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PJM's Position on Challenges and Solutions for Long-Term Reserve Certainty Reforms

Market Design

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Executive Summary

PJM's reserve needs are evolving. PJM's existing reserves markets primarily address risk associated with large unit loss (i.e., contingency risk). Contingency risk is relatively static, based on what resources are committed to the system. In general, the reserve requirements dictated by the largest contingency are the same or nearly the same day ahead as they are in real time. While PJM will always need to carry reserves to manage contingency risk, this will no longer be sufficient as the energy transition progresses. PJM will need to rely on new operating reserve paradigms, driven by more dynamic uncertainties. In 2023, PJM's hour-ahead net-load forecast error exceeded its largest contingency in more than 130 hours. As more weather-driven renewables come online, there will likely be a time when PJM's net-load forecast uncertainty will be larger than its largest single contingency in most hours – and will far exceed that reserve need in the highest-risk hours.

The time to address these issues is now, while the risks are still emerging. These reforms will take time to design and implement, and if they are not in place before operational issues arise, it will not only create reliability risk but could drive up costs considerably. Changes to PJM's markets are needed to attract and maintain required flexibility services and to shape the generation fleet of the future. If this does not happen, it may lead to significantly more price volatility without a timely recourse to bring needed flexibility online.

PJM's reserve market design must be able to accommodate the dynamic and probabilistic nature of these fundamentally different drivers. As the energy transition progresses, reserve needs will be subject to expected weather and other system conditions and will change as the time of delivery approaches. In general, forecast uncertainty 24 hours ahead of a target time is much larger than 10 minutes ahead.

To be effective, PJM's markets will need to:

- **Effectively evaluate trade-offs between reliability risk and cost.**
- **Recognize operational risk and align market solutions to support operator actions.**
- **Manage changing levels of uncertainty and flexibility needs.**
- **Pre-position the system to ensure future reliability.**

Other RTOs/ISOs are ahead of PJM in these areas and are already responding to these developing demands. Most of PJM's counterparts in other regions have undertaken or are in the process of undertaking major reserve market reforms to navigate the generation fleet's evolution.

Figure 1. Reserve Market Reforms Undertaken Across ISOs/RTOs

	Uncertainty Reserves	Forecasted Ramping Reserves	Multi-Interval Dispatch*	Day-Ahead Specific Products	Reserve Offers > $0
PJM					✓
MISO	✓	✓			✓
CAISO	✓		✓	✓	✓
ISO-NE				✓	✓
NYISO	✓		✓		✓
SPP	✓	✓			✓
ERCOT	✓	✓			✓

**Note: ISOs currently using multi-interval dispatch do not settle any of the intervals beyond the first.*

After conducting a comprehensive literature review, performing outreach to the other ISOs/RTOs, and performing analysis of PJM's operational data and posture, PJM has identified several key areas of focus as it contemplates reserve market reforms.

1 | PJM's market design must align with operational needs and actions. Operational actions that are consistently and predictably required to maintain system reliability should be reflected in PJM markets to promote transparency, to attract and maintain essential reliability services, and to drive toward least-cost solutions. When PJM operators are routinely required to take out-of-market actions for reliability reasons, this often points to the need for market reforms. Today, PJM dispatchers are sometimes required to commit resources day ahead and out of market to ensure they are available in real time to provide necessary reserve services. This is driven by various operational risks that are not currently reflected in PJM's markets, including forecast errors, lack of fuel security, the gap between the day-ahead load forecast and cleared physical generation, the modeling of network constraints, extreme weather, and generator forced outage risk. Additionally, new operational risks, such as renewable forecast error and more frequent extreme weather events, are emerging. If PJM's markets do not evolve in time to address them, more out-of-market actions will be required, and PJM's competitive markets will fail to send the necessary and appropriate incentive signals.

2 | Accurately valuing reliability services is critical. Under Reserve Price Formation, PJM proposed a holistic redesign of PJM's reserve markets, including updates to its Operating Reserve Demand Curves (ORDCs). Although the full set of reforms was initially approved by FERC, the changes to the ORDCs were later remanded, leaving PJM to implement an incomplete market design. PJM's current ORDC penalty factors are based on lost opportunity cost (LOC) information from an event in August 2007 and do not accurately reflect current operational reality. To provide clear and accurate market signals, PJM's ORDCs should be set at a level to capture economic, available operating reserves, and reserve penalty costs should be consistent with the operational costs and actions that would be taken to mitigate any shortage. If PJM markets fail to accurately represent the value of these flexibility services, PJM will not be able to attract and maintain them, jeopardizing PJM's reliability.

3 | **Avoidable costs for providing reserve services should be recoverable through reserve markets.** The cost of advanced fuel arrangements and other availability measures to provide reserve services may be unrecoverable through PJM's existing market constructs. Resources are required to offer reserves into PJM's markets even if their cost to provide these services exceeds the allowable offer caps, which today is $0/MWh or very close to $0/MWh. A failure to recognize these costs leads to a misalignment in incentives between the profit-maximizing behavior for resources and what is required for system reliability. This issue must be resolved, both in PJM's existing reserve products and any new products developed moving forward.

PJM proposes prioritizing a set of reforms that include both enhancements to PJM's existing reserve market structures and the development of new products. These reforms are summarized in **Table 1**.

Table 1. Reserve Reforms To Explore

Enhancements to PJM's Existing Reserve Market Structures
Updates to PJM's ORDCs • Bring availability cost data up to date and better reflect operational actions and costs. • Develop a coherent energy and ancillary service market design that values each reserve service in the context of both its reliability benefit within the broader suite of services and the value of lost load.
Changes to reserve offer rules • Quantify potential costs to resources to maintain availability to provide reserve services. • Update offer structures to ensure that avoidable costs for providing reserves are recoverable through PJM's reserve markets.

New Reserve Products and Services

Day-Ahead Scheduling and Energy Gap Reserves

- Align PJM's reserve markets with the operational actions required to maintain availability day ahead.
- Reflect reliability needs into the Day-Ahead Market that are currently being addressed as a part of standard operational practice outside of the market.
- Allow resources to reflect and recover their avoidable costs for providing reserve services (e.g., fuel arrangements).
- Notify resources of the reserve commitment and obligation.
- Develop a market structure to procure reserve services that are needed day ahead but do not need to be carried in real time.

Ramping/Uncertainty Reserves

- Develop a set of products to manage both:
  a) Uncertainty associated with wind, solar, load and interchange forecast error; and
  b) Forecasted ramping needs in future intervals.
- Create a market framework that supports data-driven requirements, which reflect changing operational risk and reliability needs.
- Allow resources to reflect and recover their avoidable costs for providing these services (e.g., fuel arrangements).
- Develop market rules to establish clear reserve obligations with appropriate settlement impacts.

Secondary Reserves

- Redefine PJM's existing 30-Minute Reserve product to better align with the need to carry Secondary Reserves to backfill Contingency Reserves.
- Allow resources to reflect and recover their avoidable costs for providing these services (e.g., fuel arrangements).
- Develop market rules to establish clear reserve obligations with appropriate settlement impacts.

Introduction

At the highest level, the objective of the competitive wholesale electricity market is to ensure the reliable delivery of energy at the lowest reasonable cost. PJM has identified several areas that need to be addressed in its reserve markets to better support system reliability, to align PJM's markets with operational reality, and to ensure that PJM is attracting and maintaining critical flexibility services. As PJM considers any new solutions to address existing and emerging challenges, it will be in the context of designing a more efficient, competitive and effective wholesale energy market.

As the energy transition progresses, PJM is facing a new set of challenges. For the first time in years, PJM is projecting significant load growth, driven by new large data centers and electrification. At the same time, generation is retiring due to age and environmental and policy drivers. Today, only a modest portion of PJM's total energy is supplied by renewables. In 2024, renewable energy made up 8% of PJM's energy mix, an increase of 1.1% from 2023, and wind and solar represented 3,601 MW and 5,047 MW of Reliability Pricing Model (RPM)-eligible capacity respectively. However, the share of renewables is expected to grow considerably in coming years. As of December 31, 2024, there were 84,128 MW of solar and 29,566 MW of wind in nameplate capacity in PJM's interconnection queue. These shifts in the composition of PJM's energy fleet will demand new operational paradigms and market models to ensure that PJM has the flexible capacity it needs to maintain reliability. In considering reserve certainty moving into the future, a few significant themes emerge:

1 | The risk drivers for the grid are changing. Historically, reserve products were primarily designed to manage risk associated with the unexpected loss of a generation resource. As more variable and distributed resources enter the grid, this is no longer sufficient. As additional intermittent, weather-driven resources enter the PJM system, risks associated with forecast error and uncertainty will continue to grow. With the progression of the energy transition, PJM will need to make fundamental changes to how reserve needs are quantified and to how reserve services are valued and settled.

2 | Uncertainty drivers are increasingly dynamic. Many of the operational factors that are driving additional risk and uncertainty change over planning horizons. Unlike the risk associated with the loss of the largest generating resource, which is relatively constant, the operational risks associated with forecast errors that come with the evolving resource mix change over time. As grid operations rely more on information that can never be perfectly forecasted, the telescoping nature of that forecast error must be accounted for as well as the correlation in uncertainty across the performance of weather-driven resources.

3 | The grid of the future will require more probabilistic planning. Currently, PJM markets have a largely deterministic approach to procuring flexibility services. In general, PJM's markets tend to procure services to address a single possible future or scenario, such as the most probable forecasted outcome or the largest single unit loss. This does not always allow for a comprehensive evaluation of the trade-offs between cost and reliability impact. As the drivers creating operational risk become more dynamic and probabilistic in nature, it will become increasingly important that the market is able to weigh the value and cost of procuring additional reliability services given the probability that those impacts will materialize.

4 | Better resource pre-positioning will be needed to provide future flexibility services. With anticipated increases in net-load ramp[1] and more intra-hour uncertainty, market mechanisms are needed to better pre-position the system for upcoming flexibility needs. This may require different or longer look-ahead periods in PJM tools as well as new reserve products.

[1] Net-load ramp, as discussed here, represents the ramping behavior (or the megawatt change over time) associated with demand, minus wind and solar generation.

5 | **Existing market structures do not always appropriately value and provision critical reliability services, even in today's grid.** PJM has a long history of operating the electrical grid to ensure its continued reliability and security. In some cases, this requires PJM operators to take out-of-market action. While this meets PJM's core mission of system reliability, repeated and consistent out-of-market actions are often an indicator that the wholesale electricity market does not sufficiently reflect operational needs and value reliability services. This can lead to market inefficiency, the masking of true market costs, and a lack of incentive and investment signals to attract and maintain critical services.

In 2023, PJM presented its stakeholder body with a problem statement outlining a series of near- and long-term concerns that need to be addressed to maintain system reliability, to attract and maintain critical flexibility services, and to better align PJM markets with operational needs, both now and as the energy transition progresses. As a result of the approval of this issue charge, the Reserve Certainty Senior Task Force (RCSTF) was formed.

To date, the RCSTF has advanced three immediate-term packages: one aimed at addressing performance concerns related to the deployment of Synchronized Reserves during Synchronized Reserve Events, a second to better align existing reserve quantities with current operational practice, and a third to allow the Day-Ahead Market to consider resource hourly notification times when clearing offline reserves.[2] The packages related to deployment of Synchronized Reserves and using hourly notification times in the Day-Ahead Market were endorsed by members. The package aimed at better aligning PJM's reserve requirements with operational practice failed to pass at the Markets and Reliability Committee.

While the two packages that were approved by stakeholders and are currently being implemented will provide incremental benefit, they do not begin to address the broader and significant set of challenges within the approved issue charge. Progress will need to be accelerated moving forward because these bigger reforms will take time to fully design and implement. If they are not in place in time to address reliability issues before they become acute, costs to the system will likely be higher, both in the form of out-of-market payments and in price volatility, as flexibility services become scarce. The purpose of this paper is to document PJM's thinking on the reserve market reforms that will be necessary to navigate the energy transition.

Market Design Principles

PJM has developed a set of guiding principles for market design and effective price formation. These principles will guide PJM's work to reform its ancillary services markets and are set out below.

Price Formation Principles

- Reserve and energy prices reflect system conditions and appropriately value scarcity.
- Operating Reserve Demand Curves (ORDCs) reflect the reliability value of reserves.
- The actual reserve capability on the system is accurately measured.
- Resources assigned reserves will provide them when deployed.
- Market power is mitigated.
- Social welfare is maximized.[3]

[2] The Real-Time Market already used (and continues to use) hourly notification times to clear offline reserves.

[3] Maximizing social welfare is the objective function of the market clearing algorithms. The goal of this objective function is to optimally allocate resources for energy and reserves such that the final allocation simultaneously maximizes the benefit to consumers and the revenues to suppliers. This is done by maximizing the difference between the consumer's willingness to pay for a product and the bid production cost of cleared supply.

Additional Principles Included in PJM's Response to FERC Order AD-21-10, *Modernizing Wholesale Electric Design*[4]

- Proper locational market signals guide optimal investments.
- Solutions are nimble with evolution.
- Market rules are nondiscriminatory.
- Rules encourage robust participation and create efficient market results.
- Simplicity in market design where possible
- Transparency

The Federal Energy Regulatory Commission (FERC) released information on market rules and operational practices, which highlight some areas of concern for energy price formation.[5] The summary published to the FERC website includes the following fundamental concepts, last updated on June 17, 2020, at the time of this report:

- **Use of uplift payments**: Use of uplift payments can undermine the market's ability to send actionable price signals. Sustained patterns of specific resources receiving a large proportion of uplift payments over long periods of time raise additional concerns that those resources are providing a service that should be priced in the market or opened to competition.

- **Offer price mitigation and offer price caps**: All RTOs/ISOs have protocols that endeavor to identify resources with market power and ensure that such resources bid in a manner consistent with their marginal cost. As a backstop to offer price mitigation, RTOs/ISOs also employ offer price caps that are designed to be consistent with scarcity and shortage pricing rules. These protocols require that the RTO/ISO's measure of marginal cost be accurate and allow a resource to fully reflect its marginal cost in its bid. To the extent existing rules on marginal cost bidding do not provide for this, bids and resulting energy and ancillary service prices may be artificially low.

- **Scarcity and shortage pricing**: All RTOs/ISOs have tariff provisions governing operational actions (e.g., dispatching emergency demand response, voltage reductions) to manage operating reserves as they approach a reserve deficiency. These actions often are tied to administrative pricing rules designed to reflect degrees of scarcity in the energy and ancillary services markets. In addition, in the event of an operating reserve shortage, all RTOs/ISOs have adopted separate administrative pricing mechanisms designed to set prices that reflect the economic value of scarcity. To the extent that actions taken to avoid reserve deficiencies are not priced appropriately or not priced in a manner consistent with the prices set during a reserve deficiency, the price signals sent when the system is tight will not incent appropriate short- and long-term actions by resources and load.

- **Operator actions that affect prices**: RTO/ISO operators regularly commit resources that are not economic to address reliability issues or un-modeled system constraints. Some activity may be necessary to maintain system reliability and security. However, to the extent RTOs/ISOs regularly commit excess resources, such actions may artificially suppress energy and ancillary service prices or otherwise interfere with price formation.

[4] Modernizing Wholesale Electricity Market Design, Docket No. AD21-10-000 (PDF) Report of PJM Interconnection, L.L.C., Oct. 18, 2022

[5] Energy Price Formation: Information on Market Rules and Operational Practices, Federal Energy Regulatory Commission, ferc.gov, last updated on June 17, 2020

These concepts underscore the criticality of ensuring that markets reflect the true cost of operational reliability actions and send the appropriate market signals. If markets fail to serve this core function, investment in the requisite reliability services will not keep up with system needs, jeopardizing long-run reliability.

Challenges to be Addressed

Increasing Operational Uncertainty and Net-Load Ramp

Day-Ahead and Real-Time Uncertainty

In operating the electric power system, PJM relies heavily on imperfectly known and forecasted information, including forecasted demand, forecasted renewable generation, and probable levels of resource availability or outage. This dependence is likely to increase moving forward as more variable wind and solar resources enter the system. One of the key drivers for flexibility and reserve needs within PJM system is the need to effectively manage these uncertainties.

Under the DASR construct that existed before 2022 when Reserve Price Formation was implemented, PJM procured day-ahead reserves to meet the average generator forced outage rate and the average load forecast error, multiplied by forecasted peak demand for the coming operating day. This allowed PJM's reserve quantities to: (a) reflect how reserve needs change as a function of system loading and (b) acquire reserves to manage two critical uncertainties. When the reforms under Reserve Price Formation were designed, they included changes to the ORDCs that set the value of reserves based on the probability of falling below the minimum reliability requirement driven by a comprehensive set of uncertainties, including those driven by load, wind, solar, interchange and forced outages. When this portion of the original package was removed through the FERC Remand Order, it created a gap in PJM's reserve market, which now no longer recognizes the value of reserve services in managing these uncertainties.

Day ahead, PJM dispatchers ensure that, at a minimum, there are sufficient reserves available on the system to meet the DASR requirement. During days with high levels of forecasted renewables or days when generator outage risks are higher, operators may determine that additional reserves are needed. Since these reserve quantities are not procured through the Day-Ahead Market, operators must take out-of-market actions to ensure that enough reserves are available. Often this is done through out-of-market generator commitments, where resources are asked to run at their economic minimum and then, if they do not fully recover their cost to operate through the market, given uplift payments to make them whole. This leads to market inefficiency and fails to transparently reflect the need for these services, while potentially suppressing LMPs.

