# Response to the 2019 State of the Market Report

June 29, 2020

For Public Use

This page is intentionally left blank.

# Contents

# Introduction

The 2019 State of the Market Report (SOM) for PJM[1] contained 213 recommendations that provide Monitoring Analytics' (MA) perspective regarding changes to the PJM market rules and design intended to enhance the competitiveness, efficiency and durability of PJM's markets. The purpose of this document is to provide PJM's assessment on the status of each recommendation and also to present a more detailed background, and, where appropriate, to outline next steps regarding five key areas that PJM and MA have identified as areas to further investigate in 2020.

# Focus Areas From the 2019 State of the Market Report

## *Introduction*

Prior to the release of the 2019 SOM, PJM and MA met on several occasions to discuss areas to prioritize focus in 2020. As a result of those discussions, PJM and MA have identified the following five areas.

1. Holistic Review of the Auction Revenue Rights/Financial Transmission Rights Market Design
2. Five Minute Dispatch and Pricing
3. Capacity Market Default Market Seller Offer Cap
4. The Future of Up-to-Congestion Transactions
5. Energy Market Power Mitigation

Each of these areas is linked to multiple recommendations in the 2019 SOM. Some of the recommendations in these areas propose solutions that may require additional analysis by PJM and MA; stakeholder discussion and vetting; or are recommendations on which PJM and MA have not yet agreed.

The next section of this document provides some background on each of these five issues, including where they stand within the stakeholder or regulatory process, as well as PJM's position on the topic or on a path forward. The following section provides a categorization of the SOM recommendations based upon their actionable status. Finally, the Appendix provides a complete list of the SOM recommendations identified by their section in the SOM report. PJM looks forward to discussion of these topics with members, stakeholders and MA.

## *Holistic Review of the ARR/FTR Market Design*

### Background

The Auction Revenue Rights (ARR) and Financial Transmission Rights (FTR) products have been a key area of focus of PJM, MA and stakeholders for the last several years.

In 2017, PJM filed changes to comply with a FERC order that removed the use of historic source points in the ARR allocation process and shifted the allocation of balancing congestion from FTR owners to load. In 2018 and 2019, the

[1] 2019 State of the Market Report for PJM: Volume 2 Detailed Analysis, March 12, 2020, at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2019/2019-som-pjm-volume2.pdf

credit default resulted in an acute focus on these products that called into question not only credit requirements for FTRs, but also the value of the long-term FTR auction, and the need to alter the auction structure to enhance the ability to mark positions to market. Now, in 2020, pursuant to recommendation F3 from the "Report of the Independent Consultants to the PJM Board,"[2] PJM is conducting a holistic review of the ARR/FTR products and process at the ARR/FTR Market Task Force[3] (AFMTF).

### PJM Perspective

PJM reviewed the final scope for the holistic review of the ARR/FTR market with stakeholders at the June 26, 2020 AFMTF meeting. The questions included in the scope are:

1. For what purpose were they initially created? Was it to address a problem?
2. Are they fulfilling, in the best way possible, their initial purpose and/or addressing the identified problem?
3. If not, why not? If so, how is this measured and verified?
4. Is this purpose still required and if it is addressing a problem, are there alternative ways to eliminate the problem entirely?
5. Are there additional purposes and/or sources of value to the market that ARRs and FTRs are, or should be fulfilling or delivering? If so, what are these purposes, how do they optimize value to load and other market participants; and how is this value optimization measured and verified?
6. What other mechanisms, either inside or outside the RTO, can provide alternative ways to achieve some of these purposes? If such mechanisms exist, can they work alongside each other or as variations to current mechanisms to optimize value to load and other market participants?
7. Are there changes in market design, execution or product tenor that would improve delivery of these instruments' purposes, either through increased efficiency, greater equity, a better optimized delivery of value or lower risk to load, or in some other way?

PJM is currently working on distributing a formal request for proposals. Based on the responses, PJM plans to make a selection on the consultant for the holistic review in July, at which time the review will commence.

PJM is engaging in this holistic review with an open mind and looks forward to working with MA and stakeholders on the consultant's final report. The current structure that is implemented in PJM has been in place for over 20 years. That length of time, in addition to questions raised by stakeholders on the effectiveness of the current structure, necessitates such a review.

## *Five Minute Pricing and Dispatch*

### Background

In May 2019, MA brought forth a Problem Statement and Issue Charge to the Market Implementation Committee (MIC) targeted at addressing transparency and process improvements for real-time energy price formation (https://www.pjm.com/-/media/committees-groups/committees/mic/20190515/20190515-item-04b-five-minute-dispatch-and-pricing-issue-charge.ashx). Since then, stakeholders have discussed market rule changes and areas to increase transparency in the governing documents in this area. There are several key changes being discussed:

[2] https://www.pjm.com/-/media/library/reports-notices/special-reports/2019/report-of-the-independent-consultants-on-the-greenhat-default.pdf

[3] https://www.pjm.com/committees-and-groups/task-forces/afmtf.aspx

1. The alignment of energy and reserve prices with the target time of the dispatch instructions
2. The configuration and periodicity of the dispatch algorithm
3. The formulation of the real-time dispatch and pricing
4. The transparency of the Locational Marginal Pricing (LMP) Verification process[4] performed by PJM

In January 2020, FERC issued an order[5] linking the currently outstanding PJM compliance filing to implement fast-start pricing to the five-minute pricing and dispatch issues raised by MA in the stakeholder process. Specifically, the order states in closing in paragraph 32:

> *"Given this pricing and dispatch misalignment problem, as identified in the record, we will hold PJM's fast-start pricing proceeding in abeyance for a limited time. As commenters note, PJM has a stakeholder process underway to resolve the pricing and dispatch misalignment problem. We understand that this stakeholder process is tentatively scheduled to conclude in May 2020. Therefore, we will hold PJM's fast-start pricing compliance filing in abeyance until July 31, 2020, to allow PJM and its stakeholders the opportunity to fully consider necessary changes to address PJM's pricing and dispatch misalignment issue in conjunction with the compliance directives of the Order on Paper Hearing."*

## PJM Perspective

PJM appreciates MA raising the issues regarding transparency and process improvements in the area of real-time energy price formation. The real-time dispatch and pricing of the PJM system is complex. Taking time to identify where those processes may be improved and where more transparency would be beneficial is important to PJM.

Regarding the specific changes being discussed by stakeholders, PJM is supportive of implementing all of them except for the proposed changes to the formulation of the real-time dispatch and pricing software (#3 above). Regarding that issue, there is no analysis available at this time on which PJM can determine the benefits, costs or operational impacts associated with that proposal, and therefore PJM cannot support it at this time. PJM views the changes regarding the alignment of prices and dispatch instructions (#1 above), and frequency and configuration of the dispatch algorithm (#2 above), as beneficial changes that should enhance incentives to follow dispatch.

It should be noted that changing the frequency and configuration of the execution and approval of dispatch solutions could impact system operations in a manner that necessitates other changes that require stakeholder approval, such as changes to the requirements for ancillary services. As such, PJM is performing analysis on the potential need for additional ancillary services resulting from this change. Based on the current operating conditions and analysis to date, PJM has not determined a need for additional ancillary services. Further, PJM performed an initial trial on May 21 and May 22, 2020. During this period, PJM changed the automatic execution of the dispatch algorithm from every four minutes to every five minutes, and approved dispatch solutions every five minutes, as opposed to the traditional ad hoc approval that occurs approximately every four minutes, on average. During this test, PJM observed no

[4] The LMP Verification process is performed by PJM on a daily basis and is intended to ensure that real-time prices are reflective of the dispatch of the system during the applicable time. The LMP Verification process also includes the verification of real-time ancillary service prices. For more information on this process, see section 2.10 of Manual 11 (https://www.pjm.com/~/media/documents/manuals/m11.ashx).

[5] https://www.ferc.gov/whats-new/comm-meet/2020/012320/E-4.pdf

operational issues. PJM is planning a second trial period that will commence on June 22, 2020, and will last a week. If that trial is also successful, PJM plans to continue operation in this mode and bring forward manual changes detailing this process for stakeholder endorsement. If the test identifies any operational issues, PJM will discuss those issues with stakeholders, as well as any necessary or appropriate changes.

