UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Modernizing Wholesale	)	
Electricity Market Design	)	**Docket No. AD21-10-000**

COMMENTS OF CLEAN ENERGY ASSOCIATIONS

The American Clean Power Association,[1] American Council on Renewable Energy,[2] and the Solar Energy Industries Association[3] (collectively the "Clean Energy Associations") submit these comments in response to the reports filed by the Regional Transmission Organizations and Independent System Operators ("RTOs/ISOs") on October 18, 2022 in response the Federal Energy Regulatory Commission's ("FERC" or the "Commission") April 21, 2022 Order Directing Reports issued in the above-captioned proceeding.[4]

I. INTRODUCTION AND SUMMARY

The Clean Energy Associations greatly appreciate the opportunity to submit comments on these reports. While many of the points made in these comments apply to across-the-board issues in the energy and ancillary services markets, the primary focus is on the reports from the

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[1] ACP is a national trade association representing a broad range of entities with a common interest in encouraging the expansion and facilitation of wind, solar, energy storage, and electric transmission in the United States. The views and opinions expressed in this filing do not necessarily reflect the official position of each individual member of ACP.

[2] ACORE is a national nonprofit organization that unites finance, policy and technology to accelerate the transition to a renewable energy economy, supported by members that include developers, manufacturers, top financial institutions, major corporate renewable energy buyers, grid technology providers, utilities, professional service firms, academic institutions and allied nonprofit groups. The views and opinions expressed in this filing do not necessarily reflect the official position of each individual member of ACORE.

[3] SEIA is the national trade association of the solar energy industry. As the voice of the industry, SEIA works to support solar as it becomes a mainstream and significant energy source by expanding markets, reducing costs, increasing reliability, removing market barriers, and providing education on the benefits of solar energy. The views and opinions expressed in this filing do not necessarily reflect the official position of each individual member of SEIA.

[4] *Modernizing Wholesale Electricity Market Design*, 179 FERC ¶ 61,029 (2022)

California Independent System Operator ("CAISO"), Midcontinent Independent System Operator, Inc. ("MISO"), and PJM Interconnection LLC ("PJM").

The Clean Energy Associations recognize that each RTO/ISO is unique in its generation mix, current market structure, and the regulatory paradigm of the states in its footprint, and therefore the nature and pace of market reforms will differ. However, all RTOs/ISOs' resource mixes and needs are changing in similar ways due to fundamental and ubiquitous economic factors. Actions by the Commission under Section 206 of the Federal Power Act may be warranted where the RTO/ISO and their stakeholders are not addressing issues of reliability, efficiency, or discrimination on their own. Competition in the markets will be improved if the RTOs/ISOs adopt common terms, products, protocols, and review measures. Such a standardization should be encouraged as much as possible. These comments offer the following recommendations on common areas for market design improvement across the RTOs/ISOs:

A. Use markets to reduce out-of-market actions, and while doing so ensure that the market rules not reward resources for their inflexibility. These goals can be achieved through (1) a more accurate characterization of the capabilities of all resources in markets; (2) more efficient unit commitment processes; and (3) the potential creation of new markets or market products.

B. Energy market price caps should be increased to better reflect the value of reliability and incentivize real-time performance and flexibility (while encouraging load to contract ahead of time so they do not need to pay these prices).

C. Improve transparency and efficiency by using more direct mechanisms to counter market power.

D. Transmission utilization should be improved both within RTO/ISOs and at RTO/ISO seams to decrease congestion costs, curtailment, and market power.

E. Energy market price signals can be strengthened by reducing over-procurement in capacity markets.

For further background, we point the Commission to a comprehensive list[5] of recommended market design changes, with specific recommendations for PJM[6] and MISO.[7]

II. COMMENTS

A. Use markets to replace out-of-market actions.

A common theme across the RTO/ISO reports is the benefit of using markets to replace out-of-market operator actions affecting generator commitment and dispatch to the maximum extent possible. While some operator actions will still be needed, there are benefits from maximizing the use of markets because well-functioning markets efficiently and fairly drive generator behavior, while out-of-market payments distort prices and incentives.[8] The mechanisms for moving these actions into markets include (1) more accurate characterization of the capabilities of all resources in markets; (2) more efficient unit commitment processes; and (3)

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[5] Wind-Solar Alliance, "Customer Focused and Clean – Power Markets for the Future" (November 2018) at 5, available at: https://gridprogress.files.wordpress.com/2019/03/power-markets-for-the-future-full-report.pdf.

[6] Wind Solar Alliance, "Customer Focused and Clean – Power Markets for the Future – PJM FOCUS" (Nov. 2018), available at: https://gridprogress.files.wordpress.com/2019/03/power-markets-for-the-future-pjm-focus.pdf.

[7] Wind Solar Alliance, "Customer Focused and Clean – Power Markets for the Future – MISO FOCUS" (Nov. 2018), available at: https://gridprogress.files.wordpress.com/2019/03/power-markets-for-the-future-miso-focus.pdf.

[8] For example, see Independent Market Monitor for the Midcontinent ISO ("MISO IMM"), 2021 State of the Market Report (June 2022) at 115, available at: https://cdn.misoenergy.org/20220622%20Markets%20Committee%20of%20the%20BOD%20Item%2004%20IMM%20State%20of%20the%20Market%20Report625261.pdf, stating: "This report indicates that out-of-market commitments by MISO and the associated RSG [Revenue Sufficiency Guarantee] costs increased substantially in 2021. Our analysis indicated that most of these commitments were not ultimately needed to satisfy MISO's energy, operating reserves, and other reliability needs. In addition to raising RSG costs borne by its customers, these excess commitments depress real-time prices and result in inefficiently lower imports from neighboring areas, inefficiently lower day-ahead procurements and resource commitments, and depressed long-term price signals. Therefore, it is important to curtail excess out-of-market commitments and the accompanying RSG costs.

the potential creation of new markets or market products. To better understand what market reforms are needed, it is also important for RTO/ISOs to keep better records of the factors driving out-of-market actions.[9] There should be transparency as to the reasons for out-of-market payments so that stakeholders and market participants are confident that the prices reflect market conditions and that the market is operating efficiently.

1. Better characterize resources' capabilities, but do not reward inflexibility.

We offer the following five principles for how resources should be characterized in RTO commitment and dispatch decisions.

i. Ensure accurate and detailed resource bid parameters.

The RTO/ISOs should adopt market rules that improve the accuracy of the minimum generation levels and ramp rates submitted by generators for dispatch determinations. In many cases, these submitted generator bid parameters understate the flexibility of the units, such as the use of ramp rate, startup time, or minimum output limits for generator constraints that are not actually physical limits, but rather economic costs associated with more flexible dispatch. Expressing the capabilities and limits of flexible and inflexible supply and demand resources as costs would facilitate more accurate pricing of inflexibility. Bid parameters that understate a unit's actual flexibility contribute to excess payments to inflexible units. RTOs need to know each unit's actual ramp capability to be able to dispatch available resources effectively, but many conventional units' reported ramp parameters are inaccurate. PJM's Independent Market Monitor (IMM) has also advocated more scrutiny of variable O&M costs that are included in bids.[10]

[9] For example, see *Id.* at 122.

[10] Monitoring Analytics, LLC, Independent Market Monitor for PJM ("PJM IMM"), "2021 State of the Market Report for PJM (March 20, 2022) at 87, available at: https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021-som-pjm-sec2.pdf: "The MMU

MISO has also examined how to improve bid parameter reporting and use as a means to improve system operational flexibility and price transparency. As part of this effort, MISO is attempting to reduce make-whole payments and other out-of-market compensation and replace them with transparent prices. RTO/ISOs can use more extensive and accurate bid parameters to improve actual flexibility performance, with or without new categories of reliability services.

ii. Create a universal participation model.

In their reports in this docket, various RTO/ISOs discuss their efforts to better reflect the operational characteristics and capabilities of resources including steam, gas combined cycle, battery storage, and distributed resources in their commitment and dispatch processes.[11] While such efforts are valuable, the RTO/ISOs should also explore the feasibility of a more elegant and durable solution in which all resource types can express their capabilities through a universal participation model. Under this concept, all resources could describe their capabilities relative to a theoretical perfectly flexible resource.[12] Another long-term approach would be to encourage resources to become closer to perfectly flexible resources by becoming hybrid resources.[13] This could result in considerable longer-term simplifications to market designs by expecting more of market participants.