In real time, RT SCED provides dispatch instructions to generation resources based on forecasted real-time load, scheduled interchange and renewable resource forecasts.[6] When these forecasts are not realized as expected, more flexible capacity is needed in future interval(s). However, this flexible capacity is not currently reserved through RT SCED, which may leave insufficient flexibility available. In the absence of any market mechanism to value and procure this flexible capacity, operators need to take out-of-market actions for reliable operation, such as introducing load biases into RT SCED, which has an impact on prices without sending clear flexibility incentive signals.

[6] Either PJM's forecast or those reflected in resources' bid-in parameters

Factors Driving Uncertainty

One of the key risks that PJM must manage as the energy transition progresses is increasing operational reliance on imperfect information. As more variable, weather-driven resources enter the system, more dispatchable flexibility will be required to ensure reliable operations when resources produce either more or less than forecasted. This will be particularly critical during times of tight operational conditions, high demand or large net-load ramps.

Forecast error tends to decrease as the time of delivery approaches. Therefore, PJM expects to require more reserves to manage uncertainty further ahead of the time of delivery and for these reserve needs to decrease as the uncertainty resolves. **Figure 2** and **Figure 3** provide the 97.5 and 2.5 percentile net-load forecast error for the 2023/2024 Delivery Year for five minutes ahead out to 24 hours ahead of the time of delivery. Note that the 2.5 percentile error, which are negative values given the sign conventions described above, would reflect ramping up flexibility needs, while the 97.5 percentile error reflects ramping down flexibility needs. These figures provide some insight into how uncertainty resolves as the effective time approaches.

Figure 2. 2.5 and 97.5 Percentile Net-Load Forecast Percent Error One to 24 Hours Ahead of Delivery Time During the 2023/2024 Delivery Year

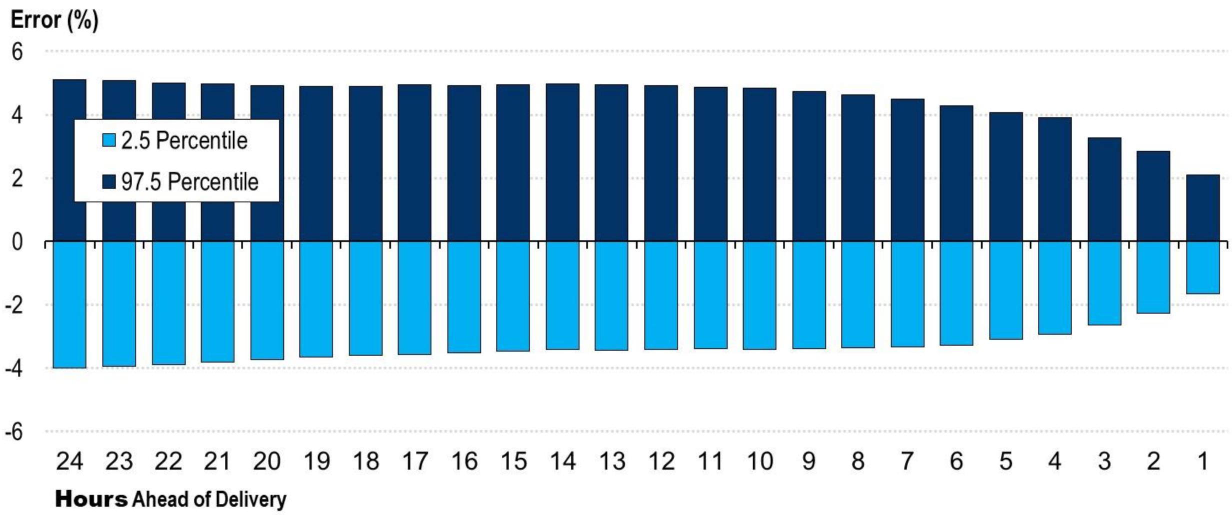


Figure 3. 2.5 and 97.5 Percentile Net-Load Forecast Percent Error Five to 55 Minutes Ahead of Delivery Time During the 2023/2024 Delivery Year

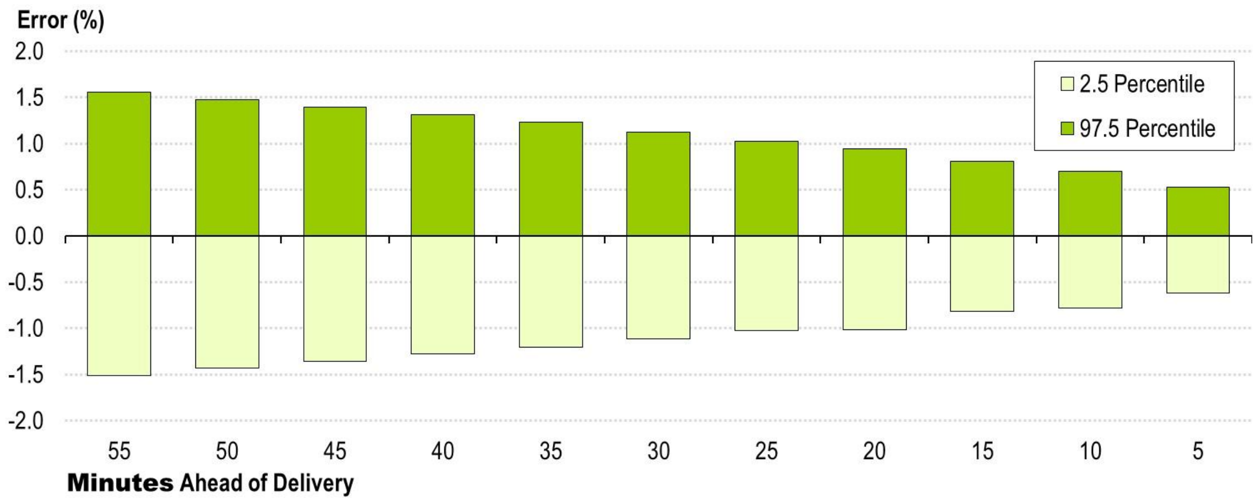


Figure 2 and **Figure 3** illustrate that while the net-load uncertainty does gradually decrease between 24 hours and seven or eight hours ahead of the time of delivery, it begins to decline more sharply after that point.

Increasing Net-Load Ramping Events

In addition to maintaining flexibility to manage forecast uncertainties, PJM will require additional flexible ramping capability and methods for pre-positioning the system to manage upcoming forecasted ramping needs. Because RT SCED is a single interval dispatch, it does not consider the ramping needs of future intervals when making dispatch decisions in the current interval. For example, take a system where there are three kinds of generation resources available to meet load over the next two hours: (1) fast-ramping online resources with very low marginal energy costs, (2) slow-ramping online resources with higher marginal energy costs, and (3) offline Fast-Start Resources with high commitment costs. For a particular upcoming ramping period, a two-hour look-ahead commitment and dispatch optimization determines that the most efficient outcome to meet the expected net-load ramp is to begin ramping up the slower moving, slightly more expensive online resources now. This will retain ramping and headroom capacity on the faster-moving resources for later and allow all demand over the next two-hour period to be met by online resources without the need to incur the high cost of committing the offline units.

Now imagine that a single interval is evaluating the dispatch instructions to send to resources for the next target time, roughly 10 minutes in the future. It has no insight into anything forecast beyond the next 10 minutes and has sufficient low-cost energy available to meet current demand through inexpensive, fast-ramping resources. It will therefore dispatch these least-expensive resources up to meet that demand. This will continue every interval until this lower-cost energy is exhausted. At some point, there will no longer be sufficient ramping flexibility available online to meet the upcoming ramping needs, and so operators will be forced to bring online fast-start, high-commitment cost resources to meet demand.

This is a challenge that exists today and is sometimes addressed by operators through the introduction of load biases into RT SCED cases to pre-ramp resources. As mentioned earlier, this can impact prices but does not send clear or consistent pricing signals, in that it is not valuing the actual service required. Additionally, this can have consequences for the deployment of regulation services, which may or may not be needed. Moving forward, as PJM projects increasingly large net-load ramping events through the energy transition, this issue will be exacerbated.

Practices in Other ISOs/RTOs

To manage uncertainty driven by increasing net-load forecast error, NYISO plans to incorporate its net-load uncertainty as an incremental quantity in its existing 10- and 30-Minute Reserve Requirements. In the Day-Ahead Market, this increase in the 30-Minute Requirement will be based on day-ahead net-load forecast uncertainty. In the Real-Time Market, the incremental 30-Minute Reserve Requirement will be based on 60-minute-ahead net-load forecast error and the incremental 10-Minute Reserve Requirement will be based on 30-minute-ahead net-load forecast error in both markets. This uncertainty portion of the reserve requirements will be distributed locationally across reserve subzones based on where net-load forecast error is highest, driven largely by resource mix. The proposed implementation of this incremental uncertainty requirement is in 2025.

Additionally, to address longer-look-ahead net-load forecast error, NYISO proposes implementing a new 60-Minute Reserve product based on four-hour net-load uncertainty with a four-hour-duration availability requirement. This new uncertainty product will not nest or overlap with NYISO's existing 10- and 30-minute products, meaning its requirement would be met separately. Studies done by NYISO showed that the four-hour uncertainty and duration requirement covers a significant amount of observed net-load forecast error while simultaneously aligning with the time to start of the bulk of their generation fleet, providing the time needed to bring additional resources online to backfill this service. NYISO proposes implementing this new product in 2026.

MISO has implemented a 30-minute Short-Term Reserve (STR) product in both its real-time and day-ahead markets to manage uncertainty, which was previously handled through out-of-market actions. MISO's STR is similar to PJM's 30-Minute Reserve product and is included in both the Day-Ahead and Real-Time Market co-optimizations. The purpose of this product is threefold: to manage transfer between the MISO north and MISO south regions, to restore transmission flows within limits following a contingency, and to ensure sufficient available flexibility for managing uncertainties associated with net-load forecast error. MISO considers net-load variations from 30 minutes to three hours when setting the STR requirements, which come out of a machine learning model that predicts high-, medium- or low-risk profiles for the current system conditions. MISO uses this requirement in both day ahead and real time.

In 2016, MISO also implemented a flexible ramping product to address both the volatility and the forecast uncertainty in its net-load, largely driven by load, intermittent generation resources and net-scheduled interchange. MISO studied both increasing their regulation requirement and increasing their synchronized reserve requirement as alternative ways to procure this additional ramping need. However, these alternative solutions resulted in higher production costs when compared with the flexible ramping product.[7] MISO's flexible ramping product has two components: Flexible Ramping Up and Flexible Ramping Down. It procures both based on the net change in demand between the current interval and the interval immediately following as well as upcoming net-load uncertainty for a forward time horizon of 10–25 minutes.[8] All resources providing this ramp service must be able to convert this ramp capability into energy within 10 minutes. In the Day-Ahead Market, this 10-minute window is scaled to one hour to accommodate the hourly time resolution. This flexible ramping product is procured at the ISO level; however, specific deployment constraints are considered during procurement to ensure the procured ramp capability is deliverable when needed.

SPP implemented a ramp product to procure the ramp capability needed for future intervals to manage both forecasted and uncertain intra-hour ramping events using a market-based approach. SPP's ramp capability requirement is determined based on two calculations. The first looks at the expected intra-hourly change in net load.

[7] Ramp Capability Product Design for MISO Markets, MISO, Dec. 22, 2013

[8] Scarcity Pricing White Paper: Value of Lost Load and Operating Reserve Demand Curve (PDF), MISO, March 2024

For the uncertainty portion of the ramp requirement, SPP looks at the historical net-load forecast error driven by errors in wind and solar generation.

SPP also has an Uncertainty Reserve product, which manages uncertainty associated with renewable resource generation across a longer time horizon.[9] The currently implemented Uncertainty Reserve product procures one-hour flexible capacity. However, operators are also concerned about flexibility across many additional time horizons, including two hours, three hours and up to several days ahead. SPP is therefore monitoring the need to implement additional uncertainty reserve products moving forward. SPP's Uncertainty Reserve Up Product can be met by the Regulation Up, Contingency Reserve and Ramping Capability Up products. Product substitution may therefore occur when the procurement of these services is co-optimized with energy.

Like SPP's ramp product, SPP's Uncertainty Reserve requirement is also set by the sum of the forecasted and uncertainty-driven flexibility needs in future intervals. The forecasted component is based on the hourly forecasted net-load change between each hour. The uncertainty component of the requirement is based on historical net-load forecast error over the prior twelve months for a given hour. The 97th percentile of the forecast error is used to set the hourly uncertainty component. As the Regulation Up, Contingency Reserve and Ramp Capability Up products can fulfill the Uncertainty Reserve service, these procurement quantities are subtracted from the total Uncertainty Reserve requirement.

To address the forecast errors that exist between the Day-Ahead and Real-Time Markets, CAISO has implemented a new Imbalance Reserve product. This Imbalance Reserve is a 15-minute ramp product and supplements CAISO's Reliability Capacity product, which is a 60-minute product. Imbalance Reserve provides flexibility to respond to intra-hour balancing needs. As discussed below, CAISO uses a multi-interval dispatch optimization to manage forecasted changes in net-load. However, even with multi-interval dispatch, CAISO found that when system conditions changed in subsequent intervals due to forecast errors, the system would sometimes lack sufficient ramp capability to get a feasible dispatch solution. CAISO therefore introduced a flexible ramping product to manage intra-hour forecast uncertainties caused by load and variable energy resource forecast error.[10] CAISO has implemented this flexible ramping product in both its 15-minute and five-minute markets. Implementation in the 15-minute market is intended to ensure that enough ramp capacity is available to meet the need for the upcoming 15-minute market solution and the three corresponding five-minute solutions. Procurement in the five-minute market is to ensure that enough ramp capability is available to meet demand in future five-minute dispatch intervals.

CAISO and NYISO use multi-interval dispatch to help pre-position the system for forecasted ramping needs. Multi-interval dispatch performs Security Constrained Economic Dispatch for multiple intervals, which allows pre-ramping of resources to maximize the economic use of available ramp capability by trading off the costs between intervals. Both ISOs optimize the dispatch over the next hour on a rolling basis, where the first interval becomes the binding dispatch instruction for the next five minutes, and the remaining dispatch intervals are advisory. The objective of the optimization is to minimize production costs across all modeled intervals, and multi-interval dispatch may dispatch resources out of merit in the current interval to preserve additional ramp capability for future intervals.[11] If a resource

[9] Submission of Tariff Revisions to Add Uncertainty Reserve Products to the Integrated Marketplace (PDF), SPP, Jan. 28, 2022

[10] Flexible Ramping Product Refinements, CAISO, Aug. 31, 2020

[11] Ramp Capability Dispatch and Uncertain Intermittent Resource Output (PDF), Rutgers Center for Research in Regulated Industries, June 2018

is dispatched down out of economic merit order from its economic maximum to reserve ramp capability for future intervals, the market must replace this energy from higher-cost resources.

In both CAISO and NYISO, only the results of the first interval are settled. If future prices do not materialize as forecasted, this can lead to a misalignment between market signals and the profit-maximizing behavior of resources, which can result in disincentives to follow dispatch instructions or uplift payments to make resources whole for financial losses. Both CAISO and NYISO help to mitigate this issue with their rules for settling uninstructed deviation.

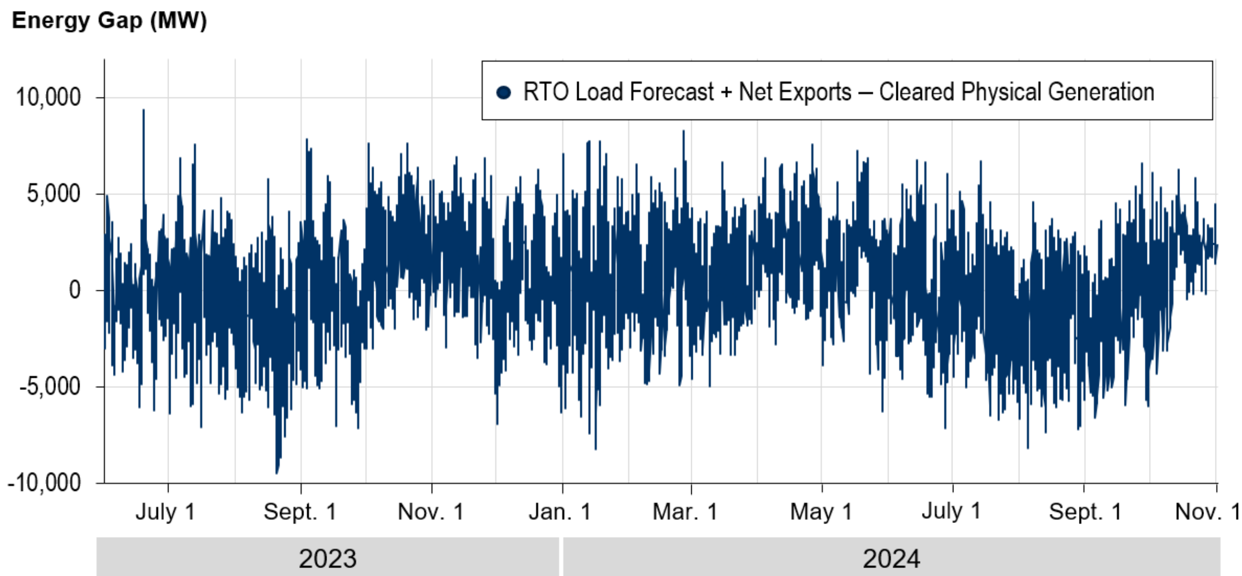
The "Energy Gap"

PJM currently clears its Day-Ahead Market to meet the bid-in demand, which may be lower than PJM's load forecast for the next operating day. Cleared virtual supply can further widen the gap between forecasted load and cleared physical generation. When this energy gap is substantial, PJM dispatchers may have to take out-of-market actions to ensure that the physical energy and reserve capability needed to meet forecasted load are available to preserve reliability.