PJM also believes that increasing transparency around the LMP Verification (#4 above) process is necessary and is supportive of making changes to the process and more fully documenting it in the applicable documents.

As stated, PJM is not supportive of changing the formulation of its dispatch and pricing algorithm in the manner proposed by MA at this time. PJM believes that this change is significant as it will directly impact the dispatch of the system and the calculation of market clearing prices, and its effects are unclear. Without further analysis, PJM is not able to determine what, if any, benefit this change provides operationally.

PJM is aware that the Southwest Power Pool (SPP) and the Midcontinent Independent System Operation (MISO) both use the formulation proposed by MA. PJM has met with both entities to talk through operational benefits and issues they have resulting from this implementation. While MISO and SPP employ this approach, other ISOs such as ISO New England, California ISO, New York ISO and Electric Reliability Coordinator of Texas do not. Each of those system operators formulates their dispatch software differently than MISO and SPP and, to varying degrees, different from PJM and each other. Given the varied implementations of dispatch algorithms across the United States, without further analysis it is difficult for PJM accept that the MISO and SPP method is better than what it currently does today, and the ideal model to adopt. At the June 3, 2020 MIC, PJM discussed this concern with stakeholders and MA, and committed to performing analysis and further discussion on the various options.

## Implementation Timing

PJM believes that the implementation of the changes required to align the target time of the dispatch solution with the prices (#1 above) can be performed shortly, following approval of the proposed changes by stakeholders and ultimately FERC. This issue was voted on and passed at the June 3, 2020 MIC and has been to the June 18, 2020 Markets and Reliability Committee (MRC) meeting for a first read. PJM will request a stakeholder vote on this issue at the July 23, 2020 MRC and Members Committee meetings. Assuming approval at that July meeting, PJM would make a filing with FERC shortly thereafter and implement the enhancements following FERC's approval.

Further, PJM plans to initiate a comprehensive analysis of the timing and method used to determine resource dispatch points and prices with stakeholders and MA in September 2020. The process will likely begin with a qualitative comparison of the dispatch methodologies utilized by other ISOs and RTOs. Using the output of this comparison, PJM will work with stakeholders and MA to identify desirable models to simulate and measure the benefits to be achieved by adopting elements of those other methodologies. If it is determined that there are sufficient benefits to be achieved, PJM will develop a plan to enhance its systems accordingly and then cut over to the new processes. The conduct of this analysis is expected to extend into 2021.

The primary focus of the stakeholder group discussing the Five Minute Pricing and Dispatch has been on the changes to dispatch timing and processes, and has not yet given dedicated focus to transparency of the LMP Verification process (#4 above). PJM anticipates greater focus in that area in the near future and looks forward to adding more transparency into this process.

## *Capacity Market Default Market Seller Offer Cap*

### Background

In 2017 and 2018, PJM stakeholders discussed changes to the capacity market Default Market Seller Offer Cap (Default MSOC) at the MIC. The Default MSOC is defined as the Net Cost of New Entry (Net CONE) multiplied by the average Balancing Ratio (B) for all Performance Assessment Intervals (PAI) in the prior three years. The purpose of the discussion was to determine if changes were needed in two areas:

1. At the time, there had been no PAIs in the prior three years, and thus the B in the Default MSOC was not able to be calculated for the upcoming Base Residual Auction (BRA) in 2018 for the 2021/2022 Delivery Year.
2. The expectation of the number of PAIs in a given year that is used for the determination of the Non-Performance Charge Rate and Default MSOC was set at 30 hours in the Tariff. This was higher than what had been observed since the implementation of Capacity Performance (CP). At the time, there had been zero PAIs since the implementation.

Despite a significant amount of discussion on this topic, consensus was not reached on changes to resolve the identified issues. In February 2019, MA filed a complaint[6] with FERC explaining the issues they believe exist with the current Default MSOC. The complaint was more specific to the assumed number of PAIs that are used in the calculation of the Default MSOC and Non-Performance Charge Rate. Specifically, the recommended solution in the complaint was to use a different, lower value for the assumed number of PAIs in the determination of the Default MSOC (five) than what is used in the Non-Performance Charge Rate (30). The net effect of the proposal would maintain the same Non-Performance Charge Rate while reducing the Default MSOC to one-sixth of Net CONE times B. This complaint is still pending at FERC.

### PJM Perspective

PJM understands the justification for the complaint filed by MA, and also recognizes that it has resulted in additional uncertainty with respect to the capacity market rules. PJM believes that, if possible, it would be preferable to resolve this issue outside of the FERC complaint rather than waiting for FERC to address it. PJM engaged with MA on potential changes to the Default MSOC with respect to the following open issues:

1. The assumption of 30 hours of PAIs each year has not been realized since the implementation of CP.
2. The current implementation of the Default MSOC does not recognize that the Bonus Rate is typically less than the Non-Performance Charge Rate.
3. Estimating the expected number of PAIs for the delivery year is complex and can lead to unreasonably high Non-Performance Charge Rates when the expected number of PAIs is low.

Each of these issues was considered as part of the stakeholder discussion in 2017 and 2018. PJM continues to work with MA to identify potential solutions that address these issues and possible mechanisms to allow wider consideration of such potential solutions.

The current rules regarding the Default MSOC have merit. As described, this framework results in a Default MSOC of Net CONE times B, and assumes an equal number of PAIs when calculating the Default MSOC and the Non-

[6] http://www.monitoringanalytics.com/Filings/2019/IMM_Complaint_Docket_No_EL19-XXX_20190221.pdf

Performance Charge Rate, and that the Bonus Rate and Non-Performance Charge Rate are equal. While the underlying logic of this method is sound, the aforementioned assumptions may not be valid or desirable. For example, if the assumed number of PAIs falls from 30 to one, the Non-Performance Charge Rate would increase to 30 times its current value (over $100,000 per MWh), and the Default MSOC would remain at Net CONE times B. Under the expectation of zero PAIs, the MSOC reduces to the Net Avoidable Cost Rate (ACR).

PJM believes it is questionable whether an expectation of zero PAIs is ever reasonable given the uncertainties inherent in operating the power system. Even if it were, and Net ACR is an appropriate MSOC in those circumstances, the default values PJM recently filed in the Minimum Offer Price Rule (MOPR) docket – and those calculated by MA and presented in the 2019 SOM for certain units – should not be viewed as potential Default MSOC values.

While the Net ACR values that PJM recently filed function well as a default offer floor for the purpose of a MOPR, those values, as well as those calculated by MA and presented in the 2019 SOM for certain units, do not include all components that any resource owner might include in a competitive offer. Specifically, while the Net ACR values PJM filed utilize a historical average energy price to determine net revenues, resource owners may choose to use forward energy prices.

Also, because default Net ACR calculations are typically based on publicly available, average plant expense values, they do not necessarily include all costs to which a given plant may be exposed. Finally, the default Net ACR values filed in the MOPR proceeding do not account for the significant risk a plant owner assumes by committing as a capacity resource years into the future.

Similarly, PJM has observed during its limited experience with the PAIs that have occurred that the existence of excusals from Non-Performance Charges will almost always result in a Bonus Rate that is less than the Non-Performance Charge Rate. PJM believes that a review of these assumptions is reasonable should stakeholders be interested in having the discussion.

## *The Future of Up-to-Congestion Transactions*

### Background

As a result of changes in market behavior and stakeholder questions on the value of Up-to-Congestion transactions (UTC), PJM wrote a paper[7] in 2015 providing background and education on the product, highlighting some concerns it observed with the use of the transaction and associated recommendations. Those recommendations were:

1. Alter the biddable locations for UTCs to generation buses as source only, trading hubs, load zones and interfaces.
2. Allocate uplift to UTCs consistent with increment (INC) and decrement (DEC) transactions.