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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."

[11] For example, see PJM Report at 28. Also see PJM IMM (2022) at 90: "The MMU recommends that PJM model generators' operating transitions, including soak time for units with a steam turbine, configuration transitions for combined cycles, and peak operating modes."

[12] Mark Ahlstrom, "The Universal Market Participation Model" (April 5, 2018), available at: https://www.esig.energy/blog-the-universal-market-participation-model/.

[13] Derek Stenclik, Michael Goggin, Erik Ela, and Mark Ahlstrom, "Unlocking the Flexibility of Hybrid Resources" (March 2022), available at: https://www.esig.energy/unlocking-the-flexibility-of-hybrid-resources/.

iii. Give resources the option to control their own commitment and dispatch.

Centralized ISO/RTO spot markets are extremely valuable for aggregating dispersed information from different participants and incentivizing participants to develop more accurate forecasts. To the maximum extent possible, RTO/ISOs should not interfere with market participants' use of their commitment and dispatch preferences to reveal expectations that set efficient prices for all market participants. This includes giving battery storage operators the option of managing their state-of-charge at all times. Some RTO/ISOs have proposed direct RTO/ISO control of storage state-of-charge to address instances of inefficient charging and discharging,[14] though in many cases those problems are symptoms of other market failures discussed below, such as when low price caps cause batteries to discharge earlier than would be optimal. However, there may be value in offering market participants the option of allowing the RTO/ISO to manage their resource for them, as long as they have the right to opt out and manage it themselves.

iv. Remove barriers to energy and ancillary services market participation.

Market rules should treat generation resources comparably and allow all generation resources capable of providing a product or service to do so and be fairly compensated. RTO/ISOs should evaluate their existing ancillary service and ramping product rules to ensure they are designed in a non-discriminatory way. As noted above, today wind and solar may or may not be the most cost-effective resources to provide certain services given the opportunity

[14] CAISO Department of Market Monitoring (CAISO DMM), Annual Report on Market Issues and Performance (July 27, 2022) at 28, 293, available at: https://www.caiso.com/Documents/2021-Annual-Report-on-Market-Issues-Performance.pdf.

cost of curtailing renewable generation. However, as the renewable penetration increases, curtailment will increase, and the opportunity cost of foregone energy production will decline so that renewables may increasingly become cost-effective sources of ancillary services and flexibility in the upward as well as downward direction.[15] RTO/ISOs must design their markets and products to allow this service to be provided on a non-discriminatory basis by all capable resources.

For example, some ancillary services products have duration requirements that require a resource to be able to sustain providing the service for a longer period of time than necessary, which can prevent variable renewable and duration-limited storage resources from providing those services even though they could efficiently provide them for shorter periods of time. Some energy and ancillary services market rules also prevent renewable and storage resources from switching among providing different services within an hour, even though they can efficiently do so.

Several of the ISO/RTO reports in this proceeding reveal an outdated understanding of the reliability services capabilities of renewable and storage resources, which may play a role in the retention of outdated rules that are preventing those resources from providing those services in those markets. For example, PJM writes that "A significant challenge PJM faces over the next five to ten years is the disorderly retirement of resources that provide needed ancillary services. The limitations in how these resources are priced today could well add to the premature and

[15] Energy + Environmental Economics, Inc., "Investigating the Economic Value of Flexible Solar Power Plant Operation" (Oct. 2018) at 34, available at: https://www.ethree.com/wp-content/uploads/2018/10/Investigating-the-Economic-Value-of-Flexible-Solar-Power-Plant-Operation.pdf.

disorderly retirement of these needed resources that are not priced accurately in today's markets."[16]

Batteries, wind,[17] and solar[18] plants all use fast and flexible power electronics that allow them to meet or exceed the ancillary services contributions of conventional generators.[19] FERC now requires new wind, solar, and battery resources to match the reactive power[20] and frequency response[21] capabilities of conventional generators. These power electronics can even use grid power to provide voltage and reactive power support when the plant is not producing power, such as solar plants providing reactive power at night.[22] In contrast, many conventional generators provide little or no flexibility, frequency response, and other needed reliability services.[23]

MISO's report also understates the ancillary services contributions of inverter-based resources while overstating the contributions of legacy resources: "In addition, as intermittent resources continue to make up a greater share of MISO's system, increasing curtailment of those

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[16] PJM Report at 18.

[17] National Renewable Energy Laboratory, "Active Power Controls from Wind Power: Bridging the Gaps" (January 2014), available at: https://www.nrel.gov/docs/fy14osti/60574.pdf.

[18] National Renewable Energy Laboratory, "Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant" (March 2017), available at: https://www.nrel.gov/docs/fy17osti/67799.pdf.

[19] Milligan et al, "Alternatives No More: Wind and Solar Power Are Mainstays of a Clean, Reliable, Affordable Grid," IEEE Power and Energy Magazine (Volume: 13, Issue: 6, Nov.-Dec. 2015), available at: https://ieeexplore.ieee.org/document/7299793.

[20] Reactive Power Requirements for Non-Synchronous Generation, 155 FERC ¶ 61,277 (June 16, 2016), available at: https://www.ferc.gov/sites/default/files/2020-06/RM16-1-000.pdf.

[21] Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response, 162 FERC ¶ 61,128 (February 15, 2018), available at: https://www.ferc.gov/sites/default/files/2020-06/Order-842.pdf.

[22] Alice Grundy, "Light Source BP delivers night time reactive power using solar in 'UK First'," Solar Power Portal (November 25, 2019), available at: https://www.solarpowerportal.co.uk/news/lightsource_bp_delivers_night_time_reactive_power_using_solar_in_uk_first.

[23] Michael Milligan, "Sources of Grid Reliability Services," The Electricity Journal, Volume 31, Issue 9, November 2018, at 1-7, available at: https://www.sciencedirect.com/science/article/pii/S104061901830215X.

resources may be necessary to manage congestion and keep resources needed for ancillary services online. Such curtailment along with the dispatch of potentially more expensive resources that can supply ancillary services will challenge market efficiency… Over time, ancillary service shortages are expected to increase in size and frequency."[24] In reality, curtailed renewables are likely to be a growing source of ancillary services, and the rapid growth of battery and hybrid resources will also likely meet any increase in need for ancillary services.

MISO also writes that "By the 2030 timeframe, resource usage and capability inadequacy needs emerge for inverter-based resources and transmission. Research and development are needed to enable ancillary services from inverter-based resources by this time to address inverter stability and inertia and frequency response needs."[25] Battery storage and curtailed renewables are excellent sources of frequency response and can even provide fast frequency response that displaces the need for inertia.[26] For example, the 150 MW Hornsdale battery in South Australia has provided fast frequency response to stabilize the grid within seconds of major real-world grid disturbances.[27] MISO is correct that research and development and expanded deployment of grid-forming inverters will further increase the ancillary services capabilities of renewable and battery resources and address weak grid stability concerns that are emerging in some parts of the grid.

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[24] MISO Report at 28.

[25] MISO Report at 40-41.

[26] NERC Inverter-Based Resource Performance Task Force, "Fast Frequency Response Concepts and Bulk Power System Reliability Needs" (March 2020), available at: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf .

[27] Giles Parkinson, "'Virtual machine': Hornsdale battery steps in to protect grid after Callide explosion," Renew Economy (May 27, 2021), available at: https://reneweconomy-com-au.cdn.ampproject.org/c/s/reneweconomy.com.au/virtual-machine-hornsdale-battery-steps-in-to-protect-grid-after-callide-explosion/amp/.

Grid-forming inverters are increasingly being used today. The Dalrymple Substation Battery project in South Australia started commercial operation in December 2018 and has demonstrated that grid-forming batteries can provide short-circuit current contribution, fast frequency response, blackstart, and islanded operation.[28] Batteries have been used to provide blackstart service in multiple islanded microgrids around the world.[29] A recently announced 185 MW battery project in Hawaii will fully replace the grid services currently provided by a nearby coal plant by providing blackstart, fast frequency response, and grid-forming services.[30] Renewable plants can also be designed to provide blackstart and other services. In Great Britain, controls of an existing 69 MW wind farm were modified to be grid-forming, and the wind farm then successfully provided fast frequency response, blackstart, and islanded operation capability.[31]

v. Price resources' inflexibility.

