AD21-10 Modernizing Wholesale Electricity Market Design – Order Directing Reports Stakeholder Feedback

PJM is seeking stakeholder feedback to the Order Directing Reports in FERC Docket No. AD21-10-000 on Modernizing Wholesale Electricity Market Design, providing the following questions as focus areas:

1 | What system needs (type and magnitude) has the RTO/ISO experienced that are attributable to changes in the resource mix and customer load profiles? *(FERC Q1)*

(a) How do these system needs, including types and magnitudes of net load variability and uncertainty, vary over different time horizons in the E&AS markets? *(FERC Q1)*

(b) For example, does a particular need exist within a real-time market interval, within an operating day, between day-ahead and real-time markets, across multiple days, and between seasons? Please include any references. *(FERC Q1)*

(c) What specific resource capabilities could address these needs (e.g., dispatchable generation)? *(FERC Q1)*

(d) What time horizons, such as times of day (e.g., minutes, hours), days, or seasons, are expected to present the biggest challenges with respect to net load variability and uncertainty? Why? *(FERC Q2.2)*

LS Power Response:

From PJM's Renewable Integration Study we note the need for significant amounts of ramping capability. While some RTOs are procuring a separate ramping product, we encourage PJM to first explore multi-interval dispatch and pricing. Multi-interval dispatch solves the sequential, real-time dispatch solution across the period modelled. Multi-interval pricing properly reflects the marginal costs of system ramping constraints over the dispatch horizon. Moreover, multi-interval dispatch eliminates the need for a separate ramping product, which in turn simplifies the ancillary services (AS) markets. As we discuss later, a market with energy, capacity, and the minimum number of AS products will support lower financing costs of dispatchable resources versus a plethora of AS products. While CAISO and NYISO implement multi-interval dispatch and pricing, both only settle on the most immediate "binding" interval; pricing for all other intervals is considered "advisory." However, settling on only the most-immediate interval may affect incentives to follow dispatch instructions (DI) or subject resources to financial risk for following DI. If a high price occurs in the most immediate interval but the advisory pricing suggests the prices are likely to go higher, the resource may receive DI that reflects the expected future higher price, not the most immediate interval pricing. If the higher future prices do not materialize the resource may incur a financial loss for following DI. This is especially acute for limited energy resources that may not be discharged at the highest prices or may be charged at the highest price. The most straightforward solution is to settle on binding pricing for all intervals; however, this creates complex settlement rules. There may be other solutions that balance the pros and cons, and we encourage PJM to explore these questions through the stakeholder process.

2 | Referring to the changing system needs discussed in the questions above, to what extent are current RTO/ISO E&AS market products and compensation schemes not designed to procure the resource capabilities needed to meet these expected changing system needs? To what extent are such prices and products unable to adequately compensate the resources possessing the capabilities necessary to meet these expected changing system needs? To what extent does the risk of disorderly retirements of resources with capabilities that are needed to address such needs (e.g., fast ramping dispatchable resources) increase if E&AS markets are not reformed? Why? *(FERC Q4)*

LS Power Response:

We understand that a significant amount of operating reserves are supplied through PJM's system operators dispatching online resources down. As others have observed, this results in an abundance of operating reserves and many intervals where the price of such reserves is zero. However, as variable energy resources (VER) replace dispatchable resources to serve load, the quantity of available spinning reserves will decline. The system operator will depend more on non-spinning reserves, and the current pricing paradigm may not provide sufficient incentives. As has been noted, the financial consequence of failing to provide operating reserves is insignificant; the system operator has such a surplus of supply that they can simply move to the next available resource. This too may not be sustainable as the pool of operating reserves dwindles and the quality of the pool becomes more relevant. It is important for PJM to model this evolution of the supply of operating reserves as dispatchable resources are displaced by VERs and to examine whether the current paradigm will be able to provide an adequate quantity of operating reserves in stressed system conditions.

3 | Over the next five years, and over the next 10 years, how well will existing RTO/ISO market designs adequately incentivize resource behaviors that will enable the RTO/ISO to meet its changing system needs? *(FERC Q6)*

LS Power Response:

See response to PJM Question #2.

4 | Parties presented different views on whether the widespread use of opportunity cost-based ancillary service pricing will continue to sufficiently incent and compensate resources for meeting system needs as the resource mix and system needs evolve in the future. Given the critical role RTO/ISO resources play in meeting system needs, more information on how E&AS markets will provide adequate compensation for these costs is needed. Will existing E&AS market designs create sufficient fixed cost recovery under existing pricing methods (i.e., opportunity costs, shortage pricing, etc.) for resources to make needed investments, remain in service, and continue to offer the capabilities necessary to meet changing system needs? *(FERC Q6.2)*

LS Power Response:

