PJM Response to the 2021 State of the Market Report

June 10, 2022

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Contents

Introduction

At the outset, PJM wishes to recognize the comprehensive and thorough analysis of the PJM markets prepared by Monitoring Analytics in the 2021 State of the Market Report (SOM). The report serves as an excellent source of information and analysis concerning each of the markets operated by PJM. PJM encourages stakeholders to review the document and utilize, to the extent they deem appropriate, the detailed data presented in the report concerning different aspects of the PJM markets.

The SOM contained 239 recommendations that provide the perspective of Monitoring Analytics, the Independent Market Monitor (IMM) or Market Monitoring Unit (MMU) for PJM, regarding changes to the PJM market design, rules and administration intended to enhance the competitiveness, efficiency and durability of PJM's markets. The purpose of this document is to review the 20 new recommendations from 2021 and provide PJM's initial responses as to the applicability of the recommendation to the current market and any next steps for pursuing design enhancements related to the recommendation. Many of the recommendations are related to stakeholder engagements that are currently in process, and such ongoing discussions are also referenced in the responses below.

Also included in this response is a categorization of the SOM recommendations based upon their actionable status, as well as an appendix providing a complete list of the recommendations identified by their section in the SOM report.

PJM looks forward to discussion of these topics with members, stakeholders and Monitoring Analytics.

Responses to New Recommendations From the 2021 SOM Report

Energy Market Recommendations

System Marginal Price Caps

> *The MMU recommends that PJM stop capping the system marginal price in RT SCED [Real-Time Security Constrained Economic Dispatch] and instead limit the sum of violated reserve constraint shadow prices used in the LPC [Locational Price Calculator] to $1,700 per MWh.*

PJM Response

This recommendation was superseded by events that occurred after it was first reported in Q1 2021. In December 2021, FERC issued an order on voluntary remand from the D.C. Circuit Court, reversing certain reserve market enhancements it had initially ordered in May 2020. Among the elements reversed was the Reserve Penalty Factor of $2,000/MWh for all reserve products. FERC directed PJM to revise its tariff to reflect the currently effective Reserve Penalty Factors of $850/MWh. However, because the order did not reverse the introduction of a new reserve product, the approach to price capping also needed to be updated.

In January 2022 PJM requested clarification regarding whether the 2021 remand order retained the Commission's prior acceptance of the removal of certain price capping provisions applicable to PJM's reserve markets or directed the restoration of the reserve market price caps. Crucially, with regard to this IMM recommendation, on February 11, 2022, the Commission clarified that the reserve market enhancements affirmed in its remand order did not include the removal of price caps in the reserve markets.[1] However, the Commission stated that because the remand order affirmed "adopt[ion of] a new 30-minute Reserve Requirement and Secondary Reserve product, PJM may propose revised reserve price caps to reflect the addition of this new product."[2]

On February 22, 2022, PJM submitted compliance filings to implement the subset of reserve market enhancements FERC originally accepted in May 2020 and affirmed in December 2021.[3] On compliance, and in accordance with the FERC clarification, PJM proposed to maintain the same general reserve price capping framework while incorporating the new 30-minute Reserve Requirement and Secondary Reserve product. PJM's proposed approach:

- Maintained the same general reserve price capping framework while incorporating the new 30-minute Reserve Requirement and Secondary Reserve product
- Maintained the upper limit on reserve prices, with Synchronized Reserve prices capped at two times the Reserve Penalty Factor, or $1,700/MWh
- Maintained the current allowed maximum energy component of the locational marginal price of $3,700/MWh

[1] See PJM Interconnection, L.L.C., 178 FERC ¶ 61,085, at P 15 ("[W]e clarify that the Remand Order did not remove the reserve price caps.").

[2] 178 FERC ¶ 61,085, at P 17.

[3] https://www.pjm.com/directory/etariff/FercDockets/6556/20220222-el19-58-012.pdf

In summary, PJM filed an approach consistent with FERC's direction that PJM retain the existing reserve market and energy market price capping framework which is also largely consistent with this specific SOM recommendation. Implementation of this design will be coincident with other reserve market enhancements, currently scheduled for October 1, 2022.

Downward Sloping Operating Reserve Demand Curves

> *The MMU recommends, if PJM implements extended downward sloping ORDCs [Operating Reserve Demand Curves], that PJM calculate the probability of reserves falling below the minimum reserve requirement (MRR) based on ten-minute rather than a 30-minute forecast error, and on forced outages in the ten-minute rather than the 30-minute look-ahead window to model the uncertainty in the inputs to RT SCED.*

PJM Response

This recommendation is not applicable to the current PJM market. As discussed above, in December 2021, FERC reversed several elements of its prior May 2020 order accepting PJM's proposed operating reserve market enhancements; among the elements reversed and rejected was the downward-sloping design for operating reserve demand curve. PJM has no plans to implement downward sloping demand curves for operating reserves at this time.

PJM continues to believe that flexible resources needed for operational reliability should be compensated in a manner that reflects their value to the system. In Q1 2022, PJM and stakeholders in the Operating Committee completed an assessment of reliability services, evaluating the need for PJM's procurement of additional reliability-based services, with a particular focus on reliability needs in the face of the changing resource portfolio and increased penetration of intermittent resource technologies. As part of that review, the Operating Committee recommended the Energy Price Formation Senior Task Force (EPFSTF) consider how to value flexibility within existing or modified ancillary services.

Flexibility Obligations

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

PJM Response

PJM and stakeholders are discussing various related Key Work Activities at the Resource Adequacy Senior Task Force (RASTF), including several intended to provide additional clarity regarding the definition of the capacity product. In particular, Key Work Activity #6 is to "Determine the desired obligations of capacity resources" including "[w]here necessary, clarify the existing obligations of a capacity resource." PJM believes that ensuring all capacity resources comply with all applicable obligations is crucial to ensuring reliability and doing so cost effectively.

However, PJM disagrees that capacity resources have broad "obligations to be flexible" under the *current* capacity market construct. Flexibility is not a core component of the capacity product definition in the PJM markets today:

- Flexibility is not an explicit requirement for the qualification for capacity resources.

- Flexibility is largely not accounted for in the accreditation of capacity resources.
- Capacity resources do not have an obligation to be flexible at all times.

It is also not clear that strict requirements, within the capacity market, to maximize resource flexibility would lead to efficient market outcomes. As further discussed in affidavits filed by Adam Keech, PJM Vice President – Market Design & Economics, and Walter Graf – Senior Director, Economics, in the FERC "Modernizing Electricity Market Design: Energy and Ancillary Services in the Evolving Electricity Sector" docket, requiring flexible parameters in offers at all times could lead to less efficient operational and investment signals and higher customer costs with no commensurate improvement in reliability.[4]

Notwithstanding the above, PJM looks forward to continued interaction with IMM and stakeholders to clarify and, where necessary, change the obligations placed on capacity resources.

Temporary Parameter Exception Process and Turn-Down Ratio Violations

The MMU recommends that PJM require generators that violate their approved turn-down ratio (by either using the fixed gen option or increasing their economic minimum) to use the temporary parameter exception process that requires market sellers to demonstrate that the request is based on a physical and actual constraint.

PJM Response

This recommendation concerns a subset of issues related to a June 17, 2021, FERC Order to Show Cause, in which the Commission found PJM's Tariff appeared to allow market sellers to circumvent being subject to parameter-limited offers.[5]

In its filed response,[6] PJM placed interim limitations on the use of Real Time Values, limiting their use only to physical and actual unit limitations that may have occurred during the real-time market. PJM believes these interim limitations sufficiently address concerns that market sellers could submit Real Time Values to inappropriately limit their flexibility since economic reasons for adjusting parameter limits are no longer acceptable reasons to override unit-specific parameters.

