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PJM’s Perspective on Challenges and Potential 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 in the day ahead and 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 preliminary 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 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 to prioritize 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** below.

Table 1. Reserve Reforms to Explore

Enhancements to Existing Reserve Markets

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.

Enhancements to performance evaluation and consequences for nonperformance

- Update performance evaluation rules for PJM's reserves to better align with how these reserve services are used operationally.
- Update the settlement implications of reserve non-performance to be more reflective of system impact and to ensure alignment with new reserve products moving forward.

Incentives for following PJM dispatch

- Revisit incentives for following PJM dispatch instructions, including deviation charges and compensation for the delivery of unrequested energy.
- Reforms should reflect and support PJM's need to effectively schedule resources to provide reserve services.

New Reserve Products

Day-Ahead Energy Imbalance Reserve

- Develop a product to procure reserves day ahead to bridge the gap between PJM's load forecast and physical generation committed through the Day-Ahead Market (DAM).
- Reflect reliability needs into the DAM 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 this service (e.g., fuel arrangement or charging costs).
- 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 arrangement or charging costs).
- 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 2023, renewable energy made up 6.9% of PJM's energy mix, and wind and solar represented 3,367 MW and 3,503 MW of Reliability Pricing Model (RPM)-eligible capacity. However, the share of renewables is expected to grow considerably in coming years. As of Nov. 27, 2024, there were 60,467 MW of solar and 19,156 MW of wind 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.

5 | Existing market structures do not always appropriately value and provide 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 actions. 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 DAM 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 DAM 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.

[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.

[2] The real-time market already used (and continues to use) hourly notification times to clear offline reserves.

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 outline PJM's initial thinking on the reserve market reforms that will be necessary to navigate the energy transition and to thereby lay the foundation for the RCSTF's work moving forward.

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]

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:

[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.

[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.

- **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, etc.) 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**: RTOs/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.

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.

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 intra-day 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 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 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.

New Reserve Products

PJM anticipates the need for two new types of reserve products in the near term. The first is a day-ahead reserve product that accounts for the gap between cleared physical supply in the DAM and forecasted load. These reserves would be procured through the DAM, with the appropriate compensation and binding performance obligation, to ensure that there is sufficient physical supply to meet the forecasted demand. Given that this gap does not exist in real time when the demand forecast materializes, this reserve requirement would not be maintained in real time.

The second category of reserve products are ramping/uncertainty reserve products, which would be used to handle uncertainties associated with net-load forecast error and the expected ramp flexibility needed in future intervals. These products would be procured both through the DAM and RTM, though greater quantities may be required day ahead.

Day-Ahead Energy Imbalance Reserve (DA-EIR)