One of the primary ways that PJM does this is with the Reliability Assessment and Commitment (RAC) tool. RAC accounts for the gap between bid-in and forecasted demand. RAC also incorporates any updated information available since the Day-Ahead Market solved, such as updates to the load forecast, unplanned outages and scheduled interchange. RAC takes the Day-Ahead Market commitment, accounting for any changes in resources' availability, and then recommends additional resource commitments as necessary to meet forecasted demand. The fact that these commitments are not included in the Day-Ahead Market optimization can lead to market inefficiency. Additionally, since units committed through the RAC do not receive day-ahead energy or reserves awards, they do not have a Day-Ahead Market position and may not always have sufficient incentive to take any necessary steps to be available to provide those services the next operating day. Such steps may include managing or making supply arrangements, conducting maintenance and staffing facilities.

Figure 4 shows the difference between the day-ahead demand forecast plus exports and the amount of physical generation cleared in the Day-Ahead Market from June 2023 through October 2024.

Figure 4. Gap Between the Amount of Generation Needed To Meet the Load Forecast and Scheduled Net Exports and the Amount of Physical Generation Cleared by the Day-Ahead Market



Practices in Other ISOs/RTOs

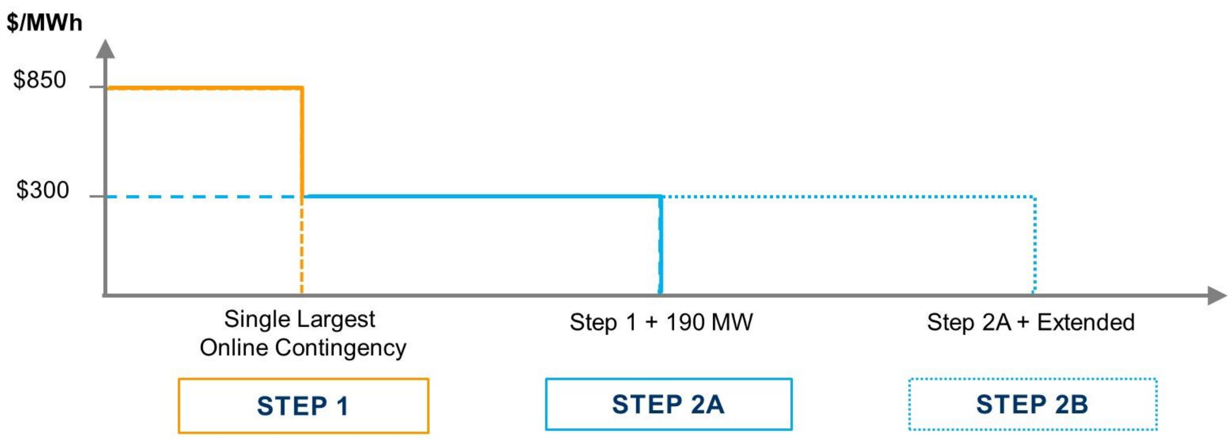
To address the need for additional flexible capacity due to the gap between the amount of physical supply cleared in the Day-Ahead Market and the load forecast, CAISO has implemented two products: "Reliability Capacity Up" and "Reliability Capacity Down." The Reliability Capacity Up product is procured when the demand forecast exceeds the cleared physical energy in the Day-Ahead Market, and the Reliability Capacity Down product is procured when the reverse is true. These capability products bridge the gap between the financial market day ahead and the physical real-time market. They do not address net-load uncertainty arising from forecast errors or intra-hour ramping needs, which are handled through separate products. CAISO implements this procurement process through its Residual Unit Commitment (RUC) tool, which is akin to PJM's RAC, but allows offer prices to be submitted for providing the service. The RUC then clears these products in a co-optimization with energy and other ancillary service reserve products based on submitted offers and accordingly sets the market clearing prices for these products. This implementation does not change the cleared quantities and clearing prices resulting from the Day-Ahead Market but procures the incremental or decremental supply to meet the forecast demand using residual supply.

At the beginning of 2025, ISO-NE implemented an Energy Imbalance Reserve (EIR) product, which is designed to address the lack of compensation, obligation and notice to resources needed to fill this energy gap. As with all the new reserve products introduced under ISO-NE's recently approved filing, the EIR product is co-optimized with energy and other ancillary service reserve products in the Day-Ahead Market and structured as an energy call option. Before the Day-Ahead Market deadline, ISO-NE sets a strike price for every hour of the next operating day. Resources will then offer energy call options into the market that reflect: (1) expected close-out charges, based on expected hub energy prices and the strike price, (2) avoidable fuel or charging costs, and (3) a risk premium. Then, in real time, if LMP exceeds the calculated strike price set by ISO-NE, the call option is settled when the resource pays the difference between the strike price and LMP. If LMP is below the strike price, the resource keeps that revenue. This call-option design does not rely on settling the day-ahead reserve product against a corollary real-time product, which is necessary for a product like EIR that is addressing a risk that only exists day ahead.

Appropriately Valuing Flexibility and Reliability Services

PJM's current ORDCs contain two steps: a $850/MWh penalty cost and a $300/MWh penalty cost. The megawatt value of the first step of the ORDC is set by the reserve reliability requirement of each reserve service. The second is the reliability requirement plus a 190 MW adder, which may be further extended during emergency conditions. **Figure 5** shows the current Synchronized Reserve ORDC.

Figure 5. Synchronized Reserve Operating Reserve Demand Curve[12]



The penalty cost at the first step in the ORDC was set based on historical lost opportunity costs paid to resources on peak days from Jan. 1, 2006, to Nov. 1, 2009, where the ultimate $850/MWh value was selected based on a single event in August 2007.[13] When PJM filed changes to its ORDCs under Reserve Price Formation in March 2019, PJM proposed changing the highest ORDC penalty cost to $2,000/MWh to be consistent with the cost-based energy offer cap. In its response, to the filing, FERC explained its rationale for accepting the proposed change.[14]

> *"The Commission found that, because resources can submit cost-based, price-setting offers as high as $2,000/MWh, resources may face higher, but legitimate, opportunity costs on a more frequent basis going forward. The market price needs to capture these opportunity costs, even if relatively rare, and it will allow emergency and pre-emergency demand response … to set the clearing price for any reserve product."*

Additionally, PJM proposed a methodology for setting the shape of the ORDCs to reflect the value of reserves above the minimum reliability requirement. Past the minimum reliability requirement (which for Synchronized Reserves [SR]) is based on the largest contingency on the system), the benefit of carrying additional reserves is in reducing the probability that PJM would fall below this requirement and end up in a reserve shortage, which could lead to reliability concerns and scarcity prices. The possibility of reserve shortage is primarily driven by forecast uncertainty and generator forced outages. If actual load is higher than was forecasted, more unloaded resources will need to be converted to energy to meet demand, which could lead to a shortage of reserves while dispatchers work to bring more resources online. If wind and solar generation produce less than expected or generation resources experience unplanned outages, this could produce a similar result. As such, PJM developed a demand curve that slopes downward from the minimum reliability requirement and reflects the incremental reduction in value of these services

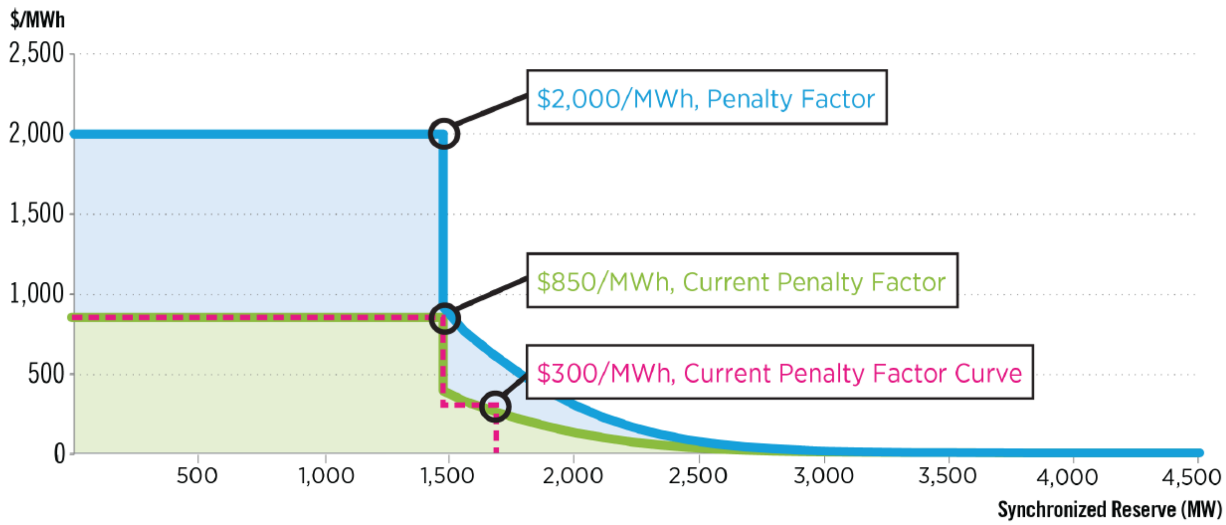
[12] Figure source: PJM Manual 11, Revision 132

[13] PJM Interconnection, LLC, Docket No. ER09-1063, issued April 19, 2012

[14] FERC response to PJM's Price Formation filing, Nov. 3, 2020

for risk mitigation as more are available on the system. For the 10-minute reserve demand curves, the probability of falling below the minimum reserve requirement is based on the historical 30-minute look-ahead forecast error from the most recent three full calendar years. For the 30-Minute Reserve demand curve, the 60-minute look-ahead forecast error is used.[15] An illustration of this concept is given in **Figure 6**.

Figure 6. Existing and Proposed ORDCs Under Reserve Price Formation[16]



Despite the Commission's original acceptance of the proposed revisions to the ORDCs, this portion of the Reserve Price Formation filing was later remanded, and PJM has continued to use the two-step ORDC shown in **Figure 5**. As such, PJM was put into the position of implementing only a portion of the comprehensive market design filed in 2019, which resulted in an incomplete market design that continues to exist today.

To be effective, ORDCs must accurately reflect the willingness to pay to mitigate reserve shortage and to avoid loss of load. This ensures that all more cost-effective measures are exhausted before taking more extreme and expensive emergency actions. It also reduces the out-of-market actions that operators need to take to maintain system reliability, which can affect prices. Taken together, if ORDCs are not designed to appropriately reflect the actual value that reserve services provide to the system, it can lead to inefficient market outcomes in the short run and inaccurate or insufficient incentive signals in the long run, ultimately compromising system reliability. As stated by FERC on its website related to energy price formation:

> *To the extent that actions taken to avoid reserve deficiencies are not priced appropriately or not priced in a manner consistent with the prices set during a reserve deficiency, the price signals sent when the system is tight will not incent appropriate short- and long-term actions by resources and load.*[17]

[15] Docket No. EL19-58-00, Enhanced Price Formation in Reserve Markets of PJM Interconnection, L.L.C.

[16] Figure source: Operating Reserve Demand Curves (ORDC) for Reserve Price Formation Project

[17] Federal Energy Regulatory Commission, Energy Price Formation, last updated on June 17, 2020

PJM's existing ORDCs do not accurately reflect current operational reality, the reliability value that reserves provide, or the actions that PJM would need to take to maintain reliability on the system. As previously mentioned, PJM's current $850/MW penalty factor is based on lost opportunity cost information from a single event more than 17 years ago. Not only is this information outdated, but the metric itself provides an incomplete picture of the cost and value of reserves.

Moving forward, PJM needs to take a holistic approach to its reserve market design, including how reserves are valued, and in consideration of the lessons learned since the Reserve Price Formation filing. In addition to lost opportunity cost, which is a driver for reserve market clearing prices and the costs incurred by resources to provide the reserve service, there are costs that would be incurred to the system in the event of a reserve shortage that should be considered in the discussion of developing an accurate ORDC. PJM Manual 13: Emergency Operations, Section 2.3, Capacity Shortages, describes the procedures that operators follow when in a capacity shortage. These include Pre-Emergency and Emergency Load Management Reductions, declaring a Maximum Generation Emergency, curtailment of nonessential building load, voltage reduction, and finally initiating a Manual Load Dump Action. Many of these actions entail real costs to the system, which are not currently transparent to PJM markets.

Practices in Other ISOs/RTOs

In March 2024, MISO released a position paper proposing ORDC changes and an update to the value of lost load (VOLL) used in its reserve and energy markets.[18] In this paper, MISO details several options and ultimately proposes a VOLL of $10,000/MWh, an increase from the current value of $3,500/MWh. This work was done in part because in its 2023 State of the Market Report,[19] MISO's Independent Market Monitor (IMM) recommended "that MISO improve its shortage pricing by improving its VOLL and the slope of its ORDC." The report goes on to detail the IMM's specific recommendations related to both items:

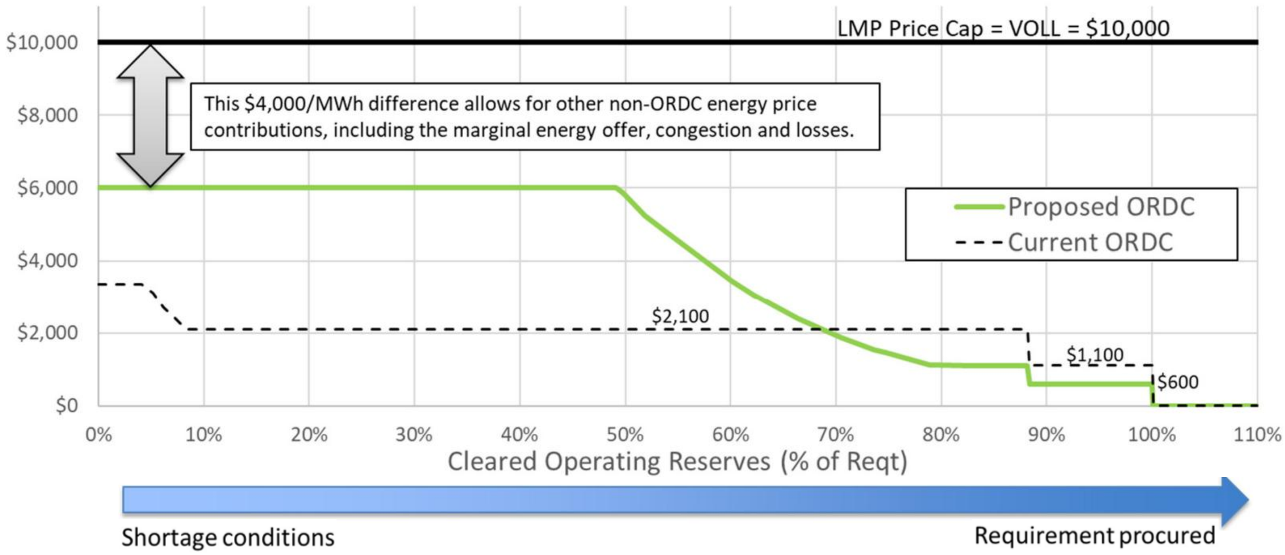
> *"**Improving the VOLL.** We reviewed the literature and used a model developed by Lawrence Berkeley National Laboratory to estimate an updated VOLL for MISO. This study and others estimate VOLLs that vary substantially by customer class. Using the Berkeley Model and MISO data, we estimated a VOLL of close to $35,000 per MWh."*
>
> *"**Improving the Slope of the ORDC.** The slope of the ORDC is determined by how the probability of losing load changes as the level of operating reserves falls. The probability of losing load depends on the vast combinations of random contingencies and other factors (wind forecast and load forecast errors, and [net-scheduled interchange] uncertainty) that could occur when MISO is short of reserves. We estimated this probability using a Monte Carlo model that simulates these factors."*

MISO ultimately selected a VOLL of $10,000/MWh, deeming that a higher value would be excessive, and this value will be used as a market price cap and for administrative pricing during load-shed events. MISO agreed with its Market Monitor's recommendation to define the ORDC based on the loss of load probability scaled to reflect the cost of shedding firm load and proposes using the $35,000/MWh value recommended by the IMM as the scaling factor. At the same time, MISO will use $6,000/MWh as an ORDC upper limit to "allow prices to appropriately rise toward VOLL as Operating Reserves are depleted." MISO's current and proposed ORDCs are shown in **Figure 7**.

