose operating costs are lower than the LMP by more than a threshold amount. We perform the output gap analysis using the Tariff's conduct threshold (the "high threshold") and a "low threshold" equal to one-half of the conduct threshold. The output gap includes both units that are online and submitting inflated energy offers, as well as units that were not committed because of inflated economic or physical offer parameters.

Figure 44: Economic Withholding – Output Gap Analysis
2021–2022



Low Threshold Results by Unit Status (MW)

	20	21	22	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Offline	8	38	95	0	90	3	0	9	8	27	46	129	103	35	9	22	24	17	20	103	118	184	238	256	27	47	82
Online	114	264	99	254	223	55	75	79	96	201	252	577	652	565	136	188	387	11	27	75	110	98	100	84	23	36	43

High Threshold Results by Unit Status (MW)

	20	21	22	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Offline	7	28	59	0	70	2	0	8	7	22	38	98	62	19	7	21	20	12	17	51	67	110	156	151	12	36	59
Online	23	125	28	49	91	18	20	20	33	82	100	322	373	333	64	67	171	4	6	7	10	12	14	16	8	6	19

The figure shows that the average monthly output gap level was 0.2 percent of load in 2022, which is effectively *de minimus,* and slightly lower than in 2021. Beginning in the fall of 2021, multiple coal-fired resources employed fuel conservation measures to ensure that they would have sufficient fuel inventory going into the winter months. Several of these resources had not requested reference level consultations to reflect their conservation plans. In contrast, by winter 2022, most coal-fired resources experiencing fuel and reagent supply issues reflected the conservation measures in their reference levels. Although these results raise no competitive concerns, we monitor these levels on an hourly basis and routinely investigate potential withholding.

C. Summary of Market Power Mitigation

Market power mitigation in 2022 effectively limited the exercise of market power. Mitigation in the energy market remained infrequent. Market power mitigation in MISO's energy market occurs pursuant to automated conduct and impact tests that utilize clearly specified criteria. The mitigation measure for economic withholding caps a unit's offer price when the offer exceeds the conduct threshold and raises energy market clearing prices or RSG payments substantially. Because conduct has generally been competitive, market power mitigation has been imposed infrequently. The mitigation thresholds differ depending on the three types of constrained areas that may be subject to mitigation:

- Broad Constrained Areas (BCAs);
- Narrow Constrained Areas (NCAs); and
- Dynamic NCAs, which are transitory constrained areas that can occur when outages create severe congestion.

The market power concerns associated with NCAs and Dynamic NCAs are greatest because they address chronic or severe congestion. As a result, conduct and impact thresholds for NCAs and Dynamic NCAs are much lower than they are for BCAs. The thresholds for NCAs depend on how frequently the NCA constraints bind, while a fixed threshold of $25 per MWh is used for Dynamic NCAs. No Dynamic NCAs were declared in 2022. The lower NCA thresholds generally lead to more frequent mitigation in NCAs, even though there are many more BCAs.

The incidence of mitigation was relatively unchanged in 2022, affecting less than one percent of real-time market hours across 38 days, although energy mitigation for offer-capping during Winter Storm Elliott contributed to another 147 hours. Assuming the real-time market is effectively mitigated, the day-ahead market should not be vulnerable to the exercise of market power as long as it is liquid, with fulsome participation by physical and virtual trading participants. Hence, mitigation was applied on eight day-ahead market days in 2022, excluding the additional eight days around Winter Storm Elliott when offer-capping was applied. Market power mitigation in MISO's energy market remained infrequent because conduct was generally competitive.

RSG payments occur when a resource is committed out-of-market to meet the system's capacity needs, local reliability requirements, or to manage congestion. If the resource offers include inflated economic or physical parameters, it may result in inflated RSG payments and the resource may be mitigated. Commitments to satisfy system-wide capacity needs are not subject to mitigation because competition is generally robust to satisfy those needs.

Average day-ahead RSG mitigation was 77 percent lower in 2022 compared to 2021, largely because of nearly $10 million of day-ahead RSG mitigation that occurred during Winter Storm Uri in February 2021. Excluding February 2021, day-ahead RSG mitigation fell by roughly one third. Average monthly real-time RSG mitigation rose sharply in 2022, partly because of the increase in gas prices. A large unit in the Midwest experienced more than $1.7 million in real-time RSG mitigation in June.

IX. DEMAND RESPONSE AND ENERGY EFFICIENCY

Demand Response (DR) involves actions taken by electricity consumers to reduce their consumption when their value of consuming electricity is less than the prevailing marginal cost to supply it. Facilitating DR is valuable because it contributes to:

- Improved operational reliability in the short term;
- Least-cost resource adequacy in the long term;
- Reductions in price volatility and other market costs; and
- Mitigation of market power.

Additionally, price-responsive demand has the potential to enhance wholesale market efficiency. Even modest reductions in consumption by end-users during high-priced periods can greatly reduce the costs of committing and dispatching generation. These benefits underscore the value of facilitating efficient DR through wholesale market mechanisms and transparent economic signals. Hence, it is important to provide efficient incentives for DR resources and to integrate them into the MISO markets in a manner that promotes efficient pricing and other market outcomes. In this section, we discuss the current level of participation of DR and energy efficiency resources (EE) and identify some significant concerns that have arisen related to MISO's approach to incorporating these demand resources in the market as supply resources.

A. Demand Response Participation in MISO

Table 16 shows DR participation in MISO and compares it to NYISO and ISO-NE in the last three years. The table shows DR resources in MISO can be divided into one or more of the following three categories:[40]

- Load-Modifying Resources (LMRs) that are capacity resources obliged to curtail in emergencies and satisfy Planning Reserve Margin Requirements (PRMR);
- Demand Response Resources (DRRs) that economically respond to prices in the energy and ancillary services markets; and
- Emergency Demand Response Resources (EDRs) that are called in emergencies, but that are not obliged to offer and do not satisfy PRMR.

As shown in Table 16, MISO had more than 12 GW of DR capability available in 2022, slightly more than in 2021. Between 2020 and 2021, DR capability fell 10 percent because no Energy Efficiency (EE) Resources cleared the PRA after the 2020/2021 auction, as discussed below, and fewer Emergency Demand Response resources have been participating in MISO year over year.

40 Some DR may participate in more than one category, depending on the resource capability and responsibilities the resource is willing to accept, as explained below.

Table 16: Demand Response Capability in MISO and Neighboring RTOs
2020–2022

		2020	2021	2022
MISO[1]		**13,528**	**12,197**	**12,389**
	LMR-BTMG	3,892	4,068	4,169
	LMR-DR	7,557	7,152	7,543
	LMR-EE	650	0	0
	DRR Type I	739	711	582
	DRR Type II	101	115	127
	Total Cross-Registered as LMR	*381*	*476*	*150*
	Emergency DR	1,439	785	456
	Total Cross-Registered as LMR	*470*	*158*	*337*
NYISO[2]		**1,199**	**1,170**	**1,234**
	Special Case Resources - Capacity	1,195	1,168	1,231
	Emergency DR	4	2	3
	Day-Ahead DRP	0	0	0
ISO-NE[3]		**3,448**	**3,934**	**4,076**
	Active Demand Capacity Resources	455	511	466
	Passive Demand Resources	2,993	3,423	3,610

[1] Registered as of December 2022. All units are MW.
[2] Registered as of July 2022. Source: Annual Report on Demand Side Management of the New York Independent System Operator, Inc., Docket ER01-3001.
[3] Capacity supply obligations as of December 2022. Source: ISO-NE Monthly Market Reports.

MISO's demand response capability constitutes around ten percent of peak load, which is a larger portion than in NYISO but slightly less than in ISO-NE. It exhibits varying degrees of responsiveness to prevailing system conditions. The first and largest category of DR (accounting for almost 95 percent of MISO's total DR) is LMRs. These capacity resources are interruptible load developed under regulated utility programs and behind-the-meter-generation. A second category is Demand Response Resources (DRRs) that can participate in MISO's capacity, energy, and ancillary services markets and are of two types, as we explain below. A third category is Emergency Demand Response (EDR). Resources may cross-register as LMRs and DRRs or EDRs, and in the table we indicate the amount of capacity that was cross-registered.

LMRs

LMRs are planning resources and thus have an obligation to curtail as instructed during emergencies. MISO can only deploy these resources during a declared emergency. Many of these legacy demand-side programs are administered by regulated utilities, such as interruptible load and direct load control programs that target residential, small commercial, and industrial customers. They also include behind-the-meter generation (BTMG). These resources do not submit an economic offer price, but LMR deployment triggers MISO's emergency offer floor price mechanism. In the PRA, MISO classifies interruptible load resources as LMR-DR and BTMG resources as LMR-BTMG. As shown in Table 16, almost all the DR in MISO participate as emergency resources, mainly in the LMR category.

Demand Response Resources

DRRs are a category of DR that are assumed to be able to respond to MISO's real-time curtailment instructions. As Table 16 shows, this category comprises only a small portion of MISO's total DR capability. These resources can participate in the energy, ancillary services, and capacity markets. Most DRRs opt to participate in the capacity markets as LMRs, which lessens the likelihood of curtailment during an emergency because EEA1 events do not call for LMR curtailment. DRRs are further divided into two subcategories:

- Type I: These resources can supply a fixed, pre-specified quantity of energy or contingency reserve through physical load interruption. These resources can qualify as Fast-Start Resources and set price in ELMP.[41]
- Type II: These resources can supply varying levels of energy or operating reserves on a five-minute basis and are eligible to set prices, just like generating resources.