Allow more resources to include fixed costs in their bids**.** Currently, FERC allows only fast-start resources to include start-up and no-load costs in their bids. Some experts argue that rules around price formation need to evolve so that resource types other than fast-start resources can include start-up and other fixed costs in their bids, as this will incorporate the cost of meeting

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[28] "A 30MW Grid Forming BESS Boosting Reliability in South Australia and Providing Market Services on the National Electricity Market," in Proc. 18th Int'l Wind Integration Workshop (October 2019), available at https://www.electranet.com.au/wp-content/uploads/2021/01/Wind-Interation-Workshop-30MW-BESS-October-2019.pdf.

[29] Oliver Schömann, "Experiences with large grid-forming inverters on various island and Microgrid projects," Hybrid Power Systems Workshop (May 2019), available at: https://hybridpowersystems.org/wp-content/uploads/sites/13/2019/06/3A_3_HYB19_017_presentation_Schoemann_Oliver_web.pdf.

[30] Julian Spector, "Hawaii building huge new battery, bidding farewell to coal," Canary Media (August 18, 2021), available at: https://www.canarymedia.com/articles/hawaii-building-huge-new-battery-bidding-farewell-to-coal/.

[31] A. Roscoe, et. al., "Practical experience of providing enhanced grid forming services from an onshore wind park," in Proc. 19th Wind Integr. Workshop (November 2020).

reliability needs in energy market prices instead of recovering them through out-of-market payments.[32]

At present, energy market prices and dispatch do not perfectly incorporate the fact that most conventional generators have "non-convex" costs, which are essentially fixed costs that occur at various points on the resource's output curve and are notably higher at unit startup and lower output levels. While these costs are accounted for in unit commitment decisions, there is active RTO/ISO stakeholder debate about whether these costs should be reflected in energy market prices or be allocated as uplift costs outside the market-clearing Locational Marginal Price (LMP) calculation. This debate has focused on which convex costs should be incorporated into price (start-up and no-load costs, or other fixed costs as well), and for which units (quick-start units, only on-line resources, etc.).

In 2017, PJM proposed to allow a range of fixed costs to be included in the market-clearing price that would be set by many inflexible units.[33] This would allow on-line coal and nuclear plants to set prices well above their true marginal cost of producing electricity. This proposed form of Extended LMP would inefficiently support generators that are not providing flexibility, imposing an unjust and unreasonable cost burden because it charges customers a premium without delivering any reliability benefits, while insulating inflexible conventional plants from the cost of their inflexibility.

While most types of flexible duration-limited resources do not have start-up and no-load costs and therefore, their bids would not be directly affected, other resources' inclusion of those

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[32] P. Gribik et al., "Extended Locational Marginal Pricing (Convex Hull Pricing)" (June 2, 2010), available at: https://cms.ferc.gov/sites/default/files/2020-05/20100530130229-Gribik%2C%2520Zhang%2C%2520Midwest%2520ISO%2520-%2520Extended%2520LMP.pdf.

[33] PJM Interconnection, LLC, "Proposed Enhancements to Energy Price Formation" (November 15, 2017), available at: https://pjm.com/-/media/library/reports-notices/special-reports/20171115-proposed-enhancements-to-energy-price-formation.ashx.

costs in their bids would increase market clearing prices and thus infra-marginal revenues for resources that do not have those costs. To avoid perversely subsidizing inflexible resources, those costs should not be recoverable through make-whole or other out-of-market payments to those resources but should be included in prices to provide accurate short- and long-run incentives to all resources.

<u>Do not reward resources for their inflexibility</u>. Today RTO market mechanisms routinely provide out-of-market payments (often called "uplift") to committed generators that cover costs associated with their inflexibility. The PJM IMM in particular has proposed a number of market reforms to appropriately price the inflexibility cost of resources and ensure they are not rewarded for their inflexibility.[34] Without weighing in on each of the proposed reforms, we generally support the intent of reducing out-of-market subsidies for inflexibility and instead directly accounting for these costs in commitment and dispatch processes.

More to the point—market participants today have a variety of technologies at their disposal to meet the needs of the power system, including flexibility. The Commission should consider ending the use of uplift payments and other out-of-market payments if a market operator could otherwise meet the availability and performance required by grid operators through the use of a better or different technology. For example, generators that are not able to ramp down and up quickly enough to meet the needs of the grid could include fast-ramping technologies in combination with existing resources to cover that liability, rather than impose that cost on load.

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[34] See certain Recommendations in the 2021 State of the Market Report for PJM, Monitoring Analytics, LLC, available at: https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021-som-pjm-sec2.pdf.

2. Establish more efficient unit commitment processes.

Unit commitment is the process by which generators are selected to operate ahead of the real-time market, which is mostly achieved through the day-ahead market. Because the vast majority of energy is transacted in the day-ahead market and inefficient commitment imposes costs on consumers while distorting efficient price signals, there is considerable benefit to improving the efficiency of the commitment process.

i. Increase the use of probabilistic unit commitment.

Probabilistic unit commitment refers to processes that directly incorporate information about uncertainty in electricity supply and demand forecasts into unit commitment decisions. Today, operators make conservative unit commitment and dispatch decisions in part because they recognize that their deterministic methods and forecasts are not fully accounting for uncertainty and risk.[35] Using more rigorous quantitative methods to account for that risk would produce more efficient, lower-risk operations.

For example, commercially available renewable output and electricity demand forecasts typically include detailed information about the uncertainty of those forecasts, but it is common for only the median (p50) value to be used as the deterministic input for committing and dispatching other resources. Most forecast vendors can quantify the uncertainties around a production forecast, such as uncertainty about the magnitude of a weather event (*e.g.*, the distribution of temperature, irradiance or wind speed outcomes) and the timing of an event (*e.g.*, when a front resulting in abrupt temperature, wind speed, or cloud cover changes will arrive). Probabilistic unit commitment tools that incorporate such uncertainties would yield more

[35] Even with these conservative assumptions, RTOs/ISOs may not always accurately predict tail-end events, such as PJM's inability to accurately forecast both load and available reserves during Winter Storm Elliott. See: https://pjm.com/-/media/committees-groups/committees/mic/2023/20230111/item-0x---winter-storm-elliott-overview.ashx.

efficient commitment of resources based on risk-managed inter-temporal solutions, especially considering that many of the uncertainties have correlated impacts on both supply and demand. For example, if forecasts indicate a significant chance of both very high load and very low renewable output, operators will likely want to commit more resources. However, because those risks are not reflected in the median value for either forecast, current deterministic methods do not automatically incorporate them into commitment decisions, forcing operators to attempt to subjectively incorporate them.

While human operators have many advantages relative to computers due to their deep knowledge of the system developed over years of experience, operators can benefit from greater use of decision support tools that identify statistical patterns and use probabilistic methods to make better, lower-risk commitment and dispatch decisions. Moreover, the use of subjective judgement can be time-consuming during critical events. The use of such tools would minimize inefficient dispatch and uplift costs and reduce generation overcommitment. Many resource owners and power traders use probabilistic methods to make decisions about the dispatch of energy-limited resources like energy storage, and therefore RTO/ISO operators would also benefit from the use of those tools. MISO's report to correctly notes the benefits of using probabilistic tools:

> MISO's operators must continue to make real-time decisions and commitments based on recommendations based on data analysis inside of their tools. Real-time decisions are often made to mitigate reliability risks and may sacrifice efficiency. But we are working to better quantify the uncertainty around various risk factors so that we can continue to improve these tools, the operator decisions they inform, and over the long term, identify and implement market products to maintain reliability and efficiency (see the two other key workstreams of MISO's Reliability Imperative, MSE and Operations of the Future). Another way to better quantify the risks is to create probabilistic forecasts that account for the uncertainty…[36]

[36] MISO Report at 24.