[18] Scarcity Pricing White Paper: Value of Lost Load and Operating Reserve Demand Curve (PDF), MISO, March 2024

[19] 2023 State of the Market Report for the MISO Electricity Markets (PDF), Potomac Economics, June 2024

Figure 7. MISO's Current and Proposed Operating Reserve Demand Curves[20]



NYISO also went through a similar process evaluating their ancillary service shortage pricing mechanisms, including analysis of historical shortage events and estimating their VOLL. NYISO also used the Lawrence Berkeley National Laboratory (LBNL) model, which underpinned the VOLL analysis done by MISO's IMM, and calculated that at that time, New York had an average estimated VOLL of $60,000/MWh across all customer types.[21] When using a simpler macroeconomic analytical approach, NYISO estimated its VOLL at $11,000/MWh. NYISO further went on to calculate its loss of load probability (LOLP) based on the approach recommended by Potomac Economics for MISO's 2017 State of the Market Report. NYISO used a Monte Carlo simulation to estimate its LOLP driven by generator forced outage risk, load and intermittent resource forecast error risk, and desired net-interchange error risk. NYISO then generated LOLP curves for its 10- and 30-Minute Reserve products based on these simulation results. **Figure 8** and **Figure 9** show the new ORDCs that NYISO generated based on these VOLL and LOLP results, juxtaposed against its existing demand curves.

[20] Figure source: Scarcity Pricing White Paper: Value of Lost Load and Operating Reserve Demand Curve (PDF), March 2024

[21] Ancillary Services Shortage Pricing (PDF), NYISO, December 2019

Figure 8. Illustrative VOLL-Based ORDC for New York Control Area (NYCA) 10-Minute Reserves[22]

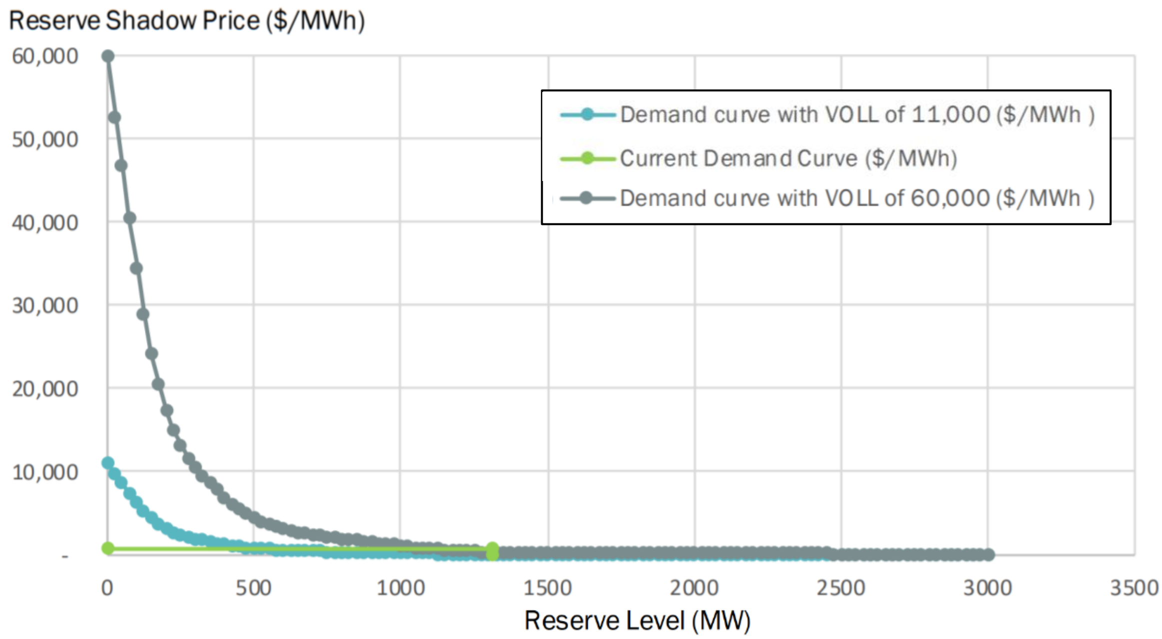
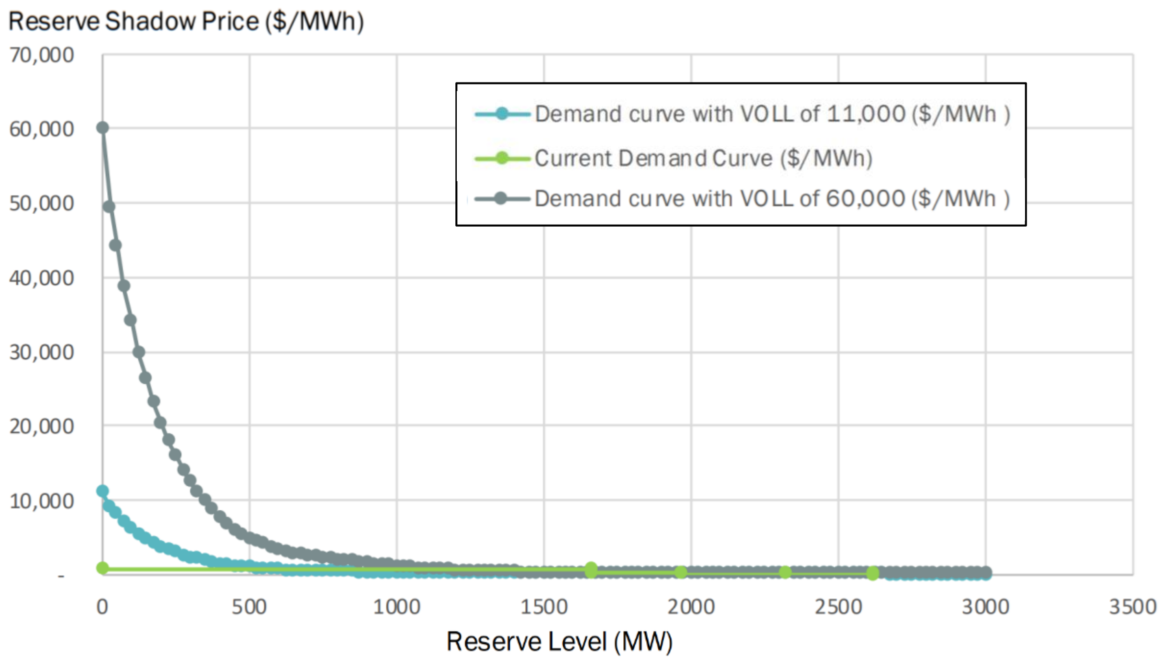


Figure 9. Illustrative VOLL-Based ORDC for New York Control Area (NYCA) 30-Minute Reserves[23]



[22] Figure source: Ancillary Services Shortage Pricing (PDF), NYISO, December 2019

[23] Figure source: Ancillary Services Shortage Pricing (PDF), NYISO, December 2019

Willingness To Pay for Reserves

An effective ORDC should ensure that (1) all more cost-effective actions are taken prior to engaging more expensive emergency procedures up to and including Manual Load Dump and (2) that those costs are made transparent to the market. ORDC penalty factors must therefore be high enough to trigger these remedial actions rather than allowing the system to go short reserves unnecessarily.

Today, as discussed in the analysis of a recent shortage event, this is not the case even when considering the relatively routine lost opportunity costs incurred by resources to provide reserves in lieu of providing energy. As a shortage condition escalates, and in particular in the case of an SR shortage, the ultimate cost is manual load shed. This is the final emergency operational action detailed in PJM's Manual 13: Emergency Operations, Section 2.3 Capacity Shortages, and will be taken as a last resort to protect the system from cascading outages.

The maximum willingness to pay for reserves where the cost of under-procurement is shedding load should be considered in the context of the value of lost load. While it may ultimately be impossible to arrive at a single, unequivocal number that accurately represents PJM's VOLL, the industry has invested significant time and effort in estimating the costs of interruptions to electricity service, including using macroeconomic modeling, such as calculating gross domestic product (GDP) to load ratios, post-event analysis following blackouts, customer surveys and market behavior observations.[24]

LBNL conducted a meta-analysis of over 100,000 customer surveys and then developed a regression model that drives their online Interruption Cost Estimate (ICE) Calculator. This methodology may be the most broadly accepted model for estimating VOLL and was used to inform the MISO and NYISO shortage pricing analyses as previously described. Conducting a similar analysis for PJM's footprint using this model yields a VOLL of $68,000 in 2023 dollars.[25] On the other hand, doing a simple GDP to load ratio calculation, as was done by both NYISO and London Economics when estimating ERCOT's VOLL,[26] yields a value of roughly $7,000 in 2023 dollars based on 2022 data.[27] Additionally, there is broad consensus that different customer classes have different costs for interruption of service. LBNL's calculator estimates the cost of electricity service interruption for PJM's residential customers closer to $6,000/MWh, much lower than the system-wide weighted average of $68,000/MWh. Given that different consumers may have a very different willingness to pay to avoid service interruptions, the most market-efficient solution would be to remove any frictions that currently exist to allow consumers to express this willingness to pay directly through participation in Price Responsive Demand or Demand Response programs and to allow prices to rise to reflect the higher willingness to pay of customers for whom service interruption is extremely costly.

While PJM is unlikely to arrive at a single and unequivocal VOLL number, understanding the credible range of values may provide a helpful backdrop in discussing a willingness to pay for reserves. Additionally, there are practical market efficiency questions that can inform the discussion. For instance, there are costs that are routinely incurred to provide these services, such as resource lost opportunity and commitment costs, as well as the costs of emergency actions that system operators may need to take to maintain system reliability in the event of a Capacity Shortage. Given that those actions entail real costs, allowing reserve prices to rise to approach these costs would ensure that if reserves can be procured at less expense, the market optimization engines will recognize that either committing

[24] The Quest To Quantify the Value of Lost Load: A Critical Review of the Economics of Power Outages, Will Gorman, October 2022

[25] More detail on the approach used to conduct this analysis is provided in the Appendix.

[26] Estimating the Value of Lost Load (PDF), prepared for ERCOT by London Economics, June 17, 2013

[27] More detail on the approach used to conduct this analysis is provided in the Appendix.

resources or redispatching the system is the cost minimizing option rather than allowing the system to go into reserve shortage.

ORDCs for Separate Reserve Services

Each reserve service has its own ORDC, which should reflect the procurement quantities and willingness to pay for that essential reliability service. The willingness to pay for a reserve service is based on the "quality" of that service. In other words, the willingness to pay for a lower-quality service will likely be lower than for a higher-quality service. Therefore, procuring one type of reserve can mitigate the likelihood of going short another type of reserve. For example, this has been demonstrated in the market designs of other ISOs where uncertainty reserves help mitigate contingency reserve shortage. PJM believes it will be important to evaluate and reform its existing ORDCs for Synchronized, Primary and 30-Minute Reserves to ensure that the reliability value of these services is appropriately captured for each in the context of the broader reserve reforms being discussed. Additional reserve services will require new ORDCs, and they will need to fit appropriately within this framework.

Enhancements to PJM Tools and Technology

In addition to the market reforms discussed within this paper, PJM also plans to consider how upgrades to its market tools and technologies can support these objectives and help to promote reliability and market efficiency.

Intermediate-Term Security Constrained Economic Dispatch (IT SCED)

To complement the broader set of market reforms and in parallel with the RCSTF's efforts, PJM intends to explore enhancements to its Intermediate-Term Security Constrained Economic Dispatch engine (IT SCED). IT SCED is PJM's intraday commitment tool that provides advisory information to dispatchers on resources to call online to serve load in future intervals. Today, IT SCED is solved 30 minutes prior to the target interval to make recommendations and has a two-hour look-ahead horizon beyond that. It uses the distribution factors of the current network topology to evaluate deliverability against constraints. IT SCED runs the Three Pivotal Supplier test and feeds that information into PJM's Real-Time Security Constrained Economic Dispatch (RT SCED) for the purpose of power market mitigation. It also schedules inflexible reserves, makes economic demand response commitment decisions, recommends commitment of Fast-Start Resources and sets the Locational Marginal Price (LMP) at interface points for the purpose of the Coordinated Transaction Scheduling (CTS) process.

As PJM considers new market mechanisms to handle system uncertainty and better pre-position the system for meeting future flexibility needs, enhancements to IT SCED may help support these efforts. PJM anticipates evaluating possible changes, which may include but are not limited to:

- The IT SCED look-ahead time and how intervals are spaced within that window
- The forecast information used
- The distribution factors used to represent system network topology in future intervals

Market Technology Upgrades

PJM is always looking at new technologies for solving its energy and ancillary service markets in a timely manner. PJM is currently focused on the Next Generation Markets (nGEM) optimization engine to improve the performance, scalability, composability, parallelization, extensibility and testability of its market clearing engines. The nGEM optimization engine will enable PJM to implement more accurate resource models that better reflect operational characteristics and limitations, including for pumped storage hydro, steam turbine, combined cycle, energy storage and hybrid resources. These enhancements to resource modeling will give PJM the ability to better quantify available reserve capability and efficiently utilize the various operating modes of combined cycle, steam, energy storage and hybrid resources. Additionally, PJM's Information Technology Services Division evaluates the currently available hardware technology roughly every three years to identify new hardware advances that will work with PJM's market clearing engine software technologies to improve overall solution time of the optimization engines.

Proposed Reserve Market Reforms

Summary of PJM's Proposed Reforms

PJM is proposing a suite of new reserve services to address both day-ahead and real-time uncertainty, provision flexibility to manage net-load ramping events, and ensure that enough reserves are available to backfill PJM's 10-minute contingency reserves following the deployment of these reserves in response to the loss of a unit. The proposed reforms would introduce two new day-ahead-only reserve services, which would be cleared in the market based on a risk assessment performed by PJM. PJM would also introduce two new online ramping and uncertainty reserve services to manage net-load forecast uncertainty and net-load ramping events 10 minutes and 30 minutes beyond the 5-minute energy dispatch. Additionally, PJM proposes redesigning its existing 30-Minute Reserve product to better reflect the operational need to provision sufficient 30-Minute Reserves to replace or unload its 10-minute contingency reserves when they are deployed during an emergency. This section details the design of these new services as well as some supporting reforms to PJM's existing reserve services and market rules. An overview table of the reserve services that would be cleared in PJM's markets moving forward is included at the end of this section in **Table 4**.

Day-Ahead Scheduling Reserves

Day-Ahead Scheduling Reserves (DASR) are reserves procured to address day-ahead uncertainty driven by day-ahead load, solar and wind forecast error, and generator performance risk.[28] For each day, an uncertainty model would be used to inform a risk evaluation, which would dictate the quantity of DASR procured for a given day. Reserves cleared in the Day-Ahead Market to meet real-time reserve needs address a portion of the DASR Requirement, and so the DASR Requirement can be met by the reserve products that also address the Ramping/ Uncertainty Reserve requirements as well as the 30-Minute Reserve requirement. Details on this nesting are included in the supplemental document Product Nesting and Resource-level Constraints (PDF).

Reserve Requirement

The DASR Requirement would be based on load, solar and wind forecast uncertainty and generator performance risk. These quantities would be calculated based on uncertainty analysis of historical operational data, and the percentile of the uncertainty distribution that would set the requirement for a given day would be based on the risk assessment for that day. The method for quantifying this day-ahead uncertainty is provided in the companion

[28] Day-Ahead Uncertainty and Risk Framework (Video)

document, Operation Uncertainty Quantification (PDF). The percentage uncertainty values for low-, medium- and high-risk days are provided in **Table 2**.

Table 2. DASR Load, Generator Performance, Solar and Wind Percentage Values Used in Calculating the DASR Requirement on Low-, Medium- and High-Risk Days

Proposed Risk Values	Percentile	Load	Generator Performance	Solar	Wind
Low	80th Load / 50th Others	2.19%	2.03%	11.28%	9.68%
	80th All	2.19%	3.12%	19.71%	21.48%
Medium	85th All	2.42%	3.49%	22.50%	24.19%
High	90th All	2.79%	3.88%	25.51%	26.54%
	95th All	3.55%	4.68%	31.33%	32.43%

To get the hourly DASR quantity, $DASR_t$, these percentage numbers would then be multiplied by the relevant forecast numbers for each hour of the day, t.

$$DASR_t = Load\ Forecast_t \times Load\ Uncertainty\ \% + Load\ Forecast_t \times Gen\ Uncertainty\ \% + Solar\ Forecast_t \times Solar\ Uncertainty\ \% + Wind\ Forecast_t \times Wind\ Uncertainty\ \%$$

$DASR_t$ would therefore vary hourly. To get the DASR Requirement value for each hour, these hourly values would be capped based on the DASR quantity, $DASR_t$ at the peak load hour, $DASR_{peak}$. In other words, if an hourly DASR quantity calculated using the above formula would exceed the DASR quantity calculated for the hour of the forecasted load peak, it would be set to $DASR_{peak}$. The final DASR Requirement for each hour t therefore becomes:

$$DASR_{t,requirement} = MIN(DASR_t, DASR_{peak})$$

Extension of the DASR Requirement on Elevated Risk Winter Days

As discussed in the Energy Gap Reserve subsection below, PJM proposes to procure reserves on medium- and high-risk winter days to address the risk that the Day-Ahead Market clears less physical supply than is needed to serve PJM's load forecast. Because the reserves procured to meet the Energy Gap Reserve Requirement are allowed to meet the DASR Requirement through the nested construct, the DASR Requirement would be extended on those days to include the Energy Gap procurement target.

Resource Eligibility

To be eligible to provide DASR, resources could be online or offline, with offline resources qualifying if their combined startup and notification times are no greater than 30 minutes. Resources would need to be able to deliver energy or reduce load within 60 minutes and sustain response for a minimum of four hours.

Performance Obligation, Performance Evaluation and Consequences for Non-Performance

Unlike Synchronized Reserves, which are deployed through operator action during an event, Day-Ahead Scheduling Reserves would be "deployed" through normal energy dispatch, and resources' performance obligation would entail (a) being available for dispatch and (b) following dispatch instructions.