Aggregators of Retail Customers (ARCs) and Load-Serving Entities (LSEs) are eligible to offer DRR capability into the energy and ancillary services markets. DRR Type II resources can currently offer all ancillary services products, whereas DRR Type I units can provide all products except regulating reserves on account of their fixed-quantity demand reduction offers.

DRR Type I resources accounted for almost all of DRR scheduling in 2022. The scheduling of these resources fell sharply in mid-2022 after we identified significant conduct issues that led two of the largest participants to cease participation. We discuss these issues in subsection B.

Emergency DRs

The third category of DR is Emergency DRs (EDR), which totaled 456 MW in 2022. These DRs do not have a must-offer requirement unless cross-registered and cleared as an LMR in the PRA. DR resources that clear MISO's PRA can offer as EDRs rather than LMRs during emergencies. These resources specify their availability and costs in the day ahead. If an emergency ensues in real time, MISO selects EDR offers in economic merit order based on offered curtailment prices up to $3,500 per MWh. EDRs that curtail are compensated at the greater of the prevailing real-time LMP or their offered costs (including shut down costs) for the verifiable demand reduction provided. Unlike LMRs, EDRs can set prices with their offers during emergencies.

Finally, DR resources may count toward fulfillment of an LSE's PRMR if the resource can curtail load within 12 hours and is available during the summer months. As part of the RAN

41 A resource can qualify as a Fast-Start Resource provided the DRR Type I resource can curtail demand within 60 minutes and offers a minimum run time of less than or equal to one hour.

initiatives, FERC has approved Tariff changes that reduce the allowable lead time for qualifying LMRs to six hours and accredits resources based on the availability throughout the planning year. These changes began in the 2022/2023 planning year and phase in across multiple planning years to allow participants to modify existing contracts and replace affected capacity.[42]

MISO did not call upon LMRs between 2007 and 2016. However, beginning in 2017, LMRs have become increasingly important in both planning and operations during emergency events. From April 2017 through December 2022, LMRs were deployed nine times in MISO South and four times in MISO Midwest. The most recent deployment occurred in December 2022 during Winter Storm Elliott, when MISO called on LMRs to provide support to a neighboring system that was shedding load. We discuss the 2022 emergency events in detail in Section II.E.

B. DRR Participation in Energy and Ancillary Services Markets

DRR settlements increased substantially in 2021 to almost $38 million, up from roughly $16 million in 2020. In contrast, payments to DRRs fell 34 percent in 2022 as resources that we had investigated ceased participation. Our investigation began in 2021 after DRR settlements increased significantly. The results raised significant concerns regarding the market design and rules, the inefficient incentives they provide, and the resulting participant conduct. In particular, we identified two types of problems with the settlement rules and participants' conduct.

Payments for artificial "curtailments". These are payments for energy that the participant never intended to consume. For example, consider an industrial facility registered as DRR with a peak load of 100 MW that will be offline for maintenance. Such a DRR could offer 100 MW of "curtailments" as a price-taker (at a very low price) even though its planned consumption was zero. Hence, the resource will be scheduled and paid the prevailing LMP for providing nothing.

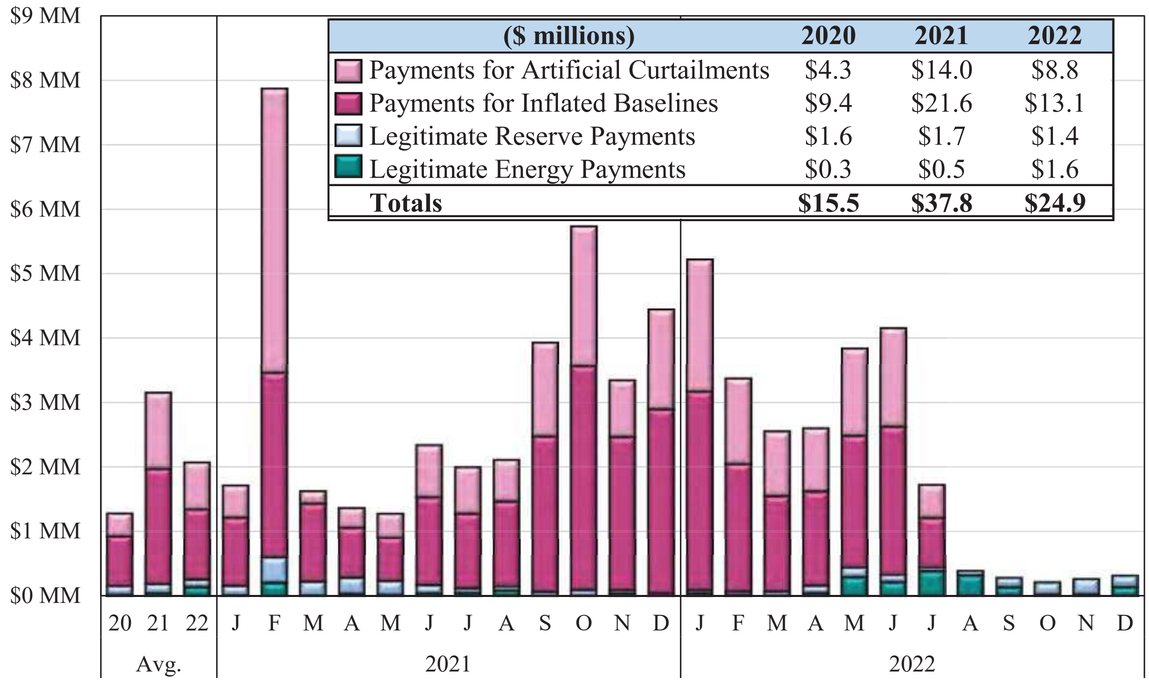
Inflating the baseline level. Hours when curtailments are scheduled are not included in the baseline calculation because, presumably, the consumption in these hours is less than normal. Some participants have inflated their baseline by offering as a price-taker in almost all hours, which will cause their curtailment offer to be scheduled and the hour to be excluded from the baseline. The participant can then simply not offer the curtailment when its load is highest, causing the baseline to substantially exceed the participant's typical consumption for the DRR resource. Having established the inflated baseline, the participant can then return to offering curtailments as a price-taker when consuming at typical levels and be paid for the difference between the peak load level and the typical load level.

These two strategies were involved in the vast majority of payments to DRR Type 1 resources. Figure 45 below shows all payments to such resources over the past three years. It separates the

42 Beginning in the 2022/2023 PRA, LMRs that register with six hours or less notification time and can provide curtailments at least ten times per year are able to fully qualify as capacity resources, and LMRs with longer registered lead times and fewer curtailments have proportionally less capacity.

payments to those that are associated with the artificial curtailments, inflated baselines, and legitimate payments for energy curtailments and ancillary services.

Figure 45: Energy Market Payments to DRR Type I Resources
2021–2022



($ millions)	2020	2021	2022
Payments for Artificial Curtailments	$4.3	$14.0	$8.8
Payments for Inflated Baselines	$9.4	$21.6	$13.1
Legitimate Reserve Payments	$1.6	$1.7	$1.4
Legitimate Energy Payments	$0.3	$0.5	$1.6
Totals	**$15.5**	**$37.8**	**$24.9**

Figure 45 shows that the payments to DRRs had been almost entirely attributable to the two strategies described above. We found that less than 6 percent of the payments in 2021 were legitimate, and 12 percent in 2022. This increased percentage was due to the fact that the DRRs that engaged in these strategies are no longer participating in MISO as of August 2022, which also reduced the reserve payments to DRR to $25 million.

Based on these results, it is essential that MISO revise its DRR rules and Tariff provisions to provide efficient incentives and to ensure that all payments made to DRRs result in real curtailments. We recommend two potential improvements to help achieve these objectives:

- DRRs should be obligated to submit their anticipated consumption absent any curtailments. The settlements could then be based on the lower of this value and the current baseline. This anticipated consumption data could be monitored and evaluated to identify when a participant submitted false or misleading data to inflate its settlements.
- MISO could establish a price floor that is significantly higher than typical LMPs. If a participant does not wish to consume at expected real-time prices, it should simply not consume, rather than offering curtailments as a price-taker. There is no reasonable basis to pay for curtailments offered at prices below expected real-time prices. Eliminating the ability to submit price-taking curtailment offers would virtually eliminate both strategies described above.

C. Energy Efficiency in MISO's Capacity Market

MISO allows energy efficiency (EE) to provide capacity. The quantity of EE participating in the PRA grew rapidly until the 2021/2022 PRA, when the sole participating provider of EE was disqualified. Table 17 summarizes the EE quantities over the past five PRAs. After the disqualification described below, the quantity has remained equal to or close to zero.

Table 17: Growth of Energy Efficiency in MISO

Planning Year	Enrolled Qty	Net Sales	Offer MW	Cleared/FRAP
2017/18	98	0	98	98
2018/19	173	0	173	173
2019/20	312	0	312	312
2020/21	650	0	650	650
2021/22	0	0	0	0
2022/23	0	0	0	0
2023/24*	4.5	0	4.5	4.5

*Average of four seasons.

In contrast to other LMRs, EE measures do not provide a dispatchable product and do not provide any other operating flexibility to assist MISO in maintaining reliability during emergency events. The IMM performed an audit of EE capacity in 2021. Based on this audit, we found the EE resources did not actually reduce MISO's peak demand, and their capacity accreditation grossly overstated their reliability value. MISO validated these findings and ultimately disqualified the audited EE participant from participating in the 2021/2022 PRA.