Given that PJM agrees the existing Tariff provisions need to be updated to more explicitly accommodate deviations to operating parameters in real time, PJM further proposed Tariff revisions to sunset the use of Real Time Values and allow Market Sellers to submit temporary exceptions during the real-time market under the existing Tariff procedures.

[4] Graf affidavit: https://www.ferc.gov/media/dr-walter-graf-senior-director-economics-pjm-interconnection-llc

Keech affidavit: https://www.ferc.gov/media/pjm-comments

[5] PJM Interconnection, L.L.C., Order to Show Cause, 175 FERC ¶ 61,231 (June 17,2021)

[6] PJM Interconnection, L.L.C., Answer of PJM Interconnection, L.L.C., Docket No. EL21-78-000 (September 15, 2021). https://www.pjm.com/-/media/documents/ferc/filings/2021/20210915-el21-78-000.ashx

This approach is consistent with the IMM's position that "[t]he temporary exception process balances the need to require flexible parameters with the ability to reflect changes to the capability of a unit due to unforeseen issues."[7]

Thus, through this filing, PJM essentially proposed to adopt the IMM's previously suggested approach of expanding the existing temporary exception procedures so that market sellers are not limited to submitting the exceptions at least one business day before the operating day.

Besides removing the temporal restrictions for when temporary exceptions may be submitted, PJM also proposed to strengthen the rules that govern temporary exceptions to ensure that any physical limitation that prompted the need for a temporary exception actually exists for the entire duration of the exception period, requiring that market provide supporting documentation to substantiate the termination date of the temporary exception and also provide updates on the physical limitation during the period of the temporary exception. This will ensure Market Sellers notify PJM of an early termination of a temporary exception in the event the physical unit limitation is remedied earlier than expected when the temporary exception was first submitted.

FERC has not yet issued an order in this open docket; while the proposed Tariff changes are not in effect, the interim limitations on the use of Real Time Values have been in effect since August 1, 2021.

ORDCs During Spin Events

The MMU recommends that PJM adjust the ORDCs during spin events to reduce the reserve requirement for synchronized and primary reserves by the amount of the reserves deployed.

PJM Response

PJM views this recommendation to be inconsistent with the NERC standard[8] that obligates PJM to procure contingency reserves and also with PJM's policy for maintaining adequate reserves. PJM's current policy regarding reserves is intended to restore reserves as quickly as possible following their deployment. The purpose of this is to make sure that the PJM system can respond to successive contingencies should they occur. This recommendation is inconsistent with that operating policy.

From a markets perspective, reducing the reserve requirement for these products following a reserve deployment is equivalent to specifying a lower demand and lower value for those reserve products. However, the reliability value of those products is no different following a reserve deployment compared to at any other time. Thus, PJM must endeavor to maintain the required levels of various reserve products at all times, including following a reserve deployment; the current market design accomplishes this objective.

[7] Protest of the Independent Market Monitor for PJM, Docket No. ER21-1591-000, at 7 (April 22, 2021).

[8] "Standard BAL-002-0 – Disturbance Control Performance," Adopted by NERC Board of Trustees, Effective Date: April 1, 2005. https://www.nerc.com/files/BAL-002-0.pdf

Shortage Price Calculation and Reserve Price Cap Implementation Manual Documentation

> *The MMU recommends that PJM clearly document the calculation of shortage prices and implementation of reserve price caps in the PJM Manuals, including defining all the components of reserve prices, and all the constraints whose shadow prices are included in reserve prices.*

PJM Response

PJM agrees that transparency in price formation is needed, and that Market Participants and stakeholders must have access to this information in order to ensure efficient operational and investment decisions. Some of the information referenced in this recommendation was clarified in revised tariff language filed with FERC as part of the reserve market compliance filing in February 2022 (see discussion above). Additional information was also provided during various education sessions of the PJM Energy Price Formation Senior Task Force (EPFSTF). PJM will continue to discuss additional education and clarifications needed to the PJM Manuals with stakeholders at the EPFSTF and plans to implement those changes pursuant to finalizing discussions at the EPFSTF.

Energy Uplift Recommendations

> *The MMU recommends that units not be paid lost opportunity cost uplift when PJM directs a unit to reduce output based on a transmission constraint or other reliability issue. There is no lost opportunity because the unit is required to reduce for the reliability of the unit and the system.*

PJM Response

Depending on the nature of the limitation leading to the PJM direction to reduce output, there may or may not be a lost opportunity, and thus there may or may not exist a need to pay lost opportunity cost uplift. For example, if PJM directs a unit to reduce output due to a transmission line thermal limitation, the resource in question may well be able to earn higher revenues (and profits) by continuing to output at a higher level than directed. Not paying lost opportunity cost uplift would lead to incentive compatibility issues where the resource is incentivized to not follow dispatch, potentially creating or compounding reliability challenges.

Alternatively, under certain transmission outage conditions, the output of nearby generating stations may need to be limited to prevent transient instability on the integrated bulk electric system from causing damage to those generating facilities due to the loss of synchronization in the event of an N-1 contingency. When reduced output is directed to such transmission stability limitation, there is no lost opportunity because operation above a certain directed output level would cause the unit to trip offline. Currently, PJM's long-established process for setting generator stability limits can result in PJM paying lost opportunity cost uplift in this case.

However, this issue was considered with stakeholders as part of the "Modeling Units with Stability Limitations" Problem Statement and Issue Charge. Together with stakeholders and the IMM, PJM designed a new market approach to enhance PJM's current operational processes for generation stability limits, which was filed with FERC on April 30, 2021, and has a planned effective date of June 1, 2022.[9] A foundational component of this filing was

[9] https://www.pjm.com/directory/etariff/FercDockets/6103/20210430-er21-1802-000.pdf

Tariff and Operating Agreement revisions to memorialize that "a temporary reduction of generator output associated with honoring a stability limit does not entitle the resource to any lost opportunity cost credits,"[10] consistent with the IMM recommendation above. The updated Tariff and Operating Agreement revisions apply in all cases except if the stability limitation is manually provided due to, for example, loss of SCED. In the case of a manual dispatch stability limitation, lost opportunity cost will apply.

Capacity Market Recommendations

PJM and stakeholders are discussing a wide range of reforms and enhancements to its capacity market and overall resource adequacy framework through the ongoing Resource Adequacy Senior Task Force (RASTF), which began in December 2021 following approval of a Charter and Issue Charge.[11] The scope of work includes a discussion of the types of reliability risks and risk drivers to be considered in the capacity market, the desired procurement metric and level, capacity resource qualification and accreditation, capacity resource obligations, performance assessments and incentives, discussions of a seasonal capacity market construct and other enhancements to the capacity procurement process, and changes to the supply-side market power mitigation rules. Many of the IMM capacity market-related recommendations are related to active discussions ongoing in the RASTF, and PJM looks forward to continuing to engage with stakeholders and the IMM on these issues over the coming months.

Value of Capacity Transfer Rights

The MMU recommends that the value of CTRs [Capacity Transfer Rights] should be defined by the total MW cleared in the capacity market, the internal MW cleared and the imported MW cleared, and not redefined later prior to the delivery year.