Resources would be expected to bid into the Real-Time Market their ability to provide energy in each hour in which they had a reserve assignment, at a minimum, at a level consistent with their DASR and energy commitments. Resources would then be expected to follow energy dispatch instructions in real time. If a resource fails to make itself available to provide energy in real time at a level commensurate with its reserve assignments cleared day-ahead plus its day-ahead energy assignment (e.g., the resource is on a full or partial outage, the resource's parameters have changed such that it can no longer be called on for energy within the prescribed time to start), it would be assessed a charge at the greater of (a) its day-ahead reserve revenue times 1.25 and (b) the 30-Minute Reserve Market Clearing Price.

If reserves on a resource are converted to energy during a period in which it held a day-ahead reserve assignment and the resource fails to perform (e.g., does not reach EcoMin within the defined reserve time to respond, does not reduce load) that resource would be assessed a charge based on the greater of (a) its day-ahead-only reserve revenue times 1.5 and (b) the 30-Minute Reserve Market Clearing Price times 1.5.

Operating Reserve Demand Curve

The Operating Reserve Demand Curve for DASR would be a single step at $50/MWh.

Locational Procurement

DASR would be procured at a system level (i.e., RTO).

Synchronized Reserves

Reserve Requirement

PJM's Synchronized Reserve Requirement would continue to be set by the largest contingency multiplied by a performance factor, which is based on historical resource performance during Synchronized Reserve events. If technologically feasible, PJM intends to enhance the way this requirement is calculated. Today, to determine the largest contingency on the system, PJM considers the economic maximum of the largest available unit the Day-Ahead Market, and the largest online unit in the Real-Time Market, where the requirement is set based on the greater of that resource's economic maximum or current output. Moving forward, PJM intends to explore whether setting the Synchronized Reserve Requirement based on the resource with the greatest output is feasible. This would remove the lower bound the Synchronized Reserve Requirement based on the largest resource's economic maximum, which could reduce the amount of reserves PJM needs to carry if the largest unit is operating below its economic maximum. This could also allow the optimization to evaluate the trade-offs between the cost of carrying additional reserves and the cost of dispatching a resource down to reduce the Synchronized Reserve Requirement. Ultimately, the feasibility of this reform will depend on software implementation and any concerns related to clearing engine performance that may arise.

Additionally, as a part of the broader set of reforms proposed here, PJM would no longer have the 190 MW adder that constitutes the second step of the Synchronized Reserve ORDC today. PJM believes this is appropriate given that the procured 10-Minute Ramp/Uncertainty Reserves that will be discussed later in this section would naturally serve to reflect the additional 10-minute reserves needed for reliability and to manage pricing volatility.

Resource Eligibility

PJM is not proposing any changes to resource eligibility for providing Synchronized Reserves. To provide Synchronized Reserves, resources must be synchronized to the grid and be able to provide energy or reduce load within 10 minutes. Resources must be located within the boundaries of the PJM region, and resources are ineligible to provide this service if they are assigned regulation in the given interval. Wind, solar and nuclear resources are only eligible to provide Synchronized Reserves by approved exception.

Performance Obligation, Performance Evaluation and Consequences for Non-Performance

When resources hold a Synchronized Reserve assignment, they are expected to deliver those reserves as quickly as possible when PJM initiates a Synchronized Reserve Event. Resources are then evaluated to determine whether they met their Synchronized Reserve obligation during the event. PJM is not proposing any changes to its existing performance evaluation methodology. Resource response for every minute during the initial 10 minutes of the event is calculated as the difference between the resource's output at the start of the evaluation period (taken as the minimum output during the minute before, minute of, and minute after the start of the period) and the resource output at the end of the 10 minutes (taken as the maximum of the minute before, the minute of, and the minute after the end of the period). For events longer than 10 minutes, any minutes after minute ten are averaged into the total response, where each minute's response is calculated as the difference between that minute's output and the output calculated for the start of the evaluation period.

If a resource holding a Synchronized Reserve assignment fails to fully convert the procured Synchronized Reserves into energy within 10 minutes, PJM would set the per MW penalty rate for that shortfall in performance at the greater of:

a) The average per MW cost of Synchronized Reserves based on the Synchronized Reserve Market Clearing Prices in the PJM's Real-Time Market from the prior year (more details on this calculation provided below), or,
b) The maximum system marginal energy price in the 6 intervals (or 30 minutes) following the SR deployment when the shortfall occurred.

PJM would also introduce a 5% tolerance band when evaluating resource performance during Synchronized Reserve Events.

Methodology for Calculating the Average per MW Cost of Synchronized Reserves

The average per MW cost of Synchronized Reserves used to set the shortfall penalty rate would be calculated using real-time market clearing prices from the prior year and would be based on the average time between events in that year. Assume that PJM has a Synchronized Reserve Event every 18 days on average, which was the average time between these events in 2025. Therefore, on average, to get the reliability benefit of Synchronized Reserves, load must procure it for 18 days for every one time it is deployed. The average cost of Synchronized Reserves over a single period is given by:

$$Per\ MW\ Cost = Avg\ RT\ SR\ MCP\ \times Avg\ Days\ between\ Events\ \times 24\ hours/day$$

Where the $Avg\ RT\ SR\ MCP$ is the average real-time market clearing price for Synchronized Reserves over the average number of days between events (in $/MWh), the $Avg\ Days\ between\ Events$ is the average number of days between Synchronized Reserve Events (in days).

This *Per MW Cost* would change daily, as it looks back over the prior period, defined by the average number of days between events. To avoid this volatility, the per MW penalty rate would be set for the entire year, and this value would be based on the average of the daily *Per MW Costs* for the prior year.

Rationale for the Proposed Synchronized Reserve Consequences for Non-Performance

PJM believes that the average cost incurred to load to provision Synchronized Reserves is a lower bound on the value of the service and therefore provides a reasonable basis for setting a penalty rate for any shortfall in performance. Additionally, it prevents instances where a resource could clear for Synchronized Reserves and make revenue despite never performing, which can occur under today's evaluation and penalty construct.

Take a resource that is inframarginal for reserves 50% of the time. It clears (and makes a profit for reserves) in half of all intervals throughout the year. The other 50% of the time it does not clear for Synchronized Reserves, either because it is offline or operating economically at its economic maximum. This resource never performs during Synchronized Reserve Events and always has a shortfall of 100% of its assigned reserves during evaluated Synchronized Reserve Events in which it has an assignment. When this happens, it must pay back the Synchronized Reserve credits it received (at the real-time Synchronized Reserve market clearing price) for every interval in which it cleared over the prior period, which is defined as the lesser of the average number of days between Synchronized Reserve Events and its last non-performance. However, because the resource only clears 50% of the time, there is a 50% chance that when a Synchronized Reserve Event occurs, this resource will not have an assignment and therefore gets to keep the revenue it received despite never having performed during an event.

Furthermore, because only events that last for at least 10 minutes are evaluated, and most events are terminated before 10 minutes have elapsed, performance failures during many events go unpenalized. Given that the prior period over which the Synchronized Reserve credit claw back occurs is based on the average number of days between events *regardless of their length*, this increases the opportunity for resources that don't perform to continue to accrue Synchronized Reserve revenues without ever performing.

Operating Reserve Demand Curve

PJM is proposing that the Synchronized Reserve Demand Curve would be a single step at $2,100/MWh. This sets the SR penalty price above the $2,000/MWh energy hard offer cap, which allows the willingness to pay for Synchronized Reserves to be high enough to allow economic redispatch up to that level to avoid a Synchronized Reserve shortage. As discussed later in this paper, it also ensures that the Synchronized Reserve Penalty Factor is higher than that of any of the other reserve services, creating the appropriate hierarchy in reserve value.

While PJM believes that this ORDC is meaningful improvement over the current ORDC, particularly when considered in the context of the broader set of reforms discussed here, PJM does not believe that a flat step of $2,100/MWh fully values scarcity as Synchronized Reserve levels are depleted. However, in light of the comprehensive discussions on investment signals across PJM's markets slated for the coming months, PJM recognizes the value in deferring the deeper discussions around scarcity pricing so that they can happen in the context of that broader review.

Locational Procurement

Following the loss of a unit, energy flows on transmission facilities can temporarily exceed their limits while PJM works to redispatch the system and get flows back below normal operating limits. However, there are specific constraints within PJM's operating footprint that have critical limits, such as Interconnection Reliability Operating Limits, which, if violated, risk system instability and cascade. Today, PJM uses its sub-zone design to represent these constraints in its procurement of Synchronized Reserves. Moving forward, PJM is proposing to leverage the same locational reserve procurement structure proposed for some of the other newly proposed services, which is discussed later in this paper. This would be done by modeling the subset of deliverability constraints that present instability or cascade risk. This is similar to what is done today, but rather than limiting the number of resources that are modeled as providing constraint help by selecting a distribution factor threshold and then averaging the distribution factors of resources on the side of the constraint, PJM would simply use the actual distribution factors of each resource. PJM believes this would have similar reliability benefits to the sub-zone structure used today while providing a more accurate representation of the resource-by-resource impact on the interface(s) of concern and without requiring a sub-zone definition and ORDC. This would also provide consistency across PJM's reserve markets. Details on the proposed design for all of the locational reserve procurement are given in the supplemental document, Locational Constraints for Reserve Services (PDF).

Primary Reserves

PJM is proposing to eliminate Primary Reserves from its markets. The Synchronized Reserves service would therefore become the only reserve service procured with the explicit intention of deploying it during a contingency reserve event following the loss of a unit. PJM believes this is appropriate because when PJM responds to the loss of a unit, PJM deploys its contingency reserves through a Synchronized Reserve event. Any Non-Synchronized Reserves procured as Primary Reserves are not deployed through this mechanism.

Ramp/Uncertainty Reserves

PJM proposes to design three new Ramp/Uncertainty Reserve (RUR) services, which would be used to ensure sufficient flexibility is available on the system to manage operational uncertainty and to meet the forecasted net-load ramping needs in future intervals. The three products would be:

1 | 10-Minute Ramp/Uncertainty Reserve Up (10-Min RUR Up)

2 | 10-Minute Ramp/Uncertainty Reserve Down (10-Min RUR Down)

3 | 30-Minute Ramp/Uncertainty Reserve (30-Min RUR)

These reserves would be procured both day ahead and in real time, though reserve quantities might change between the Day-Ahead and Real-Time Markets, as discussed later in this section. PJM views these products as critical to ensuring that enough flexibility exists within the system to manage the increasing uncertainty and variability associated with the energy transition. Almost every other RTO/ISO in the country has implemented or is in the process of implementing these types of products.

Reserve Requirements

The RUR requirements for each product would have two components: an uncertainty component to reflect net-load forecast uncertainty, and a ramping component to reflect the expected net-load ramp in future intervals beyond the target time.

Uncertainty Quantification

The uncertainty component of the RUR requirements would be based on the 95th percentile wind, solar and load forecast uncertainty for the relevant intervals beyond the target time. These uncertainty numbers would be calculated based on five-minute historical operating data from the previous delivery year and quantified as a percentage of the wind, solar and load forecasts, respectively. This would allow these percentage numbers to be multiplied by the relevant forecasts for each interval, as appropriate, to get the uncertainty reserve quantities. More details on how this uncertainty would be calculated are given in the supplemental document Real-Time Uncertainty Quantification (PDF).

$$Uncertainty = Load\ Forecast\ \times\ Load\ Uncertainty\ \% + Solar\ Forecast\ \times Solar\ Uncertainty\ \% \\ + Wind\ Forecast\ \times Wind\ Forecast\ \%$$

10-Min RUR Requirements

For the 10-Min RUR services (both Up and Down), the uncertainty and expected ramping components of the requirements would be based on the difference in the forecasts for target time *t*, the time for which the energy dispatch is being determined, and the forecasts for time *t* + 10 minutes, or ten minutes beyond the target time. For the uncertainty component of the requirement, that would mean that the uncertainty percentage numbers are driven by how much the load, solar and wind forecasts change between when the forecast is evaluated 20 minutes ahead of the effective time as compared to when the forecast is evaluated 10 minutes ahead of the effective time.

The expected ramp component for the 10-Min RUR services would be based on the difference between the net-load forecast for time *t* + 10 and the forecast for time *t*. In real time, this expected ramp calculation would be adjusted to reflect resources that have been committed to the system and are starting up, recognizing that these resources will be outputting energy that can meet demand in future intervals. In the Day-Ahead Market, the forecasts used are hourly forecasts, and so while the same general methodology would be used, the expected ramp component of the requirements would be interpolated to calculate a 10-minute net-load ramp by dividing the 60-minute net-load ramp by 6.

The final requirement calculations then become the sum of the uncertainty and ramp components as given for both 10-Min RUR Up and 10-Min RUR Down below. Note that because the expected ramp can be either positive or negative, a floor would be set on the requirements at 0 MW to ensure that the requirement would never be negative.

$$10Min\ RUR_{Up} = MAX(Uncertainty + Ramp, 0)$$

$$10Min\ RUR_{Down} = MAX(Uncertainty - Ramp, 0)$$

30-Min RUR Requirement

For the 30-Min RUR service, the uncertainty and expected ramping components of the requirement would be based on the difference in the forecasts for target time *t* + 10 and the forecasts for target time *t* + 30 minutes, or twenty minutes beyond the time that the 10-Min RUR product is procured to manage. For the uncertainty component of the requirement, that would mean that the uncertainty percentage numbers are driven by how much the load, solar and wind forecasts change between when the forecast is evaluated 40 minutes ahead of the effective time as compared to when the forecast is evaluated 20 minutes ahead of the effective time.

The expected ramp component of the 30-Min RUR service would be based on the difference between the net-load forecast for time *t* + 30 and the forecast for time *t* + 10, again because the 30-Min RUR product is procured to ensure that net-load can be served (recognizing uncertainty) 30 minutes beyond the target time and recognizing the 10-Min RUR procurement. In real time, this expected ramp calculation would be adjusted to reflect resources that have been committed to the system and are starting up, recognizing that these resources will be outputting energy that can meet demand in future intervals. In the Day-Ahead Market, the forecasts used are hourly forecasts, and so while the same general methodology would be used, the expected ramp component of the requirements would be interpolated to calculate a 20-minute net-load ramp by dividing the 60-minute net-load ramp by 3.

The final requirement calculation then becomes the sum of the uncertainty and ramp components as given below. Note that because the expected ramp can be either positive or negative, a floor would be set on the requirements at 0 MW to ensure that the requirement would never be negative.

$$30Min\ RUR = MAX(Uncertainty + Ramp, 0)$$

Resource Eligibility

Only online resources that are capable of being dispatched for energy by RT-SCED would be eligible to provide Ramp/Uncertainty Reserves. Additionally, resources would not be eligible to provide Ramp/Uncertainty Reserves if they have a Regulation assignment. For the 10-Min RUR product, resources would need to be able to provide energy or reduce load within 10 minutes to qualify, and any resource to clear for 10-Min RUR would need to be able to sustain that response (e.g., have sufficient state-of-charge) for at least 60 minutes. For the 30-Min RUR product, resources would need to be able to provide energy or reduce load within 30 minutes to qualify, and any resource to clear for 30-Min RUR would need to be able to sustain that response (e.g., have sufficient state-of-charge) for at least four hours.

Performance Obligation, Performance Evaluation and Consequences for Non-Performance

Resources with a Ramp/Uncertainty Reserve Assignment would be expected to make those reserves available and then deliver those reserves as energy if instructed to do so by PJM. Resources would be evaluated for following PJM dispatch in the same way that they are for energy, and the consequences for deviations from energy instructions would be the same. Additionally, resources would be evaluated based on whether they have the availability to provide reserve services. For example, if a resource is dispatched to make headroom (or foot room in the case of 10-Min RUR Down) to carry reserves, it would be evaluated based on whether that room was made available. Resources that do not follow dispatch and therefore are not able to provide assigned reserves (e.g., a resource that is backed down to provide up reserves but does not move down sufficiently to make reserves available or the opposite for down reserves) would be charged the a rate of 1.25 times the real-time reserve market clearing price for the reserve service.

Operating Reserve Demand Curves

The ORDC associates a marginal value $p(r)$ to a given RUR level r with respect to the expected ramp. Given an up ramp constrained system, the probability of experiencing a synchronized reserve shortage in a forward SCED run increases with decreasing RUR level; let $P(r)$ denote this conditional probability for a RUR level r. Then, for a scalar α,

$$p(r) = \alpha \times P(r),$$

is the marginal value of the RUR level r.