However, MISO and the other RTO/ISOs do not use probabilistic tools. MISO's comments propose first creating a daily risk assessment to inform operator decisions, and eventually progressing to directly incorporating probabilistic analysis into unit commitment through a Dynamic Reserve Requirement:

> As MISO is able to better quantify the uncertainty, it will be able to use advanced data analytics, to visualize risks from weather, load, wind, solar and so forth to aggregate net load, do advanced scenario analysis, and extend foresight. This work is needed to create a daily risk assessment, in essence, showing us the risk we need to manage on a given day and what is needed to mitigate it. Then, based on the use of the daily risk assessment, we'll be able to use dynamic reserve requirements to reduce operator commitments and inform additional market design changes that incentivize the resource attributes at the right time and location. This would allow MISO to create Dynamic Reserve Requirements, operationalizing and automating analytical and meteorological expertise… At a more structural level and over time, such information will help inform and improve market product demand curves and align them with systemwide, regional, or local reliability requirements.[37]

We encourage MISO and other RTO/ISOs to quickly move towards directly incorporating probabilistic tools into unit commitment. While the interim step of using probabilistic tools to inform grid operators provides value, directly incorporating probabilistic analysis into unit commitment greatly exceeds the capabilities of human operators to automatically synthesize different types of risk (*e.g.*, magnitude vs timing) as well as correlations among load and the output of different types of generators across a lengthy historical record, and optimally mitigate that risk.

ii. Decrease the lead time for unit commitment.

Because forecast error for electricity supply and demand significantly decreases as one reduces the forecast horizon,[38] there is a significant benefit in making or updating unit

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[37] MISO Report at 26.

[38] For example, see the increase in wind forecast error at greater time horizons in R. Widiss and K. Porter, "A Review of Variable Generation Forecasting in the West July 2013 — March 2014" (March 2014) at 4, available at: https://www.nrel.gov/docs/fy14osti/61035.pdf.

commitment decisions as close to real-time as possible. As discussed below, one solution for achieving this is eliminating out-of-market payments that perversely reward or at least hold harmless resources that are inflexible or otherwise require lengthy lead times to start up, procure fuel, or undertake other processes. Grid operators can also use multi-interval or rolling unit commitment processes to schedule as many resources as close to real-time as possible.

Some RTO/ISOs attempt to use multi-interval commitment processes today, though there is significant room for improvement in their processes. As the MISO Independent Market Monitor (IMM) has noted:

> MISO has developed and implemented a Look-Ahead Commitment (LAC) model to optimize the commitment and decommitment of resources that can start in less than three hours. Our evaluation of the LAC results in 2019 and 2020 indicates that the commitment recommendations are not accurate. In 2020, 65 percent of the LAC-recommended resource commitments were ultimately uneconomic to commit at real-time prices and in 2019 it was 69 percent. We also found that operators only adhered to 17 percent of the LAC recommendations in 2020, which may be attributable to the inaccuracy of the recommendations. We recommend that MISO identify and address other sources of inaccuracies in the LAC model and, in conjunction with the IMM, develop logging and other procedures to record how operators respond to LAC recommendations.[39]

Using probabilistic tools to increase the accuracy and value of demand and supply forecasts will not only yield value in the day-ahead market, but also in shorter-term unit commitment processes.

3. Evaluate new market products.

Another solution to minimize out-of-market actions and to better use the new resources interconnecting to the grid is to create new ancillary service or other market products for needed services. The design of any new products must adhere to the other two principles delineated in this section, and the creation and design of such products must be balanced with accurately

[39] MISO IMM (2022) at 123.

pricing the needed services, and a recognition of the growth of storage and hybrid resources and optimal price signals for those technologies. For example, storage requires real-time price signals that it can respond to quickly along with a longer-term horizon for determining optimal charging and discharge.[40] Ongoing large-scale additions of highly flexible battery storage and hybrid resources, combined with effective energy market price formation, may obviate the need for the new uncertainty products proposed by MISO and CAISO and the potential need for new ramping products discussed by PJM. Battery and hybrid resources will provide the needed flexibility simply by following the incentives for charging and discharging in real-time market prices. It is important that new market products aimed at flexibility not suppress those price signals. Similarly, it is important that price caps not interfere with optimal dispatch.

Market operators have tried several different approaches to procuring flexibility through ramping products. MISO has reported success from its implementation of a 10-minute ahead Ramp Capability Product. MISO assesses likely variability and uncertainty over the next 10 minutes and then procures enough flexibility to meet that need. MISO currently allows renewables and other resources to provide the service and has seen 95-97% of eligible resources participating. Pricing is based on a resource's opportunity cost, a ramp capability demand curve, and incentives for performance in following dispatch. But MISO may dilute the effectiveness of this product by its consideration of a blanket exclusion of renewable resources, despite their requirement to be dispatchable, from eligibility to provide ramping.[41]

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[40] See for example, CAISO's statement in its report that a longer-term ramp product could "support optimizing the state of charge of energy storage over a longer time horizon than the current real-time market multi-interval optimization." CAISO Report at 28-29.

[41] MISO Markets Subcommittee, "Ramp Product Enhancements" (December 1, 2022) at 20-22, available at: https://cdn.misoenergy.org/20221201%20MSC%20Item%2006%20Ramp%20Product%20Enhancements627169.pdf.

MISO and its IMM have expressed interest in developing an additional market product to address uncertainty. MISO's IMM recommends that MISO:

> Develop a real-time capacity product for uncertainty: We recommend MISO evaluate the development of a real-time capacity product in the day-ahead and real-time markets to account for increasing uncertainty associated with intermittent generation output, NSI, load, and other factors. Such a product should be co-optimized with the current energy and ancillary services products. These capacity needs are currently procured out of market through manual commitment by MISO's operators. Clearing this product on a market basis would allow MISO's prices to reflect the need and reduce RSG [Revenue Sufficiency Guarantee].[42]

Using a market to procure flexible capacity to address uncertainty is more efficient than the status quo approach of over-committing resources without regard to their flexibility, which can perversely incentivize inflexible resources. To that end, MISO and other RTO/ISOs should structure such uncertainty products so their pricing and selection of resources efficiently reflects the ability of a resource to cost-effectively provide flexibility. As discussed below, make-whole payments can perversely reward resources for their inflexibility. RTO/ISOs should also allow duration-limited resources, like battery storage and curtailed variable renewables, to provide this uncertainty product. Renewable resources are unlikely to be the most economic sources of flexibility during most intervals today, but at higher renewable penetrations curtailed renewable resources will be a primary source of flexibility.

CAISO has historically tried a different approach to procuring flexibility, most notably with its Flexible Resource Adequacy Criteria and Must Offer Obligations (FRACMOO) program. Under the initial iteration of FRACMOO, load-serving entities were required to demonstrate on an annual basis that they have enough flexible capacity to meet their contribution to the CAISO system's ramping needs, and the resources they use for compliance are required to

[42] MISO IMM (2022) at 116.

then offer into the energy market. This was an addendum to the resource adequacy requirements that are imposed on the load-serving entities, so it functioned more like a capacity product than a flexibility service product in that it is a forward procurement of a capability, not actual performance in providing a service. CAISO redesigned this service after it was widely viewed to have failed to efficiently incentivize the provision of flexibility, with CAISO itself noting it "risks exacerbating the ISO's operational challenges by sustaining largely inflexible resources,"[43] though there are still significant concerns about the efficiency of the current flexible ramping product. As the CAISO Division of Market Monitoring (DMM) notes:

> Although the CAISO has implemented numerous improvements to this product since its introduction in 2016, CAISO operators continue to rely primarily on significant manual interventions to ensure sufficient ramping capacity is available during the peak ramping hours. These manual interventions include significant upward biasing of the load forecast used in the residual unit commitment and hour-ahead scheduling processes as well as manual commitments and upward dispatches of gas-fired generating units. These manual interventions have remained high, or even increased, since introduction of the flexible ramping product. Since 2016, DMM has recommended the following two key enhancements:
>
> - Increase the locational procurement of flexible ramping capacity to decrease the likelihood that the product is not deliverable (or stranded) because of transmission constraints…
> - Increase the time horizon of real-time flexible ramping product beyond the 5-minute and 15-minute timeframe of the current product to address expected ramping needs and net load uncertainty over a longer time frame (e.g., 30, 60, and 120 minutes out from a given real-time interval) and appropriately price procurement of capacity to meet longer time horizons.[44]

CAISO's DMM further notes that the proposed day-ahead imbalance reserve product that CAISO discusses at length in its report, while helpful, may not address the fundamental problem

[43] CAISO, "Flexible Resource Adequacy Criteria and Must Offer Obligation – Phase 2" (January 31, 2018) at 3, available at: https://www.caiso.com/Documents/RevisedDraftFlexibleCapacityFrameworkProposal-FlexibleResourceAdequacyCriteria-MustOfferObligationPhase2.pdf.