We still recommend MISO revise its Tariff to strengthen the requirements and validation processes to ensure that only legitimate EE resources are qualified in the future. Although making these Tariff improvements should be MISO's focus in the near-term, we still believe that EE resources should not be qualified to participate in the capacity market for three reasons:

- *EE Payments are Inefficient*. Making payments to customers directly or to intermediaries is not efficient because customers already have efficient incentives to make energy efficiency investments. The savings they receive via lower electricity bills include the energy and capacity costs of serving them.
- *EE Capacity Values are Highly Uncertain*. It is not possible to accurately calculate how much the load has been reduced by EE in peak hours because it is based on an array of speculative assumptions. This uncertainty regarding their capacity value is why EE is not comparable to any other capacity resources since they can be tested and verified.
- *Cost Shifting Concerns*. The existing program can result in sizable cost shifting by causing other LSEs to pay for EE capacity payments that are benefiting one LSE. To avoid cost shifting, an LSE must control for the effects of the EE by explicitly grossing up their forecasts to counter the effect of EE, but they are not required to do so.

For these reasons, it would be best to simply eliminate MISO's EE program. In the alternative, MISO should develop and file the Tariff improvements described above.

X. Recommendations

Although MISO's markets continued to perform competitively and efficiently in 2022 overall, we recommend a number of improvements in MISO's market design and operating procedures. These thirty-one recommendations are organized by the aspects of the market that they affect:

- Energy and Operating Reserve Markets and Pricing: 6 total
- Transmission Congestion: 7 total, 1 new
- Market and System Operations: 10 total, 2 new
- Resource Adequacy and Planning: 8 total, 2 new

Twenty-six of the recommendations were recommended in prior *State of the Market* Reports. This is not surprising because some recommendations require substantial software changes, stakeholder review and discussions, and regulatory filings or litigation regarding Tariff changes.

MISO addressed four of our past recommendations since our last report. We discuss recommendations that have been addressed at the end of this section. For any recurring recommendations, we include a discussion of the progress MISO has made to date and next steps required to fully address the recommendations.

A. Energy and Operating Reserve Markets and Pricing

Many of MISO's reliability needs are addressed through its operating reserve requirements that ensure resources are available to produce energy when system contingencies occur. However, to the extent that MISO has system needs that are not reflected in the operating reserve requirements, MISO may commit resources out-of-market that require a guarantee payment to recover their as-offered costs. As a general matter, MISO's market requirements should reflect its operating needs to the maximum extent feasible to allow the markets to satisfy and price these needs efficiently. The recommendations in this subsection are intended to improve this consistency between market requirements and operating requirements.

2021-2: Evaluate reintroducing LMR curtailments as STR demand in pricing models and UDS

In studying emergency events that have occurred in MISO when it has deployed large quantities of LMRs, we have found that MISO emergency pricing often does not establish efficient prices. Currently, LMRs are modeled in the ELMP pricing engine as resources with offer price floors of \$500 or \$1000 per MWh that can be dispatched down and replaced by other resources. This process determines whether the LMRs are needed and should set prices.

Because the ELMP model is a dispatch model that honors resources' ramp rates, it is often not possible to replace a large volume of LMRs within a single dispatch interval with nonemergency ramping generation. This causes the LMRs to appear to be needed and set prices long after MISO's resources are sufficient to replace them by ramping up. This concern could be addressed by treating the LMRs as an operating reserve demand in the ELMP model, which would eliminate the need for other resources to be able to ramp up to replace them in the ELMP model. In this case, if the LMRs are needed, the ELMP model will register a reserve shortage and set prices accordingly at shortage levels.

Importantly, once the LMRs are no longer needed, they would stop setting real-time prices simply because other resources are ramp constrained. Therefore, we recommend that MISO reintroduce LMR curtailments as STR demand in its ELMP price model to determine when they should set prices during emergency conditions.

Status: In 2022, MISO has agreed on the problem identified, but MISO has indicated that further study and prototyping of potential software solutions will be needed. This issue is included in MISO's 5-year plan. We believe it is likely that it could be resolved more quickly.

Next Steps: MISO should complete its study and prototyping of software solutions.

2021-5: Modify the Tariff to improve rules related to demand participation in energy markets

In the past few years, we have identified a number of cases where demand response resources or energy efficiency resources were paid substantial amounts for load reductions that were not realized. Some of this was due to conduct of the resources, while some is due to suboptimal Tariff and settlement rules. Changes and clarifications in these rules will address both of these issues and ensure that MISO customers receive the benefits of the load reductions for which they have paid. This includes changes to baseline and settlement calculations to ensure that the estimated load reductions truly represent the additional load that would have existed but for the demand response resource. We recommend that MISO work with us to identify and implement these changes.

Status: MISO agrees with these issues and is actively evaluating this recommendation as part of its comprehensive investigation of demand response participation in all MISO markets. MISO believes it is appropriate to revisit the measurement and verification protocols codified in Attachment TT of the Tariff.

Next Steps: MISO plans to review best practices in measuring and validating demand response and to investigate and frame the issue and evaluate any next steps, including an evaluation of requirements of FERC Order 2222 on DERs. MISO indicates it will also consider filing limited modifications and clarifications to Tariff rules identified by the IMM to address gaming and manipulation vulnerabilities.

2020-1: Develop a real-time capacity product for uncertainty

We recommend MISO evaluate the development of a real-time capacity product in the day-ahead and real-time markets to account for increasing uncertainty associated with intermittent generation output, NSI, load, and other factors. Such a product should be co-optimized with the current energy and ancillary services products. These capacity needs are currently procured out-of-market through manual commitment by MISO's operators. Clearing this product on a market basis would allow MISO's prices to reflect the need for commitments and reduce RSG. The resources that would provide this product would include online resources and offline resources that are available to respond to MISO's uncertainties (e.g., those that can start within four hours).

The benefits of such a product will increase as MISO's reliance on intermittent resources increases. The transition in the generating fleet will increase supply uncertainty, which will in turn increase the real-time capacity needs of the system and the costs of satisfying them. Hence, we recommend MISO establish a real-time capacity product or uncertainty product that would be implemented under MISO's current market software.

<u>Status</u>: MISO agrees with the IMM's description of the issue. However, MISO believes enhancements to its Ramp Product and new Short-Term Reserve product that are underway will help. MISO plans to further evaluate the need for a new uncertainty product and will continue working on improving the LAC process to address uncertainty. This recommendation is ranked as a medium priority.

<u>Next Steps:</u> While we agree that enhancements to the Ramp and STR products will help, MISO should complete its evaluations of an uncertainty product and prioritize the design and implementation of it.

2016-1: Improve shortage pricing by adopting an improved Operating Reserve Demand Curve reflecting the expected value of lost load

Efficient shortage pricing is the primary incentive for both dispatch availability and flexibility. As the primary determinant of shortage pricing, the ORDC must accurately reflect the value of reliability. An optimal or "economic" ORDC would reflect the "expected value of lost load", equal to the product of: (a) probability of losing load and (b) the value of lost load (VOLL). Such an ORDC will track the escalating risk of losing load as shortfalls increase.

The shortage prices will send more efficient signals for participants to take actions in response to the shortage and help maintain the reliability of the system. Additionally, as MISO integrates larger quantities of renewables, the ORDC will be pivotal in compensating flexible resources that can start quickly and ramp rapidly to manage the uncertain output of intermittent resources.

MISO's current ORDC does not reflect the reliability value of reserves, overstating the reliability risks for small, transient shortages and understating them for deep shortages. Additionally, PJM's pay-for-performance rules price modest shortages as high as $6,000 per MWh (sum of the shortage pricing and capacity performance settlement), which will lead to inefficient imports and exports when both markets are tight.

Hence, we recommend MISO reform its ORDC by updating its VOLL assumption and determine the slope of the ORDC based on how capacity levels affect the probability of losing load. We have estimated that a reasonable VOLL for MISO would exceed $20,000 per MWh. Although the ORDC should be based on this VOLL, it would be reasonable to cap the ORDC at a lower price level for deep shortages, such as $10,000 per MWh. Almost all of MISO's shortages are likely to be in ranges that would establish shortage prices between $100 and $2,000 per MWh.

<u>Status:</u> MISO agrees with the recommendation and is working to develop and implement a solution. This item is currently classified as Active and a high priority by MISO. MISO is working on reforms to the ORDC and VOLL in 2023.

<u>Next Steps:</u> This recommendation should be one of MISO's highest priorities since it is critical for achieving the goals of the Reliability Imperative and requires no substantial additional resources. Hence, MISO should complete its discussions with stakeholders and file proposed enhancements with FERC.

2012-3: Remove external congestion from interface prices

When MISO includes congestion associated with external constraints in its interface prices, this congestion pricing is inefficient because it is generally not accurate and duplicates the congestion pricing by the external system operator. In addition, external operators provide MISO no credit for making these payments, neither through the TLR process nor through the M2M process. Hence, they are both inefficient and costly to MISO's customers. To fully address these concerns, we continue to recommend that MISO eliminate the portions of the congestion components of each of MISO's interface prices associated with the external constraints.

<u>Status</u>: This recommendation was originally made in our *2012 State of the Market Report* and there was no progress or change in Status in 2022. MISO agrees that interface pricing would be improved by eliminating external congestion on all interfaces. Nonetheless, MISO has no plans to address this recommendation until after implementation of the MSE. We continue to recommend that MISO take any necessary steps to remove external congestion from its interface prices at all interfaces except the PJM interface, which would require an agreement with PJM to abandon the current "common interface" approach. These changes will improve the efficiency of MISO's interface prices and its interchange transactions. MISO has said that it would evaluate the non-market interfaces as part of the Market Systems Enhancement.

