UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Participation of Distributed Energy Resource	)	
Aggregations in Markets Operated by Regional	)	**Docket No. RM18-9-000**
Transmission Organizations and Independent	)	
System Operators	)	

POST-TECHNICAL CONFERENCE COMMENTS OF ADVANCED ENERGY MANAGEMENT ALLIANCE

The Advanced Energy Management Alliance ("AEMA")[1] hereby submits its comments ("Comments") in the Notice Inviting Post-Technical Conference Comments regarding Distributed Energy Resource ("DER") aggregation topics and questions related to Panels 1, 2, 3, 6, and 7, issued on April 27, 2018.[2]

AEMA is a trade association under Section 501(c)(6) of the Federal tax code whose members include national distributed energy resource companies and advanced energy management service and technology providers, including some of the nation's largest demand response ("DR") and distributed energy resource ("DER") providers, as well as some of the nation's largest demand response and distributed energy consumers. AEMA members use and deploy distributed energy resources, including advanced energy management solutions, to achieve electricity cost savings for consumers, to contribute to reliability and resilience, and to provide sustainable solutions for a modern electric grid. This filing represents the collective

[1] Advanced Energy Management Alliance website: http://aem-alliance.org.

[2] FERC notice with questions available: https://www.ferc.gov/CalendarFiles/20180427135034-notice-for-comments.pdf

consensus of AEMA as an organization, although it does not necessarily represent the individual positions of the full diversity of AEMA member companies. AEMA is grateful to the Federal Energy Regulatory Commission ("FERC" or "Commission") for the significant amount of staff and Commissioner time that has been spent on this proceeding, and the opportunity to provide this feedback.

I. Executive Summary

This Executive Summary provides high-level recommendations for FERC regarding the practical implementation of the final Order in this proceeding.

First, *FERC should clarify that the objective of the Order is to create a framework that affords all DERs the right to non-discriminatory, open access to wholesale market revenue opportunities, and that integrates DERs in an efficient and reliable manner*. Consistent with the language in the Notice of Proposed Rulemaking ("NOPR"),[3] the Order should state the intent to remove barriers to DERs, and not add new ones.[4] Grid operators' visibility and access to DERs is becoming increasingly necessary to maintain a reliable and competitive system. Unreasonably burdensome or unnecessary requirements of DERs in wholesale markets will increase costs without reasonable opportunities for return on investments. As such, DER resources and developers will be less likely to participate in wholesale markets, resulting in less market competition and visibility to grid operators. Removing barriers is imperative.

[3] *Elec. Storage Participation in Mkts. Operated by Regional Transmission Orgs. and Independent Sys. Operators*, 157 FERC ¶ 61,121 (2016) ("NOPR").

[4] *See* NOPR, ¶ 14. "We preliminarily find that the barriers to the participation of distributed energy resources through distributed energy resource aggregations in the organized wholesale electric markets may, in some cases, unnecessarily restrict competition, which could lead to unjust and unreasonable rates. Effective wholesale competition encourages entry and exit and promotes innovation, incentivizes the efficient operation of resources, and allocates risk appropriately between consumers and producers. Removing these barriers will enhance the competitiveness, and in turn the efficiency, of organized wholesale electric markets and thereby help to ensure just and reasonable and not unduly discriminatory or preferential rates for wholesale electric services."

Second, *FERC should include in its Order, similar to Order 841, a "checklist" of required elements for just and reasonable "participation models" with which RTOs/ISOs must comply to encourage DER resources*. The "participation model" would provide necessary guidance to grid operators on the tariff provisions they must change, create, delete, or identify as already in place that are necessary to help facilitate the participation of DERs in the Regional Transmission Organization/Independent System Operator ("RTO/ISO") markets.

The Order should not create a requirement to overhaul, eliminate or replace existing programs, such as the sophisticated and mature DR programs some RTOs/ISOs have developed over the last ten plus years. Moreover, RTOs/ISOs should not have to create new specific DER programs if the existing general market structure does, or can, enable DER participation; the diverse technologies and physical traits (e.g., dispatchable vs non-dispatchable) do not lend to one single uniform "DER program."

FERC should create a "participation model" with a checklist for RTOs/ISOs to demonstrate compliance with that, at a minimum, addresses the below described elements. The checklist should require that DERs have the ability to:

- ✓ Have physical and economic access to all wholesale market revenue opportunities, earning full market value for the provision of capacity, energy, and ancillary services;
- ✓ Receive credit for net supply;
- ✓ Dually participate in both wholesale and retail opportunities, while adhering to market mechanisms and rules preventing double compensation for an *identical* service;
- ✓ Offer increases and decreases in consumption/output to monetize their valuable flexibility; and
- ✓ Aggregate across an area as "geographically broad as technically feasible".