[44] CAISO DMM (2022) at 21.

that the time horizon for the real-time flexible ramping product is too short. The DMM explains that CAISO has proposed "a day-ahead imbalance reserve product intended to ensure sufficient ramping capacity is available in the real-time market. DMM supports development of such a product. The new day-ahead imbalance reserve product will increase day-ahead market costs through the direct payments for this new product as well as through increases to day-ahead market energy prices resulting from the procurement of this product. However, if the California ISO does not extend the uncertainty horizon of the real-time flexible ramping product, DMM is concerned that the imbalance reserves that are procured in the day-ahead market will provide limited benefit in terms of increased ramping capacity in real-time or reduced real-time market costs."[45] This statement by the DMM is an illustration of the fact that directly addressing the cause of market inefficiencies with the most elegant solution possible is typically preferable to layering on new market products. As noted above, battery storage and hybrid resources will likely meet the increasing need for flexibility if price signals in the real-time energy market are not suppressed. Using energy market price signals is likely to be a more elegant and sustainable solution than layering on new products that increase market complexity and can suppress price signals.

CAISO's proposed uncertainty product is very similar to that being considered by MISO. We agree with CAISO and its market monitor that such a product is preferable to over-committing resources without regard to their flexibility, and if CAISO moves forward with it, reiterate the point made regarding the MISO market product above that the pricing and selection of resources to provide that service should efficiently reflect the ability of a resource to cost-effectively provide flexibility.

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[45] *Id.* at 22.

Another potential solution to concerns about increasing uncertainty at higher penetrations of variable resources is to make spinning and non-spinning contingency reserves available for unexpected renewable drop off events. Today contingency reserves are used to restore system supply and demand following the loss of a large conventional generator, typically with a mix of fast-acting spinning resources (faster than 10-minute response) and slower-responding non-spinning resources (less than 30-minute response). The cost of these reserves is currently socialized to load rather than assigned to generators, even though the need for these reserves is driven by large conventional generator failures and these reserves are not activated for abrupt drops in renewable output or load forecast errors. While renewable output generally changes gradually and predictably, at high penetrations a large, unexpected drop-off in wind or solar output over a fraction of an hour can occur several times per year, as multiple RTO/ISOs note in their reports. Outside of RTO/ISO footprints, grid operators like Public Service Company of Colorado have obtained FERC approval to hold non-spinning operating reserves for large and unexpected drops in renewable output, and the type and performance of resources that provide those reserves is identical to the non-spinning reserves that are used for conventional generator contingencies and load forecast shortfalls. Because conventional generator failures and sudden renewable output drops have similar impacts on short-run grid operations for reliability, drawing from a common set of reserves may be more efficient than holding separate reserves for each type of event.

Some grid operators have expressed interest in creating market products for inertia or fast frequency response. While the Eastern and Western Interconnections have abundant inertia today, which would likely result in market prices being zero for the foreseeable future, the growth of asynchronous renewable and battery storage resources is likely to eventually make such markets valuable. Renewable and storage resources can offset the need for inertia by providing fast frequency response, which is orders of magnitude faster than the typical primary frequency response of conventional generators to a grid frequency disturbance. Fast frequency response can displace much of the need for inertia by stabilizing frequency in the initial seconds following the loss of a large generator (inertia is instantaneous and determines the rate of change of frequency after a disturbance, while fast frequency response provides additional supply and is therefore not a complete substitute for inertia). NERC has recommended allowing renewable and hybrid resources to exceed a transmission line's emergency operating limit to provide fast frequency response, as this response is only needed for a short period of time and so would not risk damage to the transmission system. That would potentially create a large opportunity for battery storage, curtailed renewables, or hybrid resources with excess capacity behind the point of interconnection to provide significant amounts of fast frequency response service at low cost.[46]

FERC should 1) examine the feasibility of removing impediments to a resource temporarily exceeding its injection limit to provide fast frequency response in the *pro forma* interconnection agreements, NERC Standards, and ISO/RTO operating practices and rules, and 2) begin work with ISOs/RTOs, NERC, Reliability Coordinators, and resource owners to determine the best design for a frequency response market. This could include convening a technical conference with those parties and learning from ERCOT's experience with implementing a fast frequency response market.[47] As noted above, fast frequency response

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[46] NERC, "Utilizing the Excess Capability of BPS-Connected Inverter-Based Resources for Frequency Support" (September 2021) at 1-2; available at: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_IBR_Hybrid_Plant_Frequency_Response.pdf.

[47] ERCOT, "Implementation Details for Fast-Frequency Response (FFR) Advancement Project" (July 25, 2022), available at: https://www.ercot.com/calendar/event?id=1658240344448.

service also allows the grid to operate reliably with less inertia, so such a market can help postpone the need for an inertia market and reduce headroom requirements for the rest of the generation fleet.

B. Increase the energy market bid cap to better reflect value of lost load.

CAISO, MISO, and PJM all have relatively low price caps in their energy markets, which can mute the incentive for performance during periods of extreme scarcity and result in under-investment in flexible generation that contributes to resource adequacy. In general, real-time energy market prices provide a much stronger incentive for resource performance than capacity market requirements, which often do not reflect the timing of need.[48]

Low price caps can also cause unintended consequences in energy markets. For example, energy market price caps in CAISO caused many storage resources to prematurely discharge during early afternoon periods in the September 2022 heat wave, because once prices hit the $2000/MWh cap storage resources had no incentive to retain their state of charge even though it was known that net load would be even higher later in the afternoon and evening.[49] Similarly, different price caps between RTO/ISOs or between RTOs/ISOs and non-RTO areas can cause inefficient transactions during periods of widespread scarcity. Such an inefficiency itself can result in unjust and unreasonable transactions, which the price caps were initially intended to prevent.

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[48] For example, see CAISO DMM (2022) at 26.

[49] The Public Advocates Office, "Preliminary Analysis of California's Resiliency During the September 2022 Heat Wave" at 8, available at: https://www.publicadvocates.cpuc.ca.gov/uploadedFiles/Content/Legislation/Heat%20Wave%20Analysis%20Final%20September%202022.pdf.

In its report, MISO notes that it is "continuing the evaluation of scarcity pricing reforms, including possible reforms to reserve demand curves, the Value of Lost Load, and the Locational Marginal Pricing price cap."[50] MISO's IMM has gone further and argued that:

> MISO's current ORDC does not reflect the reliability value of reserves, overstating the reliability risks for small, transient shortages and understating them for deep shortages. Additionally, PJM's pay-for-performance rules price modest shortages as high as $6,000 per MWh (sum of the shortage pricing and capacity performance settlement), which will lead to inefficient imports and exports when both markets are tight. Hence, we recommend MISO reform its ORDC by updating its VOLL assumption and determine the slope of the ORDC based on how capacity levels affect the probability of losing load. We have estimated that a reasonable VOLL for MISO would exceed $20,000 per MWh. Although the ORDC should be based on this VOLL, it would be reasonable to allow the ORDC to plateau at a lower price level for deep shortages, such as $10,000 per MWh. Although this price may seem high, almost all of MISO's shortages are likely to be in ranges that would establish shortage prices between $100 and $2,000 per MWh.[51]

The PJM market monitor has also proposed reforms to better price scarcity:

> 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…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 ten minute rather than 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.[52]

The CAISO DMM has proposed re-evaluating the CAISO market price caps:

> In 2021, the California ISO implemented numerous changes that feature steps to allow prices to rise and increase compensation for imports during tight supply conditions. DMM supports these changes and believes they will improve the functioning of the CAISO markets during tight system conditions. The combined effect of these changes should increase the frequency of very high prices at or near the $1,000/MWh price cap under tight conditions when scarcity is most likely to occur. DMM recommends the California ISO review and consider market performance, with these changes in effect, as it considers adding additional scarcity pricing provisions. DMM has cautioned that if scarcity pricing provisions are not well designed and do not accurately account for all

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[50] MISO Report at 38.

