UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators	Docket No. RM18-9-008

COMMENTS OF ADVANCED ENERGY MANAGEMENT ALLIANCE IN SUPPORT OF PETITION FOR TECHNICAL CONFERENCE

The Advanced Energy Management Alliance ("AEMA")[1] respectfully submits these comments supporting the request that the Federal Energy Regulatory Commission ("FERC" or "the Commission") convene a technical conference to discuss collectively the key issues arising from the Regional Transmission Organizations' ("RTOs") and Independent System Operators' ("ISOs") Order No. 2222 compliance proposals.[2]

I. Background

AEMA has been engaging in issues regarding demand response ("DR") since 2014 when the U.S. Court of Appeals first vacated Order 745,[3] then through the Supreme Court

[1] 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 demand response ("DR") providers, as well as some of the nation's largest demand response and distributed energy resources ("DER"). AEMA advocates for policies that empower and compensate customers appropriately--to contribute energy or energy-related services or to manage their energy usage--in a manner which contributes to a more efficient, cost-effective, resilient, reliable, and environmentally sustainable grid. This filing represents the collective consensus of AEMA as an organization, although it does not necessarily represent the individual positions of the full diversity of AEMA member companies.

[2] AMEA uses the term ISO in this filing document for both ISOs and RTOs as compliance with Order 2222 focuses on operation of energy markets not operation of the transmission system. Therefore, regardless of the name used by the corporation to refer to itself, it is acting as an ISO in this compliance filing.

[3] See AEMA statement here: https://aem-alliance.org/aema-issues-comment-circuit-court-decision-order-745-ferc-jurisdiction/

upholding Order 745,[4] and finally, throughout the effort to include distributed energy resources ("DERs") in the wholesale market which was foundational in Order 2222. AEMA was engaged in this rulemaking process since FERC opened the process for distributed energy as separate from energy storage, filing Post-Technical Conference comments[5] in June 2018 on DER participation and Supplemental Comments[6] in March 2019 noting recently successful distributed energy resource projects and programs. Following the issuance of Order 2222, AEMA, its consultants, and its member organizations have activity engaged in the RTO/ISO stakeholder Order 2222 meetings for the past year and reviewed the California Independent System Operator, Inc. ("CAISO") and New York Independent System Operator ("NYISO") filings.

II. Comments

AEMA supports the request for a Technical Conference. AEMA agrees that every RTO/ISO has proposed productive market reforms, yet each market also retains or proposes rules that would constitute significant barriers to DER aggregation and participation in markets. AEMA has also noticed significant differences across ISOs that could benefit from concurrent exploration in the format of a technical conference. The following major themes have emerged from the Midcontinent Independent System Operator, Inc. ("MISO"), PJM Interconnection, LLC ("PJM"), Southwest Power Pool, Inc. ("SPP"), and ISO New England, Inc. ("ISO-NE") stakeholder process as well as the CAISO and NYISO proposed tariff changes, which AEMA believes would benefit from broader discussion.

[4] See AEMA statement here: https://aem-alliance.org/advanced-energy-management-alliance-reacts-with-enthusiasm-to-supreme-court-decision-on-order-745/
[5] See AEMA Post Technical Conference comments here: https://aem-alliance.org/aema-files-post-technical-conference-comments-on-distributed-energy-resources/
[6] See AEMA Supplemental comments here: https://aem-alliance.org/aema-files-supplemental-comments-in-der-rulemaking/

1. Definition of a Distributed Energy Resource

AEMA has noticed inconsistent size limitations on distributed energy resources. For example, PJM proposes a 5 MW size limit on an individual DER, while NYISO places a 20 MW limit, and MISO does not include a size limit. Given the importance of this limitation, it would be important to explore the factors that prompts one ISO to suggest a particular size limit while another does not. As the Commission is aware, many individual DR assets exceed the 5 MW limit, as it is not uncommon to find industrial applications with the ability to curtail loads that are an order of magnitude larger. Under PJM's proposed tariff, these sites would not be able to add any ability to inject energy, because any injection at the retail delivery meter would require transitioning to the DER participation model, where the individual DER are limited to 5 MW. AEMA suggests a technical conference would offer the opportunity to understand the underlying reasons for size limitations and differences from one ISO to another.