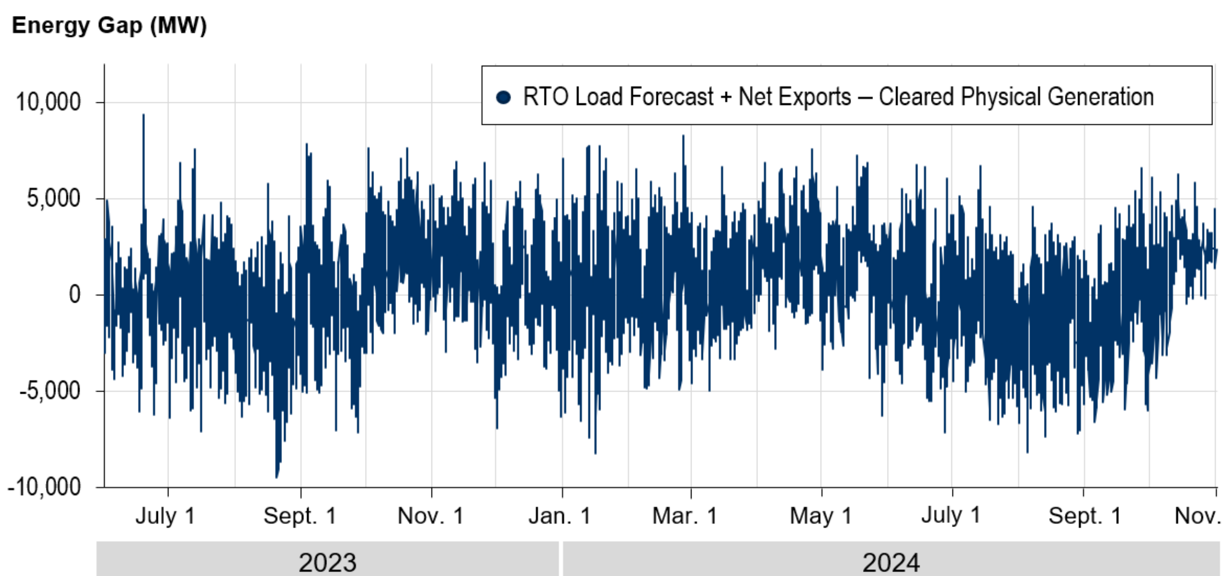
Challenges to be Addressed

PJM currently clears its DAM 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 and any difference between the reserves cleared through the DAM and the Day Ahead Scheduling Reserve (DASR) requirement, which accounts for average historical load forecast error and generator forced outage rates. 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 DAM commitment, accounting for any changes in resources' availability, and then recommends additional resource commitments as necessary to meet forecasted demand and the DASR requirement. The fact that these commitments are not included in the DAM 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 2 shows the difference between the day-ahead demand forecast and day-ahead bid-in demand from June 2023 through October 2024.

Figure 2. 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 DAM.



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 DAM 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 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.

ISO-NE is targeting the implementation of an Energy Imbalance Reserve (EIR) product in 2025, 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 will be co-optimized with energy and other ancillary service reserve products in the DAM and will be structured as an energy call option. Before the DAM deadline, ISO-NE will set 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.

PJM's Preliminary Conceptual Design

PJM proposes to explore the design and implementation of a day-ahead-only product that would account for the gap between the physical supply procured through the Day-Ahead Market and the PJM load forecast. This would be similar in intent to the Energy Imbalance Reserve product recently filed by ISO-NE and approved by FERC and would reflect reliability needs met through RAC into the DAM, thus better aligning PJM markets with operational needs. Procurement of the Day-Ahead Energy Imbalance Reserve (DA-EIR) product would be co-optimized with energy commitments in the DAM, meaning that the cost of procuring reserves would be evaluated and minimized along with the cost of energy commitments, allowing the market to economically pre-position the system based on the best currently available information. Given that this gap does not exist in real time, the DA-EIR Requirement would only exist in the DAM and would not be carried into real-time.

In addition to any gap between physical generation cleared in the DAM and the load forecast, operators also ensure that sufficient reserves are available to manage risk associated with average historical load forecast error and generator forced outages, also known as the DASR requirement. Given that these risks are greater day-ahead than in real-time, these additional reserve needs could also be included in a day-ahead-only product like the proposed DA-EIR if the performance characteristics needed from these services were the same. However, PJM's current perspective is that because the nature of these reserve drivers is fundamentally different, these reserve needs should likely be addressed in separate products. **Table 2** provides a summary comparison of the two types of reserve needs addressed by operations outside of the DAM today. Some of the design trade-offs implicit in this decision are also discussed in the Requirement and Constraint Formulation section below.

Table 2. Comparison of the Day-Ahead Energy Gap and DASR Reserve Needs

Day-Ahead Energy Gap		
Reserves required to ensure that enough physical generation is available to meet the PJM load forecast.		
Energy Gap	*= Load Forecast + Net-Scheduled Export – Physical Supply Cleared*	
Reserve need does not exist in real-time. Therefore, a corollary product will not cleared in the real-time market (RTM).	**Reserve need is based on the 50th percentile forecast**	**Because the energy gap is based on the amount of physical supply that is cleared, a trade-off could exist in the market between clearing more physical supply (and thereby reducing the energy gap) and procuring more reserves.**
DASR		
Reserves required to manage uncertainty associated with load forecast error and generator forced outages.		
DASR	*= Load Forecast x (Avg. Load Forecast Error + Avg. Generator Forced Outage Rate)*	
Reserve need exists in real-time, but at a lower level. Therefore, a corollary product might be cleared in the real-time market.	**Reserve need is based on an uncertainty distribution around the 50th percentile forecast.**	**There is not a natural trade-off between procuring reserves to manage uncertainty and clearing additional physical supply.**

Note that even after both reserve needs are reflected in the DAM, this will not eliminate the need for RAC, because there may be times when updated forecast information or generator forced outages require additional commitments after the DAM clears. However, these market reforms should reduce the number of out-of-market commitments that PJM needs to make day ahead.