<u>Next Steps</u>: MISO should develop the work plan necessary to modify its interface prices as part of its Market Systems Enhancement.

2012-5: Introduce a virtual spread product

Virtual traders arbitrage congestion-related price differences between the day-ahead and real-time markets, which improves the performance of the markets. They do this by clearing offsetting virtual supply and demand transactions that results in taking a position on the flows over a constraint without taking any net energy position. Because both transactions must clear to create an energy-balanced position, they are generally offered price-insensitively. A virtual spread product enabling participants to arbitrage congestion in a price-sensitive manner would be much more efficient. Participants offering such a product would specify the maximum congestion between two points they are willing to pay. This would reduce the risk participants currently face when they submit a price-insensitive transaction.

Status: This recommendation was originally proposed in our *2012 State of the Market Report*. MISO originally agreed with this recommendation, but in 2018 MISO indicated that technical feasibility was a concern under the current systems. The status of this project is inactive, and it is deferred beyond the 5-year action plan. The IMM continues to encourage MISO to reconsider this recommendation.

B. Transmission Congestion

Efficient energy pricing in the real-time market is essential. Even though a very small share (one to two percent) of the energy produced and consumed in MISO is settled through the real-time market, real-time spot market prices affect the outcomes and prices in all other markets. For example, prices in the day-ahead market, where most of the energy is settled, should reflect the expected prices in the real-time market. Similarly, forward prices will be determined by expectations of the level and volatility of prices in the real-time market. Therefore, one of the highest market priorities is to produce real-time prices that accurately reflect supply, demand, and network conditions. This is the objective of the recommendations in this subsection.

2022-1: Expand the TCDCs to allow MISO's market dispatch to reliably manage network flows

During a number of recent storm events in 2021 and 2022, MISO has experienced operational challenges requiring extraordinary operator actions to manage network flows. During both transmission and capacity emergencies, the current TCDCs limit the ability of MISO's market dispatch to manage transmission congestion. During capacity emergencies, the value of energy and reserves under the ORDC can prevent the dispatch model from reducing output when needed to manage network flows because the value of managing the transmission constraint is not high enough. Likewise, when the RDT or other constraints are violated, the dispatch model may not move generation as needed to manage the flows over other constraints. This has often compelled MISO operators to manually dispatch generation to reduce flows on overloaded constraints, which is costly and distorts market outcomes.

Therefore, we recommend MISO add higher segments to the TCDCs to allow the dispatch model to limit excessive violations. MISO should also improve its procedures to increase the TCDCs for a constraint when the violations raise reliability concerns or are sustained. Additionally, uncertainty regarding network flows has often caused operators to derate transmission constraints. Adding lower-priced segments to the TCDCs that would account for the value of holding back transmission capability to manage uncertainty could be valuable and we recommend MISO consider this as an alternative to its current approach to lowering transmission limits.

Status: This is a new recommendation. MISO's initial response indicated agreement with the problem and MISO has been discussing the recommendation with the IMM.

2021-1: Work with TOs to identify and deploy economic transmission reconfiguration options

We recommend MISO develop resources and processes to analyze and identify economic reconfiguration options for managing congestion in coordination with the TOs. Today, transmission congestion is primarily managed by altering the output of resources in different locations. However, it can also sometimes be highly economic to alter the configuration of the network (e.g., opening a breaker). Today, this is widely employed by Reliability Coordinators to manage congestion for reliability reasons under the procedures established in consultation with the transmission owners impacted by the reconfiguration. Such procedures could be expanded to relieve costly binding constraints that are generating substantial congestion costs.

In our *2021 Annual State of the Market Report*, we presented an analysis of one constraint that generated over $57 million in congestion during the summer quarter. The constraint primarily limits the output of wind resources in the North region. The constraint has a reconfiguration option that reduces the congestion in that path by more than two-thirds and substantially reduces wind curtailments when used. Unfortunately, it is rarely used because the congestion on the constraint rarely raises reliability concerns. This constraint serves as an instructive case study showing the potential for substantially reducing congestion costs and wind resource curtailments by deploying reconfiguration options economically as a regular congestion management action.

Hence, we recommended MISO work with the transmission owners to develop tools and processes to identify economic reconfiguration options along with the criteria to be used to deploy them. The criteria would ensure that reconfiguration options are not implemented when they would generate adverse reliability effects elsewhere on the system. Studying and identifying such options and criteria in advance for MISO's most congested paths will provide a powerful tool for managing congestion and lowering the associated costs for MISO's customers.

Status: MISO agrees with this recommendation and has been working with the TOs through the Reconfiguration for Congestion Cost Task Team (RCCTT) to develop a process for accepting and evaluating requests. The proposed process is currently being reviewed and commented on in the Reliability Subcommittee (RSC). However, MISO is not currently developing a process for MISO itself to identify and analyze reconfiguration options. It is also not planning on developing processes to validate TOs' responses to recommended reconfiguration options. To date, some valuable options have been denied by TOs in the absence of verified concerns.

Next Steps: Once the new process document is finalized, MISO will develop internal operating procedures to carry out the tasks identified in the new process. In the longer-term, we recommend that MISO develop processes and/or tools to identify potential reconfiguration options that can be evaluated and managed by MISO.

2019-1: Improve the relief request software for market-to-market coordination

A key component of successful market-to-market (M2M) coordination is optimizing the amount of relief that the monitoring RTO (MRTO) requests from the non-monitoring RTO (NMRTO). If the request is too low, then the NMRTO will not provide all its economic relief, resulting in higher congestion costs and potentially higher settlement costs for the NMRTO. If the request is too high, it can result in congestion oscillation that can raise costs.

We find that the current relief request software does not always request enough relief from the NMRTO. This can occur because the current software does not consider the shadow price differences between the RTOs. Therefore, when the NMRTO's shadow price is much lower and does not converge with the MRTO's shadow price, the relief requested from the NMRTO should increase. This would lower congestion costs and accelerate convergence. At other times, the software can request too much relief and cause constraints to bind and unbind in subsequent intervals, which is called "oscillation". Oscillations have become a substantial issue as rapid-ramping wind resources in both MISO and neighboring RTOs load the same constraints.

To address these issues in the short term, we continue to recommend that MISO base relief requests on the RTOs' respective shadow prices and implement an automated means to control constraint oscillation. In the long term, MISO should use dynamic transmission constraint demand curves to reflect the actual relief provided by the NMRTO in the dispatch of the MRTO.

Status: MISO agrees with the issue and has indicated that it will evaluate potential solutions. In 2021, MISO and SPP implemented a near-term tool using "predicted" UDS flow to address oscillations, but it has not yet been configured properly to be effective. MISO believes the IMM solution, though likely better, will require more significant changes and is not currently pursuing it. Unfortunately, it is not clear whether the current tool will be effective if MISO implements it properly, and it is not likely to increase relief requests when they are too low.

Next Steps: MISO should use the tool properly and assess its effects. After making this assessment, MISO should determine whether a more efficient solution is warranted to address oscillations and work with the IMM to identify the other improvements in the relief request software that will be needed to address this recommendation.

2019-2: Improve the testing criteria defining market-to-market constraints

The original intent of this recommendation was to identify constraints that will benefit from M2M coordination or for which the NMRTO's market flows are a substantial contributor to the congestion. Currently, a M2M constraint will be identified when the NMRTO has:

- a generator with a shift factor greater than 5 percent; or
- Market Flows over the MRTO's constraint of greater than 25 percent of the total flows (SPP JOA) or 35 percent of the total flows (PJM JOA).

These two tests are not optimal in identifying constraints that would benefit from coordination because they do not consider the economic relief the NMRTO will likely have available. As detailed in the body of the report, our analysis shows that alternative tests would be much better at identifying the most valuable constraints to define as M2M constraints. Accordingly, we recommend that MISO work with PJM and SPP to introduce a test based on the available flow relief that can be provided by the NMRTO to replace the current five-percent-shift-factor test.

<u>Status</u>: MISO agrees and has indicated that it will evaluate the IMM's recommended solutions and their effects on the administration of JOAs. However, MISO has put this recommendation as a low priority and will resume discussions after completion of the update to the Freeze Date Firm Flow Entitlement (FFE) methodology. We continue to believe this recommendation is unrelated to the FFE methodology and encourage MISO to address it in a more timely manner.

<u>Next Steps:</u> MISO has noted the testing criteria may be considered and implemented with mutual agreement with no Tariff changes. Hence, we recommend that MISO propose these changes to its JOA partners and pursue improvements in the near term.

2019-3: Develop improved capabilities to receive and validate current and forecasted dynamic ratings from transmission facilities

For years we have reported unrealized annual savings well in excess of $100 million that would have resulted from increased use of AARs and Emergency Ratings. The first step to realize these savings is for the MISO TOs to commit to providing AARs and Emergency Ratings. However, MISO's current systems and processes would not allow it to capture all these savings. Our report identifies key recommended enhancements, including:

1. <u>System Flexibility</u>: MISO should enable more rapid additions of new AAR elements.
2. <u>Forward Identification</u>: MISO should support identifying additions to AAR programs based on forward processes including outage coordination.