Moreover, the checklist should require RTOs/ISOs to:

- ✓ Have measurement and verification (M&V") rules that account for the unique and varying operating characteristics of DER (e.g. allow batteries to be measured separate from the retail load);
- ✓ Allow 100 kilowatt ("kw") minimum resource size for all markets, including ancillary services;
- ✓ Demonstrate why their telemetry requirements are necessary and why a less expensive telemetry requirement is not feasible (e.g., a principle of "equivalency" with central station requirements would not be a sufficient explanation); and
- ✓ Implement a transparent, streamlined process for distribution utilities to notify a RTO/ISO if a DER is enrolling in the wholesale market when they do not have an interconnection agreement.

Having this checklist across all FERC jurisdictional markets will provide sufficient uniformity to ensure DERs can compete in wholesale markets, while providing RTOs/ISOs flexibility to integrate DERs in the most efficient manner for those markets.

The remainder of this document contains AEMA's feedback on the topics included in Questions 1, 2, 3, 6, and 7. Rather than respond to every question, AEMA summarizes its position on the overall topic, and then provides specific recommendations for a path forward for FERC.

II. Panel 1: Economic Dispatch, Pricing, and Settlement of DER Aggregations

AEMA Position

Aggregation at a node is not aggregation; we recommend FERC require RTOs/ISOs adhere to a choice of approaches (described below) to define reasonable aggregation areas. AEMA largely maintains the position it took in the Supplemental Comments we filed on September 28, 2017.[5] We continue to support FERC's proposal to "require each RTO/ISO to revise its tariff to establish locational requirements for distributed energy resources to participate in a distributed energy resource aggregation that are as geographically broad as technically feasible."[6] In the NOPR, FERC went out of its way to recognize the value of aggregation,[7] and several commenters underscored the importance of allowing broad aggregations of DERs.[8] FERC also expressed concern over limiting aggregation to a single node, stating "we are concerned that some existing requirements for aggregations to be located behind a single point of interconnection or pricing node may be overly stringent and may unnecessarily restrict the opportunities for distributed energy resources to participate in the organized wholesale electric markets through a distributed energy resource aggregator."[9] In short, aggregation across broader geographic areas facilitates market entry from smaller DERs, reduces unnecessary administrative costs, and boosts reliability.

During Panel 1 of the April 10, 2018 technical conference, there were divergent positions from the ISOs on how FERC should move forward. PJM and California ISO ("CAISO") both shared current practices that allow for multi-nodal aggregation without compromising reliability or distorting locational price signals. In PJM's capacity market, resources are offered and defined at the zonal level; providers, however, understand in advance that resources can be dispatched on

---

[5] Advanced Energy Management Alliance, Comments, Docket No. AD16-20-000 (filed September 28, 2017).
[6] NOPR, ¶ 139
[7] NOPR, ¶ 125-126.
[8] See comments in AD16-20-000 from the Advanced Energy Economy, PJM Interconnection, the Energy Storage Association, the National Electrical Manufacturers Association, etc.
[9] NOPR, ¶ 138.

a more granular level if certain rules are followed by PJM. Given this advance notice, and certainty of rules, participants can factor economics into pricing at the zonal level. Although ISO-NE did not cover this in their April 10 verbal comments, their comments in this docket highlight that their demand response program, which ISO-NE suggests can be a vehicle for integrating certain DERs, allows for multi-nodal aggregation.[10]

AEMA Recommendation

Given that three ISOs currently allow for multi-nodal aggregation, it would be a major step backwards for any RTO/ISO to restrict aggregation to a nodal level. Each RTO/ISO should be required to consider one of three following multi-nodal approaches: 1) As allowed in CAISO, allowing aggregation across nodes with minimal congestion and price differential; 2) As allowed in PJM, allowing aggregations across multiple nodes, but grid operators can choose not to dispatch any DER that is part of the resource that would exacerbate a reliability constraint;[11] or 3) As allowed in ISO New England ("ISO-NE"), allowing aggregation to a dispatch zone level where dispatching DERs within that dispatch zone would not exacerbate constraints. Each RTO/ISO should be required to move forward with one of those paths, unless it can demonstrate with clear, objective criteria why none of the options are technically feasible. If a RTO/ISO contends that none of the options are technically feasible, the RTO/ISO should consider whether it is feasible within certain areas that are less congested. If a RTO/ISO deems that aggregation is not technically feasible beyond the nodal level, the RTO/ISO should be required to demonstrate

[10] *See* ISO New England Inc., Comments, Docket No. AD16-20-000 (filed February 13, 2017). "ISO-NE explains that, for the capacity market, demand resources may consist of an aggregation of multiple end-use customers, though they must be at least 100 kW and located within a dispatch zone or load zone as required under the participation model through which they are participating. ISO-NE further explains that for the energy and reserve markets, demand response resources may also be aggregated as long as they are individually at least 10 kW, have an expected maximum interruptible capacity of 5 MW or less, and are located within a dispatch zone and reserve zone."

what actions they have taken to reduce the number of transmission nodes in its territory without muting locational price signals.