These recommendations were discussed at the Energy Market Uplift Senior Task Force (EMUSTF) and culminated in two separate filings. One of those filings, which was accepted by FERC on Feb. 20, 2018, decreased the bidding nodes for virtual transactions in PJM. The other filing[8] proposed to allocate a portion of the uplift in PJM to UTCs as if

[7] https://www.pjm.com/~/media/library/reports-notices/special-reports/20151012-virtual-bid-report.ashx
[8] https://www.ferc.gov/CalendarFiles/20180112165550-ER18-86-000.pdf

they were an INC at the injection point and a DEC at the withdrawal point. That filing was rejected by FERC on Jan. 12, 2018. In its order, FERC stated:

> *"While we find PJM has not justified the instant proposal, we recognize that it may be appropriate to allocate some uplift costs to UTCs. Therefore, our rejection in this docket is without prejudice to PJM proposing an alternative uplift allocation method for UTCs."*

Given other competing priorities, PJM and stakeholders chose not to propose an alternative in response to FERC's invitation to do so in its Jan. 12, 2018 order.

## PJM Perspective

PJM believes that the inconsistency in the allocation of uplift costs that exists today between UTCs and other virtual transactions is inequitable and should be addressed. Under the existing methodology, this would result in allocating uplift to UTCs as a single transaction at a minimum.

Currently, PJM is working with MA on analysis on the use of UTCs, specifically regarding the volume of trades at specific locations where there are consistently profitable trades that do not seem to enhance the day-ahead resource commitment or drive price convergence between the Day-Ahead and Real-Time Energy Markets. This could be indicative of modeling discrepancies at those locations leading to the ability to use UTCs, and potentially other virtual transactions, to extract profits from the market without providing commensurate benefit.

On June 1, 2020, PJM removed one such point from the list eligible for virtual trading, the NIPSCO interface, in response to concerns raised by MA that the current configuration was effectively a modeling discrepancy that led to the ability for participants to consistently, but inappropriately, extract profits from the market. The NIPSCO interface was previously an interface pricing point at which market participants could submit physical interchange transactions between PJM and external balancing authorities. It has not been in use for physical transaction purposes for some time but remained eligible for virtual trading. Given the documented concerns described above, PJM removed the point from virtual trading eligibility. PJM is working on additional analysis in this area and will engage with stakeholders regarding any further potential actions.

Additionally, as more analysis has been performed on the ARR/FTR Market, PJM and MA have developed a better understanding between the observed uses of UTCs and FTR funding. While more research needs to be done in this area, the clearing of UTCs and FTR funding levels has not been the subject of discussion with stakeholders as it pertains to the overall value[9] proposition for the product. PJM believes it is important that stakeholders understand how these products are being used and the benefits and drawbacks of their usage prior to deciding on whether any changes are required.

[9] Virtual transactions are a long-standing market construct intended to provide price convergence, liquidity, market power mitigation and a hedging mechanism. Simulation results indicate that, in particular, UTCs do not provide any value with respect to price convergence between Day-Ahead and Real-Time energy markets – A. Long, A. Giacomoni, "*Exploring the Impacts of Virtual Transactions in the PJM Wholesale Energy Market,*" IEEE PES General Meeting, August 2020.

## Energy Market Power Mitigation

### Background

PJM's Energy Market power mitigation rules have frequently been the focus of stakeholder discussion and, from PJM's perspective, have presented challenges. PJM shares MA's desire for strong market power mitigation rules, and its objective in this area is consistent with that desire. However, the current process has identified challenges in recent years including the Fuel Cost Policy (FCP) process, the Lost Opportunity Cost Calculator, and Parameter Limited Schedules (PLS) to name a few.

In September 2018, PJM stakeholders approved a Problem Statement and Issue Charge[10] primarily focused on enhancements to the FCP process. In addition, the issue charge identified the requirement to:

> *"Explore potential alternatives to PJM's current Fuel Cost Policy rules and cost-based offer rules. Initial review suggests that the mitigated offer or cost-based offer formation paradigms of neighboring ISOs/RTOs should be reviewed as candidates for adoption in PJM."*

Discussion on this topic is currently occurring within the stakeholder process.

### PJM Perspective

PJM firmly believes that strong market power mitigation mechanisms are critical to maintain an efficient, competitive market. To ensure those rules remain strong and that they all function cohesively, PJM believes that substantive changes to the calculation of cost-based or mitigated offers should not be considered in isolation. Rather, any evaluation of material changes to the market power mitigation rules should include other components that fit within the framework of market power mitigation such as the PLS, the market power tests used, etc. Considering all of these factors is important to make sure that they all work in concert to effectively mitigate market power.

In the short-term, PJM supports working with stakeholders and MA to investigate ways to simplify and streamline the current rules without weakening them. PJM has considered several areas where simplicity may be achieved. These include the administration of the exception process used to implement the PLS, reducing any unneeded flexibility currently allowed in supply offers that complicate market power mitigation without a commensurate value add and running the Three-Pivotal Supplier test prior to running the market clearing engine as compared to during it. Reducing complexity in this area while not weakening market power mitigation could be valuable, as it, in combination with other changes, could enable other market enhancements in the future.

[10] https://www.pjm.com/-/media/committees-groups/committees/mic/20181102-special-fcpe/20181102-item-02a-fuel-cost-policy-problem-statement-issue-charge.ashx

# PJM Categorization of Recommendations From the 2019 State of the Market Report

## Background

This section categorizes the recommendations contained within the 2019 State of the Market Report (2019 SOM).[11] In 2019, the IMM introduced 23 new recommendations and marked three recommendations as adopted. Many of the IMM recommendations are repeated from past annual and quarterly State of the Market reports. PJM has conducted a review of all 213 recommendations and classified them into three categories: Actionable, Assessment and Archived.

- **Actionable –** PJM considers these recommendations the highest priority, which upon adoption will have the greatest impact to the market performance. PJM plans to take action to address these recommendations in the coming year.
- **Assessment –** PJM believes that these recommendations are of medium-to-high importance but need further investigation and analysis prior to determining if they are actionable.
- **Archived –** The remaining recommendations are currently archived. PJM does not plan to take further actions on these recommendations at the current time. These recommendations may have been proposed by PJM, but rejected by FERC, or did not reach consensus among stakeholders. Some recommendations are out of PJM's purview and are directed to another party such as a state public utility commission. Other recommendations are archived, because PJM disagrees with them or believes that they are low priority.

| Section | Actionable | Assessment | Archived | Section Percentage |
|---|---|---|---|---|
| Ancillary Services | 11 | 11 | 6 | 13% |
| Capacity Market | 1 | 3 | 25 | 14% |
| Demand Response | 0 | 1 | 26 | 13% |
| Energy Market | 4 | 4 | 36 | 21% |
| Energy Uplift | 1 | 5 | 18 | 11% |
| Environmental | 0 | 1 | 5 | 3% |
| FTRs & ARRs | 2 | 11 | 6 | 9% |
| Interchange Transactions | 3 | 1 | 8 | 6% |
| Net Revenue | 0 | 0 | 1 | 0% |
| Planning | 0 | 3 | 20 | 11% |
| **Total Recommendations** | **22** | **40** | **151** | **213** |
| **Status Percentage** | **10%** | **19%** | **71%** | |

The PJM stakeholder process is an important decision-making body that helps guide the resolution of issues identified by PJM, FERC or PJM members, including issues brought forward by the IMM. The Markets & Reliability Committee (MRC), supported by three lower-level committees, the Market Implementation Committee (MIC), the Operating Committee (OC) and the Planning Committee (PC), are each responsible for undertaking issues that impact PJM Markets, Operations and Planning, and for designing proposals that resolve these issues.

[11] Monitoring Analytics, LLC. 2019 State of the Market Report for PJM. Volume 1: Introduction. March 12, 2020

In 2019, stakeholders focused on important issues such as Energy Price Formation, Financial Risk Mitigation, Fuel Cost Policies, the Opportunity Cost Calculator, and the Minimum Offer Price Rule and auction timing associated with PJM's capacity market. Many of the recommendations that are identified as Actionable or Assessment are being discussed within the PJM stakeholder process; other recommendations marked as Archived have already been reviewed by stakeholders. The tables below list all SOM recommendations by category of Actionable, Assessment and Archived.