We believe that the system operator will not be able to grow the AS markets sufficiently to incent investment in flexible supply that will be needed to support the influx of VERs. As we pointed out in our comments under this docket, ancillary services are not a service that is actually "consumed" by ratepayers. (And it is unlikely that a liquid market for such services/products could be developed in a way that ratepayers could benefit from hedging activity.) AS will remain diminutive compared to the energy and capacity markets – e.g., OR for load forecast error is a small percentage of overall load; OR for single contingencies are relatively de minimis, quantify for ramping through an late peak, etc., and valuing AS properly will be an administrative challenge even as the need for AS grows with VER supply. Clearly the grid will need resources with attributes that have been historically under-valued: flexibility, fast start, ramping, etc. There appear to be two schools of thought on how to procure these services: (i) create an ancillary service for every attribute identified and count on the owners to reconstitute multiple revenue streams into financeable projects, or (ii) reform the capacity market to procure resource adequacy and flexibility from resources that provide multiple services. LS Power is in the latter camp. We note that providing energy and AS, especially operating reserves, regulation, ramping, and frequency response, is typically mutually exclusive, and resources may provide either from interval-to-interval based on system need, so the shift from procuring resources in the capacity market that can supply energy and operating reserves is not great.

5 | Will existing E&AS market designs create an efficient long-run price signal for investment in new resources with the capabilities necessary to meet changing system needs? *(FERC Q6.2.1)*

LS Power Response:

Currently, new investment signals are predominantly driven by the energy and capacity markets, and AS revenues are so marginal as to be given little weight in financing assumptions. (Note that RECs for VERs are critical to financing assumptions). Recent greenfield facilities have been combined cycles, which offer the owner a hedge against declining capacity market prices – i.e., more evenly split between energy and capacity market revenues, and better monetization of low-cost shale gas due to their extremely high efficiencies. Forecasts suggest continued access to low-cost gas, flat-to-declining capacity revenues, and lower LMPs as more zero marginal cost VERs are deployed. These forecasted conditions have resulted in weakening of long-term investment signals and an observable reduction of new dispatchable generation entering the interconnection queue. It is unclear how environmental regulations on the existing coal fleet will change these investment signals; however, it's unlikely novel or enhanced AS markets will materially change the investment signals. Consequently, if existing resources exit in sufficient quantities current market rules and market conditions are likely to spur a new wave of combined cycle development. We do not have a position on whether new CCs or new CTs will be more useful in the future grid but are concerned that CCs could be developed when CTs may provide more long-term value. We recommend PJM examine their long-term needs and ensure investment signals are aligned to incent the preferred technology.

6 | Should ancillary service products be co-optimized with energy so that the assignments and prices for ancillary services align with energy prices? *(variation of FERC Q6.4)*

LS Power Response:

We support the co-optimization of energy and ancillary services in the day ahead and real time markets with the goal of performing such co-optimization on no less than a zonal basis. Co-optimizing the energy and ancillary services market ensures that resources that are capable of providing multiple products or services are assigned in the most efficient way. Co-optimization ensures the system operator has allocated energy and ancillary services in the lowest cost way while meeting energy demand and maintaining system reliability. In a system that does not co-optimize energy and reserves, system operators are left to manually re-dispatch resources when operating reserves become tight. That is, the system operator holds a higher ramp rate resource down while moving slower resources up to preserve the system's reserve capabilities. This is a rational response by system operators, but these manual actions are out-of-merit, not priced in the market, and are paid through uplift. The right market design can give system operators the assurance they need that reserves will be available while sending better pricing signals to market participants.

Co-optimization also provides coordinated energy and ancillary services price signals that incent resources to follow dispatch instruction. This becomes more relevant as the basket of ancillary services increases in type and quantity. Some panelists raised concerns with cascading ancillary service prices into energy LMPs. Specifically, they raised concerns that AS prices cascading into energy LMPs would compensate less flexible resources that were providing energy for the flexibility inherent in those resources providing the ancillary service – e.g., fast-start generators, etc. We are not sure how the co-optimization would solve for the least-cost and most efficient solution if the marginal resource is not financially indifferent between providing energy and ancillary services. Moreover, if this inflexible resource were removed from the supply stack its absence would shift the clearing point to a marginal resource further up the supply stack. That is, absent the inflexible resource providing energy, load would be paying more for energy *and* operating reserves. Unlike the inflexible resource that sits idle in the moment, the online inflexible resource is providing societal value. Thus, we disagree with the concerns raised about cascading price formation. We think the better route to address resource flexibility is to consider flexibility in capacity accreditation. Finally, while many have argued for a diminished capacity market and a future panoply of ancillary services, it's unclear how a basket of smallish, technical products would create investment signals for new, flexible dispatchable resources that are needed to accompany a large influx of VERs.

7 | Referring to the changing system needs discussed in question 1, are there any operational practices in PJM that should be reviewed/altered to successfully manage changing system needs over the next five years and over the next 10 years? *(FERC Q7)*

LS Power Response:

As noted above, the right market design should relieve system operators of having to make manual adjustments to retain operating reserves, which is a more efficient outcome than today.

8 | Beyond those already asked, are there other E&AS market reforms necessary? *(FERC Q8)*

LS Power Response:

No comments offered.