PJM Response

A Capacity Transfer Right (CTR) is a right, allocated to Load-Serving Entities (LSEs) serving load in a Locational Deliverability Area (LDA), to receive payments, based on the transmission import capability into the LDA, that offset in whole or in part the charges attributable to the Locational Price Adder included in the LDA Zonal Capacity Price.

The allocation of CTRs can have substantial impacts on the implied allocation of the costs of capacity market purchases. The current approach to allocation of capacity costs requires that CTRs are allocated to each LSE serving load in an LDA pro rata based on each LSE's daily Unforced Capacity (UCAP) obligation in the LDA. Alternative approaches to allocating and settling CTRs for constrained LDAs may be considered as part of the RASTF scope.

[10] *Id., pg. 5.*

[11] https://www.pjm.com/committees-and-groups/task-forces/rastf

Capacity Offers of Intermittent Resources

The MMU recommends that intermittent resources, including storage, not be permitted to offer capacity MW based on energy delivery that exceeds their defined deliverability rights (CIRs). Only energy output for such resources below the designated CIR/deliverability level should be recognized in the definition of capacity.

PJM Response
The issues at the core of this recommendation are currently under active discussion at special sessions of the Planning Committee on "Capacity Interconnection Rights for ELCC Resources."[12] Stakeholders are currently considering alternative options proposed by stakeholders and PJM. The proposed approach would, in part, limit the generator output recognized in determining ELCC to that output deemed deliverable under the revised deliverability tests. PJM's proposed modifications to each of the generator deliverability tests would better account for expected higher variability in dispatches under increased renewable penetration and better align planning with operations, supporting operational performance.

Must-Offer Rule

The MMU recommends that the must-offer rule in the capacity market apply to all capacity resources. There is no reason to exempt intermittent and storage resources, including hydro. The purpose of the must-offer rule, which has been in place since the beginning of the capacity market in 1999, is to prevent the exercise of market power via withholding.

PJM Response
The must-offer rule in the capacity market is one component of an extensive framework for mitigating supply-side market power and, specifically, is an important part of tools available to PJM and the IMM to mitigate physical withholding in the capacity market. PJM anticipates discussing this recommendation with the IMM and stakeholders within the broader context of the key work activity considering enhancements to the supply-side market power mitigation rules in the capacity market.

Shape of the Variable Resource Requirement Curve

The MMU recommends that PJM reevaluate the shape of the VRR curve. The shape of the VRR curve directly results in load paying substantially more for capacity than load would pay with a vertical demand curve.

PJM Response
Periodic reevaluation of the Variable Resource Requirement (VRR) curve and reference technology are required by PJM Tariff. Together with stakeholders, PJM is currently reevaluating the shape of the VRR curve in special sessions of the Market Implementation Committee focused on this "Quadrennial Review." PJM looks forward to continuing

[12] https://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue=83aadda8-b6c1-4630-9483-025b6b93fc28

discussions with the IMM and stakeholders on the important tradeoffs between competing objectives of (low) costs and (high) reliability involved with the design of the VRR curve.

Capacity Market Settlements

The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used, or that the process of modifying the obligations to pay for capacity be reviewed.

PJM Response

The allocation of the costs of capacity market purchases involves numerous tradeoffs among competing objectives, including efficiency, equity, simplicity and others. As discussed above in the response regarding CTRs, the current approach to allocating capacity costs adjusts cost allocation to reflect the contribution to peak load of each LSE and each LDA, relative to RTO-wide peak loads. Alternative approaches to allocating capacity market costs to loads may be considered as part of the RASTF scope.

Capacity Emergency Transfer Limit Calculations

The MMU recommends that PJM improve the clarity and transparency of its CETL [Capacity Emergency Transfer Limit] calculations. The MMU also recommends that CETL for capacity imports into PJM be based on the ability to import capacity only where PJM capacity exists and where that capacity has a must-offer requirement in the PJM capacity market.

PJM Response

PJM agrees with the IMM regarding the value of clear and transparent market rules and calculations regarding Capacity Emergency Transfer Limits (CETL) and will work with the IMM and stakeholders to identify any additional information that may be needed.

With regard to the recommendation for CETL for capacity imports into PJM, this refers to a specific issue where, in internal conversations with PJM, the IMM has identified specific and narrow instances where it believed the CETL calculation was improperly impacted by the potential for capacity imports from NYISO. Following further discussion and information sharing, the IMM has subsequently confirmed PJM's current CETL calculations correctly account for a small amount (less than 200 MW) of firm imports from NYISO. Further discussions regarding the framework and methodology for calculating CETL are within scope at the RASTF and PJM looks forward to discussing further with stakeholders and the IMM in that venue.

Calculation of Energy and Ancillary Services Market Revenue Offset

The MMU recommends using the lower of the cost or price-based energy market offer to calculate energy costs in the calculation of the historical net revenues, which are an offset to gross ACR [Avoidable Cost Rate] in the calculation of unit-specific capacity resource offer caps based on net ACR.

PJM Response

The assessment of energy and ancillary service (E&AS) revenues is an important component in determining two elements of the PJM capacity markets. First, it is used to calculate the net cost of new entry of the reference technology for the purpose of determining VRR curve parameters; the E&AS revenues offset, in part, the gross (total) costs of new entry for the reference technology. In this context, PJM is currently discussing with stakeholders the appropriate methodology and assumptions to use when calculating the E&AS offset as part of the ongoing Quadrennial Review stakeholder engagement.

Second, as described in the recommendation above, it is used within the capacity market power mitigation framework when determining capacity resource market seller offer caps based on the avoidable cost rate. The appropriate methodology and assumptions to be used in this context are in scope for discussion as part of the RASTF discussions on supply-side market power mitigation framework enhancements.

Treatment of Seasonal Capacity Resources

The MMU recommends that any combined seasonal resources be required to be in the same LDA and preferably at the same location, in order for the energy market and capacity market to remain synchronized and reliability metrics correctly calculated.

PJM Response

PJM and stakeholders will consider all aspects of seasonal capacity market design within the ongoing RASTF. The scope of discussion includes both enhancements to the current treatment of any combined seasonal resources (whether through Commercial Aggregation or Facilitated Aggregation), as well as entirely new approaches for incorporating seasonal resources into the capacity market.

Demand Response Recommendations

Participation of Electric Distribution Companies as Distributed Energy Resource Aggregators

The MMU recommends that EDCs not be allowed to participate in markets as DER aggregators in addition to their EDC role.

PJM Response

This recommendation is inconsistent with FERC Order No. 2222, in which the Commission affirmed that "market participation agreements for distributed energy resource (DER) aggregators should not preclude distribution utilities, cooperatives, or municipalities from aggregating distributed energy resources on their systems or even microgrids from participating in the RTO/ISO markets as a DER aggregation."[13] Accordingly, PJM's DER Aggregator Participation Model, proposed as a component of PJM's Order 2222 compliance filing, does not prohibit a distribution utility from forming its own DER Aggregation Resources. This is consistent with current practice today, where certain distribution utilities participate in the PJM demand response program with their own load reduction resources.

[13] See Order No. 2222 at pp. 340 and 353.

However, unlike the PJM demand response program, the DER Aggregator Participation Model will allow Component DER to inject onto the grid, and require a greater level of distribution utility coordination to ensure safety and reliability. This sets up a scenario in which a distribution utility – the entity responsible for physically operating its distribution facilities and overriding PJM dispatch of other DER aggregators – may also be competing against other DER aggregators connected to those same distribution facilities. PJM acknowledges concerns regarding this potential conflict of interest and anticipates continued dialogue with states and stakeholders on how state and local law may address this issue.