# Appendix – Complete List of Recommendations[12]

| | ACTIONABLE | | | | |
|---|---|---|---|---|---|
| Section | 2019 Recommendation | Priority | Year Reported | IMM Status | PJM Status 2020 |
| Energy Market | 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. | Medium | 2016 | Not Adopted | Actionable |
| Energy Market | The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. | Low | 2016 | Not Adopted | Actionable |
| Energy Market | 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. | Medium | 2016 | Partially Adopted, 2018 | Actionable |
| Energy Market | 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. | Medium | 2018 | Not Adopted | Actionable |
| Energy Uplift | The MMU recommends that if PJM believes it is appropriate to implement CT price setting logic, PJM must 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. | Medium | 2016 | Partially Adopted | Actionable |
| Capacity Market | The MMU recommends that PJM develop a process for calculating a forward-looking estimate for the expected number of Performance Assessment Intervals (H) to use in calculating the Market Seller Offer Cap (MSOC). The MMU recommends that the Non-performance Charge Rate be left at its current level. The MMU recommends that PJM develop a forward-looking estimate for the Balancing Ratio (B) during Performance Assessment Intervals (PAIs) to use in calculating the MSOC. Both H and B parameters should be included in the annual review of planning parameters for the Base Residual Auction, and should incorporate the actual observed margins, and other assumptions consistent with the annual IRM study. | High | 2017 | Not Adopted | Actionable |
| Interchange Transactions | The MMU recommends that PJM ends the practice of maintaining outdated definitions of interface pricing points, eliminate the NIPSCO, Southeast and Southwest interface pricing points from Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SouthIMP/EXP pricing point. | High | 2013 | Not Adopted | Actionable |
| Interchange Transactions | The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. | Low | 2009 | Not Adopted | Actionable |
| Interchange Transactions | The MMU recommends that the Commission require that the open FFE/FFL freeze date issues be addressed at a Commission technical conference, and that the Commission set a deadline to resolve the significant issues that result from the freeze date. | Medium | 2019 | Not Adopted | Actionable |
| Ancillary Services | The MMU recommends that all data necessary to perform the Regulation Market three pivotal supplier test be saved, so that the test can be replicated. | Medium | 2016 | Not Adopted. PJM submitted a request for data verification to the vendor. | Actionable |

[12] Monitoring Analytics, LLC. 2019 State of the Market Report for PJM. Volume 2: Detailed Analysis. March 12, 2020

## A C T I O N A B L E

| Section | 2019 Recommendation | Priority | Year Reported | IMM Status | PJM Status 2020 |
|---|---|---|---|---|---|
| Ancillary Services | The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. | High | 2010 | Not Adopted, FERC Rejected, pending rehearing | Actionable |
| Ancillary Services | The MMU recommends that PJM replace the static MidAtlantic/Dominion Reserve Subzone with a reserve zone structure consistent with the actual deliverability of reserves based on current transmission constraints. | High | 2019 | Not Adopted | Actionable |
| Ancillary Services | The MMU recommends that the $7.50 margin be eliminated from the definition of the cost of tier 2 synchronized reserve, because it is a markup and not a cost. | Medium | 2018 | Not Adopted | Actionable |
| Ancillary Services | The MMU recommends that the variable operating and maintenance cost be eliminated from the definition of the cost of tier 2 synchronized reserve, and that the calculation of synchronized reserve variable operations and maintenance costs be removed from Manual 15. | Medium | 2019 | Not Adopted | Actionable |
| Ancillary Services | The MMU recommends that the rule requiring that tier 1 synchronized reserve resources are paid the tier 2 price when the non-synchronized reserve price is above zero be eliminated immediately and that, under the current rule, tier 1 synchronized reserve resources not be paid the tier 2 price when they do not respond. | High | 2013 | Not Adopted | Actionable |
| Ancillary Services | The MMU recommends that PJM be more explicit and transparent about why tier 1 biasing is used in defining demand in the tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for estimating tier 1 MW, define rules for the use and amount of tier 1 biasing, and identify the rule-based reasons for each instance of biasing. | Medium | 2012 | Not Adopted | Actionable |
| Ancillary Services | The MMU recommends that PJM eliminate the use of Degree of Generator Performance (DGP) in the Synchronized Reserve Market solution and improve the actual tier 1 estimate. If PJM continues to use DGP, DGP should be documented in PJM's manuals. | Medium | 2018 | Not Adopted | Actionable |
| Ancillary Services | The MMU recommends that a reason code be attached to every hour in which PJM market operations add additional DASR MW. | Medium | 2015 | Not Adopted | Actionable |
| Ancillary Services | The MMU recommends that PJM modify the DASR Market to ensure that all resources cleared incur a real-time performance obligation. | Low | 2013 | Not Adopted | Actionable |
| Ancillary Services | The MMU recommends that offers in the DASR Market be based on opportunity cost only in order to eliminate market power. | Low | 2018 | Not Adopted | Actionable |
| FTRs & ARRs | The MMU recommends that PJM and its members continue to review the management of a defaulted member's FTR portfolio, including options other than immediate liquidation. | High | 2018 | Not Adopted | Actionable |

## A S S E S S M E N T

| Section | 2019 Recommendation | Priority | Year Reported | IMM Status | PJM Status 2020 |
|---|---|---|---|---|---|
| Energy Market | 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. | Medium | 2016 | Not Adopted | Assessment |
| Energy Market | 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. | Medium | 2018 | Not Adopted | Assessment |
| Energy Market | The MMU recommends that PJM approve one RT SCED case for each five-minute interval to dispatch resources during that interval, and that PJM calculate prices using LPC for that five-minute interval using the same approved SCED case. | High | 2019 | Not Adopted | Assessment |
| Energy Market | The MMU recommends that PJM increase the interaction of outage and operational restrictions data submitted by market participants via eDART/eGADs and offer data submitted via Markets Gateway. | Low | 2017 | Not Adopted | Assessment |
| Energy Uplift | The MMU recommends that PJM initiate an analysis of the reasons why a significant number of combustion turbines and diesels scheduled in the Day-Ahead Energy Market are not called in real time when they are economic. | Medium | 2012 | Partially Adopted, 2019 | Assessment |
| Energy Uplift | The MMU recommends that UTC transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC. | High | 2011 | Not Adopted | Assessment |
| Energy Uplift | The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity cost credits paid to wind units should be based on the | Low | 2012 | Not Adopted | Assessment |