9 | What is the capacity market's role in incentivizing resources with specific attributes vs solely procuring to meet a total reliability requirement? *(FERC Q9.2)*

LS Power Response:

We believe that the capacity market needs to be overhauled to meet the needs of a changing grid dependent on significant quantity of energy from VERs.[1] Given the ultimate goal of many policymakers that

[1] We interpret PJM's use of "specific attributes" to be synonymous with FERC's use of "flexible attributes" in their question 9.2, and assume PJM did not broaden the definition to other attributes not central to resource adequacy or flexibility – e.g., environmental attributes, etc.

PJM seeks to accommodate, the expectation is very little energy will be needed from resources other than VERs and battery storage (along with an expectation of enhanced technology that is not currently available). Given the design of the PJM market was to rely on the energy market for primary compensation and the capacity market for the so-called missing money, PJM's capacity market should be geared toward providing compensation to those resources that can respond to a system based primarily on VERS: supply that can provide energy flexibly.

The capacity markets as they are currently designed were an appropriate vehicle to procure physical capacity to meet a reliability standard when the system was more homogenous. That is, the simple cycle gas turbine that set at the margin in the energy markets and served the last MWh of load but derived no inframarginal rents was completely dependent on capacity market revenues. The production of energy was the value attribute in clearing the capacity market. Today's capacity market does not value the resource attributes that are critical to ensuring reliability. Instead, the capacity market only considers a resource's potential to produce (or stop consuming) energy on demand, regardless of its limitations in its ability to do so.

At a high level, the capacity model of calculating when demand may outstrip supply is failing to capture observed periods of stress. Capacity models are overvaluing inflexible resources' contributions during certain periods of observed system stress. Elevated Loss-of-Load-Probability (LOLP) has recently been observed due to security constraints, not resource adequacy deficiencies. To our understanding, PRISM only models the latter.

In an attempt to draw a distinction between resource adequacy deficiencies and security violations, PJM (citing NERC) states the former deals with supplying the "aggregate electrical demand…taking into account scheduled and reasonably expected unscheduled outages". The latter "security" requirement is the "ability to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements". However, the more common mode of elevated LOLP has been loss of elements coupled with load forecast error. This failure mode bridges both "security" and "adequacy," and to our understanding, is not modelled in PRISM. We further understand PRISM does not account for the change in the load forecast between the time the DAM closes and the real-time delivery hour, nor does it take into account inter-temporal constraints of slow starting resources.

Moreover, the problem of managing real-time changing conditions is currently isolated to demand-side conditions – i.e., load forecast error, and system contingencies; however, as VERs become more prevalent, the challenge will be compounded. As PJM, itself, suggests the introduction of more VERs will create elevated LOLP in hours and seasons that have not historically experienced high LOLP. In this future with more dynamic conditions, the inflexible resources will be sidelined more frequently from participating in the energy market. In preparation for these future conditions, we suggest PJM should explicitly model the probability that inflexible resources can respond to changing real-time system conditions. If such resources' *unavailability due to slow response* contributes to elevated LOLP, then the UCAP for inflexible resources should be reduced appropriately.

We are keenly aware of the modelling complexity of our suggested approach and offer that a simpler heuristic approach would be an improvement over the status quo. Others have proposed a sliding scale that reduces capacity values 10% for each additional hour above a baseline 2-hour notification + start-up time. An alternative approach grounded in the NERC reliability requirements suggests PJM could, instead, allow full UCAP for resources with notification + start-up times of 90 minutes or less, a reduction of (say) 10% for resources that have notification + start-up times greater than 90 minutes but less than 4-6 hours, and UCAP reductions of (say) 25% for resources that have notification + start-up times greater than 4-6 hours. Requirement 3 of NERC BAL-003 requires PJM to restore 10-minute Operating Reserves within 90-minutes following the end of the Contingency Event Recovery Period hence the basis for fully accrediting units that are able to deliver their energy within 90 minutes. While PJM may be able to restore these reserves with surplus 10- or 30-minutes operating reserves, there is no guarantee this surplus will persists with an evolving resource mix. Therefore, it is important to specify today what AS are needed in the future. Regarding the 4-6 hour requirement, an empirical analysis of load forecast error vs time-to-real-time-delivery-interval and PJM's historical need to commit slow starting resources in the Operating Day may inform this duration. With regard to the amount of the discount, these values could be relatively small and increase as more VERs are added to the system. The important condition is for PJM to telegraph early to market participants that it intends to commence including notification + start-up time in capacity accreditation.

10 | Are there actions outside of the Tariff that should be considered? *(FERC Q10)*

(a) NERC standards

(b) Gas market

(c) JOAs

LS Power Response:

Of course, PJM is required to comply with NERC standards so any tariff changes would have to be compatible with them. That said, such standards typically are not nearly as granular as the rules provided in PJM's tariff, so that should not be an issue.

11 | Please provide any additional comments or responses to FERC questions you believe PJM should consider.

LS Power Response:

No comments offered.

Please provide all feedback to Rebecca.carroll@pjm.com and Dennis.hough@pjm.com by July 8, 2022