FERC should allow parties to comment on the RTO/ISO filing and if FERC finds that the RTOs/ISOs have not justified why they are not allowing more broad aggregation, then FERC can require broader aggregation be allowed, at least in certain sections of the RTOs/ISOs grid or for particular market products. FERC should also clarify that the "technically feasible" aggregation level allowed for energy/ancillary services should not restrict capacity aggregation, and that capacity resources should be allowed to aggregate on a broader level.

III. Panel 2: Operational Implications of DER Aggregation with State and Local Regulators

AEMA Position

AEMA will focus mostly on the "opt-in, opt-out" issue where FERC has requested feedback. In our Panel 2 recommendation section, we offer a variation of the "opt-out" light proposal from Chairman Thomas that attempts to balance FERC's clear jurisdictional authority over DER participation in wholesale markets with the desire of certain Midwestern states to retain control over system planning. We will also provide high-level responses to the other questions asked by FERC in Panel 2.

Regarding DER access to wholesale markets, the same logic and principles that apply to electric storage resources should also apply to DER aggregations. DER aggregations must have the option to participate in wholesale markets. In Order 841, FERC rejected requests to "allow states to decide whether electric storage resources in their state that are located behind a retail meter or on the distribution system are permitted to participate in the RTO/ISO markets through the electric storage resource participation model".[12] Given that an original intent of the NOPR was to remove barriers to DER aggregations in order to "enhance the competitiveness, and in turn the efficiency, of organized wholesale electric market,"[13] it would be inconsistent to allow states the ability to block access to those opportunities.

During Panel 2 of the DER Technical Conference, states emphasized the importance of allowing DERs access to wholesale markets. The Pennsylvania Public Utility Commission ("PUC") stated that DERs could substantially enhance the health of the PJM market and rejected the notion of an opt-out.[14] Similarly, both the Ohio PUC and the District of Columbia Public Service Commission ("PSC") stressed the importance of "consumer-driven" markets and choices.[15] FERC can protect consumer choices, and the benefits they confer to wholesale markets, by ensuring that DERs have the opportunity to access RTO/ISO markets.

AEMA supports the rights of states to create retail tariffs that facilitate wholesale market participation for DERs, and to condition participation in the retail tariff on the DER not participating directly in the wholesale market. There are existing models for this, most notably in the PJM portion of Indiana. Provided states design those retail tariffs well, customers/DER owners may choose to participate via such a retail tariff instead of directly in the wholesale market. However, the customer/DER owner must have the choice, and the Relevant Electric Retail Regulatory Authority ("RERRA") should be prohibited from opting-out.

We will provide significantly more detail on this topic in the recommendations section, and focus the rest of this section on responding to FERC's questions:

---

[12] *Elec. Storage Participation in Mkts. Operated by Regional Transmission Orgs. and Independent Sys. Operators*, 162 FERC ¶ 61,127 ("Order No. 841"), at ¶ 35.
[13] NOPR, ¶ 14.
[14] *Transcript of FERC DER Technical Conference in RM18-9-000* (April 2018) ("Technical Conference Transcript"), p. 144.
[15] Ibid, pp. 116 and 147.

- When there is appropriate visibility and coordination, DERs participating in the wholesale market can have positive operational impacts on distribution-level systems. States can create retail-level tariffs that are available to DERs participating in the wholesale market, and use those DERs to reduce distribution-level expenditures. New York's retail-level demand response programs, described at length during the technical conference by Con Edison and the New York Public Service Commission ("NYPSC"), enables utilities to specifically account for DERs in their system planning. These DERs also participate in the wholesale market, and any negative impacts are mitigated by 1) interconnection agreements that need to happen regardless of wholesale participation that ensure the DERs are safely connecting; and 2) coordination between the New York ISO ("NYISO") and Con Edison. Both parties described this coordination during the technical conference. Con Edison stressed the importance of all parties being partnered together and "understanding what is going to be on the system and when" based on the information that DERs provide in their registration.[16] NYISO described how DR dispatch calls are coordinated with Con Edison so that both parties are aware of the response and how it might impact their programs.[17]
- Interconnection process should determine whether a resource could safely deliver kilowatt-hours ("kWh") to the grid. The local distribution grid does not distinguish between kWh that are sold for retail and wholesale purposes. No resource is interconnected with the intent to sit idle, so we are puzzled by the notion that participating in the wholesale market introduces another level of reliability risk not

[16] Technical Conference Transcript, p. 409.
[17] Technical Conference Transcript, pp. 172-173.

contemplated in interconnection (with the potential exception of frequency regulation). Of course, if a wholesale dispatch could exacerbate a distribution-level constraint, then coordination frameworks need to be in place for the distribution utility to notify the RTO/ISO and potentially change the dispatch. But overall, wholesale participation should not have negative impacts on distribution-level reliability provided that the interconnection process serves its purpose and there is operational coordination.