| | ASSESSMENT | | | | |
|---|---|---|---|---|---|
| Section | 2019 Recommendation | Priority | Year Reported | IMM Status | PJM Status 2020 |
| | lesser of the desired output, the estimated output based on actual wind conditions, and the capacity interconnection rights (CIRs). The MMU recommends that PJM allow wind units to request CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. | | | | |
| Energy Uplift | The MMU recommends that PJM develop and implement an accurate metric to define when a unit is following dispatch to determine eligibility to receive balancing operating reserve credits and for assessing generator deviations. | Medium | 2018 | Not Adopted | Assessment |
| Energy Uplift | The MMU recommends that PJM eliminate the exemption for fast-start resources (CTs and diesels) from the requirement to follow dispatch. The performance of these resources should be evaluated in a manner consistent with all other resources. | Medium | 2018 | Not Adopted | Assessment |
| Capacity Market | The MMU recommends that energy efficiency resources (EE) not be included on the supply side of the capacity market, because PJM's load forecasts now account for future EE, unlike the situation when EE was first added to the capacity market. However, the MMU recommends that the PJM load forecast method should be modified so that EE impacts immediately affect the forecast without the long lag times incorporated in the current forecast method. If EE is not included on the supply side, the implementation of the EE add-back mechanism should be modified to ensure that market clearing prices are not affected. | Medium | 2016 | Not Adopted | Assessment |
| Capacity Market | The MMU recommends use of the Sustainable Market Rule (SMR) in order to protect competition in the capacity market from non-market revenues. | High | 2016 | Not Adopted | Assessment |
| Capacity Market | The MMU recommends that the market data posting rules be modified to allow the disclosure of expected performance, actual performance, shortfall and bonus MW during a PAI by area without the requirement that more than three market participants' data be aggregated for posting. | Low | 2019 | Not Adopted | Assessment |
| Demand Response | The MMU recommends, as a preferred alternative to including demand resources as supply in the capacity market, that demand resources be on the demand side of the markets, that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion, that customer payments be determined only by metered load, and that PJM forecasts immediately incorporate the impacts of demand-side behavior. | High | 2014 | Not Adopted | Assessment |
| Environmental | The MMU recommends that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing. | Medium | 2018 | Not Adopted | Assessment |
| Interchange Transactions | The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. | Medium | 2013 | Not Adopted | Assessment |
| Ancillary Services | The MMU recommends that the ability to make dual offers (to make offers as both a RegA and a RegD resource in the same market hour) be removed from the Regulation Market. | High | 2019 | Not Adopted | Assessment |
| Ancillary Services | The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the optimization, assignment and settlement process. The MBF should be defined as the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. | High | 2012 | Not Adopted, FERC Rejected, pending rehearing | Assessment |
| Ancillary Services | The MMU recommends that the lost opportunity cost calculation used in the Regulation Market be based on the resource's dispatched energy offer schedule, not the lower of its price or cost schedule. | Medium | 2010 | Not Adopted, FERC Rejected, pending rehearing | Assessment |
| Ancillary Services | The MMU recommends that, to prevent gaming, there be a penalty enforced in the Regulation Market as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to de-assign assigned regulation resources within the hour. | Medium | 2016 | Not Adopted, FERC Rejected, pending rehearing | Assessment |
| Ancillary Services | The MMU recommends that the components of the cost-based offers from providing regulation and synchronous condensing be defined in Schedule 2 of the Operating Agreement. | Low | 2019 | Not Adopted | Assessment |
| Ancillary Services | The MMU recommends that the tier 2 synchronized reserve must-offer requirement be enforced on a daily and hourly basis. The MMU recommends that PJM define a set of acceptable reasons why a unit can be made unavailable daily or hourly and require unit owners to select a reason in Markets Gateway whenever making a unit unavailable either daily or hourly or setting the offer MW to 0 MW. | Medium | 2013 | Partially Adopted | Assessment |
| Ancillary Services | The MMU recommends that, for calculating the penalty for a tier 2 resource failing to meet its scheduled obligation during a spinning event, the definition of the IPI be changed from the average number of days between events to the actual number of days since the last event greater than 10 minutes. | Medium | 2018 | Not Adopted | Assessment |

## A S S E S S M E N T

| Section | 2019 Recommendation | Priority | Year Reported | IMM Status | PJM Status 2020 |
|---|---|---|---|---|---|
| Ancillary Services | The MMU recommends that aggregation not be permitted to offset unit-specific penalties for failure to respond to a synchronized reserve event. | Medium | 2018 | Not Adopted | Assessment |
| Ancillary Services | The MMU recommends that all resources, new and existing, have a requirement to include and maintain equipment for primary frequency response capability as a condition of interconnection service, and that compensation is provided through the capacity and energy markets. | Medium | 2018 | Not Adopted | Assessment |
| Ancillary Services | The MMU recommends that for oil tanks shared with other resources that only a proportionate share of the minimum tank suction level (MTSL) be allocated to black start service. The MMU further recommends that the PJM Tariff be updated to clearly state how the MTSL will be calculated for black start units sharing oil tanks. | Medium | 2017 | Not Adopted | Assessment |
| Ancillary Services | The MMU recommends that the same capability be requested of both new and existing resources. The MMU agrees with Order No. 842 that RTOs not be required to provide additional compensation specifically for frequency response. The current PJM market design provides compensation for all capacity costs, including these, in the capacity market. The current market design provides compensation, through heat rate-adjusted energy offers, for any costs associated with providing frequency response. Because the PJM market design already compensates resources for frequency response capability and any costs associated with providing frequency response, any separate filings submitted on behalf of resources for compensation under section 205 of the Federal Power Act should be rejected as double recovery. | Low | 2017 | Not Adopted | Assessment |
| Planning | The MMU recommends that, if the market efficiency process is retained, PJM modify the rules governing benefit/cost analysis, the evaluation process for selecting among competing market efficiency projects, and cost allocation for economic projects in order to ensure that all costs, including congestion costs and the risk of project cost increases, in all zones are included and in order to ensure that the correct metrics are used for determining benefits. | Medium | 2018 | Not Adopted | Assessment |
| Planning | The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated, and that the basis for all such exemptions be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build such projects or to effectively replace the RTEP process. | Medium | 2017 | Not Adopted | Assessment |
| Planning | The MMU recommends, to increase the role of competition, that the exemption of end-of-life projects from the Order No. 1000 competitive process be terminated, and that end-of-life transmission projects should be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build such projects. | Medium | 2019 | Not Adopted | Assessment |
| FTRs & ARRs | The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. | High | 2015 | Not Adopted | Assessment |
| FTRs & ARRs | The MMU recommends that all historical generation to load paths be eliminated as a basis for assigning ARRs. | High | 2015 | Partially Adopted | Assessment |
| FTRs & ARRs | The MMU recommends that the long-term FTR product be eliminated. | High | 2018 | Not Adopted | Assessment |
| FTRs & ARRs | The MMU recommends that, if the long-term FTR product is not eliminated, the long-term FTR Market be modified, so that the supply of prevailing-flow FTRs in the long-term FTR Market is based solely on counter-flow offers in the long-term FTR Market. | High | 2017 | Not Adopted | Assessment |
| FTRs & ARRs | The MMU recommends that, under the current market design, the full capability of the transmission system be allocated as ARRs prior to sale as FTRs. Reductions for outages and increased system capability should be reserved for ARRs rather than sold in the long-term FTR auction. | High | 2017 | Not Adopted | Assessment |
| FTRs & ARRs | The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. | High | 2015 | Not Adopted | Assessment |
| FTRs & ARRs | The MMU recommends that, under current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. | High | 2018 | Not Adopted | Assessment |
| FTRs & ARRs | The MMU recommends that PJM improve transmission outage modeling in the FTR auction models, including the use of probabilistic outage modeling. | Low | 2013 | Not Adopted | Assessment |
| FTRs & ARRs | The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. | Low | 2018 | Not Adopted | Assessment |
| FTRs & ARRs | The MMU recommends that PJM examine the source and sink node combinations available in the FTR Market and eliminate generation-to-generation paths, and all other paths that do not represent the delivery of power to load. | High | 2018 | Not Adopted | Assessment |
| FTRs & ARRs | The MMU recommends that if IARRs are not eliminated, IARRs should be subject to the same promotion rules that apply to all other ARR rights. | Low | 2018 | Not Adopted | Assessment |