Requirement and Constraint Formulation

The DA-EIR Requirement would be set based on the difference between the total physical generation committed through the Day-Ahead Market and the PJM load forecast plus net-firm export for each hour of the next operating day. The requirement would therefore change hourly, and DA-EIR would be procured on an hourly basis. The constraint in the DAM optimization could be formulated in a few different ways, which would have different implications for the optimization and market outcomes, and different attendant complexities. To begin, a few definitions to enable the discussion moving forward:

- **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 DAM 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[6]

In the DAM optimization, the constraint that dictates how DA-EIR is procured could be formulated in three different ways as outlined below. Note that in these formulations, and specifically relevant for highlighting the difference between Options 2 and 3, everything on the left-hand side of the equality constraint is assumed to be a variable, while the right-hand side is assumed to be a fixed value.

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

All three options procure DA-EIR to address the gap between the forecast and bid-in demand. However, only Options 2 and 3 also ensure that sufficient physical supply has been cleared to meet forecasted load. Additionally, Option 3 allows the optimization to trade off between clearing physical supply and procuring DA-EIR if the former is more economical, while Option 2 does not. Option 2 is included in this discussion because it would allow the DA-EIR requirement to be formulated strictly as a reserve service, which could allow the requirement to be extended to address other reserve needs. Including it in the discussion also has the benefit of highlighting the effect that co-optimization has on market outcomes, which is a departure from using a sequential approach, such as the separate commitment PJM does today. For Option 1, the question of trading off between additional commitments and additional DA-EIR procurement is irrelevant because only the incremental difference between the forecast and bid-in demand is required to be hedged with physical supply resources. A simple example is provided below to highlight the difference between how these three different constraint formulations would lead to different market outcomes.

Assume there are two physical generation resources, R1 and R2, and one Increment Offer, I1. The energy offer information for each of the market participants is given in **Table 3**. Assuming that DA-EIR is cleared based on 60-minute resource capability, the amount of DA-EIR a resource would be eligible to provide would be based on its 60-minute ramping capability.

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[6] 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.

Table 3. Example Energy Offers

Market Participant	Price	MW	Ramp
R1	$10	200 MW	1 MW/min.
R2	$50	200 MW	0.5 MW/min.
I1	$20	20 MW	

For simplicity, there are no Decrement Bids, no Price Responsive Demand and no net export in this example. Bid-in demand is 250 MW, and the load forecast is 275 MW. The total physical supply in the system will be the sum of the energy commitments given to R1 and R2. The total virtual supply will be the energy commitment given to I1. The energy balance constraint in the optimizations requires that the total cleared energy (the sum of the physical and virtual supply) be exactly equal to the bid-in demand of 250 MW.

Physical supply	*= R1 energy + R2 energy*
Virtual supply	*= I1 energy*
Cleared energy	*= physical supply + virtual supply – virtual demand*

In the absence of a DA-EIR Requirement, the Day-Ahead Market would assign R1 a 200 MW energy commitment, R2 a 30 MW energy commitment, and I1 a 20 MW commitment. R2 would be marginal, setting the system marginal energy price (SMP) at $50.

Cleared energy	*= 230 MW + 20 MW – 0 MW = 250 MW*

Now, consider the implications of each of the above sets of constraints for clearing the DA-EIR product. In Option 1, the amount of DA-EIR would simply be based on the difference between the bid-in demand and the load forecast as outlined below.