[51] MISO IMM (2022) at 112.

[52] PJM IMM (2022) at 84 (referred to here as the Market Monitoring Unit or "MMU").

available capacity, such provisions could encourage withholding of supply in order to trigger scarcity pricing.[53]

It is important to note that load-serving entities and their consumers can and do use long-term contracts and other hedging mechanisms to avoid incurring extremely high energy market prices, particularly in markets with high price caps like ERCOT. The vast majority of energy is procured through those bilateral contracts, with most generators and load-serving entities only using the energy market to address marginal deviations in supply or demand. While retail electricity markets are regulated by states and not FERC, retail markets play an important role in resource adequacy by ensuring that load-serving entities can and are incentivized to use contracts to hedge price risk and are not "free riding" on the power system's resource adequacy.[54]

FERC should work with the states to ensure value-based pricing along with hedging to protect consumers from high and volatile prices, and clarify that economic hedging is a state responsibility. States can elect to have the RTO/ISO enforce reserve requirements but recognize that it was never the purpose of RTO/ISOs to procure long term energy or manage price risk for consumers. States can and should ensure their retail structures enable and facilitate long-term contracting or other mechanisms to protect retail customers from high and volatile prices and to procure the types of power the state and state load serving entities and their customers wish to utilize. Some states have retail competition and allow more sophisticated customers to procure their own power, while some do not, and there are wide varieties of arrangements even within RTOs/ISOs. FERC should ensure that wholesale spot prices at all times and locations reflect the

[53] CAISO DMM (2022) at 23.

[54] See Wind Solar Alliance, "Who's the Buyer? Retail Electric Market Structure Reforms in Support of Resource Adequacy and Clean Energy Deployment" (March 2020), available at: https://gridprogress.files.wordpress.com/2020/03/whos-the-buyer.pdf.

full value of reliability, while states work with their retail structures to ensure appropriate hedging.

C. Improve transparency and efficiency by using other mechanisms to counter market power.

Market power mitigation rules that come into effect if resources fail the three pivotal supplier test generally limit resources' bids to their marginal operating costs (heat rate multiplied by fuel cost plus variable O&M costs for a typical fossil fuel plant). That method, while justified for conventional resources to achieve competitive prices where true supply and demand intersect, does not apply well to storage or demand resources, for which the marginal cost of production is based on a temporal opportunity cost rather than the cost of fuel. The opportunity cost of storage fluctuates widely over time and is not known to market monitors because it is based on expectations of future prices and dispatch. Therefore, storage and demand resources should not be subject to such operating cost-based bid caps.

Another potential improvement for the Commission and RTO/ISOs to consider is to make planned generator and transmission outages transparent so they are priced in the market, rather than keeping them confidential to prevent the exercise of market power as is standard under RTO/ISO operating practice today. RTO/ISOs, their market monitors, and FERC can instead use existing monitoring and regulatory oversight mechanisms (including market monitor review of conventional generator bids to ensure they reflect true marginal cost when markets fail pivotal supplier tests) to prevent a resource owner from exercising market power by withholding output when other generators or transmission lines are on outage. This would allow more efficient commitment and dispatch of resources and market transactions in advance of and during those outages.

Another valuable reform is for RTOs to play a greater role in coordinating transmission and generation outages to reduce congestion costs. MISO's IMM has recommended just such a change, noting that: "ISO-New England does have the authority to examine economic costs in evaluating and approving transmission outages, which has been found to have been very effective at avoiding unnecessary congestion costs.[55] We recommend MISO expand its outage approval authority to include some form of economic criteria for approving and rescheduling planned outages."[56]

The PJM IMM has also recommended greater outage coordination by PJM: "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… 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."[57]

D. Improve transmission utilization within RTO/ISOs and at RTO/ISO seams.

In their reports to FERC, the RTO/ISOs correctly note that stronger transmission and regional coordination are the solution to many challenges, as they provide geographic diversity in load and supply and access to a larger pool of resources. While transmission expansion is outside of the scope of this docket, we would refer the Commission to comments submitted by these parties in FERC's NOPRs on Transmission Planning and Cost Allocation and Generator Interconnection. However, many aspects of how the existing transmission system is used in

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[55] ISO-NE Market Rules: Section III, Market Rule 1 – Appendix G; Presentation by ISO-NE at June 25, 2012 FERC Staff Technical Conference on Increasing Real-Time and Day-Ahead Market Efficiency.

[56] MISO IMM (2022) at 113.

[57] PJM IMM (2022) at 103.

RTO/ISO markets are germane to this docket, including seams issues at RTO/ISO borders, accounting for congestion in RTO/ISO markets, and using ambient ratings and grid-enhancing technologies to reduce congestion.

1. Fix seams between RTO/ISOs and between RTO/ISO and non-RTO/ISO areas.

The most ambitious but potentially beneficial solution to RTO/ISO seams issues appears to be that proposed by the PJM independent market monitor (also known as the market monitoring unit): "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."[58] Such an optimization between market and non-market entities would be a way to increase seams coordination and might serve as a model for seams management in other regions.

In addition, the PJM market monitor "recommends that PJM permit unlimited spot market imports as well as unlimited nonfirm point to point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market."59 And 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."60

[58] PJM IMM (2022) at 99.

59 *Id.*

60 *Id.*

MISO's market monitor has recommended other incremental solutions to seams problems. Most notably, the MISO IMM recommends "that MISO eliminate all transmission and other charges applied to CTS [Coordinated Transaction Scheduling] transactions, while encouraging PJM to do the same…"[61] This change would produce more liquidity for CTS transactions and more efficient price formation. The MISO IMM also notes that inefficiencies in the calculation of interface prices incorrectly double congestion at MISO-SPP seam.[62] MISO's IMM also notes the use of a 30-minute ahead forecast for scheduling seams transactions costs tens of millions of dollars relative to more efficiently using prices from the latest 5-minute market interval.[63] The MISO IMM further notes that a redispatch agreement with TVA and Ontario could greatly reduce congestion relative to the current practice of issuing transmission loading relief requests.[64]

Finally, the MISO IMM recommends that MISO "Remove external congestion from interface prices. When MISO includes congestion associated with external constraints in its interface prices, this congestion pricing is inefficient because it is generally not accurate and duplicates the congestion pricing by the external system operator. In addition, external operators provide MISO no credit for making these payments, neither through the TLR process nor through the M2M process. Hence, they are both inefficient and costly to MISO's customers. To fully address these concerns, we continue to recommend that MISO eliminate the portions of the

[61] MISO IMM (2022) at 121.

[62] MISO IMM, "OMS-RSC: Seams Study: Market-To-Market Coordination" (May 2020) at 91, available at: https://www.potomaceconomics.com/wp-content/uploads/2020/06/Seams-Study_MISO-IMM_M2M-Evaluation_Final.pdf.

[63]MISO IMM (2022) at 89.

[64] *Id.* at 113.

congestion components of each of MISO's interface prices associated with the external constraints."[65]

2. Price congestion more efficiently.

The cost of transmission congestion within RTO/ISOs is has been increasing. While the ultimate solution is building more transmission, market reforms can help to more efficiently account for congestion. In its report, MISO notes that it has been unable to accurately forecast transmission congestion in its renewable forecasts.[66]

MISO's IMM has proposed that MISO allow market participants to more efficiently price and hedge congestion through a virtual spread product: "Participants using such a spread product would specify the maximum congestion difference between two points they are willing to pay (i.e., by scheduling a transaction). This would reduce the risk participants currently face when they submit a price-insensitive transaction and avoid inefficient day-ahead congestion."[67]

3. Use ambient ratings and Grid-Enhancing Technologies.

RTO/ISO market monitors strongly recommend more efficient practices for rating transmission lines, including the use of ambient ratings and Grid-Enhancing Technologies. The PJM 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, PJM and the MMU, and approval by FERC,"[68] and 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

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[65] *Id*. at 114.