- We challenge the premise of the question "how should the costs associated with monitoring and addressing such potential impacts on the distribution grid caused by the NOPR proposal be addressed, and fairly allocated?"[18] DERs are built for a host of reasons, including resilience, demand charge savings, corporate sustainability objectives, etc. FERC should not be assuming that the NOPR is causing incremental costs on the distribution grid. If a DER imposes costs on the grid when they connect, regardless of reason, those costs can be recovered in the interconnection costs under the authority of state regulators. But neither FERC nor states should be imposing additional costs on resources that wish to participate in the wholesale market, as that could be a "poison pill" for participation and undermine FERC's objectives of increasing market competition.

AEMA Recommendation

FERC should enable and protect consumers' and DER aggregations' access to wholesale market opportunities. Consistent with its decision in Order 841, it should reject any requests from states that would deny consumers the choice of participating either directly or through an

[18] Notice of Technical Conference, p. 3. https://www.ferc.gov/CalendarFiles/20180215200832-RM18-9-000.pdf

aggregator in RTO/ISO markets. There should be no restriction on where DER aggregators can recruit customers to participate in the wholesale market.

However, consistent with the principle of cooperative federalism, FERC should clarify that states have the right to design and implement voluntary retail tariffs that prohibit participants from direct participation in wholesale markets. In that instance, customers would choose whether they preferred to participate in a retail tariff or directly (or via an aggregator) in the wholesale market. The retail tariff could facilitate wholesale services and enable states to preserve their jurisdiction over retail customers, programs, and activities without impinging on customers' ability to access wholesale markets.

There are already successful models of retail tariffs that align with wholesale services. Indiana and Michigan Power's ("I&M") Demand Response Service Rider 1 ("D.R.S.1")[19] is an example of such a tariff.[20] States concerned about losing control over their resource planning processes or losing jurisdiction over retail customers could implement similar tariffs for DER aggregations. The key points of the I&M tariff [21] are:

- The tariff aligns with PJM's capacity-based DR program, which enables I&M to enroll customers in the PJM program and receive capacity credit. This offsets the amount of capacity they need to procure from the wholesale market or build/maintain.
- DR Providers that are qualified by I&M are allowed to aggregate retail customers to participate in DR, but instead of the DR Provider enrolling the customers directly

[19] Rider D.R.S.1 (Demand Response Service – Emergency)" at 98, https://www.indianamichiganpower.com/global/utilities/lib/docs/ratesandtariffs/Indiana/IMINTB1605-30-2018.pdf.
[20] For more detail, see AEMA's white paper on "Advancing Demand Response in the Midwest": http://aem-alliance.org/advanced-energy-management-alliancereleases-options-develop-untapped-resource-engage-consumers/
[21] We note that the I&M tariff is strictly for capacity. For energy/ancillary, there could be a DER retail tariff that would govern participation (e.g. telemetry to provide to the distribution utility, when a distribution utility could say that a DER cannot be dispatched for local reliability reasons). Given the real-time nature of these markets, the frequency of which bidding would need to be done, and the potential number of bidders, the most practical approach is likely to have the DER aggregator be the market interface. This could potentially evolve over time.

with PJM, the Provider must register the customer with I&M, who subsequently enrolls those customers in the PJM DR program.

- I&M compensates DR Providers at the higher of the average of the PJM capacity market clearing price over the last four years or 35% of Net Cost of New Entry ("CONE"), which represents the assumed cost of building new generation.

By aligning the retail tariffs with wholesale products and services, states can harmonize both systems while retaining control and jurisdiction over participating resources. To increase the attractiveness of retail programs relative to wholesale participation, states could also add additional value streams such as peak load management or distribution-level services to the tariff(s). This approach would respect both state and FERC jurisdiction and harmonize retail and wholesale markets and operations.

IV. Panel 3: Participation of DERs in RTO/ISO Markets

AEMA Position

In our February 13, 2017, written comments[22] in this proceeding and at the April 10, 2018, technical conference, an AEMA member detailed[23] the reliability, economic, and coordination benefits of dual participation, and summarized how FERC can determine what constitutes the "same service." We also highlighted how retail demand response programs in New York and Pennsylvania provided incremental value to the RTO/ISO wholesale programs, while avoiding paying twice for the same service. We continue to support the positions we took in those written and oral comments and will not repeat them at length in these comments. Instead, we offer further clarification to FERC on what does and does not constitute the "same

[22] Advanced Energy Management Alliance, Comments, Docket No. AD16-20-000 (filed February 13, 2017).
[23] *See* Technical Conference Transcript, Panel 3 comments by Katie Guerry of EnerNOC, Board member of AEMA.

service," drawing briefly on the New York and Pennsylvania examples, and in the next section, we provide a specific recommendation for FERC to protect against the "same service" not receiving double compensation.