| ARCHIVED | | | | | |
|---|---|---|---|---|---|
| Section | 2019 Recommendation | Priority | Year Reported | IMM Status | PJM Status 2020 |
| Energy Market | 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. | Low | 2018 | Not Adopted | Archived |
| Energy Market | 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 for the basis for Fuel Cost Policies but should not be required. | Low | 2018 | Not Adopted | Archived |
| Energy Market | The MMU recommends that the market rules should explicitly require that offers in the Day-Ahead 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. | Medium | 2009 | Not Adopted | Archived |
| Energy Market | The MMU recommends that PJM require that all Fuel Cost Policies be algorithmic, verifiable, and systematic, and accurately reflect short-run marginal costs. | Medium | 2016 | Not Adopted | Archived |
| Energy Market | The MMU recommends removal of all use of FERC System of Accounts in the Cost Development Guidelines. | Medium | 2016 | Not Adopted | Archived |
| Energy Market | The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. | Medium | 2016 | Not Adopted | Archived |
| Energy Market | The MMU recommends the removal of all labor costs from the Cost Development Guidelines. | Medium | 2016 | Not Adopted | Archived |
| Energy Market | The MMU recommends the removal of all maintenance costs from the Cost Development Guidelines. | Medium | 2019 | Not Adopted | Archived |
| Energy Market | The MMU recommends the removal of nuclear fuel and non-fuel operations and maintenance costs that are not short-run marginal costs from the Cost Development Guidelines. | Medium | 2016 | Not Adopted | Archived |
| Energy Market | The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2. | Medium | 2016 | Not Adopted | Archived |
| Energy Market | 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. | High | 2016 | Partially Adopted | Archived |
| Energy Market | 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. | Medium | 2015 | Not Adopted | Archived |
| Energy Market | 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. | High | 2015 | Not Adopted | Archived |
| Energy Market | 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 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. | High | 2015 | Not Adopted | Archived |
| Energy Market | The MMU recommends that in order to ensure effective market power mitigation, 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. | High | 2019 | Not Adopted | Archived |
| Energy Market | 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. | High | 1999 | Partially Adopted | Archived |
| Energy Market | 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. | Medium | 2012 | Partially Adopted | Archived |
| Energy Market | The MMU recommends that market sellers not be allowed to designate any portion of an available capacity resource's ICAP equivalent of cleared UCAP capacity commitment as a maximum emergency offer at any time during the delivery year. | Medium | 2012 | Not Adopted | Archived |
| Energy Market | 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 CONE reference resource for performance assessment and energy uplift payments, and that this standard be applied to all technologies on a uniform basis. | Medium | 2015 | Not Adopted | Archived |
| Energy Market | The MMU recommends that the parameters which determine non-performance 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 dispatchers what a unit is capable of during the operating day should not determine capacity performance assessment or uplift payments. | Medium | 2015 | Partially Adopted | Archived |

| Section | 2019 Recommendation | Priority | Year Reported | IMM Status | PJM Status 2020 |
|---|---|---|---|---|---|
| | A R C H I V E D | | | | |
| Energy Market | 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 for at least a defined sub-zonal or zonal level. | Medium | 2018 | Not Adopted | Archived |
| Energy Market | 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. | Low | 2018 | Not Adopted | Archived |
| Energy Market | 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. | Medium | 2019 | Not Adopted | Archived |
| Energy Market | 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. | Medium | 2015 | Partially Adopted | Archived |
| Energy Market | 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. | Low | 2013 | Partially Adopted | Archived |
| Energy Market | 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. | Low | 2013 | Not Adopted | Archived |
| Energy Market | 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. | Low | 2013 | Not Adopted | Archived |
| Energy Market | 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. | Low | 2013 | Not Adopted | Archived |
| Energy Market | The MMU recommends that PJM identify and collect data on available behind-the-meter generation resources, including nodal location information and relevant operating parameters. | Low | 2013 | Partially Adopted | Archived |
| Energy Market | The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. | Low | 2014 | Not Adopted | Archived |
| Energy Market | The MMU recommends that PJM not allow nuclear generators that do not respond to prices, or that only respond to manual instructions from the dispatcher, to set the LMPs in the Real-Time Market. | Low | 2016 | Not Adopted | Archived |
| Energy Market | The MMU recommends that PJM model generators' operating transitions, including modeling soak time for units with a steam turbine and configuration transitions for combined cycles, and peak operating modes. | Medium | 2019 | Not Adopted | Archived |
| Energy Market | The MMU recommends that PJM market rules require the fuel type be identified for every price and cost schedule, and PJM market rules remove non-specific fuel types such as other or co-fire other from the list of fuel types available for market participants, to identify the fuel type associated with their price and cost schedules. | Medium | 2015 | Adopted, 2019 | Archived |
| Energy Market | 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. | Medium | 2015 | Partially Adopted | Archived |
| Energy Market | The MMU recommends that PJM continue to enhance its posting of market data to promote market efficiency. | Medium | 2005 | Partially Adopted | Archived |
| Energy Market | 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. | High | 2018 | Not Adopted | Archived |
| Energy Uplift | The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM capacity market. | High | 2018 | Not Adopted | Archived |
| Energy Uplift | The MMU recommends that PJM not use closed-loop interface 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. | Medium | 2013 | Not Adopted | Archived |
| Energy Uplift | 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. | Medium | 2015 | Not Adopted | Archived |
| Energy Uplift | The MMU recommends eliminating intraday time segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24-hour operating day. | High | 2018 | Not Adopted | Archived |

| | ARCHIVED | | | | |
|---|---|---|---|---|---|
| Section | 2019 Recommendation | Priority | Year Reported | IMM Status | PJM Status 2020 |
| Energy Uplift | The MMU recommends the elimination of the day-ahead operating reserves to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output. | Medium | 2013 | Not Adopted | Archived |
| Energy Uplift | The MMU recommends enhancing the current energy uplift allocation rules to reflect the elimination of day-ahead operating reserves, the timing of commitment decisions and the commitment reasons. | High | 2012 | Not Adopted | Archived |
| Energy Uplift | The MMU recommends re-incorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. | Medium | 2018 | Not Adopted, Stakeholder Process | Archived |
| Energy Uplift | The MMU recommends that self-scheduled units not be paid energy uplift for their startup cost when the units are scheduled by PJM to start before the self-scheduled hours. | Low | 2013 | Not Adopted, Stakeholder Process | Archived |
| Energy Uplift | The MMU recommends calculating LOC based on 24-hour periods for combustion turbines and diesels scheduled in the Day-Ahead Energy Market, but not committed in real time. | Medium | 2014 | Not Adopted | Archived |
| Energy Uplift | The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. | Medium | 2015 | Not Adopted | Archived |
| Energy Uplift | The MMU recommends that only flexible fast-start units (startup plus notification times of 10 minutes or less) and short minimum run times (one hour or less) be eligible by default for the LOC compensation to the units scheduled in the Day-Ahead Energy Market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. | Medium | 2015 | Not Adopted | Archived |
| Energy Uplift | The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges. | High | 2013 | Adopted, 2018 | Archived |
| Energy Uplift | The MMU recommends allocating the energy uplift payments to units scheduled as must run in the Day-Ahead Energy Market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels. | Medium | 2014 | Not Adopted, Stakeholder Process | Archived |
| Energy Uplift | The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the balancing operating reserve credits calculation. | High | 2012 | Not Adopted, Stakeholder Process | Archived |
| Energy Uplift | The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load. | Low | 2013 | Not Adopted | Archived |
| Energy Uplift | The MMU recommends that PJM clearly identify and classify all reasons for incurring operating reserves in the Day-Ahead and the Real-Time Energy Markets, and the associated operating reserve charges, in order to make all market participants aware of the reasons for these costs and to help ensure a long-term solution to the issue of how to allocate the costs of operating reserves. | Medium | 2011 | Partially Adopted | Archived |
| Energy Uplift | The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of complete information about the level of operating reserve charges by unit, and the detailed reasons for the level of operating reserve credits by unit in the PJM region. | High | 2013 | Partially Adopted | Archived |
| Energy Uplift | The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. | Medium | 2018 | Not Adopted | Archived |
| Capacity Market | The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports. | High | 2013 | Not Adopted | Archived |
| Capacity Market | The MMU recommends that demand response (DR) providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six-months prior to any capacity auction in which the DR is offered. | High | 2016 | Not Adopted | Archived |
| Capacity Market | The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. | Medium | 2013 | Not Adopted | Archived |
| Capacity Market | The MMU recommends that the net revenue calculation by PJM to calculate the Net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations. The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. | High | 2013 | Not Adopted | Archived |
| Capacity Market | The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and re-evaluate the triggers for holding conditional incremental auctions. | Medium | 2013 | Not Adopted | Archived |