Option 1	*DA-EIR ≥ load forecast + net firm forecasted export – fixed demand – net bid export*
	DA-EIR ≥ 275 MW + 0 MW – 250 MW – 0 MW = ***25 MW***

There is sufficient headroom and ramping capacity available on R2 to provide this 25 MW through unloaded capability. The resource would therefore have no lost opportunity cost, and the pricing outcomes would be very similar to status quo described above. Additionally, the DA-EIR service would not guarantee that all of the forecasted load could be met through physical resources since 20 MW would be supplied from the virtual supply.

In Option 2, where the DA-EIR constraint requires that sufficient DA-EIR be procured to hedge the physical risk associated with cleared virtual supply, the DA-EIR Requirement would be 45 MW.

Option 2	*DA-EIR ≥ load forecast + net firm forecasted export – physical supply*
	DA-EIR ≥ 275 MW + 0 MW – 230 MW = ***45 MW***

R2 no longer has sufficient available ramping capability to provide this service using unloaded capacity, as it can provide a maximum of 30 MW in 60 minutes based on its 0.5 MW/min. ramp. Therefore, R1 would need to be backed down to provide the additional 15 MW and would therefore incur a lost opportunity cost (LOC) of $40/MWh.

Finally, in Option 3, the optimization will evaluate the trade-off between committing more physical generation and procuring more DA-EIR to meet the DA-EIR Requirement to identify the cost-minimizing outcome. In this scenario, the production cost minimization would decrease the energy commitment awarded to I1 in favor of awarding a larger energy commitment to R2. Because I1 now has available capacity, the system marginal price becomes $20 based on its marginal cost, and the LOC associated with cleared DA-EIR becomes $30. **Table 5** below provides a summary of these results.

Table 4. Example Results of the Three Different Constraint Formulation Options

Scenario	Energy Assignment R1	Energy Assignment R2	Energy Assignment I1	DA-EIR Assignment R1	DA-EIR Assignment R2	System Energy Price	DA-EIR LOC	Total Production Cost
Status Quo (No DA-EIR)	200 MW	30 MW	20 MW	N/A	N/A	$50	N/A	$3,900
Option 1	200 MW	30 MW	20 MW	0 MW	30 MW	$50	$0	$3,900
Option 2	185 MW	45 MW	20 MW	15 MW	30 MW	$50	$40	$4,500
Option 3	200 MW	45 MW	5 MW	0 MW	30 MW	$20	$30	$4,350

The implementation of Option 1 is by far the simplest. The requirement is based solely on inputs to the market rather than having an inherent interdependence with cleared energy. The disadvantage of Option 1 is that it does not provide a physical hedging mechanism that would guarantee that – between energy and DA-EIR assignments – all forecasted load could be met by physical resources with binding day-ahead commitments.

Option 2 could be formulated as a separate clearing process from the Day-Ahead Market commitment, using the outputs of that optimization as an input to this process, treating the cleared physical generation as a fixed quantity. The primary differentiator for Option 2 when compared with Option 3 is that it allows the requirement to be treated as a separate and discrete reserve service rather than as product that is substitutable with energy. While this may be less optimal, it could provide additional flexibility in how the requirement is structured. For instance, if PJM has additional reserve needs day ahead that it would like to include in this product definition, that could more appropriately be done if the resources assigned to provide this service are strictly treated as reserves, rather than allowing the optimization to clear more physical supply to reduce the reserve requirement. Additionally, fixing the energy gap quantity could simplify the optimization itself, which could have advantages if the ultimate market design would otherwise introduce interdependences which could lead to computational challenges. However, if this product is intended to solely address the day-ahead energy gap and any additional complexity does not present a challenge within the full market design, then Option 3 is the better solution, because it is inherently more efficient, as it allows for product substitution between cleared energy and DA-EIR.

Product Definition Resource Eligibility Requirements

PJM's current thinking is that the DA-EIR would be a 60-minute product to align with the hourly day-ahead load forecast. Resources would be cleared based on their achievable megawatt output within 60 minutes, and both online and offline resources (i.e., both resources with and without an energy commitment in the hour) would be able to provide the service. To be eligible to be assigned DA-EIR, a resource would need to be able to sustain its assigned megawatt output for at least 60 minutes. To align with operational needs and to mitigate the risk of resources failing to start, offline resources (i.e., resources without an energy commitment for a given hour) would need to be able to come online and become dispatchable within 30 minutes to be eligible to provide DA-EIR and would need to have a minimum run time of no greater than one hour. Offline resources would also be ineligible to receive a DA-EIR assignment in any hour within a minimum down-time window based on their energy commitments for the day.

