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Introduction

PJM is pleased to provide these comments for Commission consideration as part of its Sept. 14, 2021, Technical Conference entitled "Energy and Ancillary Services in the Evolving Electricity Sector."

The objective of competitive wholesale electricity markets is to efficiently reinforce grid reliability and thereby achieve a reliable power system at the lowest reasonable cost. The PJM energy and ancillary services markets, in conjunction with PJM's other markets, have achieved great benefits for customers, including reliability, affordability, reduced emissions, and incentivizing low cost investments and operations. While much time and effort have been spent discussing reforms to energy and capacity markets, far less time has been invested in ancillary service market design. As it stands now in PJM, the existing ancillary service markets are not operating effectively and require reform. These reforms serve a sole purpose to ensure the markets transparently reflect the demand for and value of ancillary services needed to maintain reliability.

As public policy efforts to address climate change continue to expand, resource costs for certain technologies continue to decline, the system resource mix shifts in response, and the penetration of distributed energy resources grows, PJM anticipates the power system shifting from one that has historically been predictable and controllable to one that is less so in the future. This rise in uncertainty must be met with flexibility to manage the grid reliably and cost-effectively. This responsibility, in part, falls on the ancillary services markets and is why PJM, and others, have pursued necessary ancillary service reforms. It is imperative to continue to evolve these markets to meet the emerging challenges to ensure the markets' objectives are met. It is incumbent upon the system operators, in this case the ISOs/RTOs, to clearly define the services that are necessary to maintain a reliable system. Once that clear definition is established, those services must be procured in a manner that results in prices that transparently reflect the value of those services to the system. Those transparent prices will enable competition by any resource capable of providing those services, thereby minimizing the cost of procuring them to load.

PJM's Current Ancillary Services Market Design

PJM operates ancillary services markets for regulation (i.e. secondary frequency response), 10-minute reserve, and 30-minute reserve products.[1] Provided below is a brief summary. The commitment of energy and 30-minute reserves are co-optimized in the Day-ahead Energy Market, while 10-minute reserves and regulation are cleared in real-time through various market clearing processes, with the objective of finding the most economic set of resources to meet the combined requirements.

Regulation Market

PJM's regulation market provides market-based compensation to resources for providing regulation. Resources in the regulation market must follow one of two types of regulation signals:

[1] Certain other ancillary services, including voltage control, black start capability, and inertial and primary frequency response are not explicitly modeled in, nor compensated through, PJM markets today.

1 | The Regulation A signal is primarily followed by conventional generation resources capable of adjusting their output up or down within five minutes, and

2 | The dynamic Regulation D signal is intended for fast-moving resources such as batteries and others.

The market clears and commits resources on an hour-ahead basis via co-optimization with forecasted energy and reserve needs to satisfy the regulation requirement of the RTO. Signals for regulation are sent out every two seconds to resources providing regulation to help keep the system in balance and frequency at 60 Hz.

Reserve Markets

PJM's current reserve markets provide compensation to resources that provide various types of operating reserves. In the real-time markets, PJM clears Synchronized and Non-Synchronized Reserves and calculates prices for these products that are co-optimized with energy needs. Both products require a 10-minute or less response time and are cleared through a combination of an hour-ahead clearing and co-optimization with real-time energy during the 5-minute dispatch of the system.

Day-ahead Scheduling Reserve are 30-minute reserves that are co-optimized with energy in the Day-ahead Energy Market. These reserves are not maintained or priced through a market-based mechanism in real-time.

March 2019 Reserve Market Reform Filing

In March 2019, PJM made a comprehensive filing to reform its market-based reserve products and Operating Reserve Demand Curves (ORDC). This filing was approved by the FERC in May 2020. It was recently remanded back to FERC in August 2021 pursuant to a request for voluntary remand by the FERC. That filing contained three primary changes:

1 | Consolidate the existing Tier 1 and Tier 2 Synchronized Reserve products into a single, 10-minute, Synchronized Reserve product,

2 | Align the reserve markets between day-ahead and real-time, and

3 | Add a downward slope to the ORDCs for all reserve products to better address the need for additional reserves due to uncertainty and increasing penalty factors to ensure the willingness to pay to maintain reserves is reflected.

PJM views the aforementioned changes as necessary for its reserve and energy markets to function optimally.