The conditional probability of subsequent SR shortage is based on the uncertainty (deviations in forecasts) associated with the forward net-load ramp. Let t_0 denote the next RT SCED target time, which relies on forecasts made at time $t < t_0$. In practice, the RT SCED run relies on forecasts made approximately 10 minutes before the target time. Let $\tilde{\ell}(t, \tau)$ denote the net-load forecast made at time t for time τ. Then, the uncertainty associated with the 10-minute-forward net-load ramp is given by,

$$\widetilde{\Delta}_{\ell}(t_0, 10) = \tilde{\ell}(t_0, t_0 + 10) - \tilde{\ell}(t_0 - 10, t_0 + 10)$$

Similarly, for the 30-Min RUR, the uncertainty associated with the 30-minute-forward net-load ramp (discounting the 10-minute-forward ramp uncertainty) is given by,

$$\widetilde{\Delta}_{\ell}(t_0, 30) = \tilde{\ell}(t_0 + 10, t_0 + 30) - \tilde{\ell}(t_0 - 10, t_0 + 30)$$

Using historical observations of $\widetilde{\Delta}_{\ell}(t_0, 10)$ and $\widetilde{\Delta}_{\ell}(t_0, 30)$, we estimate an uncertainty distribution associated with the 10-minute-forward net-load ramp and 30-minute-forward net-load ramp, respectively, using Kernel Density Estimation (KDE). The cumulative density functions (CDF) of these distributions are given by, respectively,

$$F^{10}(r) = \mathrm{Prob}(\{\widetilde{\Delta}_{\ell}(t_0, 10) \leq r\})$$

$$F^{30}(r) = \mathrm{Prob}(\{\widetilde{\Delta}_{\ell}(t_0, 30) \leq r\})$$

Then, the conditional probabilities of SR shortage at a RUR level r given an up ramp constrained system for 10-Min RUR and 30-Min RUR are given by, respectively,

$$P^{10}(r) = \mathrm{Prob}(\{\widetilde{\Delta}_{\ell}(t_0, 10) > r\}) = 1 - F^{10}(r)$$

$$P^{30}(r) = \mathrm{Prob}(\{\widetilde{\Delta}_{\ell}(t_0, 30) > r\}) = 1 - F^{30}(r)$$

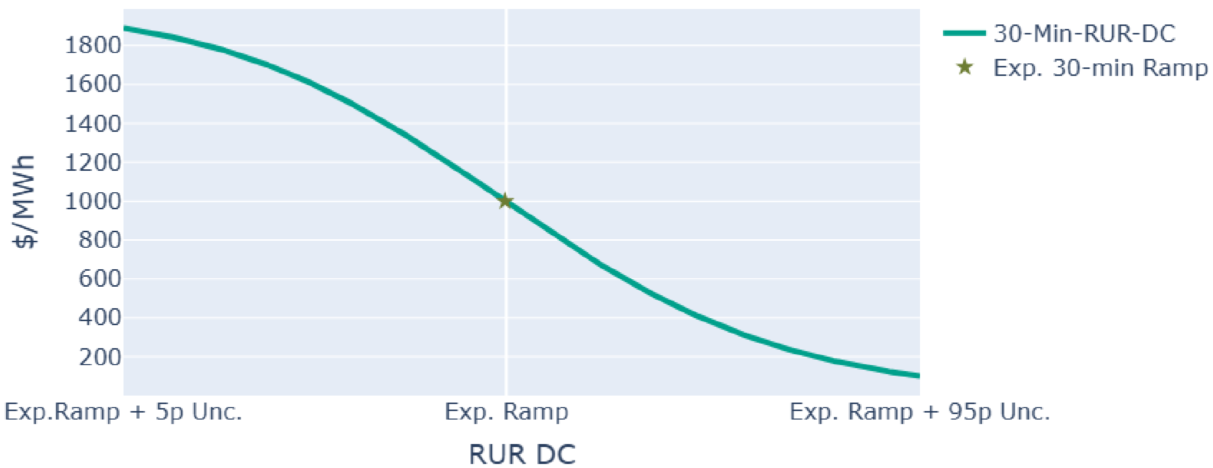
Since the uncertainty requirements described in the preceding section are based on 95th percentile of forecast deviations, we constrain $P(r)$ to be between 0.05 and 0.95 (symmetric around the median ramp forecast): scaling by α gives the inverse demand function $p(r)$. The demand curve is the graph of the inverse demand function.

For the two Ramp/Uncertainty Reserve Demand Curves (10-Min RUR Up and 30-Min RUR), the demand curves would be anchored at a $1,000/MWh penalty factor at the point of expected net-load ramp. The curves are then symmetric around this expected net-load ramp point, reflecting the increasing willingness to pay as the probability reaches near certainty that the net-load ramp will materialize in the forward interval and the decreasing willingness to pay for reserves as the probability decreases that each incremental megawatt of reserves will be needed to address net-load ramping needs in that interval.

Figure 10 and **Figure 11** show the realized 10-Min RUR Up and 30-Min RUR Demand Curves respectively. We can observe that both curves have similar shapes and indicate a symmetric uncertainty distribution of forecast deviations. The expected ramp – 95th percentile uncertainty is approximately equal to the expected ramp + 5th percentile uncertainty. At the left-hand side of the curve, prices are allowed to rise to about $1,900/MWh. On the right-hand side, the curves terminate at about $100/MWh. The maximum willingness to pay for both RUR services at the left-most point is therefore below $2,000/MWh, or the energy hard-offer cap, which would keep the maximum willingness to pay for RUR services at below the willingness to pay for Synchronized Reserves, thus maintaining the reserve service procurement hierarchy.

Figure 10. 10-Min RUR Up Service

Figure 11. 30-Min RUR Service

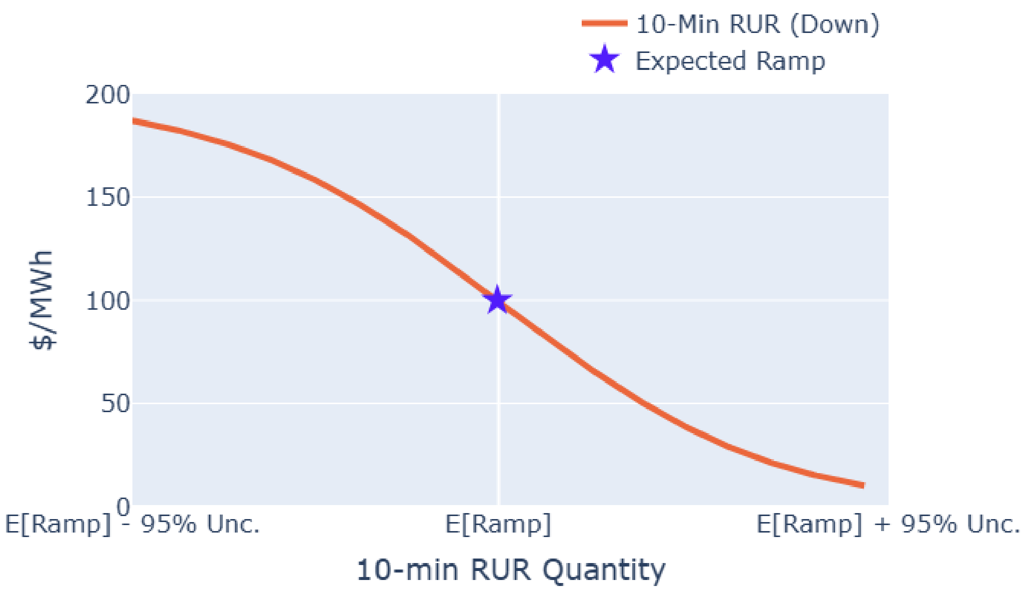


The demand curve for the down RUR is a flipped and scaled version of $F(r)$. That is, for a down RUR level r and a scaling constant β, the marginal value for the down RUR will be given by:

$$p(r) = \beta \times F(-r)$$

Since the estimated distribution of the forecast deviations is approximately symmetric, the shape of the demand curves for the 10-Min RUR down service is similar to that shown in Figure 10. However, the point of expected net-load ramp down is anchored at $100/MWh, which is 10% of the penalty factor at the expected net-load point in the 10-Min RUR Up curve. Figure 12 shows the realized 10-Min RUR Down Demand Curve. At the left-hand side of the curve, prices are therefore allowed to rise to about $190/MWh. On the right-hand side, the curves terminate at about $10/MWh.

Figure 12. 10-Min RUR Down Service



Locational Procurement

Locational deliverability of the ramp and uncertainty reserve service is important. Because online ramping and uncertainty reserve products are often cleared based on lost opportunity cost, several other ISOs, including CAISO and SPP, have seen these products clear on resources behind binding constraints. CAISO has changed its economic dispatch engine to ensure that its ramp product is simultaneously deliverable with energy. It does this by running two separate dispatch scenarios in addition to the base scenario that ultimately determines energy dispatch and price: One scenario also deploys all ramping up reserves, and the second also deploys all ramping down reserves. PJM is similarly proposing a locational procurement design for Ramp/Uncertainty Reserves that would recognize the need to dispatch reserves along with energy under the existing set of network constraints. PJM proposes to procure Ramp/Uncertainty Reserves nodally by introducing a new congestion constraint into the optimization that would ensure that RUR is deliverable with energy across the network constraints being monitored for energy. This would create nodal reserve prices for RUR, driven by the system marginal RUR price, which would be based on the cost of the marginal resource providing reserves across the RTO, and a congestion component of RUR price, which would be based on the congestion costs at every node in the system. Note that because congestion costs can be either positive or negative, nodal reserve prices may be greater or less than the system marginal reserve price. Details on the proposed design for all of the locational reserve procurement are given in the supplemental document, Locational Constraints for Reserve Services (PDF).

30-Minute Reserves

PJM proposes redefining its existing 30-Minute Reserve product to more explicitly and accurately reflect PJM's need to carry Secondary Reserves to replace its contingency reserves if contingency reserves are deployed in response to an event. PJM's new 30-Minute Reserve service would be nested with the previously discussed 30-Min RUR service, meaning that all reserves procured to meet the 30-Min RUR Requirement would also count towards meeting the 30-Minute Reserve Requirement.

Reserve Requirement

The 30-Minute Reserve (30-Min) requirement would be based on the largest contingency active on the system plus the 30-Min RUR procurement target to reflect the nesting of these two services. The minimum Reserve Requirement for 30-Min Reserves would be floored at the largest contingency in the system.

Resource Eligibility

30-Minute Reserves would be held on resources that are either (a) online and able to increase output or reduce load within 30 minutes or (b) offline and able to start within 30 minutes. Resources would need to be able to sustain response for at least four hours, and resources would not be eligible to provide 30-Minute Reserves if they have a Regulation assignment.

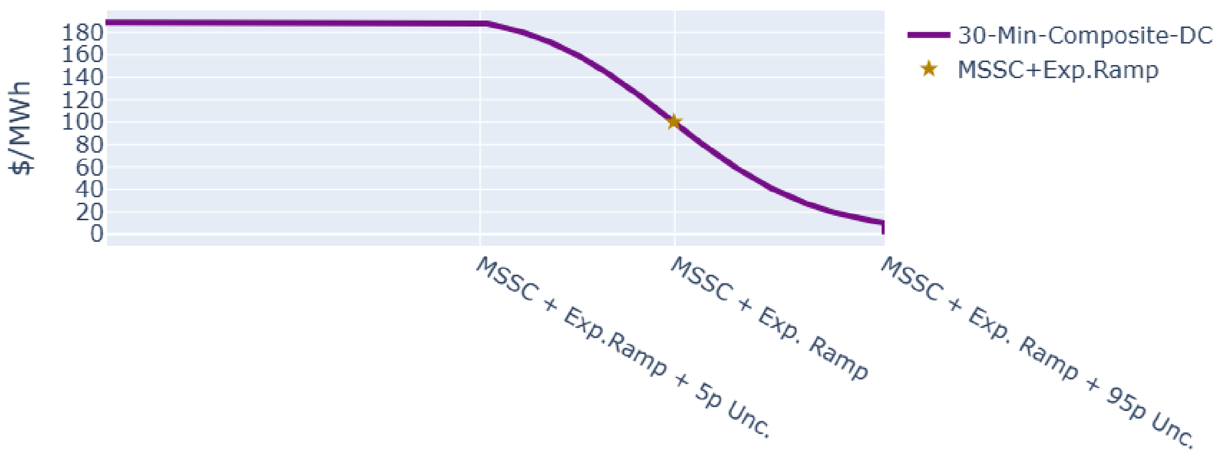
Performance Obligation, Performance Evaluation and Consequences for Non-Performance

30-Minute Reserves would be deployed as energy. For online 30-Minute Reserves, this would be done through PJM's five-minute economic dispatch engine, RT-SCED. For offline 30-Minute Reserves, this would be done by calling those resources online when they are needed. The performance evaluation and consequences for non-performance would be the same for online 30-Minute Reserves as discussed for RUR above. The performance evaluation for offline 30-Minute Reserves would be the same as today for offline SECR: Resources are evaluated based on whether they reach EcoMin within 30 minutes after being called online by PJM. However, PJM is proposing changes to the consequence of non-performance for offline 30-Minute Reserves. When a resource holding a 30-Minute Reserve assignment fails to reach EcoMin within 30 minutes, it would be assessed a penalty of the 30-Minute Reserve Market Clearing Price times 1.25.

Operating Reserve Demand Curve

The 30-Minute Reserve Demand Curve is a flat step to reflect the Secondary Reserve need (i.e., the need to carry 30-Minute Reserves to backfill 10-minute contingency reserves) up and to the point of the megawatt quantity that reflects the largest contingency on the system. Beyond that point, the right-hand side of the 30-Minute Reserve Curve has a downward-sloping tail, which is the same shape as the 30-Min RUR Demand Curve, and reflects the decreasing willingness to pay for the next incremental megawatt of reserve capability as the probability of the uncertainty materializing decreases. The maximum willingness to pay for 30-Minute Reserves has been set to $190/MWh, which is 10% of the maximum willingness to pay for 30-Min RUR. This ensures that even if both 30-Min RUR and 30-Minute Reserves are clearing at 0 MW, the added price of both curves will not exceed the willingness to pay for Synchronized Reserves. Figure 13 provides the 30-Minute Reserve Demand Curve.

Figure 13. 30-Minute Reserve Demand Curve



Locational Procurement

As in the case of Ramp/Uncertainty Reserves, PJM is proposing to procure 30-Minute Reserves locationally such that the economic dispatch engine recognizes the need to be capable of dispatching reserves along with energy. The difference between the locational deliverability constraint for RUR and for 30-Minute Reserves is that 30-Minute Reserves might consider a different set of constraints and contingency scenarios to reflect the difference in how and when 30-Minute Reserves would be used. The ability to utilize 30-Minute Reserves would be of primary concern when managing a set of high-risk contingencies that could otherwise result in cascade risk. In this way, locational reserve procurement of 30-Minute Reserves is more similar to locational procurement of Synchronized Reserves. Given the different nature of these reserves, PJM anticipates using different transmission limits, such as cascade limits, in these congestion constraints and will explore penalizing these transmission limit violations at a different penalty level. Details on the proposed design for all of the locational reserve procurement are given in the supplemental document, Locational Constraints for Reserve Services (PDF).

Energy Gap Reserves

Energy Gap Reserves would be procured on medium- and high-risk days that fall within the "winter" season, defined here as November through March. Energy Gap Reserves would be provisioned to mitigate the reliability risk of having insufficient physical supply cleared through the Day-Ahead Market to meet PJM's load forecast. These reserves would be held on online resources and would only be cleared in the Day-Ahead Market. Similar to DASR, resources holding a Ramp/Uncertainty Reserve assignment can help address the Energy Gap Reserve need, and so Energy Gap Reserves would be nested with these services. More detail on how this nesting would occur is provided in the supplemental document Product Nesting and Resource-level Constraints (PDF).

Reserve Requirement

The quantity of Energy Gap Reserves that would be cleared in the Day-Ahead Market would be based on an Operating Reserve Demand Curve that represents the market's willingness to pay for Energy Gap Reserves as a function of observed instances where the Day-Ahead Market cleared insufficient physical supply to meet PJM's load forecast on winter days over the preceding three years. The Energy Gap Demand Curve would be terminated at the 90th percentile of the distribution of this data set.

Resource Eligibility

Only online resources would be eligible to provide Energy Gap Reserves. Resources would need to be able to provide energy or reduce load within 60 minutes to qualify, and any resource to clear for Energy Gap Reserves would need to be able to sustain that response for at least four hours.

Performance Obligation, Performance Evaluation and Consequences for Non-Performance

Similar to Day-Ahead Scheduling Reserves, resources with an Energy Gap Reserve obligation would be expected to be available to provide energy or reserves in real time at a level commensurate with their Energy Gap and energy commitments coming out of the Day-Ahead Market. If a resource fails to meet that obligation, they would be charged a penalty for each megawatt shortfall in availability at the greater of the 1.25 times the Energy Gap Reserve Market Clearing Price and the 30-Min RUR Market Clearing Price.