Locational Procurement

As DA-EIR would be procured to meet forecasted load, deliverability of the service is important. Currently, when PJM makes commitments through RAC, network constraints are modeled in that tool and reliability studies are run to ensure that any subsequent commitments will not create constraint control issues. One of PJM's central goals is to design the markets to better align with operational practice, and to not do so in this instance could ultimately mean that PJM's markets might procure a service that did not provide its intended reliability value. To the extent possible, the reliability and deliverability constraints that would require dispatchers to commit different or additional resources should be modeled in the market. This will reduce out-of-market commitments, promote market efficiency and transparency, and align incentive signals with operational needs.

Ultimately, the location procurement of DA-EIR may have implications for how the product is settled. Using an energy call-option settlement structure akin to ISO-NE's approach where a strike price is determined day ahead, may be more complicated if the service is not procured at the RTO level. More work will need to be done to study possible approaches and their resulting market implications, but if a single strike price were used, it could make it challenging to evaluate resources with the same or similar offers at different settlement locations. Alternatively, setting different strike prices at different locations in the system could add significant complexity to the market design.

Performance and Settlement

Unlike Synchronized Reserves, which are deployed through operator action during an event, DA-EIR 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 RTM their ability to provide energy in each hour in which they were assigned, at a minimum, at a level consistent with their DA-EIR and energy commitments. Resources would then be expected to follow energy dispatch instructions in real-time.

PJM has been exploring possible ways to settle the obligation entailed with a DA-EIR assignment, and it has raised several important questions about how this market and product should be designed. In PJM's existing reserve market constructs, reserves are procured based solely on their availability costs without reference to their deployment or dispatch costs. For a product like Synchronized Reserve, which is deployed during an event, this may make sense. However, for a product like DA-EIR, which is being procured to ensure that sufficient generation is available to serve forecasted load, this may not be as appropriate. A very simple example is provided below to illustrate some of the limitations that may exist if DA-EIR is cleared such that only resource availability costs are minimized without consideration of real-time costs.

Assume there are two resources, R1 and R2, which have different operating postures. R1 has no avoidable costs day-ahead to provide reserve services. R2 could be available to run in real-time but must make arrangements at some cost day-ahead to be available to provide reserves (and by extension energy in real-time). Based on the day-ahead energy prices, neither resource will get an energy commitment, but both are eligible to provide DA-EIR. For simplicity, both resources have sufficient capability to meet all of a 100 MW DA-EIR requirement. Table 5 provides the day-ahead offers for R1 and R2.

Table 5. Example resource offers.

Day-Ahead Offer	R1	R2
Energy	$150	$50
DA-EIR (i.e., availability costs)	$0	$25

Now consider two different scenarios: one where the market clears DA-EIR solely based on availability costs, and a second where the market minimizes total costs when clearing DA-EIR. **Table 6** and **Table 7** provide notional results for each scenario.

Table 6. Results for Scenario 1 where the availability costs are minimized.

Resource	DA-EIR			Real-Time Energy			Total
	Offer	Commitment	Cost	Offer	Commitment	Cost	
R1	$0	100 MW	$0	$150	$15,000	$15,000	$15,000
R2	$25	0 MW	$0	N/A	0 MW	$0	$0
Total			$0			$15,000	**$15,000**

Table 7. Results for Scenario 2 where both availability and deployment costs are minimized.

Resource	DA-EIR			Real-Time Energy			Total
	Offer	Commitment	Cost	Offer	Commitment	Cost	
R1	$0	0 MW	$0	$150	$0	$0	$0
R2	$25	100 MW	$2,500	$50	100 MW	$5,000	$7,500
Total			$2,500			$5,000	**$7,500**

First and foremost, procurement of DA-EIR is intended to address a reliability need and to better align PJM's markets with what's needed for operations. However, if the expectation is that the quantity of energy procured as DA-EIR will be needed in real-time to meet forecasted demand, the most efficient solution may sometimes be to incur additional but lesser costs day-ahead to avoid the likelihood of incurring greater costs in real-time. The higher the probability that reserves will be converted to energy, the more valuable it would for PJM's markets to be able to do that more holistic cost-benefit analysis.