The consolidation of Tier 1 and Tier 2 reserve products is necessary from a reliability and market efficiency perspective. Tier 1 reserves are relied upon to respond to reserve events but are not required to do so and are not penalized today for failure to meet their estimated reserve capability. As such, their response rate is significantly lower than that of Tier 2 reserves, which are paid the clearing price and obligated to respond. This creates uncertainty for system operators on how Tier 1 reserves will respond if deployed and results in market clearing results that are based on an uncertain level of reserves because the Tier 1 estimated in the market clearing does not align with actual performance. The solution to this issue is simple yet important. Require all reserves assigned to respond when deployed, pay them the clearing price and penalize them when they do not perform. This is standard market design and is consistent with the design in other ISO/RTO markets.

Alignment between the reserve market models in the Day-ahead and Real-time Markets is critical to maintaining consistency. The current reserve market structure is fragmented and would result in different energy and reserve market commitments and prices between day-ahead and real-time under identical operating conditions. This creates false arbitrage opportunities between day-ahead and real-time, and commitment and dispatch results in the Day-ahead Market that do not reflect the reserve needs in real-time. This can lead to a suboptimal unit commitment and dispatch in the Day-ahead Market.

In addition to these obvious reforms, the ORDC reforms, which are explained in more detail throughout this statement, are necessary to incorporate the reality of uncertainty as to generator performance into PJM's reserve requirements and also ensure that the cost of the actions that PJM would take to maintain reserves are included in the appropriate compensation for these more specific obligations on generators.

Understanding the Need for Additional Operational Flexibility in RTO/ISO Energy and Ancillary Services Markets

The need for operational flexibility is driven by two things: 1) flexibility required to manage anticipated system changes, forecasted changes in load, interchange schedule changes, etc., and, 2) flexibility necessary to manage deviations from what is expected or forecasted (i.e., uncertainty). The degree to which each of these drivers affects the flexibility needs of each ISO/RTO will differ and therefore market solutions to incentivize flexibility will also vary by region.

PJM views the most critical types of flexibility necessary to be the commitment, decommitment and ramping capability of resources. The ability to dispatch a resource up or down and cycle them on or off in relatively short periods of time to maintain supply and demand balance throughout the day are important today and are anticipated to grow in importance in the future. The need for ramping and commitment flexibility is evident in other regions with greater levels of renewable penetration than currently seen in PJM, such as California ISO, Midcontinent ISO and Southwest Power Pool, which explicitly model and compensate flexible ramping products in their markets.

The "traditional ancillary services" identified in Order No. 888 provide a solid framework but need to be expanded in PJM in both the product and quantity dimensions from their current models to ensure a reliable future grid and market signals that incentivize efficient investment. As an example, NERC standards generally stipulate reserve minimum requirements based on the most severe single contingency.[2,3] While the most severe single contingency is a factor in the total uncertainty on the system, it does not reflect other uncertainties that are known to exist such as load forecast error, renewable forecast error, etc., that can challenge the ability of the ISO/RTO to maintain reserves at

[2] Currently effective Operating Reserve Demand Curves used by PJM today for Synchronized and Primary Reserves also have a smaller second step of approximately 190 MW at $300/MWh. This step was added to address price spikes due to transient shortages, not to model uncertainty.

[3] BAL-002-3, R2: https://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf

the required level. As some ISO/RTOs with higher levels of renewable penetration have already observed, the increase in renewable penetration on the system will lead to increased uncertainty and thus a need to properly incentivize flexibility. Based on state policy objectives in PJM, PJM anticipates an increasing level of uncertainty on its system that drives needed reserve levels resulting from changes in the profile of the fleet as well as the development of distributed energy resources. Failure to account for this uncertainty in ancillary service requirements prevents an accurate representation of the true flexibility needs on the system and mutes investment signals for the required level of flexibility. Further, not carrying additional operational flexibility to manage this uncertainty can potentially jeopardize the ability to maintain the minimum single contingency requirement. This can have clear, negative reliability consequences. *To be clear, not incorporating uncertainty into ancillary service requirements is a problem today. This problem worsens as uncertainty increases. It is akin to not increasing the minimum reserve requirement when the most severe single contingency increases.*

From a product perspective, analysis performed by PJM[4] indicates that at high levels of renewable penetration, a flexibility service specifically targeted at ramping down or decommitment capability may be valuable as well. The traditional Order No. 888 services generally target adding MWs to the system. While this is necessary to ensure that supply does not fall short of the system's energy and reserve needs, there may be cases in the future where there is too much supply available and energy curtailment may be required. This could take the form of fast decommitment of conventional generation, reduced economic minimum output levels, fast load increase capability, incentivizing renewable resources to curtail, increased down regulation capability, etc. While is not an immediate problem in PJM and likely will not be in the near future, it could be an additional form of flexibility that is needed.