| ARCHIVED | | | | | |
|---|---|---|---|---|---|
| Section | 2019 Recommendation | Priority | Year Reported | IMM Status | PJM Status 2020 |
| Capacity Market | The MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. | Medium | 2017 | Not Adopted | Archived |
| Capacity Market | The MMU recommends changing the RPM solution method to explicitly incorporate the cost of make-whole payments in the objective function. | Medium | 2014 | Not Adopted | Archived |
| Capacity Market | The MMU recommends that PJM clear the capacity market based on nodal capacity resources locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. The current nested LDA structure used in the capacity market does not adequately represent all the capacity transfers that are feasible among LDAs. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a non-nested model for all LDAs and specify a VRR curve for each LDA separately. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should price separate if that is the result of the LDA supply curves and the transmission constraints. | Medium | 2017 | Not Adopted | Archived |
| Capacity Market | The MMU recommends that the maximum price on the VRR curve be defined as Net CONE. | Medium | 2019 | Not Adopted | Archived |
| Capacity Market | The MMU recommends that the Fixed Resource Requirement (FRR) rules, including obligations and performance requirements, be reviewed. | Medium | 2019 | Not Adopted | Archived |
| Capacity Market | The MMU recommends that, as part of the MOPR unit-specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions. | High | 2013 | Not Adopted | Archived |
| Capacity Market | The MMU recommends that modifications to existing resources not be treated as new resources for purposes of market power-related offer caps or MOPR offer floors. | Low | 2012 | Not Adopted | Archived |
| Capacity Market | The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed, and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in make-whole payments. | Medium | 2017 | Not Adopted | Archived |
| Capacity Market | The MMU recommends that the offer cap for capacity resources be defined as the Net Avoidable Cost Rate (ACR) of each unit, so that the clearing prices are a result of such Net ACR offers, consistent with the fundamental economic logic for a competitive offer of a CP resource. | High | 2017 | Not Adopted | Archived |
| Capacity Market | The MMU recommends that capacity market sellers be required to request the use of minimum MW quantities greater than 0 MW (inflexible sell-offer segments) and that the requests should only be permitted for defined physical reasons. | Medium | 2018 | Not Adopted | Archived |
| Capacity Market | The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer reflect an appropriate outage. | Medium | 2009 | Not Adopted | Archived |
| Capacity Market | The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAIH not be allowed, and that, more generally, retroactive replacement capacity transactions not be permitted. | Medium | 2016 | Not Adopted | Archived |
| Capacity Market | The MMU recommends that there be an explicit requirement that capacity resource offers in the Day-Ahead Energy Market be competitive, where competitive is defined to be the short-run marginal cost of the units. | Low | 2013 | Not Adopted | Archived |
| Capacity Market | The MMU recommends that Capacity Performance resources be required to perform without excuses. Resources that do not perform should not be paid regardless of the reason for non-performance. | High | 2019 | Not Adopted | Archived |
| Capacity Market | The MMU recommends that all capacity imports be required to be deliverable to PJM load prior to the relevant delivery year to ensure that they are full substitutes for internal, physical capacity resources. Pseudo ties alone are not adequate to ensure deliverability. | High | 2016 | Not Adopted | Archived |
| Capacity Market | The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in the unit offers in the capacity market. | High | 2016 | Not Adopted | Archived |
| Capacity Market | The MMU recommends clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. PJM has modified these rules, but the rules need additional clarification and operational details. | Low | 2010 | Partially Adopted | Archived |
| Capacity Market | The MMU recommends that the notification requirement for deactivations be extended from 90-days prior to the date of deactivation to 12-months prior to the date of deactivation, and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. | Low | 2012 | Not Adopted | Archived |
| Capacity Market | The MMU recommends that Reliability Must Run (RMR) units recover all and only the incremental costs, including incremental investment costs, required by the RMR service that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. Customers should bear no responsibility for paying previously incurred costs, including a return on or of prior investments. | Low | 2010 | Not Adopted | Archived |

| | A R C H I V E D | | | | |
|---|---|---|---|---|---|
| Section | 2019 Recommendation | Priority | Year Reported | IMM Status | PJM Status 2020 |
| Capacity Market | The MMU recommends elimination of the cost-of-service recovery rate in OATT Section 119, and that RMR service should be provided under the deactivation avoidable cost rate in Part V. The MMU also recommends specific improvements to the DACR provisions. | Medium | 2017 | Not Adopted | Archived |
| Demand Response | The MMU recommends that the option to specify a minimum dispatch price (strike price) for demand resources be eliminated, and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. | Medium | 2010 | Not Adopted | Archived |
| Demand Response | The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources. | Medium | 2013 | Not Adopted | Archived |
| Demand Response | The MMU recommends that the demand resources be treated as economic resources, responding to economic price signals like other capacity resources. The MMU recommends that demand resources not be treated as emergency resources, not trigger a PJM emergency and not trigger a Performance Assessment Interval. | High | 2012 | Not Adopted | Archived |
| Demand Response | The MMU recommends that the Emergency Program Energy Only option be eliminated, because the opportunity to receive the appropriate energy market incentive is already provided in the economic program. | Low | 2010 | Not Adopted | Archived |
| Demand Response | The MMU recommends that, if demand resources remain in the capacity market, a daily energy market must-offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources. | High | 2013 | Not Adopted | Archived |
| Demand Response | The MMU recommends that demand resources be required to provide their nodal location, comparable to generation resources. | High | 2011 | Not Adopted | Archived |
| Demand Response | The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, sub-zonal dispatch of demand resources with no advance notice required. | High | 2015 | Not Adopted | Archived |
| Demand Response | The MMU recommends that PJM not remove any defined sub-zones and maintain a public record of all created and removed sub-zones. | Low | 2016 | Not Adopted | Archived |
| Demand Response | The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and sub-zonal approach and creates larger mismatches between the locational need for the resources and the actual response. | High | 2015 | Not Adopted | Archived |
| Demand Response | The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately. | Medium | 2009 | Not Adopted | Archived |
| Demand Response | The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. | Medium | 2012 | Not Adopted | Archived |
| Demand Response | The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that operators have the necessary information for reliability, and that market payment-to-demand resources be calculated based on interval meter data at the site of the demand reductions. | Medium | 2013 | Not Adopted | Archived |
| Demand Response | The MMU recommends limited, extended summer and annual demand response event compliance be calculated on an hourly basis for non-Capacity Performance resources and on a five-minute basis for all Capacity Performance resources, and that the penalty structure reflect five-minute compliance. | Medium | 2013 | Partially Adopted | Archived |
| Demand Response | The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event. | Low | 2012 | Not Adopted | Archived |
| Demand Response | The MMU recommends that shutdown cost be defined as the cost to curtail for a given period that does not vary with the measured reduction or, for behind-the-meter generators, be the start cost defined in Manual 15 for generators. | Low | 2012 | Not Adopted | Archived |
| Demand Response | The MMU recommends that the Net Benefits Test be eliminated, and that demand response resources be paid LMP less any generation component of the applicable retail rate. | Low | 2015 | Not Adopted | Archived |
| Demand Response | The MMU recommends that the Tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of materials changes affecting the capability of the resource to perform as registered, and must terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at defined levels, because load has been reduced or eliminated, as in the case of bankrupt and/or out-of-service facilities. | Medium | 2015 | Not Adopted | Archived |
| Demand Response | The MMU recommends that there only be one demand response product in the capacity market, with an obligation to respond when called for any hour of the delivery year. | High | 2011 | Partially Adopted | Archived |
| Demand Response | The MMU recommends that the lead times for demand resources be shortened to 30 minutes with an hour minimum dispatch for all resources. | Medium | 2013 | Partially Adopted | Archived |
| Demand Response | The MMU recommends setting the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting. | High | 2010 | Partially Adopted | Archived |
| Demand Response | The MMU recommends the Relative Root Mean Squared Test be required for all demand resources with a CBL. | Low | 2017 | Partially Adopted | Archived |
| Demand Response | The MMU recommends that PRD be required to respond during a PAIH to be consistent with all CP resources. | High | 2017 | Not Adopted | Archived |