Before providing the clarification mentioned above, we note our gratitude to the Commission for recognizing the value of dual participation in Order 841, where FERC stated "it is possible for electric storage resources that are selling retail services also to be technically capable of providing wholesale services, and it would adversely affect competition in the RTO/ISO markets if these technically capable resources were excluded from participation."[24] This same logic should apply to DERs.

The "same service" is limited to instances where a retail tariff or program compensates a DER for a wholesale revenue stream, and at the same time, the same exact kW or kWh from that DER is receiving compensation from the wholesale market for the same wholesale revenue stream. This is a straightforward determination and clear examples exist. For instance, if a DER on a net metering tariff or participating in a retail-level program receives compensation for the value of wholesale energy for every kWh of output or reduction, and at the same time, the same kWh from the DER also receives wholesale energy market compensation, it is a "same service." The DER has provided no incremental value to the retail and wholesale system, and has earned the same revenue stream twice for the same kWh of dispatch.

There are solutions that FERC can implement to prevent that "same service" from receiving direct wholesale payments, and we provide those solutions in the recommendations part of this section. Indeed, demand response programs in New York and Pennsylvania already have mechanisms in place at the state and RTO/ISO level, respectively, so that DR does not receive two wholesale energy payments for kWh it delivers during overlapping wholesale and

[24] Order No. 841, ¶ 320

retail dispatches. In the case of Con Edison's Commercial System Relief Program ("CSRP") and Distribution Load Relief Program ("DLRP"), the tariff states "Performance Payments will not be made under CSRP or DLRP if the Direct Participant or Aggregator (on behalf of its customer) receives payment for energy under Rider P, V, or W or any other demand response program (e.g., NYISO's Day-ahead Demand Reduction Program or NYISO's Special Case Resources Program) in which the customer is enrolled through the Company during concurrent Load Relief hours in the same Networks."[25]

Retail-level and wholesale level services are *not* the "same services" if any of the following are true:

- A DER participates in a retail-level program, tariff, or rate structure where the compensation stream is not tied to or includes a wholesale revenue stream. In the New York programs mentioned above, there is a "Reservation Payment" rate based off avoided distribution costs, so there is no duplication between the availability payment and a wholesale revenue stream. In the case of a net metering tariff, there could be compensation for energy, but not capacity. Therefore, if the resource participating in net metering wished to participate in the wholesale capacity market, that would be an entirely different service than what is being compensated under net metering. We recognize that if the DER is participating in net metering that all of the relevant Minimum Offer Price Rules would apply, but the customer should not be prohibited from the wholesale market.
- The retail-level program, tariff, or rate structure has a different dispatch trigger than the wholesale program. In the example of the two New York programs, one program

[25] Consolidated Edison Company of New York, Inc., Rider T (Commercial Demand Response Programs), https://www.coned.com/-/media/files/coned/documents/save-energy-money/rebates-incentives-tax-credits/smart-usage-rewards/rider-t.pdf.

is triggered when there is a contingency on the local distribution system, and the other program is triggered when load on the local network reaches 92% of the forecasted network peak. A service cannot be considered the same if there are two different sets of performance requirements. The DER has to respond to two different dispatch signals from two different authorities, likely at different times, to earn each payment, and so the same kWh is not earning two revenue streams. If the DER only participated in wholesale, then the retail side could not count on the DER during a distribution reliability event and would incur additional expenses. FERC has ruled there is incremental value to that service.

- The dual participation in retail and wholesale provides an incremental value to the distribution level and wholesale level. This can be incremental cost savings, reliability, or resilience value. If the retail tariff requires the DER to go beyond what it is required of it in the wholesale market, it should provide additional value. For the Pennsylvania programs, the demand response must respond at 96% of system peak for four hours, regardless if there is a PJM dispatch.

Given this incremental value, dual participation harmonizes wholesale and retail markets, increases reliability, and facilitates coordination and visibility. It would damage reliability and market competition to require the bulk system to ignore certain resources that the distribution utilities have access to in their retail programs, and vice versa.

AEMA Recommendation

In this section, we will provide a recommendation for how FERC can ensure that RTOs/ISOs do not provide compensation for the same service already receiving compensation at the retail level. Before detailing that recommendation, we urge FERC in its final Oder to clarify that:

- Provided it is not the "same service", the same DER is eligible to participate in all wholesale markets, even if it participates in a retail tariff or program;[26]
- Any RTO/ISO tariff that prohibits dual participation, either explicitly or through rules that make dual participation impractical is unjust and unreasonable; and
- The "same service" is limited to instances where a retail tariff or program compensates a DER for a wholesale service, and at the same time, the same exact kW or kWh from that DER is receiving compensation from the wholesale market for the same wholesale service.