[66] MISO Report at 25.

[67] MISO IMM (2022) 114.

[68] PJM IMM (2022) at 103.

transmission system are accurate and reflect standard ratings practice."[69] MISO's market monitor concurs, stating that:

> For years we have reported unrealized annual savings well in excess of $100 million that would have resulted from increased use of AARs and Emergency Ratings. The first step to realize these savings is for the MISO TOs to commit to providing AARs and Emergency Ratings. However, MISO's current systems and processes would not allow it to capture all these savings. Our report identifies key recommended enhancements, including: 1. System Flexibility: MISO should enable more rapid additions of new elements to AAR programs. 2. Forward Identification: MISO should support identification of additions to AAR programs based on forward processes including outage coordination. 3. Forecasted Ratings: MISO should enable use of forecasted AARs in the day-ahead market and Forward Reliability Commitment Assessment (FRAC). Currently, MISO does not have a process to receive or use forecasted ratings. [70]

The MISO market monitor also recommends use of topology optimization to relieve congestion:

> We recommend MISO develop resources and processes to analyze and identify economic reconfiguration options for managing congestion and in coordination with the TOs. Today, transmission congestion is primarily managed by altering the output of resources in different locations. However, it can also sometimes be highly economic to alter the configuration of the network (e.g., opening a breaker). Today this done on a regular basis by Reliability Coordinators to manage congestion for reliability reasons under the procedures established in consultation with the transmission owners impacted by the reconfiguration. Such procedures should be expanded to relieve costly binding constraints that are generating substantial congestion costs. In our Summer 2021 Quarterly Report, we presented an analysis of one constraint that generated over $57 million in congestion during the quarter. The constraint primarily limits the output of wind resources in the North region. The constraint has a reconfiguration option that reduces the congestion in that path by roughly two-thirds and substantially reduces wind curtailments when used. Unfortunately, it is rarely used because the congestion on the constraint rarely raises reliability concerns."[71]

E. Improve energy market price signals by reducing over-procurement of capacity.

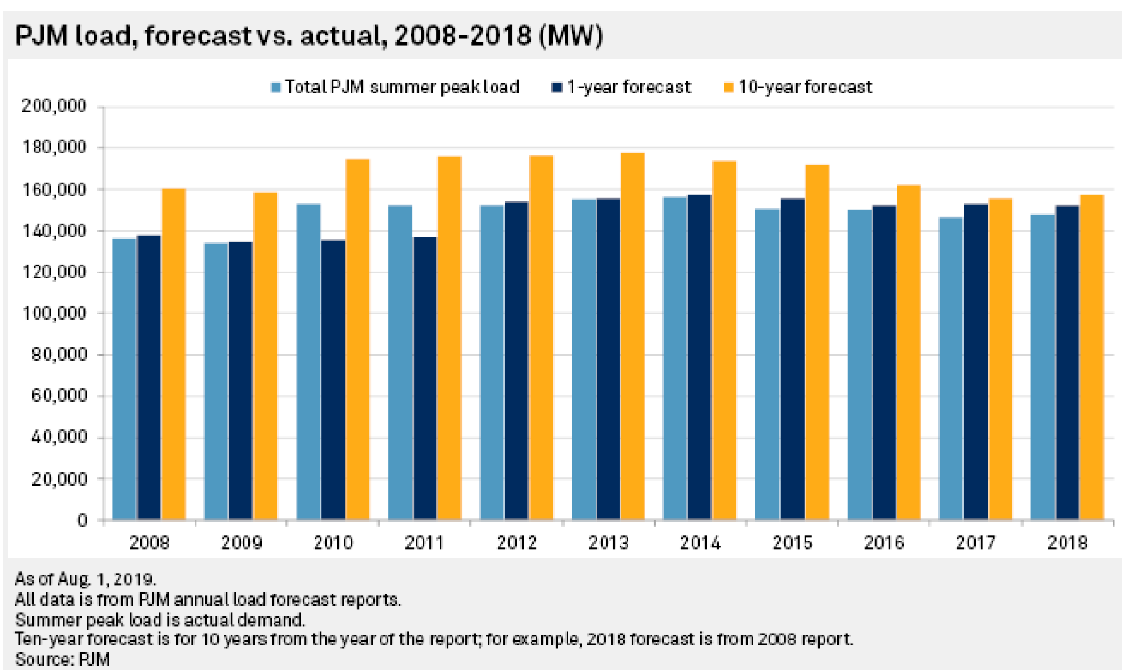
[69] *Id.* at 89.

[70] MISO IMM (2022) at 111.

[71] MISO IMM (2022) at 107-108.

While this docket is primarily focused on energy and ancillary services market reforms, the Commission did ask for "information about any other reforms, including capacity market reforms and any other resource adequacy reforms that would help each RTO/ISO meet changes in system needs."[72] Capacity market rules and their resulting procurement have a large impact on energy market prices and functioning. In particular, the history of capacity market over-procurement has harmed energy market price formation and depressed incentives for real-time performance and flexibility.

For example, PJM's capacity market has resulted in over-procurement due to overestimates of load growth, as shown below, and other factors that inflate capacity market prices, including unduly conservative assumptions about the availability of imports during peak demand periods and an assumed net Cost of New Entry (CONE) that is too high because the calculated energy and ancillary services revenue offset is too low.



PJM load, forecast vs. actual, 2008-2018 (MW)

As of Aug. 1, 2019.
All data is from PJM annual load forecast reports.
Summer peak load is actual demand.
Ten-year forecast is for 10 years from the year of the report; for example, 2018 forecast is from 2008 report.
Source: PJM

[72] Order Directing Reports (April 2022) at 1.

FERC can significantly improve the accuracy of the net CONE calculation by allowing the use of a forward-looking instead of backward-looking energy and ancillary services revenue offset,[73] as endorsed by the PJM IMM.[74] Other improvements to the net CONE calculation include better accounting for how new gas generators tend to be optimally located in areas that minimize pipeline expansion costs and also offer a lower delivered cost of gas supply, increasing their profits from providing energy and ancillary services. Finally, the shape of the Variable Resource Requirement curve should be based on the Marginal Reliability Impact of additional capacity.[75]

PJM and MISO can also better account for the availability of imports to meet resource adequacy needs. MISO assumes imports provide 2,331 MW towards meeting capacity needs,[76] while PJM assumes imports provide 2,127 MW of reduced installed capacity need.[77] However, during peak periods like Winter Storm Uri, MISO has imported as much as 13,000 MW. Imports during PJM's highest load hours are often around 5,000 MW, and in the range of 6,000-7,000 MW when PJM electricity prices are also higher than $180/MWh.[78] Imports during some high demand hours have been as high as 10,000 MW. PJM and MISO could realize significant

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[73] Brattle Group, "PJM CONE 2026/2027 Report" (April 21, 2022) at vii-viii, available at: https://www.pjm.com/-/media/library/reports-notices/special-reports/2022/20220422-brattle-final-cone-report.ashx.

[74] PJM IMM (2022) at 98.

[75] The Brattle Group, Fifth Review of PJM's Variable Resource Requirement Curve (April 19, 2022) at 25-26, available at: https://www.pjm.com/-/media/committees-groups/committees/mic/2022/20220422-special/brattle-pjm-fifth-vrr-curve-study-2026-27---final.ashx.

[76] MISO, "Planning Year 2022-2023 Loss of Load Expectation Study Report," (Dec. 6, 2021) at 22; available at: https://cdn.misoenergy.org/PY%202022-23%20LOLE%20Study%20Report601325.pdf.

[77] PJM, "2021 PJM Reserve Requirement Study – 11-year Planning Horizon: June 2021 – May 2032," (Oct. 5, 2021) at 34; available at: https://www.pjm.com/-/media/committees-groups/committees/pc/2021/20211005/20211005-item-05b-2021-pjm-reserve-requirement-study.ashx.