| | A R C H I V E D | | | | |
|---|---|---|---|---|---|
| Section | 2019 Recommendation | Priority | Year Reported | IMM Status | PJM Status 2020 |
| Demand Response | The MMU recommends that the limits imposed on the pre-emergency and emergency demand response share of the Synchronized Reserve Market be eliminated. | Medium | 2018 | Not Adopted | Archived |
| Demand Response | The MMU recommends that 30-minute pre-emergency and emergency demand response be considered to be 30-minute reserves. | Medium | 2018 | Not Adopted | Archived |
| Demand Response | The MMU recommends that energy efficiency MW not be included in the PJM capacity market, and that PJM should ensure that the impact of EE measures on the load forecast is incorporated immediately rather than the existing lag. | Medium | 2018 | Not Adopted | Archived |
| Demand Response | The MMU recommends that demand reductions based entirely on behind-the-meter generation be capped at the lower of economic maximum or actual generation output. | High | 2019 | Not Adopted | Archived |
| Net Revenue | The MMU recommends that the net revenue calculation used by PJM to calculate the Net Cost of New Entry (CONE) and Net ACR be based on a forward-looking estimate of expected energy and ancillary services net revenues using forward prices for energy and fuel. | Medium | 2019 | Not Adopted | Archived |
| Environmental | The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. | Medium | 2010 | Not Adopted | Archived |
| Environmental | The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets, because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates. | High | 2018 | Not Adopted | Archived |
| Environmental | The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent. | Low | 2018 | Not Adopted | Archived |
| Environmental | The MMU recommends that load and generation located at separate nodes be treated as separate resources in order to ensure that load and generation face consistent incentives throughout the markets. | High | 2019 | Not Adopted | Archived |
| Environmental | The MMU recommends that emergency stationary RICE be prohibited from participation as DR either when registered individually or as part of a portfolio if it does not meet emissions standards, because the environmental run hour limitations mean that emergency RICE cannot meet the capacity market requirements to be DR. | Medium | 2019 | Not Adopted | Archived |
| Interchange Transactions | The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after-the-fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. | High | 2012 | Not Adopted | Archived |
| Interchange Transactions | The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule by concealing the true source or sink of the transaction. | Medium | 2013 | Not Adopted | Archived |
| Interchange Transactions | The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. | Medium | 2013 | Not Adopted | Archived |
| Interchange Transactions | The MMU recommends that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. | Medium | 2003 | Not Adopted | Archived |
| Interchange Transactions | The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market. | Medium | 2014 | Not Adopted | Archived |
| Interchange Transactions | The MMU recommends that PJM permit unlimited spot market imports, as well as unlimited non-firm, point-to-point willing to pay congestion imports and exports, at all PJM interfaces in order to improve the efficiency of the market. | Medium | 2012 | Not Adopted | Archived |
| Interchange Transactions | The MMU recommends that the emergency interchange cap be replaced with a market-based solution. | Low | 2015 | Not Adopted | Archived |
| Interchange Transactions | The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three-hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner. | Medium | 2014 | Partially Adopted | Archived |
| Ancillary Services | The MMU recommends that the total regulation (TReg) signal sent on a fleet-wide basis be eliminated and replaced with individual regulation signals for each unit. | Low | 2019 | Not Adopted | Archived |
| Ancillary Services | The MMU recommends enhanced documentation of the implementation of the Regulation Market design. | Medium | 2010 | Not Adopted, FERC Rejected, pending rehearing | Archived |
| Ancillary Services | The MMU recommends that PJM be required to save data elements necessary for verifying the performance of the Regulation Market | Medium | 2010 | Not Adopted | Archived |

| ARCHIVED | | | | | |
|---|---|---|---|---|---|
| Section | 2019 Recommendation | Priority | Year Reported | IMM Status | PJM Status 2020 |
| Ancillary Services | The MMU recommends that separate cost-of-service payments for reactive capability be eliminated, and the cost of reactive capability be recovered in the capacity market. | Medium | 2016 | Not Adopted | Archived |
| Ancillary Services | The MMU recommends that payments for reactive capability, if continued, be based on the 0.90 power factor that PJM has determined is necessary. | Medium | 2018 | Not Adopted | Archived |
| Ancillary Services | The MMU recommends that fleet-wide, cost-of-service rates used to compensate resources for reactive capability be eliminated and replaced with compensation based on unit-specific costs. | Low | 2019 | Not Adopted | Archived |
| Planning | The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors. | Low | 2013 | Adopted, 2012 | Archived |
| Planning | The MMU recommends that rules be implemented to ensure that CIRs are terminated within one year if units cannot qualify to be capacity resources and, if requested, after one CP must-offer exception to permit the issue of CP status to be addressed. | Low | 2018 | Adopted, 2019 | Archived |
| Planning | The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants, and reflect the uncertainty and resultant risks in the cost of new entry used to establish the capacity market demand curve in RPM. | Low | 2012 | Not Adopted | Archived |
| Planning | The MMU recommends improvements in queue management, including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. | Medium | 2013 | Partially Adopted | Archived |
| Planning | The MMU recommends continuing analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service. | Medium | 2014 | Partially Adopted | Archived |
| Planning | The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated, and the owner of transmission also owns generation. | Low | 2013 | Not Adopted | Archived |
| Planning | The MMU recommends that the market efficiency process be eliminated, because it is not consistent with a competitive market design. | Medium | 2019 | Not Adopted | Archived |
| Planning | The MMU recommends that, if the market efficiency process is retained, PJM modifies the rules governing the market efficiency process benefit/cost analysis, so that competing projects with different in-service dates are evaluated on a symmetric, comparable basis. | Medium | 2018 | Not Adopted | Archived |
| Planning | The MMU recommends that PJM enhance the transparency and queue management process for non-incumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from non-incumbent transmission providers. | Medium | 2015 | Not Adopted | Archived |
| Planning | The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market-driven processes as much as possible. | Low | 2001 | Not Adopted | Archived |
| Planning | The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. | Low | 2013 | Not Adopted | Archived |
| Planning | The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove barriers to entry and permit competition between incumbent transmission providers and non-incumbent transmission providers in the RTEP. | Medium | 2014 | Not Adopted | Archived |
| Planning | The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. | Low | 2013 | Not Adopted | Archived |
| Planning | The MMU recommends that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. | Medium | 2015 | Not Adopted | Archived |
| Planning | The MMU recommends consideration of changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum usage impact on the line. | Medium | 2015 | Not Adopted | Archived |
| Planning | The MMU recommends that all PJM transmission owners use the same methods to define line ratings, subject to NERC standards and guidelines, subject to review by NERC and approval by FERC. | Medium | 2019 | Not Adopted | Archived |
| Planning | The MMU recommends that PJM re-evaluate all transmission outage tickets as on time or late if they were new requests when an outage is rescheduled, and apply the standard rules for late submissions to any such outages. | Low | 2014 | Not Adopted | Archived |
| Planning | The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review. | Low | 2015 | Not Adopted | Archived |

| | ARCHIVED | | | | |
|---|---|---|---|---|---|
| Section | 2019 Recommendation | Priority | Year Reported | IMM Status | PJM Status 2020 |
| Planning | The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date. | Low | 2015 | Not Adopted | Archived |
| Planning | The MMU recommends that PJM not permit transmission owners to divide long-duration outages into smaller segments to avoid complying with the requirements for long-duration outages. | Low | 2015 | Not Adopted | Archived |
| FTRs & ARRs | The MMU recommends that FTR auction revenues not be used to buy counter-flow FTRs for the purpose of improving FTR payout ratios. | High | 2015 | Not Adopted | Archived |
| FTRs & ARRs | The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR Market participants. | High | 2012 | Not Adopted, Rejected by FERC | Archived |
| FTRs & ARRs | The MMU recommends that PJM eliminate subsidies to counter-flow FTRs by applying the payout ratio to counter-flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. | High | 2012 | Not Adopted | Archived |
| FTRs & ARRs | The MMU recommends that PJM eliminate geographic cross subsidies. | High | 2013 | Not Adopted | Archived |
| FTRs & ARRs | The MMU recommends that PJM examine the mechanism by which self-scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. | Low | 2011 | Not Adopted | Archived |
| FTRs & ARRs | The MMU recommends that PJM reduce FTR sales on paths with persistent over allocation of FTRs, including clear rules for what defines persistent over allocation and how the reduction will be applied. | High | 2013 | Partially Adopted | Archived |