Size Limit for Distributed Energy Resource Aggregations

The MMU recommends that PJM include a 5 MW maximum size cap on DER aggregations.

PJM Response
This issue was considered as part of the stakeholder process culminating in PJM's Order No. 2222 compliance filing on Feb. 1, 2022, relating to the participation of DER aggregators in PJM's energy, capacity and ancillary services markets.[14] Specifically, in Order No. 2222, the Commission directed PJM to propose a maximum capacity requirement for individual DER participating in its markets through a DER aggregation or, alternatively, to explain why such a requirement is not necessary. In compliance with this directive, PJM proposed to establish a cap of 5 MW on the maximum capacity of individual Component DER participating in a DER Aggregation Resource. Component DER that are greater than the maximum capacity requirement of 5 MW would be required to participate through a different applicable participation model in PJM markets.

However, FERC did not require, nor did stakeholders endorse, a 5 MW maximum size cap on DER Aggregation Resources. PJM did propose implementation of nodal aggregation for DER Aggregation Resources, which places some natural bounds on the size of DER Aggregation Resources that will be managed by the distribution interconnection process and the hosting capacity of the distribution system.

Environmental and Renewable Regulations Recommendations

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. The MMU recommends that there be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real-time delivery.

PJM Response
PJM agrees with the IMM regarding the potential value of integrating state renewable and clean energy policies more closely with the PJM markets, and, as such, has been pursuing potential solutions in this space through two forums.

First, PJM has been working closely with the OPSI Competitive Policy Achievement Working Group to provide education, information, and support to enable the working group to "develop a proposal for a voluntary, market-based

[14] https://www.pjm.com/directory/etariff/FercDockets/6522/20220201-er22-962-000.pdf

procurement option that enables states and willing buyers to access competitive energy resources in line with their policy goals."[15]

Second, in June 2022, PJM and stakeholders will begin meetings of the Clean Attribute Procurement Senior Task Force, following approval of the "Procurement of Clear Resource Attribute" Issue Charge at the April 27, 2022, Markets & Reliability Committee. This forum will enable a "comprehensive discussion of market enhancements to enable states and other willing buyers to procure clean resource attributes, on a voluntary basis, through a regional and centralized procurement or market."[16] The IMM recommendation of a PJM-operated forward market for renewable energy credits (RECs) is potentially one of several design options to be considered by this stakeholder group.

Ancillary Services Recommendations

> *The MMU recommends that the $12.00 margin adder be eliminated from the definition of the cost-based regulation offer because it is a markup and not a cost.*

PJM Response

This recommendation is in scope for consideration within the Regulation Market Design Senior Task Force (RMDSTF), which held its first meeting on March 22, 2022, following approval of a joint PJM/IMM Problem Statement and Issue Charge. The RMDSTF will address regulation market design flaws and potential enhancements including regulation signal design, regulation performance scoring, regulation requirement, regulation market clearing and regulation market settlement.[17]

Financial Transmission Rights and Auction Revenue Rights Recommendations

> *The MMU recommends the use of a 99 percent confidence interval when calculating initial margin requirements for FTR Market Participants, in order to assign the cost of managing risk to the FTR holders who benefit or lose from their FTR positions.*

PJM Response

This recommendation is related to a set of issues concerning the credit requirements for FTR Market Participants, currently under consideration by PJM and stakeholders at the PJM Members Committee. FTR Market Participant credit requirements, or "initial margin requirements," are determined based on an historical simulation analysis that reflects expected volatility of FTR position values. Alternative proposals concerning the assumptions and inputs to that Historical Simulation Initial Margining (HSIM) approach require that credit requirements be sufficient to cover either a 97% confidence interval or 99% confidence interval of potential FTR position value. Following stakeholder discussion, PJM filed a proposed HSIM approach with the FERC on December 21, 2021, with a proposed 97% confidence interval; the Commission subsequently rejected the filed revisions as unsupported by the record.

[15] https://opsi.us/wp-content/uploads/2021/10/OPSI-Competitive-Policy-Achievement-Staff-Working-Group-10.21.21.pdf

[16] https://www.pjm.com/committees-and-groups/task-forces/capstf

[17] https://www.pjm.com/-/media/committees-groups/task-forces/rmdstf/postings/rmdstf-issue-charge.ashx

PJM has been in active discussion with stakeholders concerning next steps in the first half of 2022. In March, PJM held two meetings to share its thoughts on a recommended path and to seek feedback, and a March 23 Members Committee meeting included an advisory vote by members on a path forward; members supported refiling the 97% confidence interval accompanied by new supporting rationale. Based on stakeholder feedback, PJM conducted additional analyses regarding the costs and benefits of the 97% and 99% confidence interval options.[18] The 97% confidence interval option showed to be the most cost beneficial proposal: across the membership, the increase in cost of collateral moving from 97% to 99% confidence interval appears greater than the benefit, given the expected reduction in default size. Based on this and other additional analysis, PJM believes it can supplement the December 205 filing with additional evidence to support use of the 97% confidence interval to address most of FERC's concerns. PJM also plans to work with stakeholders on provisions to identify the riskiest portfolios and determine necessary requirements to address remaining concerns regarding collateral requirements for those portfolios.

[18] https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220414-special/20220414-item-01-ftr-credit-requirements.ashx

PJM Categorization of Recommendations From the 2020 State of the Market Report (SOM)

This section categorizes the recommendations contained within the 2021 State of the Market Report (2021 SOM). In 2021, the IMM introduced **20** new recommendations and marked **6** recommendations as adopted. Many of the IMM recommendations are repeated from past annual and quarterly SOM reports. PJM has conducted a review of all **241** recommendations and concluded the following:

- **Adopted Recommendations: 6** recommendations are considered by the IMM and PJM as adopted. Therefore, PJM believes these recommendations could be removed from future SOM reports.
- **Active Recommendations: 96** recommendations are considered by PJM to be active. These are recommendations that are categorized as actionable, assessment or archived.

Actionable – PJM considers these recommendations to be the highest priority. PJM plans to take action to address these recommendations in the coming year. This includes topics under stakeholder discussion.	**Assessment** – PJM believes that these recommendations are of medium importance but need further investigation and analysis prior to determining if they are actionable.	**Archived** – PJM believes that these recommendations are low in priority and are therefore currently archived.

- **Inactive Recommendations: 139** recommendations are considered by PJM to be inactive. PJM does not plan to take any further action (in the near future) for these recommendations due to one or more of the following reasons: the recommendation has not gained stakeholder consensus, the recommendation is rejected by FERC, the recommendation is addressed or the recommendation is out of PJM's purview (recommendation is raised to other regulatory bodies such as NERC, state PUC, etc.).

In an attempt to be concise and focused, PJM will limit its response to the adopted and active recommendations. The following table provides summary statistics for active recommendations.