As stated above, there are solutions FERC can direct RTO/ISOs to implement to ensure that RTOs/ISOs do not provide compensation for the same service already receiving compensation at the retail level. Upon wholesale registration, RTOs/ISOs could require the party enrolling the DER to identify whether the DER is receiving a wholesale revenue stream through a retail program or tariff. If yes, the RTO/ISO would prompt the enrolling party to list those specific wholesale revenue streams, and the portion of the DER receiving those revenues. The DER would then have the ability to submit documentation proving there was no risk of the same service receiving double compensation. In the New York example, they would submit proof of the Con Edison tariff stating that resources were not eligible for energy payments during overlapping dispatches. If the DER did not submit adequate proof, then the DER would not receive compensation for the specific wholesale revenue stream that the retail tariff is already

[26] Unless the retail program explicitly prohibits direct participation in wholesale markets. See above comments on Panel 2.

paying. The DER would still be eligible to provide other wholesale services, and if only a portion of the DER was providing retail services, the other portion could still provide wholesale.

This solution should be straightforward to implement, prevent compensating twice for the same service, and be easy for the RTO/ISO to verify.

V. Panel 6: Coordination of DER Aggregations Participating in RTO/ISO Markets

AEMA Position

AEMA recognizes the need to facilitate coordination between distribution utilities and RTOs/ISOs. It is important for distribution utilities to be aware of any wholesale DER participation in their territory and understand how they intend to operate in wholesale markets. However, FERC can accomplish that without creating a review process for DER wholesale registrations that leads to unnecessary barriers to entry or that enables discriminatory treatment. AEMA therefore supports a limited "exception only" model, where distribution utilities are never required to approve DER participation in FERC-jurisdictional markets, but may review and raise objections.

The DR registration process in PJM incorporates this approach and could serve as a model for wholesale DER registrations. Its non-discretionary registration procedure has enabled thousands of aggregated DR customers to access wholesale markets without jeopardizing distribution-system reliability. The essential characteristics of the process are:

a. Distribution utilities ("EDCs") are given the opportunity to review DR registrations;
b. EDCs can only deny registrations if the information provided by DR Providers is inaccurate, incorrect, or the DR resource is ineligible to participate in the market;

c. EDCs have ten business days to complete the review and verify information, after which the registration is automatically accepted by PJM; and

d. If a registration is denied by its EDC, the DR Provider may correct the inaccurate information and resubmit the registration to the EDC.[27]

Giving distribution utilities discretionary authority to approve DERs could create unnecessary barriers and usurp FERC's clear jurisdiction over the conditions for wholesale market eligibility. Instead, RERRAs and distribution utilities can exercise their proper authority *prior* to a DER's registration in a RTO/ISO by defining non-discriminatory interconnection procedures that ensure the distribution grid can accommodate DERs. The interconnection process should determine whether a resource can safely deliver kWh to the grid. The local distribution grid does not distinguish between kWh that are sold for retail and wholesale purposes. No resource interconnects with the intent to sit idle, so participating in the wholesale market should not introduce an additional level of reliability risk not contemplated in interconnection (with the potential exception of frequency regulation). Of course, if a wholesale dispatch could exacerbate a distribution-level constraint, then coordination frameworks need to be in place for the distribution utility to notify the RTO/ISO and potentially change the dispatch. However, that can be done without a complicated and lengthy review process that delays DER registrations in the wholesale market.

AEMA Recommendation

FERC should recognize the clear distinction between the distribution interconnection process and the wholesale market registration process. RERRAs have authority over criteria for a non-discriminatory distribution interconnection process. FERC has authority over criteria for

[27] PJM Market Manual 11, Energy & Ancillary Services Market Operations, Section 10.2.4.

wholesale market registration and participation. These processes can work together to coordinate the operation of DER aggregations.

For the wholesale market registration process, FERC should put in place the following parameters to ensure sufficient RTO/ISO coordination with distribution utilities while protecting DER access to markets:

1. RTO/ISOs should provide distribution utilities 10 days to complete a non-discretionary review of DER registrations. This review should be limited to ensuring that DERs a) have the necessary interconnection agreements in place (in cases where the customer seeks to net supply); b) are not taking service under a retail tariff or similar service that disallows the wholesale participation; and c) have provided accurate administrative information (e.g., utility account numbers).
2. If a distribution utility does not object to or deny a registration within 10 days, the RTO/ISO can automatically approve the DER registration. After the ten days, the distribution utility would still have the opportunity to notify the RTO/ISO if the DER did not have the necessary interconnection agreements or participating in a retail tariff that did not allow wholesale participation.