2. Development of Participation Models for DER Aggregations and the Exclusion of Changes to Demand Response

AEMA has noticed significant differences in the development of participation models across ISOs. For example, SPP has chosen to not develop a new participation model, while ISO-NE has provided seven participation models. CAISO, ISO-NE and PJM have specifically excluded any changes to their demand response participation models, treating those changes as out of Order 2222's scope. NYISO intends to retire their economic DR programs upon implementation of its DER model, however, this change was approved by the FERC prior to Order 2222 and was not discussed as part of its compliance filing. While FERC certainly provided the ISOs with freedom in how to comply with Order 2222, placing narrow boxes around tariff changes limits the ISO from looking holistically at barriers to DER Aggregations. AEMA has identified the following concerns that should be investigated in a Technical Conference:

A. Inclusion of Frequently Dispatched DER and Impact of Existing DR Models:

By refusing to consider changes to DR participation models to comply with Order 2222, those ISOs are leaving barriers in place for frequently dispatched technologies such as fleets of electric vehicles ("EVs"). For frequently dispatched DERs, current DR baselines are subject to baseline erosion. This makes this participation model ineffective for use cases such as EVs, behind the meter ("BTM") storage, residential smart thermostats and smart water heaters. AEMA argues a Technical Conference would help inform whether full compliance with Order 2222 requires the ISOs to consider the operational characteristics of frequently dispatched DER in their DR models.

B. Compensation of DERs that Both Curtail and Inject:

MISO, PJM, CAISO and NYISO have all created new participation models for DER Aggregations. Each ISO is unique in how it compensates DER Aggregations capable of both reduction of load and the injection of energy. Specifically, compensation at a retail delivery meter where there is both the ability to curtail load and inject electricity and seamlessly transition from either curtailing or injecting from one dispatch interval to another.

SPP's approach, as of January 2022, is to define a "Resource,"[7] which will go into effect after Order 2222 is implemented, and only a "Resource" can receive credit for both curtailment

[7] Definitions section, "Resource: An asset that injects energy into the transmission grid or reduces the withdrawal of energy from the transmission grid that has been registered in the market." RR 468 Recommendation Report, Southwest Power Pool Markets and Operations Policy Committee (MOPC) January 10, 2022 Approved https://www.spp.org/spp-documents-filings/?id=21069

and injection. A Dispatchable Demand Response Resource ("DDR") cannot, but after Order 2222 is implemented, will be able to by re-registering as a Resource instead of a DDR.

Under PJM's DER participation model, sites cannot earn capacity revenues for injection unless it is in excess of their maximum loads (defined as their maximum load over prior 36 months)[8] because PJM claims they procure capacity to meet maximum loads. PJM's claim is puzzling as capacity is not procured based on the maximum load of each individual customer. If that were the case, PJM's capacity requirement would be determined by the non-coincident peak of each customer, which is not the case. PJM may have to procure energy to meet a customer's maximum load, but PJM should not conflate that with capacity, which is procured to meet the previous year's Peak Load Contribution.

In short, compensation of curtailment and injection in one participation model appears to be one of the more complex use cases identified during the stakeholder processes. AEMA suggests FERC consider a panel at a Technical Conference dedicated to this use case and compare how each ISO proposes to compensate curtailment and injection as well as the services DER aggregations are allowed to provide.