[78] Energy Information Administration, Form EIA-930; available at https://www.eia.gov/electricity/gridmonitor/knownissues/xls/PJM.xlsx; https://dataminer2.pjm.com/feed/rt_hrl_lmps.

consumer savings with more accurate assumptions for the availability of imports during peak periods. PJM and MISO should also explore ways to credit capacity value to new interregional transmission lines that reduce the need for peak capacity by accessing diversity in electricity demand and supply with neighboring grid operators. Accessing and accounting for geographic diversity will become increasingly important at higher renewable penetrations, given geographic diversity in wind and solar output patterns.

Correcting those assumptions will counter a historical pattern of over-procurement in capacity markets. Not only does capacity market over-procurement impose billions of dollars in excess cost on consumers, it also distorts the energy market in ways that harm price formation and the transition to more flexible resources. Over-procuring capacity shifts revenue from the energy market to the capacity market and suppresses energy market prices during periods of scarcity. This revenue shift harms the earnings of renewable resources, which earn most of their revenue in the energy market and suppresses the energy market price signal for all resources, and particularly flexible resources like battery storage, to perform during periods of scarcity.[79]

The harm to flexible resources and to the transition to cleaner resources is compounded by the fact that the capacity markets in PJM and MISO only procure capacity, and not flexible capacity.[80] Flexible capacity from batteries and other resources is increasingly more valuable than inflexible capacity as the penetration of variable renewable resources increases, yet capacity markets do not distinguish between flexible and inflexible capacity. Capacity markets also do not inherently incentivize the performance of resources during periods of scarcity, although PJM and

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[79] Grid Strategies, "Too Much of the Wrong Thing: The Need for Capacity Market Replacement or Reform" (November 2019) at 8-9, 12, available at: https://gridprogress.files.wordpress.com/2019/11/too-much-of-the-wrong-thing-the-need-for-capacity-market-replacement-or-reform.pdf.

[80] Energy Systems Integration Group, "Beyond Capacity Adequacy" (September 5, 2018), available at: https://www.esig.energy/beyond-capacity-adequacy/.

MISO have recently reformed their capacity markets to better incentivize performance. However, energy markets are still the optimal means for incentivizing performance and flexibility during periods when those services are most needed. The CAISO market monitor has similarly noted the concern that the state's resource adequacy mechanisms inadequately incentivize performance, recommending that "the California ISO and local regulatory authorities consider developing stronger resource adequacy mechanisms tied to resource performance that could better ensure that resource adequacy capacity is available and is incentivized to perform on critical operating days. The current California ISO resource adequacy availability incentive mechanism (RAAIM) is based solely on resource availability (as measured by bids submitted to the market) during a large number of hours, rather than on actual performance during the most important hours. Potential penalties under this mechanism are very limited compared to resource adequacy capacity payments in recent years."[81]

PJM's IMM has recently recommended that capacity resources be required to offer flexibility. "The MMU recommends, in order to ensure effective market power mitigation and to ensure that capacity resources meet their obligations to be flexible, that capacity resources be required to use flexible parameters in all offers at all times."[82]

The PJM IMM has also noted that current capacity market rules often pay resources even if they fail to perform, which distorts market outcomes: "The MMU recommends that resources not be paid the daily capacity payment when unable to operate to their unit specific parameter limits." For gas generators, "The MMU recommends that PJM not approve temporary exceptions

[81] CAISO DMM (2022) at 26.

[82] PJM IMM (2022) at 84.

that are based on pipeline tariff terms that are not routinely enforced, and based on inferior transportation service procured by the generator."[83]

The PJM market monitor has also recommended reforms to minimize out-of-market reliability must run payments: "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."[84]

Another important step to ensure capacity markets properly credit resources' contributions to resource adequacy is to account for correlated outages of all types of generators, including thermal generators. During extreme heat, cold, or widespread disruptions to fuel supply or cooling water, many conventional generators experience forced outages or derates at the same time. Correlated outages, including widespread loss of gas generators due to fuel supply interruptions, occurred in multiple regions during the 2014 and 2019 Polar Vortex events, the 2018 Bomb Cyclone, Winter Storm Uri in 2021, and Winter Storm Elliott in 2022. Astrapé Consulting found that in part of PJM, these outages can reduce the capacity value of conventional generators to around 85% in summer and 82% in winter, and as low as 76% if gas generator fuel supply interruptions are accounted for in winter.[85] However, the impact of correlated outages on conventional generators' capacity value is not fully accounted for in any RTO/ISO's method of capacity accreditation. NERC data indicate that correlated outages of

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[83] *Id.* at 89.

[84] *Id.* at 95.

[85] Astrapé Consulting, "Accrediting Resource Adequacy Value to Thermal Generation" (March 30, 2022), available at: https://info.aee.net/hubfs/Accrediting%20Resource%20Adequacy%20Value%20to%20Thermal%20Generation-1.pdf.

thermal generators occur in all ISO/RTO markets.[86] In addition to understating the resource adequacy risk posed by correlated outages from conventional generators, the inappropriate accreditation biases markets towards conventional generators and away from renewable and storage resources, whose correlations in their output patterns are accounted for by current methods, such as the Effective Load Carrying Capability methodologies MISO and PJM use to assign capacity value to renewables (and storage in PJM). Masking the risk from correlated outages ultimately reduces the perceived need for resource flexibility--and corresponding procurement or market pricing--that will enable RTOs/ISOs to respond to reliability events driven by correlated outages.

RTO/ISOs should include all resources in a single capacity accreditation method instead of only applying separate methods to thermal generation and to renewables and storage resources. Methods should account for correlated outages and derates of conventional generators, including gas supply and transportation interruptions and shortfalls. For example, instead of using the reserve margin to cover unexpected failures of generating units, many experts now believe it is more efficient to reduce the reliability contributions accredited to resources that experience widespread correlated failures. As Astrapé explained in its recent report:

> Overall, directly evaluating resource uncertainty on the supply-side delivers a more accurate accreditation of the reliability contributions from each resource type. Today, a portion of the thermal resource uncertainty is not being directly accounted for in its capacity accreditation, and therefore that uncertainty is being socialized to load. Accounting for the uncertainty categories in this report creates a more consistent approach for determining capacity accreditation between resources currently assessed via ELCC (wind, solar, storage) and thermal resources.

[86] Murphy et al., "Resource adequacy risks to the bulk power system in North America," Applied Energy, Volume 212, 15 February 2018, Pages 1360-1376, available at: https://www.sciencedirect.com/science/article/pii/S0306261917318202.

Capacity accreditation methods like ELCC should also account for changes in resource accreditations due to correlations across all resources in portfolio, instead of looking at correlation within each resource type alone--i.e., just using a declining curve based on the penetration for each resource.[87] In particular, wind, solar, and storage resources have a large synergistic benefit that is often ignored in capacity market accreditation. Using a declining curve for each resource without accounting for offsetting synergistic benefits among resources can significantly understate the capacity value of those resources and bias resource selection against resources that add positive interactions with other resources.

Capacity accreditation methods should also properly model the output patterns of the future renewable fleet. If the future fleet is modeled by scaling up historical renewable output profiles, benefits from expected performance improvements from technology advances and geographic diversity in the future renewable fleet should be accounted for. Scaling methods that miss geographic diversity benefits, such as the common error of linearly scaling the output of existing resources, should be avoided.[88] In general, using synthetic output profiles to model the addition of future resources avoids the errors from attempting to scale historical output profiles.

The Commission should further develop the record to support more accurate and consistent capacity accreditation. To that end the Clean Energy Associations support the recommendation that the Commission hold a dedicated technical conference on capacity accreditation.

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[87] Energy + Environmental Economics, "ELCC Concepts and Considerations for Implementation," Presentation to the NYISO Installed Capacity Working Group (August 30, 2021) at 29-35, available at: https://www.nyiso.com/documents/20142/24172725/NYISO%20ELCC_210820_August%2030%20Presentation.pdf.

[88] National Renewable Energy Laboratory, "Cost-Causation and Integration Cost Analysis for Variable Generation" (June 2011) at 27-29, available at: https://www.nrel.gov/docs/fy11osti/51860.pdf.

III. CONCLUSION

The Clean Energy Associations greatly appreciate the work of the Commission to assess the need for market reforms to address the requirements of a renewable and storage-based grid. Such reforms have the potential to create greater efficiencies and cost savings, while also improving reliability and the utilization of cleaner energy sources.

Respectfully submitted,

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