3. Forecasted Ratings: MISO should enable use of forecasted AARs in the day-ahead market and Forward Reliability Commitment Assessment (FRAC). Currently, MISO does not have a process to receive or use forecasted ratings.

In addition, we recommend MISO make changes to support current and future needs related to verification of transmission ratings and situational awareness. MISO currently does not receive or maintain important data on transmission elements including: 1) Rating Methodologies, 2) limiting elements for transmission constraints and 3) response times for post-contingent actions. We recommend MISO make necessary changes to enable receipt of this information, which will improve its operational awareness and transmission planning. Although the benefits of the last three improvements would be difficult to quantify, we believe the reliability and market benefits are likely large and will grow in the future.

Status: MISO agrees with this recommendation, and it has been designated as a high priority. FERC Order 881 requires the use of AARs and Emergency Ratings in real time and forecasted ratings in the day-ahead. It also requires transmission owners to provide rating methodologies to RTO/ISOs and their market monitors. In 2022, MISO filed compliance plans for Order 881, which will address a large share of this recommendation. However, Order 881 does not require MISO to collect the information needed to validate ratings although we believe this is essential. Accordingly, we have provided a detailed list of data we recommend MISO collect to establish its capability to adequately validate transmission ratings provided by transmission owners.

Next Steps: MISO should complete implementation of Order 881 and begin collecting the data necessary for it to effectively validate transmission ratings. These plans should include completing its scoping of improvements that can be implemented through the MSE project or through other means to facilitate the receipt and use of AARs and Emergency Ratings.

2016-3: Enhance authority to coordinate transmission and generation planned outages

MISO is responsible for approving the schedules of planned transmission and generation outages. This approval process considers only reliability concerns associated with requested outages and not the potential economic costs. As a result, we have seen numerous cases where simultaneous generation and/or transmission outages in an electrical area have led to severe transmission congestion. In 2022, multiple simultaneous generation outages contributed to more than $1 billion in real-time congestion costs, or 30 percent of real-time congestion costs, indicating large potential savings.

Most of the other RTOs in the Eastern Interconnect have limited authority comparable to MISO's, with the exception of ISO-New England. ISO-New England does have the authority to examine economic costs in evaluating and approving transmission outages, which has been found to have been very effective at avoiding unnecessary congestion costs. We recommend

MISO expand its outage approval authority to include some form of economic criteria for approving and rescheduling planned outages.

Status: MISO agrees with this recommendation and lists it as an Active item, but little progress has been made to date. MISO has not sought additional outage coordination authority but began working on an evaluation approach for measuring costs and benefits of rescheduling outages in 2022. Economic considerations for outage coordination continue to be in the RAN work plan.

Next Steps: MISO should consider accelerating the process to address this recommendation and file for increased authority to coordinate outages.

2014-3: Seek joint operating agreements with the control areas around MISO to improve congestion management and coordination during emergencies

As noted in prior years, the dispatch of the integrated MISO system has increased the frequency of TLRs called for constraints in TVA, AECI and IESO. TLRs result in substantial congestion costs, which could be mitigated and produce sizable benefits for MISO if it were to develop redispatch agreements with TVA and IESO. Under such agreements, the TLR process could be replaced with a coordination process that would allow MISO and its neighbors to procure economic relief from each other, which will lower costs and improve reliability. Additionally, coordination between MISO and its neighbors has been inconsistent during emergency conditions, as highlighted by events during Winter Storms Uri and Elliott. JOAs with each of MISO's neighbors can specify the emergency coordination each system will provide and the associated settlements between the areas.

Status: MISO agrees with this recommendation and has reached out to both IESO and TVA regarding agreements. IESO has indicated they are working on major system changes and are postponing further discussions. MISO is working on a balancing authority agreement with TVA and plans to start discussions on a JOA once the BA agreement is complete. MISO also agrees that JOAs with other adjacent control areas to coordinate during emergencies would be valuable.

Next Steps: MISO should continue to attempt to negotiate redispatch agreements with TVA and IESO that will allow economic coordination and redispatch to efficiently manage congestion on their respective systems. Additionally, coordinated emergency procedures and settlements should be proposed with each of MISO's neighbors.

C. Market and System Operations

As discussed above, the efficient performance of the real-time market is essential to achieving the full benefits of competitive wholesale electricity markets, which includes satisfying the system's needs reliably at the lowest cost. MISO's real-time operators play an important role in this process because they monitor the system and make a variety of changes to parameters and other inputs to the real-time market and take operating actions to maintain reliability. Each of these actions can substantially affect market outcomes. The following recommendations seek to improve MISO's operating actions and real-time market processes.

2022-2: Improve the real-time wind forecast by adopting enhancements to its current persistence forecasting methodology

MISO's near-term wind forecast for each resource is used in its real-time dispatch as its Economic Maximum level. Hence, efficient dispatch of the system requires that this near-term forecast be as accurate as possible. Currently, MISO utilizes a "persistence" forecast that assumes wind resources will produce the same amount of output as it most recently observed. The downside of this approach is that the forecasted output will be predictably lower when output has been increasing and will be predictably higher when wind output is dropping.

We recommend that MISO improve the performance of its real-time market by modifying its persistence forecast to recognize the recent movement in wind output. We demonstrated this approach in this report and showed that large portfolio errors (above 500 MW) could be reduced by 92 percent and large unit-level errors (above 50 percent) could be reduced by 45 percent by adopting such an approach.

Status: This is a new recommendation.

2022-3: Improve excess and deficient energy penalties to improve generators' incentives to follow MISO's dispatch instructions

Currently, generators do not accrue excess or deficient energy penalties until they exhibit such deviations for four consecutive intervals. Even after this time, the current penalties do not ensure that generators will benefit by following MISO's dispatch instructions. This is particularly concerning when resources load binding transmission constraints. In this case, UDS assumes all dispatch instructions will be followed and the flows will be consistent with the dispatch. If generators do not follow the instructions, the constraint flows can substantially exceed the transmission limits. This raises substantial economic and reliability concerns.

To address this, we recommend that MISO implement EXE/DFE penalties based on generators' LMP congestion component. The application of the penalty could begin in the first interval that a generator deviates and increase in size the longer the deviations persist.

Status: This is a new recommendation.

2021-3: Evaluate and reform MISO's unit commitment processes

In 2021, we observed increased out-of-market commitments by MISO and associated RSG costs. During 2022, we worked with MISO to identify commitments that were not ultimately needed to satisfy MISO's energy, operating reserves, or other reliability needs. We also identified the assumptions, procedures, and forecasting issues that have led to these unneeded commitments.

In addition to raising RSG costs borne by its customers, excess commitments depress real-time prices and result in inefficiently lower imports from neighboring areas, inefficiently lower day-ahead procurements and resource commitments, and distort long-term price signals. Therefore, it is important to minimize excess out-of-market commitments and the accompanying RSG costs. We recommend that MISO:

1. Implement the identified improvements in its tools, procedures, and the criteria used to make out-of-market commitments.
2. Ensure that operators can observe the relevant offer costs that MISO will guarantee associated with each out-of-market commitment.
3. Update VLR operating guides in a timely manner when resources enter or exit the VLR area or transmission upgrades are made that affect the VLR area.

Status: MISO agrees with this recommendation and worked with the IMM in 2022 to begin implementing improvements to its procedures and the LAC process. MISO has committed to continuing this work in 2023.

Next Steps: The IMM provided nineteen specific recommendations to improve the out-of-market generator commitments. MISO and the IMM plan to work through these recommendations in 2023.

2021-4: Develop a look-ahead dispatch and commitment model to optimally manage fluctuations in net load and the use of storage resources

As reliance on intermittent resources grows, the need to manage fluctuations in net load (load less intermittent output) will grow. Because these demand changes occur in multi-hour timeframes, managing them efficiently requires the market to optimize both the commitment and dispatch of resources over multiple hours. This multi-hour optimization will also allow the markets to optimize the scheduling of energy storage resources. This is important because these resources are likely to play a key role in operating an intermittent-intensive system.

Therefore, we recommend that MISO begin developing a look-ahead dispatch and commitment model that would optimize the utilization of resources for multiple hours into the future. This is a long-term recommendation that will require substantial research and development. However, we believe this will be a key component of the MISO markets' ability to economically and reliably manage the transition of its generating portfolio.

Status: MISO has indicated general agreement to add the development of a look-ahead commitment and dispatch solution engine to its R&D prioritization, and MISO recognizes the need for this capability will increase in the future to manage storage resources.

Next Steps: MISO should prioritize further evaluation of this recommendation and begin the R&D necessary for design and implementation of a look-ahead dispatch and commitment model.

2020-2: Align transmission emergency and capacity emergency procedures and pricing

Capacity emergencies that cause MISO to progress through its EEA levels and associated procedures produce very different operational and market results than transmission emergencies. These differences are sometimes justified because of different system needs. Often, however, insufficient supply in a local area (i.e., a local capacity deficiency) will lead to transmission overloads as the real-time dispatch seeks to serve the load by importing power into the area. In these cases, the reliability actions and market outcomes should be comparable regardless of whether operators decide to declare a transmission emergency or a capacity emergency.

In the *2021 State of the Market Report*, we highlighted two declared emergency events – one a capacity emergency and the other a transmission emergency – which resulted in very different market outcomes and price signals. The divergence of the outcomes was a concern, and we continue to recommend MISO bring alignment between the two types of emergencies by:

1. Reviewing the emergency actions available to operators during capacity emergencies and identifying those that could be applicable during transmission emergencies. An example, this would include curtailing non-firm external transactions that could have provided relief for some of the transmission emergencies that occurred during Winter Storm Uri.
2. Raising TCDCs for violated constraints as the emergency escalates, allowing prices in the pocket to approach VOLL as MISO moves toward shedding load to relieve the constraint.
3. To the extent that a local reserve zone is defined in the area, increasing the Post Reserve Deployment Constraint Demand Curves to achieve efficient local emergency pricing.