This coordination can occur under RTO/ISO tariffs (and business practice manuals, as appropriate), with no further agreements needed. Just as for demand response, tariffs and manuals can set the requirements for DER providers, the RTO/ISO procedures for review, information sent to distribution utilities, and how the RTO/ISO acts upon distribution utility responses. Such an approach has the advantage of placing no requirements on distribution utilities, which may not be FERC jurisdictional. Furthermore, this approach eliminates any need for multi-party agreements between RTO/ISOs, distribution utilities, and DER aggregators that could raise jurisdictional questions and complicate projects.

VI. Panel 7: Ongoing Operational Coordination

AEMA Position

Safe and predictable DER operational coordination is essential to DER participation in wholesale markets; the key word being coordination, not simply a sharing of information. FERC should provide the minimum criteria necessary for RTOs/ISOs to establish communications protocols and timelines for the coordination of information between RTOs/ISOs, Distribution System Operators ("DSOs") and DERs, both leading up to and in real time. FERC should provide RTOs/ISOs reasonable flexibility, however FERC's direction should be specific enough to ensure the RTOs/ISOs are clear on the minimum expectations and obligations of their coordination with DSOs. The following are AEMA's thoughts on the various matters that FERC should consider in developing reasonable and effective criteria.

A. Dispatch and Signal Clarity, Protocols and Technology

From a revenue perspective, dispatch protocols drive the behavior of a DER in the market and will determine the potential upside for an aggregator to develop projects. In addition, from a cost perspective, dispatch protocols can also play a key role in project economics by adding costs to a project in the form of potentially overly burdensome compliance requirements and other issues that complicate or prevent projects from coming to fruition. Communications protocols must not present burdensome new technology investments such as fiber optic cable on top of the energy infrastructure. Instead, RTOs/ISOs should permit existing utility meters and secure, cost-effective telecommunications equipment.

To identify instances where wholesale dispatch of a DER would exacerbate a DSO local reliability issue, we support a mechanism with clear coordination and communication requirements when dispatching wholesale DER in order to identify if it could create or exacerbate a physical reliability issue for the applicable DSO, and if so how to adjust the wholesale dispatch accordingly. Rather than a hand off of information in a vacuum, there should be a dynamic feedback loop to allow for adjustments in real time to wholesale dispatches based upon reliability criteria triggered on the DSO. To be clear, this should be for physical reasons only. The dispatch of resources by a RTO/ISO must meet the needs of the most economic fashion of the resources available in the dispatch stack, this should not be disrupted. However an economic driver on the DSO end should not be allowed to remove that DER from the wholesale operator's dispatch stack.

It is expected that rights and obligations impacting physical ability of a DER to operate on a DSO will be generally addressed in DER interconnection agreements, as such that information should inform the criteria built into the DERs dispatch availability. However, we recognize that a DER could seek to participate in the wholesale market well after it has completed an interconnection requirement, and therefore they should not be the only source of information as to the physical capabilities and rights of a DSO connecting to a RTO/ISO from a DSO. For instance, at the Tech Conference speaker Marty Ryan of NRG Energy compared this proposed process to how generators today receive a single signal from the RTO/ISO that has already taken into account Transmission limits.[28] The DER should not receive a dispatch signal from a RTO/ISO only to be told by the DSO not to follow the dispatch signal; this would lead to unnecessary confusion and threaten reliability.

[28] Technical Conference Transcript, pg. 442

At the Technical Conference on April 11, we heard from panelists that there are already a range of communications technologies and protocols that are being used to dispatch DERs, and often physically located on the distributed system. AEMA encourages FERC to adopt standards that allow a range of technologies and protocols to be in place. The needs can vary among region, distribution operator, RTO/ISO and customer. Overly prescriptive rules on specific technologies and protocols could add significant cost to customers and make projects uneconomic. Several commenters articulated that communications tools are in place today, which can cost-effectively communicate among DERs and bring information into the Aggregator to be shared with the RTO/ISO and distribution operator. Information is gathered from individual resources over inexpensive mobile communications, brought to a central hub and then transferred to dispatch via Inter-Control Center Protocol ("ICCP") or Remote Terminal Unit ("RTU"). The benefit of this approach is that communications are secure, but also affordable enough to implement on a commercial scale.

Some commenters contend that communication among RTO/ISO, DSO and DER currently is by way of phone and email. In some cases this is true, although it runs the gamut and it depends more so on the service, than on the DER technology. For instance, DERs that are serving in the PJM frequency regulation market require different metering and telemetry than DERs that are only providing emergency demand response.