Regardless of the products and quantities, the objectives of future market designs are the same as they are today: to ensure the cost to operate the system reliably and cost-effectively is transparently captured in prices. Additionally, the rules should be technology-agnostic and all resources providing the same service should receive the same compensation regardless of their cost to provide the service. Deviating from these well-established principles can be viewed as discriminatory and violate the fundamentals of market design. To accomplish this will require valuing reserves beyond the minimum requirement, as stated, but also going beyond the conventional use of lost opportunity cost as the basis for compensation. While uncertainty motivates the need for valuing ancillary services beyond the minimum requirements, there are two primary reasons why the legacy modeling of pricing based on lost opportunity cost is not workable in the future. First, there need to be strong performance incentives for providing ancillary services. Strong performance incentives likely mean strong penalties for failure to perform. Penalties on their own create risk-related marginal costs for suppliers to provide the services that are unrelated to opportunity costs. Second, there may be additional costs necessary, such as the prearrangement of fuel, so that if called, resources committed for reserves can deliver energy. These costs are not considered in today's market structure but may need to be in the future.

[4] Slide 16, https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/general-session/2021/20210504/20210504-overview-of-pjms-reliability-and-renewable-integration-analyses.ashx

Revising Existing Operating Reserve Demand Curves (ORDCs) to Address Operational Flexibility Needs

It is necessary to evolve the way in which the demand for existing ancillary service products is determined to meet the changing needs of the system. PJM's March 2019 filing proposed significant changes to the way its ORDCs are constructed. The proposal adapted the well-documented economic theory of using Value of Lost Load (VOLL) and the probability of curtailing load in real-time to construct the ORDC. The enhancements focused on including uncertainty-related load forecast error, renewable forecast error and future forced outages. Rather than use the VOLL, the maximum price on each ORDC was set at a level high enough to reflect all possible operator actions taken to maintain reserves. PJM believes this methodology provides a model to assess the need and value of reserves that is supported by economic theory and engineering analysis.

In power systems operations there is always uncertainty. The actions taken by system operators to maintain reliability are based on forecasted information such as load and renewable forecasts. Despite efforts to minimize errors in these forecasts, by their nature, they have some degree of inaccuracy. Additionally, the dispatch of the system is based on the expectation that the resources being dispatched will continue to be available and will perform as stated. These expectations are not always correct. Both of these factors, and potentially others depending on the demographics of each ISO/RTOs system, introduce uncertainty that requires flexibility to respond. This uncertainty exists all the time. It may vary on average with time of day or time of year but it is never zero. Procuring additional flexibility through market-based methods ensures that the true need for ancillary services of the system operator are reflected in the demand functions of the market, those needs are transparently priced and that the procurement of the needed flexibility beyond the minimum requirement is done in a least cost manner along with other necessary ancillary services. PJM believes that not reflecting this uncertainty today is a deficiency in the market design and believes there is ample evidence that it will increase in the future.

More broadly, ORDC enhancements are necessary to facilitate and enable a future decarbonized system. Transparent signals that reflect system conditions and system needs, and translate them into prices for well-defined products, are crucial building blocks of that future system. There may be different approaches to determining the exact shape and design of the revised ORDCs. PJM believes the framework presented in its filing is a compelling way for thinking through the evolving challenges on the system, and setting prices in a way that is flexible and reflective of system needs. Paying for ancillary services in a targeted way—when and to the extent they are providing value to the system by addressing measured uncertainty, as enabled by the ORDC enhancements discussed here—is a crucial next step to preparing the future decarbonized system the operate reliably

The ORDC should not reflect any individual consumer's preference or willingness to pay for incremental reserves. In fact, there is no reason to believe any individual consumer has a well-formed preference regarding their willingness to pay for esoteric energy products such as reserves. Rather, the level of the ORDC should reflect the *system's* willingness to pay for incremental reserves, where that willingness to pay represents the benefit *to the system* of avoiding reserve shortfalls and meeting the reliability objectives. This expression of the ORDC at the system level is consistent with reliability which is a public good. For example, the system is not designed to curtail a single customer's load who was unwilling to pay for reserves. Those consumers with a different (lower) willingness to pay than what is expressed in aggregate should participate as demand response. This would provide valuable services to the system while lowering costs to those customers, increasing system-wide welfare.

In PJM's ORDC design, reserves are intended to be used to manage system uncertainty, regardless of the cause. In this methodology, the ORDC must contain all the drivers of uncertainty for which reserves may be used. Other ISOs/RTOs that have different operational practices and problems they need to address have sought different solutions, particularly ramping products. The important takeaway here is that there are different operational problems, different operating practices, and therefore a need for each region to develop their own solution to fit their needs.