ADOPTED & ACTIVE RECOMMENDATIONS

Section	ADOPTED	ACTIONABLE	ASSESSMENT	ARCHIVED	Section Percentage
Ancillary Services	1	11	8	6	25%
Capacity Market	3	12	3	3	21%
Demand Response	0	0	1	3	4%
Energy Market	1	5	3	17	25%
Energy Uplift	0	4	2	3	9%
Environmental	0	1	0	0	1%
FTRs & ARRs	1	3	0	0	4%
Interchange Transactions	0	3	0	3	6%
Net Revenue	0	1	0	0	1%
Planning	0	1	3	0	4%
Total Recommendations	**6**	**41**	**20**	**35**	**102**
Status Percentage	6%	40%	20%	34%	

Appendix – Complete List of Adopted and Active Recommendations

ADOPTED

Section	2021 Recommendation	Priority	Year Reported	IMM Status 2021
Ancillary Services	The MMU recommends 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	Adopted, 2021
Capacity Market	The MMU recommends that PJM updates the values in the CRF table in the Tariff when the components change.	High	2020	Adopted, 2021
	The MMU recommends that the offer cap for capacity resources be defined as the Net Avoidable Cost Rate (Net 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	Adopted, 2021
	The MMU recommends that the net revenue calculation by PJM to calculate the Net Cost of New Entry (Net CONE) VRR parameter reflects 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	Adopted, 2021
Energy Market	The MMU recommends that PJM approve one RT SCED case for each five-minute interval to dispatch resources during that interval using a five-minute ramp time, and that PJM calculate prices using LPC for that five-minute interval using the same approved RT SCED case.	High	2019	Adopted, 2021
FTRs & ARRs	The MMU recommends that PJM enforce the FTR auction bid limits at the parent company level starting immediately.	High	2020	Adopted, 2021

ACTIONABLE

Section	2021 Recommendation	Priority	Year Reported	IMM Status 2021
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
	The MMU recommends that resources not be paid the daily capacity payment when unable to operate to their unit-specific parameter limits.	Medium	2018	Not Adopted

ACTIONABLE				
Section	**2021 Recommendation**	**Priority**	**Year Reported**	**IMM Status 2021**
	The MMU recommends that PJM require generators that violate their approved turn-down ratio (by either using the fixed gen option or increasing their economic minimum) to use the temporary parameter exception process that requires market sellers to demonstrate that the request is based on a physical and actual constraint.	Medium	2021	Not Adopted
	The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding.	Medium	2020	Not Adopted
	The MMU recommends that PJM clearly document the calculation of shortage prices and implementation of reserve price caps in the PJM Manuals, including defining all the components of reserve prices and all the constraints whose shadow prices are included in reserve prices.	High	2021	Not Adopted
Energy Uplift	The MMU recommends that PJM not pay uplift to units not following dispatch, including uplift related to fast-start pricing, and require refunds where it has made such payments.	Medium	2018	Not Adopted
	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
	The MMU recommends that PJM designate units whose offers are flagged for fixed generation in Markets Gateway as not eligible for uplift. Units that are flagged for fixed generation are not dispatchable. Following dispatch is an eligibility requirement for uplift compensation.	Medium	2020	Not Adopted
	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
Capacity Market	The MMU recommends that intermittent resources, including storage, not be permitted to offer capacity MW based on energy delivery that exceeds their defined deliverability rights (CIRs). Only energy output for such resources below the designated CIR/deliverability level should be recognized in the definition of capacity.	High	2021	Not Adopted
	The MMU recommends that the must-offer rule in the capacity market apply to all capacity resources. There is no reason to exempt intermittent and storage resources, including hydro. The purpose of the must-offer rule, which has been in place since the beginning of the capacity market in 1999, is to prevent the exercise of market power via withholding.	High	2021	Not Adopted

ACTIONABLE				
Section	**2021 Recommendation**	**Priority**	**Year Reported**	**IMM Status 2021**
	The MMU recommends that PJM reevaluate the shape of the VRR curve. The shape of the VRR curve directly results in load paying substantially more for capacity than load would pay with a vertical demand curve.	High	2021	Not Adopted
	The MMU recommends that the maximum price on the VRR curve be defined as Net CONE.	Medium	2019	Not Adopted
	The MMU recommends that the value of CTRs should be defined by the total MW cleared in the capacity market, the internal MW cleared and the imported MW cleared, and not redefined later prior to the delivery year.	Medium	2021	Not Adopted
	The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used, or that the process of modifying the obligations to pay for capacity be reviewed.	Medium	2021	Not Adopted
	The MMU recommends using the lower of the cost or price-based energy market offer to calculate energy costs in the calculation of the historical net revenues that are an offset to gross ACR in the calculation of unit-specific capacity resource offer caps based on net ACR.	Medium	2021	Not Adopted
	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
	The MMU recommends that modifications to existing resources be subject to market-power-related offer caps or MOPR offer floors and not be treated as new resources and therefore exempt.	Low	2012	Not Adopted
	The MMU recommends that any combined seasonal resources be required to be in the same LDA and preferably at the same location in order for the energy market and capacity market to remain synchronized and reliability metrics correctly calculated.	Medium	2021	Not Adopted
	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 nonperformance.	High	2019	Not Adopted
	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 Performance Assessment Interval (PAI) by area without the requirement that more than three Market Participants' data be aggregated for posting.	Low	2019	Not Adopted
Net Revenue	The MMU recommends that the net revenue calculation used by PJM to calculate the Net CONE and net ACR be based on a	Medium	2019	Not Adopted

ACTIONABLE				
Section	**2021 Recommendation**	**Priority**	**Year Reported**	**IMM Status 2021**
	forward-looking estimate of expected energy and ancillary services net revenues using forward prices for energy and fuel.			
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. The MMU recommends that there be a single PJM-operated forward market for RECs for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real-time delivery.	High	2021	Not Adopted
Interchange Transactions	The MMU recommends that PJM end the practice of maintaining outdated definitions of interface pricing points; eliminate the NIPSCO, Southeast and Southwest interface pricing points from the Day-Ahead and Real-Time energy markets; and, with VACAR, assign the transactions created under the reserve sharing agreement to the South interface pricing point.	High	2013	Partially Adopted, 2020
	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
	The MMU recommends modifications to the FFE calculation to ensure that FEE calculations reflect the current capability of the transmission system as it evolves. The MMU recommends that the Commission set a deadline for PJM and MISO to resolve the FEE freeze date and related issues.	Medium	2019	Not Adopted
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
	The MMU recommends that the $12 margin adder be eliminated from the definition of the cost-based regulation offer because it is a markup and not a cost.	Medium	2021	Not Adopted
	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
	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				
Section	**2021 Recommendation**	**Priority**	**Year Reported**	**IMM Status 2021**
	The MMU recommends that the variable operating and maintenance cost be eliminated from the definition of the cost of tier 2 synchronized reserves and that the calculation of synchronized reserve variable operations and maintenance costs be removed from Manual 15.	Medium	2019	Not Adopted
	The MMU recommends that the rule requiring that tier 1 synchronized reserve resources be paid the tier 2 price when the nonsynchronized 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
	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
	The MMU recommends that a reason code be attached to every hour in which PJM market operations adds additional DASR MW.	Medium	2015	Not Adopted
	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
	The MMU recommends that, in order to mitigate market power, offers in the DASR Market be based on opportunity cost only.	Low	2018	Not Adopted
	The MMU recommends that new CRF rates for black start units, incorporating current tax code changes, be implemented immediately. The new CRF rates should apply to all black start units. The black start units should be required to commit to providing black start service for the life of the unit.	High	2020	Not Adopted
Planning	The MMU recommends that, if the market efficiency process is retained, PJM modify the rules governing cost/benefit 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 increased congestion costs and the risk of project cost increases, in all zones are included in order to ensure that the correct metrics are used for defining benefits.	Medium	2018	Not Adopted
FTRs & ARRs	The MMU recommends a requirement that the details of all bilateral FTR transactions be reported to PJM.	High	2020	Not Adopted
FTRs & ARRs	The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create.	Low	2018	Not Adopted
FTRs & ARRs	The MMU recommends the use of a 99% confidence interval when calculating initial margin requirements for FTR Market Participants, in order to assign the cost of managing risk to the FTR holders who benefit or lose from their FTR positions.	High	2021	Not Adopted