Status: MISO agrees emergency procedures can be better aligned and should include all appropriate reliability actions and tools for managing the system under different types of emergencies. MISO indicates this effort is Active. In 2021, MISO updated some of its procedures to improve its emergency actions and its Reserve Zone definitions to reflect emergency conditions. This will allow more timely responses to emergency conditions.

Next Steps: The IMM and MISO continue to discuss the emergency procedures and supporting tools. MISO will need to develop specific procedures regarding how it will increase its TCDCs and Post Reserve Deployment Constraint Demand Curves to ensure efficient locational pricing during transmission emergencies. This includes establishing prices approaching VOLL in the constrained areas when load-shedding is deployed in a transmission emergency.

2019-4: Clear CTS transactions every five minutes through the UDS based on the RTOs' most recent five-minute prices

We have concluded that persistent sizable forecasting errors by MISO and PJM have hindered the use of CTS. These errors severely hinder the effectiveness of CTS, clearing transactions that are uneconomic based on real-time prices or not clearing transactions that would have been economic. Given the timing of the forecasts and the resources necessary to improve them, we have little optimism that substantially improving the forecasts is possible.

Hence, we recommend the RTOs modify the CTS to clear CTS transactions every five minutes through UDS based on the most recent five-minute prices in the neighboring RTO area. The most recent five-minute prices are a much more accurate forecast of the prices in the next five minutes. Additionally, making adjustments every five minutes rather than every 15 minutes would result in more measured and dynamic adjustments that would achieve larger savings. We have estimated annual production costs savings exceeding $40 million, which are much larger than can be achieved by improving the current process.

Status: MISO agrees with the IMM that forecasts used in the 15-minute clearing have been inaccurate and that the IMM solution would improve accuracy and result in more efficient transactions. However, MISO has no current plans for further effort as MISO believes the IMM solution would require significant time and effort by MISO and PJM. Given other priorities and the dependency on MSE, MISO designated this issue inactive and will consider evaluating it once resources are available. This recommendation maps to issue IR066.

Next Steps: Given the substantial benefits available from a well-functioning CTS process, we continue to recommend that MISO evaluate the software requirements for implementing this recommendation and begin discussing this proposal with both PJM and SPP.

2018-4: Clarify the criteria and improve the logging for declaring emergencies and taking emergency actions

Over the past few years, MISO has experienced a significant increase in the frequency of generation emergencies, primarily at the regional level. Based on our review of these events, we find that MISO's emergency declarations and actions have been inconsistent from event to event. This includes both the timing of the declarations and the forecasted regional capacity margins (the difference between the regional supply and demand). Hence, we recommend that MISO evaluate its operating procedures, tools, and criteria for declaring emergencies. This should include clarifying the criteria for making each emergency declaration and logging the factors that are the basis for operator actions.

Status: MISO agrees and is actively evaluating its operating procedures, tools, and criteria for declaring emergencies to improve consistency. MISO continues to work with the IMM to identify and review changes to MISO's Emergency Operating Procedures related both to declaring emergencies and documenting the emergency actions taken. MISO also has a multi-phase project underway to improve its Capacity Sufficiency Analysis Tool, which is designed to provide more accurate situational awareness and improve decision-making prior to and during an emergency. In 2022, MISO made some clarifications to the MISO's Emergency Procedures and plans to work with the IMM to improve its processes and procedures.

Next Steps: We recommend MISO continue the collaborative work described above to improve the clarity of the procedures and the tools used to trigger the declarations of different levels and types of emergencies. Improving the logging of the emergency determinations and actions should be a high priority.

2017-2: Remove transmission charges from CTS transactions

CTS with PJM was implemented in October 2017. It promised substantial economic benefits by adjusting the scheduled interchange based on forecasted energy prices in the two RTO areas. CTS transactions give the RTOs the ability to dynamically schedule the interface and lower the costs of serving load in both regions. We had advised the RTOs not to apply transmission charges or allocate costs to these transactions because they do not cause any of these costs. Nonetheless, MISO and PJM apply transmission reservation charges to these transactions when they are offered (not just when they are scheduled) and additional charges when they are scheduled. The reservation portion of charges are a substantial barrier to submitting CTS offers.

Our analyses have shown that CTS transactions are unprofitable only because of the transmission charges. CTS transactions would not only be profitable, but more profitable than conventional scheduling, but for the transmission charges. This suggests that participants would utilize the CTS process if these charges were eliminated, particularly the reservation charges.

We continue to recommend MISO not wait for PJM and to eliminate its own charges. MISO should also eliminate the requirement that participants reserve transmission for CTS transactions since the RTOs can make interface adjustments by utilizing any available transmission capability.

Status: MISO agrees that CTS has not performed well and that the transmission reservation charges are a significant factor. Although forecast errors are also an important factor limiting the performance of CTS as MISO has cited, the removal of the reservation charge is the easiest and most effective near-term improvement. This item was inactive in 2022 and MISO does not anticipate any activity in 2023. We believe this is not the right decision because the CTS process will not be effective unless the current charges are eliminated.

Next Steps: MISO should reconsider its decision to suspend action on this recommendation. Most of the benefits from this recommendation could be achieved by eliminating the reservation charges, so we encourage MISO to remove these charges at a minimum.

2017-4: Improve operator logging tools and processes related to operator decisions and actions

Operator decisions in all the MISO functions, including the day-ahead and real-time markets, can significantly impact both market outcomes and reliability. While automated tools and models support most of the market operations, it is still necessary for operators to take actions outside of the markets. Although these operator actions are necessary, it is also critical both from a management oversight and a market monitoring perspective for the actions to be logged in a manner that enables oversight and evaluation. Operator actions can indicate market performance or design issues, and they can point to potential market improvements or procedural improvements that would lower overall system costs.

Examples of operator adjustments include:

- Real-time adjustments to market load with the "load-offset" parameter, made to account for supply and demand factors that cause the dispatch model inputs to be inaccurate.
- Real-time adjustments to model inputs to LAC for wind and load to compensate for forecast errors.
- Adjustments to TCDCs to manage transmission constraints under changing conditions.
- Limit Control changes that alter the real-time limits for transmission constraints.
- Requests for M2M constraint tests and activations.
- Manual redispatch of resources that are made to satisfy system needs.
- Changes in operating status of generating units, including placing a unit "off-control," which causes the unit to receive a dispatch instruction equal to its current output.

Actions that impact settlements tend to be more completely logged. For example, manual generator commitments are well-logged because the reason and timing of the commitment are used by the settlement system to allocate RSG charges. However, other actions listed above are logged in a narrative field that is inconsistently populated and difficult to use for evaluation. Because these actions can have significant cost and market performance implications, we recommend MISO upgrade its systems and procedures to allow these and other operator actions to be logged in a more complete and detailed manner.

Status: MISO agrees with the importance of this issue and with the IMM recommendations. MISO has made some improvements in logging features within the current MCS and has put more emphasis on training for operators to facilitate clear and concise log entries. MISO indicates that requirements are being identified for further enhancements to the operator logging functionality in MCS.

Next Steps: MISO and IMM staff will continue to work on identifying additional logging needs. MISO should complete appropriate designs for future logging processes, including what operator logging should occur through the MCS or through separate systems.

2016-6: Improve the accuracy of the LAC recommendations and record operator response to LAC recommendations

MISO has developed and implemented a Look-Ahead Commitment (LAC) model to optimize the commitment and decommitment of resources that can start in less than three hours. Our evaluation of the LAC results in 2019 and 2020 indicates that the commitment recommendations are not accurate. In 2020, 65 percent of the LAC-recommended resource commitments were ultimately uneconomic to commit at real-time prices and in 2019 it was 69 percent. We also found that operators only adhered to 17 percent of the LAC recommendations in 2020, which may be attributable to the inaccuracy of the recommendations. We continue to recommend that MISO identify and address other sources of inaccuracies in the LAC model and, in conjunction with the IMM, develop logging and other procedures to record how operators respond to LAC recommendations.

Status: MISO generally agrees with this recommendation. In the last several years MISO has implemented tools that support the review of recommendations from LAC and operator commitments. This includes tools to measure the LAC's accuracy and metrics to assess commitment decisions. In late 2021 into 2022, MISO devoted additional resources to identify the causes of inaccurate LAC recommendations. This recommendation maps to issue IR008.

Next Steps: MISO added a LAC Phase II plan intended to implement enhancements in 2023. We expect to work with MISO to evaluate and discuss high-value enhancements.

D. Resource Adequacy and Planning

Reasonable resource adequacy requirements and a well-functioning capacity auction are intended to facilitate efficient investment and retirement decisions. The efficiency of MISO's market signals has become increasingly important as planning reserve margins in MISO have fallen, particularly as evidenced in the capacity market shortage in the Midwest in MISO's 2022-23 planning resource auction. We have identified a number of critical issues that are undermining the economic signals provided by the MISO planning resource auctions. The impacts of these issues are mitigated to some extent by the fact that regulated utilities serve load in a large portion of MISO. Hence, these regulated utilities may invest in new resources and maintain needed existing units because they receive supplemental revenues through the state regulatory process.