Creating New Products to Address Operational Flexibility Needs in RTOs/ISOs

Procurement of additional flexibility needs can be handled in a number of different ways, depending on the operational needs of each region. These can include additional reserve products, ramping products and reconfiguring existing dispatch algorithms, discussed below.

In PJM's case, more efficient utilization of the ramping capability that is available today should be the first step. PJM's current dispatch is a single interval solution that minimizes bid production cost using all online units. This type of solution does not consider reserving flexibility for future periods when it is needed most by taking steps like pre-ramping less flexible generators. Reconfiguring existing dispatch algorithms to take steps like pre-ramping requires reforms to locational marginal pricing calculations and settlements to make sure there is no incentive to deviate from the multi-interval dispatch. PJM believes a critical step in fully developing these multi-interval approaches is determining how to calculate prices that are incentive compatible with the multi-interval dispatch.

Under a multi-interval dispatch model, the unit-commitment and dispatch problem would consider multiple, coupled, periods in advance of the immediate dispatch interval and position a system in a way that minimizes cost while meeting system needs over the modeled intervals. The dispatch solution in each interval is linked to the others to ensure the ramping of generators across all periods is feasible. There are two primary questions that arise under these models. The first is regarding how to structure the intervals observed in the dispatch problem. The second, and more complicated one, is how to set prices and settle the market in a manner that does not result in the incentive to deviate from dispatch. The ramping products in place today typically look forward one interval ahead of the immediate dispatch interval and aim to ensure ramp feasibility over that period. This solution is adequate for short-term flexibility needs. However, if the flexibility needs are spread over a longer period of time, for example an hour, a multi-interval approach should be strongly considered. The benefit of the multi-interval approach is in linking multiple intervals to create a dispatch trajectory over an hour that not only meets the ramping needs in an hour, but also ensures ramping adequacy throughout the hour. Pricing and settlement under this model becomes complex because the dispatch, and necessarily the prices, for the settlement interval are linked to the pricing and dispatch in the look-ahead intervals. More research needs to be done to further develop these models.

As a general rule, PJM believes that new products should address a clearly articulated problem that is distinct from those addressed through other existing products. PJM also believes it is appropriate that any new products needed to maintain operational reliability be efficiently procured and priced in the operating time frame first, before considering a forward procurement. In general, transparent price signals that are aligned with real-time system conditions will best incentivize optimal operations and investments. Forward procurements of any ancillary service products should only be considered if the real-time prices do not incentivize sufficient investments in the resources that can provide the products. Just like the capacity market can complement price signals in the operating time frame to incentivize efficient investment and retirement decisions, forward procurement of certain ancillary services *could* do the same if necessary. PJM believes that its proposed reforms that are currently being reviewed by the FERC are a necessary first step in ensuring that reserves are appropriately procured and priced in the operating timeframe. It is necessary to implement changes such as these prior to pursuing a forward procurement process.

ISOs/RTOs have done a significant amount of thinking, research, and coordination on this topic. While continued inter-regional coordination remains important, given regional operational differences, each entity should be responsible for crafting their own solution to meet their needs.

Market Design Issues and Tradeoffs to Consider in Reforms to Increase Operational Flexibility in RTO/ISO Energy and Ancillary Services Markets

While there are many tradeoffs to consider when taking on any type of market reform, in this context, PJM believes it is worthwhile to highlight two:

1 | As noted in the panel questions, there is an inherent tradeoff in procuring reserves beyond the minimum requirements and transient shortage pricing events. In general, those are inversely related. The more reserves we commit beyond the minimum, the better protected the system is against reserve shortages. It is important to ground this discussion in system reliability. Shortage pricing should not be an explicit objective. Targeting some level of shortage pricing indicates an objective to operate the system at a degraded reliability state. This is not a good operating practice.

However, the objective to stay out of reserve shortages must be bounded as there is not a limitless willingness to pay by consumers. This is why the aforementioned ORDC methodology is critical. It provides a pragmatic method that is rooted in engineering and economic theory to describe the value to the system of reserves beyond the minimum requirement. The overarching principle here is to more accurately value reserves via the ORDC and allow prices to reflect that value. Shortage pricing on its own is an outcome, not an objective.

2 | Changes to ancillary services market designs that place more value on ancillary services in the operating timeframe will inherently shift revenues from the capacity market to those ancillary service markets and the energy market via co-optimization. If there is a clear reliability benefit to this increased value, this tradeoff should be welcomed. Spot markets have much clearer and more granular incentives for performance and investment and should be utilized as the primary approach to sending incentives.

With these thoughts in mind, PJM looks forward to further discussion of these issues at this Technical Conference.