ASSESMENT				
Section	**2021 Recommendation**	**Priority**	**Year Reported**	**IMM Status 2021**
Energy Market	The MMU recommends, in order to ensure effective market power mitigation and to ensure that capacity resources meet their obligation to be flexible, that capacity resources be required to use flexible parameters in all offers at all times.	High	2021	Not Adopted
	The MMU recommends, if the preferred recommendation is not implemented, that in order to ensure effective power mitigation, PJM always enforce parameter-limited values when the TPS test is failed and during high load conditions such as cold and hot weather alerts and emergency conditions.	High	2015	Not Adopted
	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
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
	The MMU recommends modifications to the calculation of lost opportunity cost credits paid to wind units. The lost opportunity cost credits paid to wind units should be based on the 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.	Low	2012	Not Adopted
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

ASSESMENT				
Section	**2021 Recommendation**	**Priority**	**Year Reported**	**IMM Status 2021**
	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, there is no reason to have an add-back mechanism. If EE remains 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
	The MMU recommends use of the Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.	High	2016	Not Adopted
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 with the existing lag.	Medium	2018	Not Adopted
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
	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-offer schedule.	Medium	2010	Not Adopted, FERC Rejected
	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 deassign assigned regulation resources within the hour.	Medium	2016	Not Adopted, FERC Rejected
	The MMU recommends that the details of VACAR Reserve Sharing Agreement (VRSA) be made public, including any responsibilities assigned to PJM and including the amount of reserves that Dominion commits to meet its obligations under the VRSA.	Medium	2020	Not Adopted
	The MMU recommends that the VRSA be terminated and, if necessary, replaced by a reserve sharing agreement between PJM and VACAR South, similar to agreements between PJM and other bordering areas.	Medium	2020	Not Adopted

ASSESMENT				
Section	**2021 Recommendation**	**Priority**	**Year Reported**	**IMM Status 2021**
	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. The PJM capacity and energy markets already compensate resources for frequency response capability and any marginal costs.	Medium	2018	Not Adopted
	The MMU recommends that, if payments for reactive are continued, 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	Partially Adopted
	The MMU recommends that Schedule 2 to the OATT be revised to state explicitly that only generators that provide reactive capability to the transmission system that PJM operates and has responsibility for are eligible for reactive capability compensation. Specifically, such eligibility should be determined based on whether a generation facility's point of interconnection is on a transmission line that is a Monitored Transmission Facility as defined by PJM and is on a Reportable Transmission Facility as defined by PJM.	Medium	2020	Not Adopted
Planning	The MMU recommends that PJM modify the project proposal templates to include data necessary to perform a detailed project lifetime financial analysis. The required data includes, but is not limited to: capital expenditure; capital structure; return on equity; cost of debt; tax assumptions; ongoing capital expenditures; ongoing maintenance; and expected life.	Medium	2020	Not Adopted
	The MMU recommends that storage resources not be includable as transmission assets for any reason.	High	2020	Not Adopted
	The MMU recommends a comprehensive review of the ways in which the solution-based dfax is implemented. The goal for such a process would be to ensure that the most rational and efficient approach to implementing the solution-based dfax method is used in PJM. Such an approach should allocate costs consistent with benefits and appropriately calibrate the incentives for investment in new transmission capability. No replacement approach should be approved until all potential alternatives, including the status quo, are thoroughly reviewed.	Medium	2020	Not Adopted

INACTIVE				
Section	**2021 Recommendation**	**Priority**	**Year Reported**	**IMM Status 2021**
Energy Market	The MMU recommends that the market rules should explicitly require that offers in the energy market be competitive, where competitive is defined to be the short-run marginal cost of the units. The short-run marginal cost should reflect opportunity cost when and where appropriate. The MMU recommends that the level of incremental costs includable in cost-based offers not exceed the short-run marginal cost of the unit.	Medium	2009	Not Adopted
	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
	The MMU recommends that the temporary cost method be removed, and that all units that submit nonzero cost-based offers be required to have an approved fuel cost policy.	Low	2020	Not Adopted
	The MMU recommends that the penalty exemption provision be removed, and that all units that submit nonzero cost-based offers be required to follow their approved fuel cost policy.	Medium	2020	Not Adopted
	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
	The MMU recommends removal of all use of FERC System of Accounts in the Cost Development Guidelines.	Medium	2016	Not Adopted
	The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines.	Medium	2016	Not Adopted
	The MMU recommends the removal of all labor costs from the Cost Development Guidelines.	Medium	2016	Not Adopted
	The MMU recommends the removal of all maintenance costs from the Cost Development Guidelines.	Medium	2019	Not Adopted
	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	2015	Partially Adopted
	The MMU recommends that PJM require every Market Participant to make available at least one cost schedule based on the same hourly fuel type(s) and parameters at least as flexible as their offered price schedule.	Medium	2015	Not Adopted
	The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM Energy Market except when cost-based offers exceed $1,000 per MWh, and retain other existing rules that limit incentives to exercise market power.	High	1999	Partially Adopted, 2017

INACTIVE				
Section	**2021 Recommendation**	**Priority**	**Year Reported**	**IMM Status 2021**
	The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy.	Medium	2012	Not Adopted
	The MMU recommends that capacity performance resources be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments, and that this standard be applied to all technologies on a uniform basis.	Medium	2015	Not Adopted
	The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity performance construct. The operational parameters used by generation owners to indicate to PJM operators what a unit is capable of during the operating day should not determine capacity performance assessment or uplift payments.	Medium	2015	Partially Adopted
	The MMU recommends that PJM update the Tariff to clarify that all generation resources are subject to unit-specific parameter limits on their cost-based offers using the same standard and process as capacity performance capacity resources.	Medium	2018	Not Adopted
	The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including: the level of the penalty factors; the triggers for the use of the penalty factors; the appropriate line ratings to trigger the use of penalty factors; the allowed duration of the violation; the use of constraint relaxation logic; and when the transmission penalty factors will be used to set the shadow price.	Medium	2015	Partially Adopted, 2020
	The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice.	Low	2013	Partially Adopted
	The MMU recommends that PJM not use closed-loop interface constraints or surrogate constraints to artificially override nodal prices based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand-side resource capacity product; address the inability of the power-flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason.	Medium	2013	Not Adopted

INACTIVE				
Section	**2021 Recommendation**	**Priority**	**Year Reported**	**IMM Status 2021**
	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
	The MMU recommends that if PJM believes it appropriate to implement CT price-setting logic, PJM first initiate a stakeholder process to determine whether such modification is appropriate. PJM should file any proposed changes with FERC to ensure review. Any such changes should be incorporated in the PJM Tariff.	Medium	2016	Partially Adopted
	The MMU recommends that PJM include in the Tariff or appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.	Low	2013	Not Adopted
	The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP, even if the MW are settled to the generator. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP, even if the injection MW are settled to the Load Serving Entity.	Low	2013	Not Adopted
	The MMU recommends that PJM identify and collect data on available behind-the-meter generation resources, including nodal location information and relevant operating parameters.	Low	2013	Partially Adopted
	The MMU recommends that PJM document how LMPs are calculated when demand response is marginal.	Low	2014	Not Adopted
	The MMU recommends that PJM not allow nuclear generators that do not respond to prices or that only respond to manual instructions from the operator to set the LMPs in the Real-Time Market.	Low	2016	Not Adopted
	The MMU recommends that PJM increase the coordination of outage and operational restrictions data submitted by Market Participants via eDART/eGADs and offer data submitted via Markets Gateway.	Low	2017	Not Adopted
	The MMU recommends that PJM stop capping the system marginal price in RT SCED and instead limit the sum of violated reserve constraint shadow prices used in LPC to $1,700 per MWh.	Medium	2021	Not Adopted