However, MISO also relies on a large quantity of supply owned by competitive unregulated companies that rely entirely on MISO's wholesale market price signals to make long-term investment and retirement decisions. Therefore, it is critically important to respond to the recommendations in this subsection that are intended to establish the efficient price signals necessary to ensure that the market will facilitate investment in resources over the long term.

2022-4: Improve the LRTP processes and benefit evaluations

As MISO moves towards evaluating Tranche 2 of the LRTP, it will be increasingly important to evaluate the costs and benefits of the alternative transmission investments in a process that avoids costly inefficient investments. This is also becoming important for MISO's MTEP process as costs have risen sharply in recent years. This is important because inefficient investment in transmission can undermine incentives that govern other long-term decisions that address congestion at a fraction of the costs of the transmission upgrades. These long-term decisions include generation investment and retirement decisions, investment in energy storage and grid-enhancing technologies, and improved siting decisions by new clean energy resources.

The report identifies concerns that Future 2A (the basis for Tranche 2) includes unrealistically high levels of intermittent resources and unrealistically low levels of dispatchable, hybrid, and battery storage resources. We believe these concerns will substantially affect MISO's assessment of its future transmission needs, so we recommend that it reconsider its Future 2A to address these concerns. We also recommend that MISO develop improved cost-benefit methodologies and principles for future LRTP Tranches, including:

1. Using forecasted siting and retirement assumptions that are based on the economic incentives provided by the market. This can be accomplished by employing a capacity expansion model that optimizes these decisions.
2. Including an evaluation of energy storage alternatives when evaluating the benefits of transmission investment.
3. Maintaining logical consistency between all base cases and all LRTP cases, including:
    - Ensuring that any estimated benefits include all of the costs incurred to realize the benefits; and
    - Incorporating the "foregone benefits" as a cost associated with any "foregone costs" that are deemed to benefits, such as the forgone transmission investments.
4. All "but for" base cases should reflect an accurate forecast or assumption regarding market participant actions and investments that would take place absent the LRTP investments.

We also recommend that MISO consider whether its allocation of the LRTP costs and requirement to show that all zones benefit may become a barrier to efficient investments.

Status: This is a new recommendation. IMM and MISO are discussing the issues identified.

2022-5: Implement jointly optimized annual offer parameters and improve outage penalty provisions in the seasonal capacity market

MISO ran the first seasonal PRA in April 2023. The initial implementation included only seasonal offer parameters, which raises substantial challenges for participants that have annual going forward costs they must cover. For example, suppliers with a resource that requires a capital investment to remain in operation would find it difficult to offer such costs since it will not know how many seasons in which the resource will clear. MISO is considering giving participants the option of an annual offer in addition to the seasonal offers.

Additionally, MISO implemented penalties that applied to any resource with non-exempt outages exceeding 31 days as part of this new framework. This framework has created some distorted incentives for the market participants:

- We observed a number of suppliers shifting their longer outages to straddle seasons. This can be problematic for outages that are shifted from shoulder seasons into higher-demand winter and summer seasons.
- The penalty framework can make it profitable for resources that will be out of service the entire season to sell capacity and pay the penalty.
- The penalty is difficult to accommodate under the market power mitigation rules because expected penalties cannot be included in resources' reference levels under the Tariff.

To address these issues, we recommend that MISO:

1. Implement annual offer parameters that are jointly optimized with the seasonal parameters in the PRA.
2. Reform the penalty provisions and mitigation measures to improve participants' outage scheduling and offer incentives.

2020-4: Develop marginal ELCC methodologies to accredit DERs, LMRs, battery storage, and intermittent resources

The ELCC represents the amount of planning resource requirements that a resource is capable of satisfying. Such a methodology is needed for intermittent resources because the amount that it will be producing in peak hours is highly variable and uncertain. The unique characteristics of storage resources, LMRs, and DERs also require an ELCC approach to accurately accredit them.

The current ELCC methodology applied to wind resources accredits them roughly 15 percent of their nameplate level on average. Unfortunately, this reflects the average reliability contribution of all wind resources, not the marginal reliability value of these resources. This results in excessive accreditation for these resources that provides poor investment, retirement, and planning incentives. Therefore, we recommend MISO implement marginal accreditation for all of these types of resources.

Status: MISO initiated work on this issue in 2022. MISO evaluated ELCC along with other potential solutions to more accurately accredit non-thermal resources. MISO's initial proposal reflects a marginal accreditation approach, and it should have a final proposal in early 2023.

Next Steps: Continue discussion with stakeholders and finalize its proposal for filing.

2019-5: Improve the Tariff rules governing Energy Efficiency and their enforcement

The increasing levels of Energy Efficiency ("EE") capacity credits raise concerns because the claimed savings are based on a wide array of speculative assumptions, and we have found them to be vastly overstated. Hence, EE resources to date have yielded very little real benefits. We recommend the following changes to ensure that the savings offered are more likely to be real:

- Clarify the Tariff to require a contractual relationship with the end-use customer that: (a) prompts an action that would not likely have occurred otherwise, and (b) transfers the energy efficiency credits from the customer to the supplier;
- Specify that baseline assumptions must reflect prevailing consumer preferences and purchase patterns, rather than minimum efficiency standards.
- Enforce the measurement and verification rules by requiring some form of credible measurement of the savings, even if simply by sampling or surveying after installation.

Status: MISO agrees that Tariff clarifications could be made related to ownership rights, baseline assumptions, and measurement & verification protocols but has no activity underway.

Next Steps: MISO should work with its stakeholders and the IMM to complete its evaluation and prioritize changes to address this recommendation.

2017-7: Establish PRA capacity credits for emergency resources that better reflect their expected availability and deployment performance

Emergency-only resources, including LMRs and other emergency resources, can sell capacity and are only required to deploy during emergencies when instructed by MISO. If they are not available to mitigate shortages during emergency events, they provide little value. Some emergency resources have long notification or start-up times that render them unavailable in an emergency. Operators typically do not declare emergency events more than a few hours in advance because they are often caused by contingencies or unexpected changes in wind output or load. Hence, emergency resources with long notification times provide little value in most emergencies. This is not a problem for conventional resources with long start times because an emergency need not be declared to commit these resources. Therefore, we recommend that MISO account for the availability impacts of the emergency designation in its accreditation.

Status: MISO agrees with the recommendation and filed in March to allow the rules restricting use of the emergency commit status to be effective for June 1, 2023 (Planning Year 2023/24). Other changes to Module C and Schedule 53 will be requested to be effective in time for Planning Year 2024/25. In 2022, MISO implemented rules pertaining to LMRs by imposing tighter standards for notification times and call limits. This recommendation has been aligned with IR025 (sub issue RASC009) and is deemed to be a high priority by MISO.

Next Steps: MISO should continue working with stakeholders and develop possible alternatives for addressing this recommendation.

2015-6: Improve the modeling of transmission constraints in the PRA

MISO employs a relatively simple representation of transmission limits in the PRA, modeling only aggregate import and export limits to and from each capacity zone. Additionally, MISO accommodates the transfer limitations between the MISO South and Midwest regions. All other constraints are evaluated through a simultaneous feasibility analysis that may cause MISO to re-run the PRA with modified zonal import or export limits. Ultimately, these issues lead to sub-optimal capacity procurements and sub-optimal locational prices. Hence, we recommend that MISO add transmission constraints to its auction model to address potential simultaneous feasibility issues and to reflect the differing impact of zonal resources on regional constraints.

For relevant internal constraints, MISO should establish shift factors that define how each internal and external zone affects each constraint. Ultimately, this is a very simple version of a constrained optimal dispatch (much simpler than MISO's energy market). It would allow MISO to represent all regional constraints that may be affected by multiple local zones (e.g., the way the three zones in MISO South affect the south-to-north transfer constraint) and activate any constraints that may arise in its simultaneous feasibility assessment.

Status: MISO agrees with the issues identified and has done some preliminary analysis of this recommendation. MISO believes that further evaluation is required.

Next Steps: MISO should evaluate the software and other implications of implementing an efficient locational framework in the PRA. Building on the concepts implemented for the RDT constraint, modeling could be expanded to address additional internal transmission constraints.

2014-6: Define local resource zones based on transmission constraints and local reliability requirements

Currently, a local resource zone cannot be smaller than an entire LBA. In some cases, however, capacity is needed in certain load pockets within an LBA. For example, NCAs in MISO South have substantial capacity needs to satisfy local reliability requirements. In neither case, however, can the capacity prices in the PRA reflect the need for capacity because of the limited transmission capability into the areas. Therefore, we recommend that MISO adopt procedures for defining capacity zones that would allow the zones to be determined by transmission constraints and other local reliability needs rather than the historical LBA boundaries that are unrelated to the transmission network.

Status: Although MISO indicates that it agrees with the recommendation, it is currently in an inactive status. MISO indicates it will evaluate this recommendation further after completing higher priorities such as the RAN.

Next Steps: We continue to encourage MISO to evaluate the benefits of improving the zonal capacity market definitions.

2010-14: Improve the modeling of demand in the PRA by implementing reliability-based demand curves

The use of only a minimum requirement coupled with deficiency charges to represent demand in MISO's capacity market results in an implicit vertical demand curve for capacity. This does not efficiently reflect the reliability value of capacity and understates capacity prices as capacity levels continue to fall. This is particularly harmful as large quantities of resources are facing the decision to retire in response to prevailing market conditions. In this report, we identify more than 5 GW of economic resources that have retired prematurely primarily because of the severely understated capacity prices produced by MISO's PRA. These uneconomic retirements have caused MISO's capacity levels in the Midwest region to fall below the minimum requirement in the 2022-2023 PRA, resulting in prices throughout the Midwest clearing at CONE.