In its EIR product design, ISO-NE has addressed this by designing its day-ahead reserve products as energy call-options. ISO-NE will set a strike price day ahead, and then resources will bid in their day-ahead reserve offers, which would include their avoidable costs to maintain availability, their expected settlement costs given that strike price, and a risk premium. Then, in real time, if LMP exceeds the 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.

Unlike PJM's existing reserve products, this call-option design does not rely on settling the day-ahead reserve product against a corollary real-time product, which is important for a product like the DA-EIR product currently under consideration, because the service will not be procured through the RTM. It also provides an endogenous mechanism for hedging or partially mitigating high real-time prices in real-time, which is a significant benefit.

The call-option market design also has the advantage of relative simplicity in how it's settled. No evaluation of a resource's performance or investigation of whether the procured capacity was in fact available on the resource in real time is necessary. However, it does come with different complexities, including the need to develop a methodology for setting the strike price, and this would be further complicated if the reserve service is not procured at the RTO level, which PJM anticipates will likely be necessary, given congestion within PJM's footprint.

As an alternative, the DA-EIR service could be settled based solely on resource performance in real time, and there would be consequences for nonperformance more akin to PJM's existing reserve products. This would entail developing processes for doing this evaluation as well as establishing financial settlement consequences that appropriately reflect the impact to the system when a DA-EIR resource fails to provide the procured reliability service. The performance evaluation would likely involve two separate evaluations, one to determine whether the resource is available in real-time to provide the service, and one to evaluate whether – if called upon to convert procured reserves into energy – the resource follows PJM dispatch instructions. Possible options for settlement consequences when resources fail to perform could include a claw back of the DA-EIR revenue received or payment for replacement energy based on the real-time LMP. The latter option could help mitigate high real-time prices, and these settlement risks would then be reflected in resource offers.

One concern that ISO-NE had, which in part led them to develop the energy call-option structure, was that resources might not be sufficiently incentivized to make themselves economic to provide energy in real time. For example, assume a gas resource submitted an offer to provide DA-EIR based on its costs to make fuel arrangements day ahead and received an award for DA-EIR. Then, in real time, gas prices are higher than they were day ahead, and the resource has the option to sell back the gas it procured at a profit. This resource's profit-maximizing behavior, and in fact its marginal cost, is now not based on what it spent to make fuel arrangements yesterday, but on the price of gas in real time. It might then update its real-time energy offer to reflect that and if – because of this increase – that resource is no longer economic, it will not be called on to convert that DA-EIR assignment into energy.

If PJM ultimately determines that a call-option design is not feasible within its footprint, PJM will evaluate whether there are alternate ways to reflect deployment costs into its market clearing for DA-EIR. These may also be developed with complementary economic obligations in real-time for resources with a day-ahead reserve assignment. For example, the market rules might be structured such that resources would have to make any megawatt-hours cleared for DA-EIR available to the market in real-time based on their day-ahead energy offers. Ultimately, the market design for this product will hinge on two central questions that need to be considered moving forward:

1 | Is DA-EIR purely intended to provide the identified reliability need or – to the extent possible – should real-time market outcomes be considered in its procurement?

2 | Can real-time time deployment costs be practically represented in clearing DA-EIR in a way that consistently improves market efficiency?

Days of Elevated Operational Risk

Everything previously discussed in this paper has been in reference to the market design for a typical operating day. PJM recognizes that additional provisions are necessary to maintain reliability during times of elevated risk. PJM believes this will need to be considered comprehensively and so proposes to explore how to align reserve markets with operational needs during emergency conditions in the context of the complete set of reforms.

Ramping/Uncertainty Reserves (RUR)

To be populated in future updates to this position paper

Enhancements to PJM's Existing Reserve Markets

To be populated in future updates to this position paper

Reserve Procurement during Times of Elevated Reliability Risk

To be populated in future updates to this position paper