INACTIVE				
Section	**2021 Recommendation**	**Priority**	**Year Reported**	**IMM Status 2021**
	The MMU recommends, if PJM implements extended downward-sloping ORDCs, that PJM calculate the probability of reserves falling below the minimum reserve requirement (MRR) based on 10-minute rather than 30-minute forecast error, and on forced outages in the 10-minute rather than the 30-minute look-ahead window to model the uncertainty in the inputs to RT SCED.	Medium	2021	Not Adopted
	The MMU recommends that PJM allow generators to report fuel type on an hourly basis in their offer schedules and to designate schedule availability on an hourly basis.	Medium	2015	Partially Adopted
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
Energy Uplift	The MMU recommends enhancing the current energy uplift allocation rules to reflect the recommended elimination of day-ahead operating reserves, the timing of commitment decisions and the commitment reasons.	High	2012	Not Adopted
Energy Uplift	The MMU recommends that units not be paid lost opportunity cost uplift when PJM directs a unit to reduce output based on a transmission constraint or other reliability issue. There is no lost opportunity because the unit is required to reduce for the reliability of the unit and the system.	High	2021	Not Adopted
Energy Uplift	The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits.	Medium	2009	Not Adopted
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
Energy Uplift	The MMU recommends calculating LOC based on 24-hour daily periods for combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time.	Medium	2014	Not Adopted
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

INACTIVE

Section	2021 Recommendation	Priority	Year Reported	IMM Status 2021
	The MMU recommends that only flexible fast-start units (startup plus notification times of 10 minutes or less) and units with 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
	The MMU recommends that up-to congestion (UTC) transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC.	High	2011	Partially Adopted
	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
	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
	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 uplift.	Medium	2011	Partially Adopted
	The MMU recommends that PJM revise the current uplift (operating reserve) confidentiality rules in order to allow the disclosure of complete information about the level of uplift (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
Capacity Market	The MMU recommends that 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
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

INACTIVE				
Section	**2021 Recommendation**	**Priority**	**Year Reported**	**IMM Status 2021**
	The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a non-nested model with all LDAs modeled including VRR curves for all LDAs. 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 be allowed to price separate if that is the result of the LDA supply curves and the transmission constraints between LDAs.	Medium	2017	Not Adopted
	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 reevaluate the triggers for holding conditional incremental auctions.	Medium	2013	Not Adopted
	The MMU recommends that PJM not sell back any capacity in any IA, at much lower prices, procured in a BRA. If PJM continues to sell back capacity, 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
	The MMU recommends changing the RPM solution method to explicitly incorporate the cost of uplift (make whole) payments in the objective function.	Medium	2014	Not Adopted
	The MMU recommends that the Fixed Resource Requirement (FRR) rules, including obligations and performance requirements, be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM capacity market.	Medium	2019	Not Adopted
	The MMU recommends that PJM improve the clarity and transparency of its CETL calculations. The MMU also recommends that CETL for capacity imports into PJM be based on the ability to import capacity only where PJM capacity exists and where that capacity has a must-offer requirement in the PJM capacity market.	Medium	2021	Not Adopted
	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 uplift (make whole) payments for seasonal resources.	Medium	2017	Not Adopted

INACTIVE				
Section	**2021 Recommendation**	**Priority**	**Year Reported**	**IMM Status 2021**
	The MMU recommends that any unit that is not capable of supplying energy consistent with its day-ahead offer requirement (ICAP) be required to reflect an appropriate outage.	Medium	2009	Not Adopted
	The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAI not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted.	Medium	2016	Not Adopted
	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
	The MMU recommends that all capacity imports be required to be deliverable to PJM load in an identified LDA 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 to PJM load.	High	2016	Not Adopted
	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 unit offers in the capacity market.	High	2016	Not Adopted
	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
	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
Demand Response	The MMU recommends that, as a preferred alternative to including demand resources as supply in the capacity market, 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 be metered load, and that PJM forecasts immediately incorporate the impacts of demand side behavior.	High	2014	Not Adopted

INACTIVE				
Section	2021 Recommendation	Priority	Year Reported	IMM Status 2021
	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
	The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources.	Medium	2013	Not Adopted
	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
	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
	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
	The MMU recommends that demand resources be required to provide their nodal location, comparable to generation resources.	High	2011	Not Adopted
	The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. The MMU recommends that, if PJM continues to use subzones for any purpose, PJM clearly define the role of subzones in the dispatch of demand response.	High	2015	Not Adopted
	The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones.	Low	2016	Not Adopted
	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 subzonal approach and creates larger mismatches between the locational need for the resources and the actual response.	High	2015	Not Adopted

INACTIVE				
Section	**2021 Recommendation**	**Priority**	**Year Reported**	**IMM Status 2021**
	The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately.	Medium	2009	Not Adopted
	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
	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 payments to demand resources be calculated based on interval meter data at the site of the demand reductions.	Medium	2013	Not Adopted
	The MMU recommends demand response event compliance be calculated on a five-minute basis for all capacity performance resources, and that the penalty structure reflect five-minute compliance.	Medium	2013	Partially Adopted
	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
	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
	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
	The MMU recommends that the Tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material 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
	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
	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

INACTIVE				
Section	**2021 Recommendation**	**Priority**	**Year Reported**	**IMM Status 2021**
	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
	The MMU recommends the Relative Root Mean Squared Test be required for all demand resources with a CBL.	Low	2017	Partially Adopted
	The MMU recommends that PRD be required to respond during a PAI to be consistent with all CP resources.	High	2017	Not Adopted
	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
	The MMU recommends that all demand resources register as Pre-Emergency Load Response and that the Emergency Load Response Program be eliminated.	High	2020	Not Adopted
	The MMU recommends that EDCs not be allowed to participate in markets as DER aggregators in addition to their EDC role.	High	2021	Not Adopted
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 and the distribution of carbon revenues.	High	2018	Not Adopted
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
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.	Low	2018	Not Adopted
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
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 cannot meet the capacity market requirements to be DR as a result of emission standards that impose environmental run-hour limitations.	Medium	2019	Not Adopted

INACTIVE				
Section	**2021 Recommendation**	**Priority**	**Year Reported**	**IMM Status 2021**
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
	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
	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
	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
	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
	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
	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, 2015
Ancillary Services	The MMU recommends that all data necessary to perform the Regulation Market three pivotal supplier test be saved by PJM, so that the test can be replicated.	Medium	2016	Not Adopted
	The MMU recommends enhanced documentation of the implementation of the Regulation Market design.	Medium	2010	Not Adopted, FERC Rejected

INACTIVE				
Section	**2021 Recommendation**	**Priority**	**Year Reported**	**IMM Status 2021**
	The MMU recommends that PJM be required to save data elements necessary for verifying the performance of the Regulation Market.	Medium	2010	Not Adopted
	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
	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
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	Partially Adopted
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
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 that have failed to make progress, subject to rules to prevent gaming.	Medium	2013	Partially Adopted
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
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