This is evidence that implementing a reliability-based demand curve is required to satisfy MISO's Reliability Imperative. A reliability-based demand curve that is sloped (rather than vertical) would more accurately reflect the reliability value of capacity in excess of the minimum requirement. It also would produce more efficient and stable capacity prices, particularly as the supply of available regional capacity moves toward the minimum planning reserve requirement. This report shows that this recommendation would lower the costs of satisfying the planning reserve requirements for both regulated and unregulated participants alike.

Understated capacity prices are particularly harmful to MISO's integrated utilities, most of which own surplus capacity and are compelled to sell it at inefficiently depressed prices. They are also problematic for unregulated participants that rely on the market to retain adequate resources to ensure reliability.

Status: MISO agrees with the IMM's concern and has been engaging the IMM and stakeholders including MISO states on this issue. This recommendation maps to RASC-2019-8 (Sloped Demand Curve in the Capacity Market (misoenergy.org)) in the MISO Dashboard.

Next Steps: MISO needs to continue to develop the details of its proposal. It plans to file proposed changes to implement a Reliability-Based Demand Curve in 2023 if it gains adequate support from its market participants and states.

E. Recommendations Addressed by MISO or Retired

In this subsection, we discuss past recommendations that MISO has addressed since last year.

2020-3: Remove eligibility for wind resources to provide ramp product

Wind resources are currently qualified to supply MISO's ramp product, although they generally can only ramp up when they are dispatched down for congestion. This makes wind units a poor option to provide the ramp product because they will generally be loading transmission constraints if MISO attempts to ramp them up. Therefore, we recommended that MISO remove eligibility for wind resources to provide the ramp product. MISO filed at FERC in February 2023 to adopt this recommendation. If approved, this will improve the performance of the ramp product by causing MISO to procure ramp capability from other types of resources that are better suppliers of ramp.

2018-3: Improve the RDT Agreement to procure reserves on the RDT and compensate the joint parties when the reserves are deployed

This recommendation would improve the performance of MISO's markets, lower the costs of satisfying regional capacity requirements, and equitably compensate the joint parties. Nonetheless, we are retiring the recommendation because the joint parties had minimal interest in modifying the agreement to implement this recommendation.

2018-5: Improve capacity accreditation by basing it on resource availability during tight supply periods

Accreditation is one of the largest opportunities for improvement to MISO's capacity market. We recommended MISO improve its accreditation methodology based on resource availability in the tightest margin hours. This would account for *all* outages and derates, as well as long start times and other inflexibilities. MISO filed these proposed changes, which FERC approved in 2022 and MISO is implementing in early 2023.

2014-5: Transition to seasonal capacity market procurements

Both the needs of the system and the available system supply change substantially from one season to the next. To improve the performance of the capacity market in meeting these seasonal needs, we recommended that MISO clearing the PRA on a seasonal basis rather than on an annual basis. MISO filed this proposed change, which FERC approved in 2022 and MISO is implementing the first seasonal PRA in Spring of 2023.

From: Marie Fagan
To: Christopher, Mahila
Cc: Windle, Rodney
Subject: RE: Draft AEP Ohio OVEC Audit
Date: Tuesday, September 8, 2020 3:42:14 PM
Attachments: image001.png
Image002 png
Image003 png
Image004 png
Image005 png
image007 png

Okay, thanks v much for the head start

From: mahila.christopher@puco.ohio.gov <mahila.christopher@puco.ohio.gov>
Sent: Tuesday, September 8, 2020 2:59 PM
To: Marie Fagan <marie@londoneconomics.com>
Cc: rodney.windle@puco.ohio.gov
Subject: RE: Draft AEP Ohio OVEC Audit

Hi Marie,
Please find attached Staff's initial comments on LEI's latest draft of the AEP Ohio, 2018-2019 PPA rider audit final report. This may help you get a head start on Staff's editorial suggestions. The comments can be discussed further at tomorrow's meeting.

**If you could please note that Staff still needs final acquiescence from PUCO Admin. regarding the overall tone of the draft report!

Staff's main observation regarding the tone of the draft is the following:
•Milder tone and intensity of language would be recommended such as the language on page 10, para 3: "**Therefore, keeping the plants running does not seem to be in the best interests of the ratepayers.**"
•Reduced subjectivity and level of detail/specifics would be required such as the language on page 26, para 2: "**HB 6 also provides subsidies for two large nuclear power plants in Ohio, and for that reason is the center of a federal bribery investigation. First Energy Corporation and the company's political action committee, and Generation Now, a 501 (c) (4) non-profit group are charged with paying $60 million to advocate for the passage of HB 6. The case has led to federal charges against Ohio House Speaker Larry Householder and four associates.**"

I am attaching a redlined Word version of the draft for your perusal/review. If you could, please take a look and incorporate Staff's comments as far as possible? Please let me know of any questions, comments, and concerns.
Thank you
Mahila Christopher
Public Utilities Commission of Ohio
Office of the Federal Energy Advocate
Utility Specialist
(614) 728-6954
www.PUCO.ohio.gov

From: Christopher, Mahila
Sent: Tuesday, September 8, 2020 1:09 PM
To: Marie Fagan <marie@londoneconomics.com>
Cc: Windle, Rodney <rodney.windle@puco.ohio.gov>
Subject: RE: Draft AEP Ohio OVEC Audit

Hi Marie-
As per the RFP, the Final Report is due to be filed on the 16th of September:

1. Audit Proposals Due February 28, 2020
2. Award Audit March 11, 2020
3. Audit Conducted March 11, 2020 through September 1,
4. 2020 Draft Audit Report Presented to Staff September 1, 2020
5. Final Audit Report Filed with Commission September 16, 2020

Should Staff reach our edits to LEI by 2:00pm today, would it be possible for LEI to send an updated draft to the Company tomorrow?

Thank you
Mahila Christopher
Public Utilities Commission of Ohio
Office of the Federal Energy Advocate
Utility Specialist
(614) 728-6954
www.PUCO.ohio.gov
This message and any response to it may constitute a public record and thus may be publicly available to anyone who requests it.

From: Marie Fagan <marie@londoneconomics.com>
Sent: Tuesday, September 8, 2020 12:29 PM
To: Christopher, Mahila <mahila.christopher@puco.ohio.gov>
Cc: Windle, Rodney <rodney.windle@puco.ohio.gov>
Subject: RE: Draft AEP Ohio OVEC Audit

Okay, will do. Once we have your comments I'll have a good idea of how long it will take to address them, but I would guess we can complete it by the end of the week in any case, and likely sooner than that. So that
means we can get the draft to Ed by this Friday 11th or maybe a day or so sooner, at least in electronic format. I think that the week that Ed wants for AEP Ohio review is reasonable, which means that they would get
their review back to us by about Sept 18.th We would then address their comments (again, that should take a day or so, unless comments are extensive). Then we would provide you with the final report including
workpapers the week of Sept. 21.
Best,
Marie

From: mahila.christopher@puco.ohio.gov <mahila.christopher@puco.ohio.gov>
Sent: Tuesday, September 8, 2020 9:32 AM
To: Marie Fagan <marie@londoneconomics.com>
Cc: rodney.windle@puco.ohio.gov
Subject: FW: Draft AEP Ohio OVEC Audit
Importance: High

Hi Marie,
Staff should be able to communicate our comments on the draft by tomorrow's meeting.

If you could, please assess Edward's question based on this and let me know if you have any concerns with his request for a week to review the draft for confidentiality and factual inaccuracies?

Thank you
Mahila Christopher
Public Utilities Commission of Ohio
Office of the Federal Energy Advocate
Utility Specialist
(614) 728-6954
www.PUCO.ohio.gov
This message and any response to it may constitute a public record and thus may be publicly available to anyone who requests it.

From: Edward J Locigno <ejlocigno@aep.com>
Sent: Tuesday, September 8, 2020 9:19 AM
To: Marie Fagan <marie@londoneconomics.com>
Cc: Andrea E Moore <aemoore@aep.com>; Christopher, Mahila <mahila.christopher@puco.ohio.gov>; Shelli A Sloan <sasloan@aep.com>; Steven T Nourse <stnourse@aep.com>
Subject: RE: Draft AEP Ohio OVEC Audit
Importance: High

Mahila/Marie
When can we expect the report to review for confidentiality and factual inaccuracies? We need a solid week really at least to review it. Please let me know. Thank you!

EDWARD J LOCIGNO | REGULATORY ANALYSIS & CASE MGR
EJLOCIGNO@AEP.COM | D:614.716.3495 | C:614.619.9460
1 RIVERSIDE PLAZA, COLUMBUS, OH 43215

From: Marie Fagan <marie@londoneconomics.com>
Sent: Wednesday, September 2, 2020 3:09 PM
To: Edward J Locigno <ejlocigno@aep.com>
Cc: Andrea E Moore <aemoore@aep.com>
Subject: [EXTERNAL] Draft AEP Ohio OVEC Audit

Dear Ed,
This is to confirm that LEI provided the draft OVEC audit report to the Commission Staff. The process now, as I understand it, is that Staff will review, and after that we will provide it to AEP Ohio for redacting. At that time, we can talk about a secure way to provide it to you, perhaps uploading to the data room.
Thank you for all your help with the audit.
Best,
Marie

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