Operating Reserve Demand Curve

The Energy Gap (EG) Reserve demand curve seeks to associate a marginal value $p(r)$ to an EG Reserve level r. The probability of experiencing an RUR shortage in RT decreases with increasing EG Reserve level. Let G denote the random variable representing the difference between DA load forecast and DA cleared physical generation, and F_G denote the corresponding CDF:

$$F_G(r) = \text{Prob}(\{Load\ Forecast + Exports - Cleared\ Supply - Imports \leq r\})$$

Then, the probability of not procuring sufficient EG Reserves to meet the DA load forecast as a function of the EG Reserve level r is given by,

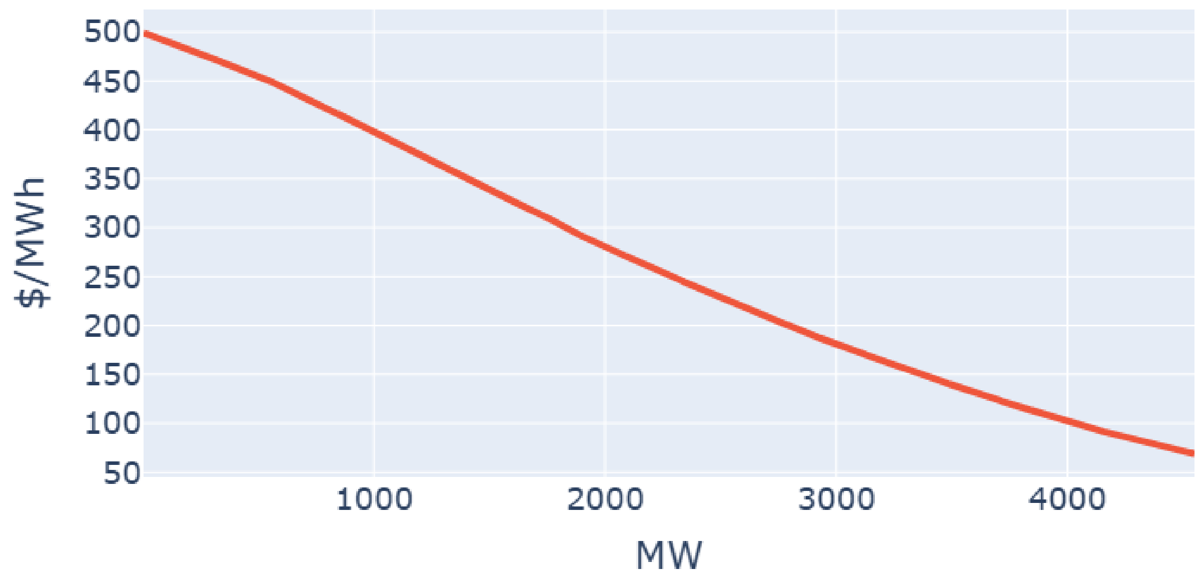
$$P(r) = 1 - F_G(r)$$

We constrain $P(r) \geq 0.1$, to avoid procuring above the 90th percentile historical realization of the energy gap. The inverse demand function is defined to be a scaled function of $P(r)$. For a scalar α, the marginal value at EG Reserve level r is,

$$p(r) = \alpha \times P(r)$$

The plot of this function is the demand curve. Since there are seasonal trends in virtual participation, the EG Reserve demand curves will have seasonal variations. In other words, $F_G(r)$ will be estimated from historical observations on a seasonal basis. Figure 14 illustrates the EG reserve demand curve for winter: the distribution $F_G(r)$ is estimated from historical energy gap observations from December 2022 through November 2025. The 90th percentile of the historical energy gap defines the terminal point of the curve at approximately 4,500 MW. The price at this point is approximately 15% of the maximum price associated with the demand curve.

Figure 14. Energy Gap Demand Curve for the Winter Season



Locational Procurement

Like Day-Ahead Scheduling Reserves, Energy Gap Reserves would be procured at a system level (i.e., RTO).

Reserve Offers

PJM proposes to allow resources to submit greater than $0 offers for providing reserve services under conditions where PJM recognizes that resource owners may incur additional costs for undertaking a reserve obligation. PJM has identified the following types of costs that it believes resource owners could incur to provide reserves:

1 | **Availability costs.** This would include any steps a resource owner needs to take day ahead to maintain availability to provide energy in real time if called upon. For example, this might involve making advanced fuel arrangements.

2 | **Performance risk.** In so much as a reserve assignment comes with an increased performance obligation and settlement consequences if the resource does not fulfill that obligation, resources should be allowed to reflect this penalty risk into their reserve offers.

3 | **Revenue loss.** If the deployment of reserves could result in a financial loss to a resource, resource owners should be allowed to reflect those costs in their offers. Examples of this include:

(a) resources deployed during a spin event at a time when LMP is below their marginal energy offer for the level at which they are deployed,

(b) limited energy resources asked to stop charging or to discharge early, thereby impacting their ability to provide energy later, and

(c) Demand Response resources that have deployment costs that are not covered through energy payments.

For all instances where resources are allowed to offer >$0/MWh for providing reserve services, resources would be able to offer up to a $10/MWh soft offer cap, below which resources would not be subject to mitigation. If resources can demonstrate costs above the $10/MWh soft offer cap, they would be able to submit cost-based offers above this level, which would be subject to approval by PJM. In the case of Synchronized Reserves, the soft offer cap would be $10/MWh + the expected Synchronized Reserve penalty rate. In practice, PJM believes this translates most neatly into allowing resources to submit three distinct reserve offers in $/MWh: one offer to provide Synchronized Reserves, one to provide online reserves other than Synchronized Reserves and one to provide offline reserves. **Table 3** provides a breakdown of how these offers would be structured and how they map to reserve services. Because of the potential for availability costs day ahead, all reserve products would allow for offers up to the $10/MWh soft offer cap in the Day-Ahead Market. In real time, reserve offers would be capped at $0/MW unless the reserve obligation comes with an elevated penalty risk, as with offline and Synchronized Reserves, or if the deployment of reserves could lead to revenue loss, as with Synchronized Reserves.

Table 3. Reserve Offer Structure

Offer	Associated Reserve Services	Day-Ahead Soft Offer Cap	Real-Time Soft Offer Cap
Synchronized Reserves	Synchronized Reserves	$10/MWh + Expected Penalty Rate	$10/MWh + Expected Penalty Rate
Online Reserves (non-SR)	• 10-Min RUR • 30-Min RUR • Energy Gap Reserves	$10/MWh	Capped at $0
Offline Reserves	• 30-Min Reserves • DASR	$10/MWh	$10/MWh

Reserve Cost Allocation

All reserve costs would be allocated to real-time load and exports based on their Load Ratio Share. This is a change from PJM's current reserve allocation rules, which allocate all reserve costs to real-time load based on their Load Ratio Share, but does not allocate reserve costs to exports.

Table 4. Summary of the Reserve Services Included in PJM's Proposed Reforms

	Purpose	RTM / DAM	Response Time	Online Only	Locational
Synchronized Reserve	Contingency recovery	Both	10 minutes	✓	✓
10-Min Ramp/ Uncertainty Reserve	Real-time net-load ramp and uncertainty	Both	10 minutes	✓	✓
30-Min Ramp/ Uncertainty Reserve	Real-time net-load ramp and uncertainty	Both	30 minutes	✓	✓
30-Min Reserves	Replacement for contingency reserves	Both	30 minutes	✗	✓
Day-Ahead Scheduling Reserves	Day-ahead uncertainty	DAM-only	60 minutes	✗	✗
Energy Gap Reserves	Scheduling physical supply to meet the PJM load forecast	DAM-only	60 minutes	✓	✗

Appendix

Analysis Details

VOLL Calculation: Gross Domestic Product (GDP) to Load Ratio

$$VOLL = \sum_{k=1}^{n} \frac{GDP_i}{Load_i} C_i$$

Where:

- GDP: State annual GDP (2022$)
- Load: State annual load (MWh)
- C: Percentage of state contribution to PJM's overall load

Table 5. 2022 Data Used in GDP to Load VOLL Calculation

STATE	GDP (Millions of $)[29]	Annual Load (Million kWh)[30]	Percentage of PJM Load[31]
DC	165,061	10,241	1.2%
DE	90,208	11,539	1.6%
IL	1,025,667	135,872	11.9%
IN	470,324	100,044	2.8%
KY	258,981	75,338	2.9%
MD	480,113	59,683	8.1%
MI	622,563	100,639	0.6%
NC	715,968	139,207	0.6%
NJ	754,948	74,443	9.8%
OH	825,990	149,500	19.8%
PA	911,813	145,045	19.4%
TN	485,658	102,112	0.2%
VA	663,106	132,265	16.6%
WV	97,417	32,986	4.6%
*VOLL **~ $6,500 (2022$)** or **~$7,000 (2023$)***			

VOLL Calculation: Lawrence Berkeley National Laboratory (LBNL) ICE Calculator

The LBNL ICE Calculator[32] was used to estimate the interruption costs of a single average hour, using the breakdown of residential and nonresidential load by state from 2022,[33] and weighted by each state's contribution to PJM's total load in the same year.[34] Nonresidential load was assumed to be 25% small commercial and industrial (C&I) customers, and 75% medium and large C&I customers.

	Residential	Small C&I	Medium and Large C&I	Weighted Total
ICE Calculator Results:	$5,900	$220,000	$67,000	**$68,000**
**All values updated to 2023$ from 2016$ provided by ICE Calculator.*				

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[29] Source: Bureau of Economic Analysis

[30] Source: U.S. Energy Information Administration

[31] Source: Monitoring Analytics

[32] Ice Calculator

[33] Sources: EIA State Profiles , EIA Data Browser

[34] Source: Monitoring Analytics

Alternatives Considered

Alternate Approaches to Managing the "Energy Gap"

PJM initially proposed to design a dedicated product to manage the "Energy Gap" and referred to this product as a "Day-Ahead Energy Imbalance Reserve." PJM was considering market designs that were directionally similar to the approach ISO-NE has taken to address the same reliability concern. Unlike under the current proposal set forward by PJM, this product would have been procured every day rather than just during times of elevated reliability risk. PJM considered multiple ways to procure and settle this product, including a formulation that would endogenously calculate the amount of reserves needed to ensure that enough physical supply had either a reserve or an energy commitment to meet PJM's load forecast. PJM initially put forward four different approaches to quantifying the "Energy Gap."

Option 1:	DA-EIR ≥ load forecast + net firm forecasted export – fixed demand – net bid export – losses
Option 2:	DA-EIR ≥ load forecast + net firm forecasted export – physical supply
Option 3:	DA-EIR + physical supply ≥ load forecast + net forecasted export
Option 4:	DA-EIR ≥ load forecast + net firm forecasted export – adjusted fixed demand - losses

Where:

- **PJM day-ahead load forecast (load forecast):** The most recent available load forecast for each hour of the following operational day at the time the Day-Ahead Market runs
- **Cleared physical supply (physical supply):** The total energy commitments cleared through the Day-Ahead Market on physical resources capable of producing energy in real time
- **Cleared virtual supply (virtual supply):** The total energy commitments cleared through the Day-Ahead Market in Increment Offers
- **Total cleared energy (cleared energy):** The total energy commitments cleared through the Day-Ahead Market on both physical and virtual supply, minus cleared Decrement Bids (virtual demand)
- **Bid-in fixed demand (fixed demand):** The total fixed demand bid-in to the Day-Ahead Market. This does not include Price Responsive Demand.
- **Net bid-in firm export (net bid export):** Bid-in firm export – bid-in firm import
- **Net forecasted firm export (net forecasted export):** Forecasted firm export – forecasted firm import[35]

PJM's ultimate determination was that while Option 3 was inherently the most optimal, the interaction between the DA-EIR market clearing price and energy locational marginal prices might lead to too much additional complexity, particularly given that this is a reliability challenge that is most critical to address on elevated risk days, which are less than 5% of all days.

[35] If PJM forecasts interchange and needs to mitigate the risk of any delta between forecasted and bid-in interchange for operational reliability, this formulation will provide the flexibility to do so. However, if PJM does not need to operationally forecast interchange day ahead (as is the practice today), then the net forecasted firm export value should be set to be equal to the net bid-in firm export.

PJM then considered a return to a previous approach, which used a "Seasonal Conditional Demand Factor" to estimate the Energy Gap for a given day. This approach was in place before Reserve Price Formation, and attempted to estimate how much demand, inclusive of price sensitive demand and virtual bids, would be cleared in the Day-Ahead Market by looking at cleared demand on the peak winter and summer days in the last year. This quantity was referred to as "Adjusted Fixed Demand" and details on how it was calculated can be found in Manual 11 Revision 113. Using this approach to calculate the Adjusted Fixed Demand and a similar approach to calculate "Estimated Losses," which was described in PJM's presentation on Elevated Risk Days at the October 15, 2025, RCSTF, yields a fixed reserve quantity that can be input to the Day-Ahead Market optimization in the form of Option 4 above. While PJM still recognizes this as a technically feasible approach, it ultimately moved away from this solution given the volatility of the demand cleared in the Day-Ahead Market. Rather than introduce a more complicated approach, which might in fact be falsely precise, PJM opted for a simpler, more transparent approach in the form of a fixed seasonal demand curve that represents the willingness to pay for additional reserves day ahead as a function of market clearing outcomes from the last three years.

Multi-Interval Dispatch

Multi-interval dispatch (in contrast to PJM's existing single-interval RT SCED) could address forecasted ramping needs by allowing slower-moving resources to be ramped proactively to meet forecasted demand in upcoming intervals. Recall the narrative example posed previously of a system with three types of resources: fast-ramping inexpensive resources, slow-ramping more expensive resources and offline Fast-Start Resources with high commitment costs. Entering a ramping period, a multi-interval dispatch optimization might determine that the most cost-effective way to meet demand over the next two hours is to pre-ramp more expensive, slower-moving resources earlier to avoid having to incur high commitment costs later. A single-interval dispatch would not be able to evaluate those intra-temporal trade-offs and would instead ramp up the least expensive resources to meet demand in the current interval. From this example, it may seem that multi-interval dispatch is inherently superior to single-interval dispatch in terms of promoting least-cost, market-efficient dispatch, and in many respects it is. However, there are some important caveats that need to be understood when considering implementing multi-interval dispatch in practice.

1 | **The future may not materialize as forecast.** Given that the forecast entails some level of uncertainty, it is possible that future system conditions – and by extension, energy prices – may not materialize as expected. Where significant deviations occur, this could lead to material changes to resource compensation through PJM's energy markets, which could require out-of-market uplift payments and potentially suppress prices.

2 | **If only the first interval in a multi-interval dispatch solution is settled, it can lead to unintuitive pricing outcomes and disincentives to follow PJM dispatch.** Pre-ramping a more expensive resource in one interval in preparation for expected energy needs in a future interval inherently involves dispatching resources out of merit order. A more expensive resource is dispatched up, although this dispatch is not justified by the real-time LMP, and that dispatch is necessarily displacing energy that would have been produced by a less expensive resource. This will tend to have price suppressing impacts. Given the uncertainty of future LMPs, the profit-maximizing behavior for resources might be to operate based on current LMPs rather than to follow PJM dispatch instructions in expectation of future LMPs.

3 | **Multi-interval settlement would entail considerable additional complexity.** Currently, neither NYISO or CAISO, who are the two ISOs currently using multi-interval dispatch, settle any of the intervals beyond the first. While an area of research and interest, PJM is concerned that implementing a multi-interval dispatch framework would be too complex to be feasible at this time.

These challenges lead PJM to the preliminary conclusion that any attempt in PJM's markets to allow the pre-ramping or pre-positioning of resources to manage upcoming forecasted ramping needs would have to be handled through the inclusion of a forecasted ramp component in any ramping/uncertainty reserve product(s), similar to the approach taken by SPP and MISO.

Contrast the scenario posed in the second item above with another where the resource being held down to provide future flexibility needs is given a reserve assignment. That resource, which might otherwise be marginal, is now compensated through the reserve market clearing price for any LOC it might need to incur and is therefore indifferent to providing reserves or energy in that interval. This resource can no longer be used to meet the next unit of energy demand because its available capacity is consumed by its reserve commitment, which causes another resource, perhaps a slower-moving resource at a slightly higher price, to be dispatched up economically. This second resource now becomes marginal and sets price, aligning its economic incentive with its dispatch instructions.

Including Ramping and Uncertainty in Existing PJM Synchronized Reserve Structure

As previously discussed, NYISO intends to extend its existing reserve requirements to include the flexibility needed to manage uncertainty associated with its net-load forecast error. NYISO is pursuing this path in part because it will simplify and expedite implementation of these uncertainty reserve products. PJM considered taking a similar approach with its existing 30-Minute Reserve product. PJM has already identified that its 30-Minute Reserve service does not appropriately capture operational risk or align with dispatcher needs. Given that, PJM is proposing to redefine its 30-Minute Reserve service to align with its uncertainty and net-load ramping flexibility needs as well as the need to carry sufficient 30-Minute Reserves to be able to backfill its Synchronized Reserves. PJM is also intending to introduce a new online 30-Minute Ramping/Uncertainty Reserve service, which will be nested with its 30-Minute Reserve service. This will ensure that sufficient 30-Minute Reserves are online and available to manage upcoming net-load ramping and forecast uncertainty flexibility needs.

PJM also considered increasing its Synchronized Reserve requirement to manage its shorter term (i.e., 10-Minute Ramping/Uncertainty flexibility needs). However, PJM ultimately decided not to pursue this route for several reasons, mostly stemming from the fact that Synchronized Reserves are deployed during a Synchronized Reserve event while Ramping/Uncertainty Reserves would be dispatched economically through PJM's RT-SCED engine to serve demand. This fundamentally different deployment results in differences in how the reserve products will need to be procured. As previously discussed in the section on proposed market reforms, the nature of when and how Synchronized Reserves are deployed allows for the temporary exceedance of transmission facility limits. However, reserves dispatched through RT-SCED and procured to meet demand must be deliverable across the network without violating transmission facility limits. Otherwise, they do not provide their intended reliability value. Additionally, because Synchronized Reserves are deployed through an All-Call during emergencies, this allows for resources to participate in providing this service that are otherwise not able to follow a RT-SCED dispatch signal. For example, during an All-Call, PJM can flip resources that are in condensing mode such that they begin injecting energy into the system. PJM can also deploy SR-only Demand Respond resources by posting the deployment instruction to DR Hub. These are examples of resources that can effectively provide the Synchronized Reserve service but would not be able to provide the Ramping/Uncertainty service.