INACTIVE				
Section	**2021 Recommendation**	**Priority**	**Year Reported**	**IMM Status 2021**
	The MMU recommends that the market efficiency process be eliminated, because it is not consistent with a competitive market design.	Medium	2019	Not Adopted
	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, FERC Rejected
	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, FERC Rejected
	The MMU recommends that PJM enhance the transparency and queue management process for nonincumbent 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 nonincumbent transmission providers.	Medium	2015	Not Adopted
	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
	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
	The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and nonincumbent transmission providers in the RTEP.	Medium	2014	Not Adopted
	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

INACTIVE				
Section	**2021 Recommendation**	**Priority**	**Year Reported**	**IMM Status 2021**
	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
	The MMU recommends that all PJM transmission owners use the same methods to define line ratings and that all PJM transmission owners implement dynamic line ratings (DLR), subject to NERC standards and guidelines, subject to review by NERC and approval by FERC.	Medium	2019	Not Adopted
	The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as 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
	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
	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
	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
FTRs & ARRs	The MMU recommends that the current ARR/FTR design be replaced with defined congestion revenue rights (CRRs). A CRR is the right to actual congestion that is paid by physical load at a specific bus, zone or aggregate.	High	2015	Not Adopted
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
FTRs & ARRs	The MMU recommends that all historical generation to load paths be eliminated as a basis for assigning ARRs. The MMU recommends that the current design be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node.	High	2015	Partially Adopted
FTRs & ARRs	The MMU recommends that, under the current FTR design, the rights to all congestion revenue 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

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Section	**2021 Recommendation**	**Priority**	**Year Reported**	**IMM Status 2021**
	The MMU recommends that IARRs be eliminated from PJM's Tariff, but that if IARRs are not eliminated, IARRs should be subject to the same proration rules that apply to all other ARR rights.	Low	2018	Not Adopted
	The MMU recommends that FTR funding be based on total congestion, including day-ahead and balancing congestion.	High	2017	Not Adopted
	The MMU recommends that PJM reduce FTR sales on paths with persistent over allocation of FTRs, including a clear definition of persistent over allocation and how the reduction will be applied.	High	2013	Partially Adopted
	The MMU recommends that PJM eliminate generation to generation paths and all other paths that do not represent the delivery of power to load.	High	2018	Not Adopted
	The MMU recommends that the long-term FTR product be eliminated. If the long-term FTR product is not eliminated, the long-term FTR Market should 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
	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
	The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels.	High	2015	Not Adopted
	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
	The MMU recommends that FTR auction revenues not be used by PJM to buy counter-flow FTRs for the purpose of improving FTR payout ratios.	High	2015	Not Adopted
	The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR Market Participants.	High	2012	Not Adopted, FERC Rejected
	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
	The MMU recommends that PJM eliminate geographic cross subsidies.	High	2013	Not Adopted

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Section	**2021 Recommendation**	**Priority**	**Year Reported**	**IMM Status 2021**
	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
	The MMU recommends that the FTR portfolio of a defaulted member be canceled rather than liquidated or allowed to settle as a default cost on the membership.	High	2018	Not Adopted

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Section	**2021 Recommendation**	**Priority**	**Year Reported**	**IMM Status 2021**
Energy Market	The MMU recommends that Market Participants be required to document the amount and cost of consumables used when operating in order to verify that the total operating cost is consistent with the total quantity used and the unit characteristics.	Medium	2020	Not Adopted
	The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that Market Participants be permitted to include only variable maintenance costs, linked to verifiable operational events, and that can be supported by clear and unambiguous documentation of the operational data (e.g., run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced.	Medium	2020	Not Adopted
	The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short-run marginal costs from the Cost Development Guidelines.	Medium	2016	Not Adopted
	The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases.	Low	2016	Not Adopted
	The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be constantly positive or negative across the full MWh range of price and cost-based offers.	High	2015	Not Adopted
	The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the Real-Time Market that were not offer capped at the time of commitment in the Day-Ahead Market or at a prior time in the Real-Time Market.	High	2020	Not Adopted
	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, 2014

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Section	**2021 Recommendation**	**Priority**	**Year Reported**	**IMM Status 2021**
	The MMU recommends that resources are not allowed to violate the ICAP must-offer requirement. The MMU recommends that PJM enforce the ICAP must-offer requirement by assigning a forced outage to any unit that is derated in the energy market below its committed ICAP without an outage that reflects the derate.	Medium	2020	Not Adopted
	The MMU recommends that storage and intermittent resources be subject to an ICAP must-offer rule that reflects the limitations of these resources.	Medium	2020	Not Adopted
	The MMU recommends, if the capacity market seller offer cap were to be calculated using the historical average balancing ratio, that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs), and only include those events that trigger emergencies at a defined zonal or higher level.	Medium	2018	Not Adopted
	The MMU recommends that PJM clearly define the business rules that apply to the unit-specific parameter adjustment process, including PJM's implementation of the Tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources.	Low	2018	Not Adopted
	The MMU recommends that PJM not approve temporary exceptions that are based on pipeline Tariff terms that are not routinely enforced and based on inferior transportation service procured by the generator.	Medium	2019	Not Adopted
	The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability, and the reliability analyses used in the 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
	The MMU recommends that PJM adjust the ORDCs during spin events to reduce the reserve requirement for synchronized and primary reserves by the amount of the reserves deployed.	Medium	2021	Not Adopted
	The MMU recommends that PJM define clear criteria for operator approval of RT SCED cases, including shortage cases that are used to send dispatch signals to resources and for pricing, to minimize discretion.	High	2018	Partially Adopted
	The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets.	Medium	2020	Not Adopted

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Section	**2021 Recommendation**	**Priority**	**Year Reported**	**IMM Status 2021**
	The MMU recommends eliminating INC, DEC and UTC bidding at pricing nodes that allow Market Participants to profit from modeling issues.	Medium	2020	Not Adopted
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
Energy Uplift	The MMU recommends eliminating intraday 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
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 credit calculation.	Medium	2012	Not Adopted, Stakeholder Process
Capacity Market	The MMU recommends that capacity market sellers be required to explicitly request and support the use of minimum MW quantities (inflexible sell offer segments) and that the requests only be permitted for defined physical reasons.	Medium	2018	Not Adopted
Capacity Market	The MMU recommends that 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
Capacity Market	The MMU recommends elimination of the cost-of-service recovery rate in OATT Section 119, that RMR service should be provided under the deactivation avoidable cost rate in Part V, and that the revenue cap under the avoidable cost rate option be eliminated. The MMU also recommends specific improvements to the DACR provisions.	Medium	2017	Not Adopted
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
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
Demand Response	The MMU recommends that PJM include a 5 MW maximum size cap on DER aggregations.	Medium	2021	Not Adopted
Interchange Transactions	The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SOUTH interface pricing point based on the locational price impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM.	High	2020	Not Adopted

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Section	**2021 Recommendation**	**Priority**	**Year Reported**	**IMM Status 2021**
	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
	The MMU recommends that the emergency interchange cap be replaced with a market-based solution.	Low	2015	Not Adopted
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
	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
	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
	The MMU recommends that, for calculating the penalty for a tier 2 resource failing to meet its scheduled obligation during a spinning event, the penalty should be based on the actual time since the last spinning event of 10 minutes or longer during which the resource performed, because performance is only measured for events 10 minutes or longer.	Medium	2018	Not Adopted
	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
	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