B. Recognizing Variation in DSOs

While the Commission is doing the right thing in requesting input from distribution system operators, the Commission should refrain from imposing metering and telemetry requirements beyond those necessary for delivery and monitoring of wholesale commitments. DSO telemetry requirements and monitoring of individual DERs occurs at a more granular level than RTOs/ISOs, are driven by the needs of that DSO system, and DERs looking to participate in the DSO programs must adhere to them. Conversely, the telemetry requirements to participate in a wholesale program should be driven by that of the RTO's/ISO's system and the programs it runs. A DER that seeks participation only in the wholesale market should only be required by the RTO/ISO to fulfill its metering requirements.

Future DSO needs are uncertain and will vary considerably, as such the Commission should maintain a light hand when considering data and telemetry requirements. As AEMA stated in its initial comments in February 13, 2017,[29] wholesale telemetry requirements should be no more granular than five minutes for energy or thirty-minute reserves and one minute for ten-minute reserves, as is the case in ISO-NE. We stand by those comments, and would urge the Commission not to require RTOs/ISOs to have more granular telemetry when there is no proven need.

C. Confidentiality

It may be that DERs providing wholesale services have monitoring and telemetry that is more robust than the DSO requires. Information from this capability may have value to the DSO. RTOs/ISOs should be permitted to share this data freely as long as both entities maintain confidentiality. In addition, special confidentiality requirements must be in place to protect the competitive market considering many DSOs will have affiliated entities that provide DER aggregation services. DSOs must be prohibited from sharing competitive data with their own affiliated DER aggregator.

D. Operation of a Single DER in both RTO/ISO and DSO Markets

[29] AEMA filing, p. 17.

Operational rules can maximize the benefits of a single DER across markets. One of the other themes we heard at the technical conference was that there are many cases in which a DER operating for RTO/ISO markets could be used to improve distribution operations and reliability. When this question came up on Panel 7, every speaker agreed that a DER operating for RTO/ISO markets could be used to improve distribution operations and reliability. Of course, more analysis is needed on a local basis. However, the first stage is for FERC to complete this rulemaking.

For instance, Doug Parker of SoCal Edison provided the view from a distribution system operator that this is an empirical question that should be evaluated on a local basis.[30] In many cases dispatch of a distribution level asset may provide a benefit to the distribution system and bulk power system on a one to one basis. At other times it may be beneficial but at a different ratio. And in cases that it is not beneficial, that would have to be taken into consideration by the DSO and RTO/ISO. In sum, the panelists were optimistic that wholesale DERs could provide benefits to the distribution level system.

As described above, AEMA believes that there is no inherent barrier to DERs providing both RTO/ISO market support and DSO support. Aggregations for RTO/ISO and DSO markets will likely be comprised of different resources given that DSO markets will be focused on more localized areas. Therefore, with aggregation, a DSO dispatch need not compromise RTO/ISO level performance, and vice versa. Moreover, properly designed market rules and transparency regarding dispatch triggers should lead to aggregators building their resources in a way that ensures they are available when needed for reliability reasons. Rules that preclude any possibility of conflict between RTO/ISO and DSO obligations would preclude participation by large numbers of viable resources and perhaps significant quantities of supply.

[30] Technical Conference Transcript, pg. 453

Ultimately, the two systems should be considered largely separate for the purposes of FERC regulation. For one thing, the systems can load differently over the course of the day and it is very likely that a unique DER will provide RTO/ISO and DSO services at different times of the day. As we have stated previously in our comments, the indicator of participation in wholesale or retail markets should be the origin of the dispatch signal.

AEMA Recommendations

AEMA's high level recommendations are: (1) create clear coordination requirements of DER dispatches in RTO/ISO rules in order to identify if a wholesale dispatch of a DER will exacerbate a physical reliability issue for the applicable DSO, and if so how to adjust the wholesale dispatch accordingly; (2) establish cost-effective data sharing protocols that will maintain a safe and reliable power system; (3) impose requirements only on wholesale markets, but that will provide the structure for effective coordination with DSOs; (4) maintain data confidentiality; (5) allow a single DER's participation in both RTO/ISO and DSO markets ; and (6) do not impose unnecessary and costly telemetry requirements such as six-second telemetry for non-regulation energy and ancillary services.

VII. Conclusion

AEMA respectfully thanks the Commission for consideration of AEMA's comments in this proceeding. To reiterate, we believe that the Commission should make clear that the purpose of the Order is to create a framework that affords all DERs the right to non-discriminatory, open access to wholesale market revenue opportunities, and that integrates DERs in an efficient and reliable manner. In addition, FERC should include in its Order the required elements for just and reasonable participation models with which RTOs/ISOs must comply to encourage DER resources. We are confident that an Order could be issued that ensures DERs can participate in all wholesale markets while maintaining jurisdictional boundaries, giving consumers choice, increasing resilience, and ensuring safe and reliable grid operations.

Respectfully Submitted,

Katherine Hamilton
Executive Director, Advanced Energy Management Alliance
www.aem-alliance.org
1200 18th Street, NW, Suite 700
Washington, DC 20036

June 25, 2018