Alternate Approaches for Quantifying Uncertainty for Reserve Procurement

Rather than using a percentage-based approach for quantifying uncertainty for reserve procurement in real-time, PJM also explored using fixed MW quantities that would vary by time of day and by season. PJM believes this is a still a feasible approach, but ultimately favors the percentage-based approach as it inherently scales reserve levels with the forecast at any given time.

ORDC Clearing Examples

ORDCs are used in both PJM's commitment and dispatch market engines to determine above what level PJM will not incur additional cost to make reserves available. In the case of PJM's commitment engine, this will dictate which resources are committed to the system for the purpose of providing or making available reserve services. If the ORDC penalty factors are lower than the incremental costs that would need to be incurred to commit a resource (e.g., resource start-up and no-load costs), then the optimization will go short reserves rather than commit that resource. In the dispatch engine, the ORDC penalty factors limit the costs that the system will incur to redispatch to make reserve services available. Today, those costs are based on the lost opportunity costs that resources would incur to provide reserves in lieu of providing energy. If the ORDC penalty factors are lower than the incremental costs that would need to be incurred to back a resource down to make reserves available, the optimization will once again go short reserves rather than redispatch that resource. Below are two simple examples walking through these market engine clearing outcomes to illustrate these two points.

The following assumptions apply to both examples presented:

- Only the RTO-level SR requirement is considered for simplicity. No other reserve product is considered.
- In the commitment example, only one interval is considered for simplicity. The example addresses the load requirement as the first priority followed by meeting the reserve requirement with remaining resource capability (as available).
- A single-step ORDC is considered at the penalty factor specified for each scenario.
- Resources SR offer prices are $0, consistent with the SR offer cap today.

Example 1: Commitment

The inputs for the example are given in **Table 6** and **0**.

Table 6. System-Level Requirements

Load (MW)	599
SR Requirement (MW)	2

Table 7. Unit Parameters and Offers

	Gen1	Gen2
EcoMin (MW)	0	0
EcoMax (MW)	600	600
Energy Offer ($/MWh)	50	60
Start-Up Cost ($)	0	851
No-Load Cost ($/hr)	0	0

The market clearing engine outcomes for running this commitment problem with first a penalty factor of $850 and then increasing that penalty factor to $852 are given below. Note that while the optimization engine performs the co-optimization of energy and reserve simultaneously, it is presented below separately for the purpose of explaining the results.

Solution Using an SR Penalty Factor of $850/MW

The cost to start each resource and run at its economic minimum is based on each resource's offer and given in **Table 8**.

Table 8. The Costs Incurred To Commit Each Resource

	Commitment Costs + Cost to Run at EcoMin
Gen1	$0
Gen2	$851

To meet the energy requirement of 599 MW, either Gen1 or Gen2 can meet the load with the following production costs:

Gen1 Cost = Start-up cost + No-load cost + Incremental energy cost

*= 0 + 0 + (599*50) = $29,950*

Gen2 Cost = Start-up cost + No-load cost + Incremental energy cost

*= 851 + 0 + (599*60) = $36,791*

As Gen1 can meet the full load requirement at least cost, Gen1 would be committed for energy and provide 599 MW.

Co-optimization of Energy and Reserve

Gen1's unloaded online reserve capability of 1 MW will be counted toward fulfilling the 2 MW SR requirement. This incurs no additional cost to the system. However, there is no additional unloaded online reserve capability available because Gen2 is offline, meaning that there is still 1 MW of SR needed to meet the SR requirement. This 1 MW either needs to come from committing Gen2 or from a fictitious resource that costs $850/MW, the SR penalty factor. The cost for each of these options is given below.

Option 1:

If Gen2 is committed for energy at 0 MW, it would have sufficient unloaded capability to meet the remaining 1 MW SR requirement. The total cost to get this 1 MW of SR from Gen2 would be:

*Start-up cost + No-load cost + Incremental energy cost = (851 + 0 + 0*60) = $851*

Option 2:

If the fictitious resource with a penalty factor of $850 provides the one additional megawatt to meet the SR requirement, then the cost would be:

*Penalty factor * SR shortage megawatts = 850*1 = $850*

In this case, it is therefore more economical to go into shortage for 1 MW of SR rather than commit Gen2 to meet the SR requirement.

System Energy Price

Gen1 is committed and dispatched to 599 MW to meet the load. To supply the next megawatt of energy, Gen1, as the marginal resource, needs to provide the additional megawatt at a cost of $50. However, that would reduce 1 MW of SR contribution to meet the SR requirement, and that would have to come from a fictitious resource at the cost of $850. Therefore, the next 1 MW of energy would increase the overall production cost by $900. ($50 for the increase in energy cost for Gen1 to meet the 1 MW of additional demand and $850 to meet the SR requirement at the penalty factor.) Therefore, the shadow price of the power balance constraint is $900. This sets an energy-clearing price of $900/MWh.

Reserve Clearing Price

If the reserve requirement is increased by 1 MW, it would come from the fictitious resource for $850 as that is the most economical option to meet the requirement. Hence, the shadow price of SR requirement would be $850/MWh.

Solution Using an SR Penalty Factor of $852/MW

The cost to start each resource and run at its economic minimum would remain the same as seen above with the SR penalty factor of $850**.** The energy requirement would also be met in the same way as previously described.

Co-optimization of Energy and Reserve

To meet the 2 MW SR reserve requirement, Gen1's unloaded online reserve capability of 1 MW will be counted toward fulfilling the SR requirement. This incurs no additional cost to the system. However, there is no additional unloaded online reserve capability available because Gen2 is offline, meaning that there is still 1 MW of SR needed to meet the SR requirement. This 1 MW either needs to come from committing Gen2 or from the fictitious resource that costs $852/MW, the SR penalty factor. The cost of each option is detailed below.

Option 1:

If Gen2 is committed for energy at 0 MW, it would have sufficient unloaded capability to meet the remaining 1 MW SR requirement. The total cost to get this 1 MW of SR from Gen 2 would be:

*Start-up cost + No-load cost + Incremental energy cost = (851 + 0 + 0*60) = $851*

Option 2:

If the fictitious resource with the penalty factor of $852 provides the one additional megawatt to meet the SR requirement, then the cost would be:

*Penalty factor * SR shortage megawatts = 852*1 = $852*

In this case, it is therefore more economical to commit Gen 2 to meet the reserve requirement rather than violating the SR requirement at a penalty cost of $852/MW.

System Energy Price

Gen1 is committed and dispatched to 599 MW to meet the load. To supply the next megawatt of energy, Gen1, as the marginal resource, needs to provide the additional megawatt at a cost of $50. However, that would reduce its 1 MW of SR contribution to meet the SR requirement. That additional megawatt would then come from Gen2 as it is now online and has unloaded capability at no cost. Hence, the next 1 MW of energy would increase the overall cost by $50. Therefore, the shadow price of power balance constraint is $50. This sets an energy-clearing price of $50/MWh.

Reserve Clearing Price

If the reserve requirement is increased by 1 MW, it would come from Gen2's unloaded capability as that is the most economical option to meet the requirement. Hence, the shadow price of SR requirement would be $0.

Table 9 provides a summary of these commitment example results for both the $850/MW and $852/MW penalty factors.

Table 9. Summary of Example 1 Results

$850 Penalty Factor				$852 Penalty Factor			
System Energy Price ($)			900	System Energy Price ($)			50
SR Clearing Price ($)			850	SR Clearing Price ($)			0
SR Deficit (MW)			1	SR Deficit (MW)			0
	Commit Status	Energy Dispatch (MW)	SR Assignment (MW)		Commit Status	Energy Dispatch (MW)	SR Assignment (MW)
Gen1	online	599	1	Gen1	online	599	1
Gen2	*offline*	0	0	Gen2	*offline*	0	1

Example 2: Dispatch

The inputs for the example are given in **Table 10** and **Table 11**.

Table 10. System-Level Requirements

Load (MW)	600
SR Requirement (MW)	20

Table 11. Unit Parameters and Offers

	Gen1	Gen2	Gen3
EcoMin (MW)	0	0	0
EcoMax (MW)	200	200	300
Energy Offer ($/MWh)	1,000	20	10
Initial Operating Point (MW)	100	200	300
Ramp Rate (MW/Min)	1	5	5

The optimization engine performs the co-optimization of energy and reserves simultaneously. However, for the purpose of illustrating the market clearing engine outcomes, the results are broken out in the explanations below.

Solution Using an SR Penalty Factor of $850/MW

The energy dispatchable range for each unit, which is based on initial MW, energy time horizon, ramp rate and a resource's economic limits, is determined as described below.

*Lowest energy dispatch point = Maximum ([Initial MW – Ramp rate*60], EcoMin)*
*Highest energy dispatch point = Minimum ([Initial MW + Ramp rate*60], EcoMax)*

The unit-specific dispatchable range based on resource input parameters are given in **Table 12**.

Table 12. Resource Dispatchable Ranges

	Energy Dispatchable Range
Gen1	40–160 MW
Gen2	0–200 MW
Gen3	0–300 MW

To meet the load requirement of 600 MW, the least cost resource, Gen3, provides its maximum megawatt capability of 300 MW of energy. The next economic resource is Gen2, which will provide its maximum megawatt capability of 200 MW of energy toward meeting the requirement. The remaining 100 MW of load to be served (600 MW – 300 MW – 200 MW = 100 MW) will be provided by Gen1. **Table 13** provides a summary of these dispatch results.

Table 13. Resource Dispatch To Meet Load

	Energy MW
Gen1	100
Gen2	200
Gen3	300

Co-optimization of Energy and Reserve

To meet the 20 MW SR reserve requirement, Gen1's unloaded online reserve capability of 10 MW, based on its ramp capability, will be counted toward fulfilling the SR requirement. Because this is available unloaded capability, this incurs no additional cost. However, there is no additional unloaded online reserve capability available because Gen2 and Gen3 are fully dispatched to their EcoMax values to meet load.

To procure the needed SR, there are three options available as described below.

Option 1:

Reduce the energy output from Gen2 to make room to provide the additional 10 MW of needed SR to meet the SR requirement. However, to maintain power balance, Gen1 would have to increase its energy output by 10 MW. The total cost to redispatch under this option is therefore:

*Increase in energy cost for Gen1 – Decrease in energy cost from Gen2 = 1,000*10 – 10*20 = $9,800*

Option 2:
Reduce the energy output from Gen3 to make room to provide the additional 10 MW of needed SR to meet the SR requirement. However, to maintain power balance, Gen1 would have to increase its energy output by 10 MW. The total cost to redispatch under this option is therefore:

*Increase in energy cost for Gen1 – Decrease in energy cost from Gen2 = 1,000*10 – 10*10 = $9,900*

Option 3:
Without any energy redispatch among resources, the needed 10 MW of SR would be provided by a fictitious resource at the penalty factor of $850. The total cost for meeting the remaining 10 MW of the SR requirement would therefore be:

*Penalty factor * SR shortage megawatts = 850*10 = $8,500*

Out of all three options available to meet the SR requirement, option 3 is the most economical, and so the optimization engine would not redispatch the system to provide the additional 10 MW of reserves and allow the system to go into shortage.

Table 14 summarizes the energy dispatch points and SR assignments resulting from the co-optimized energy and reserve solution with an $850/MW penalty factor.

Table 14. Summary of Resource Energy and SR Assignments Given an $850/MW Penalty Factor

	Energy MW	Sync Reserve MW
Gen1	100	10
Gen2	200	0
Gen3	300	0

System Energy Price
Gen1, Gen2 and Gen3 are dispatched to 100 MW, 200 MW and 300 MW respectively. To supply the next megawatt of energy, Gen1 needs to provide an additional megawatt at a cost of $1,000 because Gen2 and Gen3 are dispatched at their maximum capability. Therefore, the shadow price of power balance constraint is $1,000. This sets an energy-clearing price of $1,000/MWh.

Reserve Clearing Price
If the SR requirement is increased by 1 MW, it would come from a fictitious resource at a cost of $850/MW. Therefore, the shadow price of the SR requirement would be $850/MWh, and the reserve clearing price would also be $850/MWh.

Solution Using an SR Penalty Factor of $1,000/MW
The energy dispatchable range for each resource and energy dispatch solution to meet load would be the same as explained above for a penalty factor of $850.

Co-optimization of Energy and Reserve

To meet the 20 MW SR reserve requirement, Gen1's unloaded online reserve capability of 10 MW will be counted toward fulfilling the SR requirement. However, there is no additional unloaded online reserve capability available because Gen2 and Gen3 are being dispatched to their EcoMax values to meet the load requirement.

To procure the needed additional 10 MW of SR, there are three options available as described below.

Option 1:
Reduce the energy output from Gen2 to make room to provide the additional 10 MW of needed SR to meet the SR requirement. However, to maintain power balance, Gen1 would have to increase its energy output by 10 MW. The total cost to redispatch under this option is therefore:

*Increase in energy cost for Gen1 – Decrease in energy cost from Gen2 = 1,000*10 – 10*20 = $9,800*

Option 2:
Reduce the energy output from Gen3 to make room to provide the additional 10 MW of needed SR to meet the SR requirement. However, to maintain power balance, Gen1 would have to increase its energy output by 10 MW. The total cost to redispatch under this option is therefore:

*Increase in energy cost for Gen1 – Decrease in energy cost from Gen2 = 1,000*10 – 10*10 = $9,900*

Option 3:
Without any energy redispatch among resources, the needed 10 MW of SR would be provided by a fictitious resource at the penalty factor of $1,000/MW. The total cost for meeting the remaining 10 MW of the SR requirement would therefore be:

*Penalty factor * SR shortage megawatts = 1,000*10 = $10,000*

Out of all three options available to meet the SR requirement, option 1 is the most economical, which is to reduce the energy of Gen2 such that it has available headroom to provide the needed SR. As a result, Gen2 will provide 10 MW of SR toward fulfilling the SR requirement along with Gen1, which is providing its 10 MW of unloaded capability.

Table 15 summarizes the energy dispatch points and SR assignments resulting from the co-optimized energy and reserve solution with a $1,000/MW penalty factor.

Table 15. Summary of Resource Energy and SR Assignments Given a $1,000/MW Penalty Factor

	Energy MW	Sync Reserve MW
Gen1	110	10
Gen2	190	10
Gen3	300	0

System Energy Price

Gen1, Gen2 and Gen3 are dispatched to 110 MW, 190 MW and 300 MW, respectively. To meet the next megawatt of energy demand, Gen1 needs to provide the additional megawatt at a cost of $1,000 since that is most economical. Therefore, the shadow price of power balance constraint is $1,000, and this sets an energy-clearing price of $1,000/MWh.

Reserve Clearing Price

If the SR requirement is increased by 1 MW, that requirement would be met by reducing 1 MW of energy output from Gen2 and increasing the energy output from Gen1 by 1 MW. This cost of these actions would be as follows:

*Increase in cost of Gen1 – Decrease in cost of Gen2 = 1,000*1 – 1*20 = $980*

Therefore, the shadow price of the SR requirement would be $980, and so the reserve clearing price would also be $980.

Table 16 provides a summary of these commitment example results for both the $850/MW and $1,000/MW penalty factors.

Table 16. Summary of Example 2 Results

$850 Penalty Factor			$1,000 Penalty Factor		
System Energy Price ($)		1,000	System Energy Price ($)		1,000
SR Clearing Price ($)		850	SR Clearing Price ($)		980
SR Deficit (MW)		10	SR Deficit (MW)		0
	Energy Dispatch (MW)	SR Assignment (MW)		Energy Dispatch (MW)	SR Assignment (MW)
Gen1	100	10	Gen1	110	10
Gen2	200	0	Gen2	190	10
Gen3	300	0	Gen3	300	0

Analysis of a Recent Reserve Shortage Event

Most instances of reserve shortage that have occurred since the Reserve Price Formation changes were implemented were during Winter Storm Elliott in December 2022. However, PJM does experience instances of reserve shortage outside of these more major events. For example, in February 2025, PJM had reserve shortage events on two days, Feb. 5 and Feb. 11. Both were relatively short events, the one on Feb. 5 lasting two intervals, and the one on Feb. 11 lasting a single interval. PJM ran a simple counterfactual scenario for one of the two intervals on Feb. 5 to evaluate whether more reserves were available on the system that could have alleviated the SR shortage in the RTO if the penalty factor had been increased. **Table 17** provides the SR deficit and SR market clearing price (MCP) that occurred during this interval with the $850 as well as the SR deficit and SR MCP that would have occurred if the penalty factor for the first step of the ORDC had been increased to $1,500.

Table 17. Results of an Analysis of a Shortage Interval in RTO on Feb. 5, 2025, 10:15

First Step Penalty Factor	SR Deficit (RTO)	SR MCP (RTO)	Deficit Type
$850 *(status quo)*	258 MW	$850	Minimum reliability requirement (i.e., first step)
$1,500	190 MW	$1,361	Extended reserve requirement (i.e., second step)

During this interval, PJM had an SR shortage of 258 MW in the RTO, which included a 68 MW deficit below the first step of the ORDC at the $850/MW penalty factor and a 190 MW deficit below the second step of the ORDC at the $300/MW penalty factor. Increasing the $850/MW penalty factor to $1,500/MW cleared the shortage experienced at the minimum reliability requirement but left the willingness to pay at the extended reserve requirement unchanged, resulting in a 190 MW deficit of the extended reserve requirement at the second step of the ORDC. These results demonstrate that during this interval, reserves were available on the system at a cost above $850/MW, which suggests that PJM's current ORDC penalty factors are not high enough to reflect the lost opportunity costs that resources can reasonably be expected to incur to provide reserve services.