C. Submetering of DER:

ISO-NE's Order 2222 compliance proposal includes seven participation models.[9] While this appears to provide a wide array of choice, none of the models resolve underlying metering challenges, a core underlying issue that will limit participation in any of the models proposed by the ISO. ISO-NE refused to consider industry-offered amendments approved in other ISOs,

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[8] PJM DIRS, *Oder 2222 Use Case Update: Clarifications and Capacity, Energy, AS Walkthrough*, January 5, 2022.
[9] ISO New England, *Revisions to ISO New England Inc. Transmission, Markets and Services Tariff to Allow for the Participation of Distributed Energy Resource Aggregations in New England Markets*; Docket No. ER22-983-000, February 2, 2022. Pages 11 & 12.

specifically NYISO, to allow participation of submetered resources.[10] AEMA believes a Technical Conference may help provide guidance on the role of submetering in DER Aggregation participation models and provide a forum for a comparative discussion of the ISOs submetering proposals, as discussed further in Section 5 of these comments.

3. Locational Requirements

Regarding the aggregation scope, the Commission requires ISOs to revise their 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."[11] A technical conference would allow all parties to compare and contrast how the ISOs are approaching DER aggregations. Some ISOs are proposing limiting aggregations to the point of interconnection, while others are allowing very broad geographies in which aggregations may form.

At PJM, MISO, and SPP, multi-nodal aggregations are prohibited for energy. SPP's proposal[12] essentially precludes any aggregation by limiting aggregations to the point of interconnection. PJM has not substantively addressed how multi-nodal aggregation could be accomplished for energy market participation for aggregations that include injection. Instead, they have focused on the obstacles of "inefficient dispatch" and propose limiting energy aggregations to a single pricing node ("PNode").

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[10] Advanced Energy Economy Memo to ISO NE, *Response to ISO New England's November 4 Memo Regarding Advanced Energy Economy's Amendments to ISO New England's Order No. 2222 Compliance Proposal*, December 3, 2021. Located on NEPOOL Markets Committee website under a03a_mc_2021_12_07_09_aee_memo.

[11] Order 2222, ¶ 188.

[12] "A DER Aggregation registration must be consistent with the nodal aggregations applicable to other Resources in accordance with Section 2.2(3) of this Attachment AE." RR 468 Recommendation Report, Southwest Power Pool Markets and Operations Policy Committee (MOPC) January 10, 2022. Approved https://www.spp.org/spp-documents-filings/?id=21069

At NYISO, the Transmission Node construct will define points at which aggregations may form. NYISO states that it has identified 115 Transmission Nodes in coordination with the Transmission Owners.[13] As this large number of nodes suggests, the Transmission Nodes will be much more granular than the Load Zone levels utilized today for Special Case Resource ("SCR") and Demand-Side Ancillary Service Program ("DSASP") participation.

At ISO-NE, aggregations need not be limited to a single node, and all component DERs must be within a single Demand Response Resource aggregation zone and within a single utility meter domain. Any single DER greater than or equal to 5 MW may not aggregate with others but can participate as a single asset, single node aggregation. Any DER or group of DERs with a combined injection capability greater than or equal to 5 MW at one node may not aggregate with DERs or other nodes.

CAISO allows aggregations across a Sub-Load Aggregation Point ("S-LAP")[14] of which there are approximately 24. Therefore, CAISO's aggregation scope is significantly larger than any other RTOs/ISO's and reduces the number of stranded market participants.

AMEA argues a Technical Conference will help elucidate the assumptions and physical constraints that are fundamental to the differences in aggregation scope.

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[13] *See*, Meeting Materials for the December 14, 2021, New York Independent System Operator, Inc., Market Issues Working Group, Item 5, *available at*, https://www.nyiso.com/documents/20142/26734185/Ongoing%20TSO-DSO%20Coordination%20Update.pdf/

[14] California Independent System Operator Corporation, *Tariff Amendment to Comply with Order No 2222*, July 19, 2021, page 17.

4. Double Counting and Net Metering

FERC disallows DER Aggregations to be paid twice for the same service, commonly referred to as double counting. The most complex double counting use case that could benefit from further investigation at a Technical Conference is net-energy metering ("NEM").

For example, PJM argues double counting bars the ability of NEM DER from participating as capacity. In PJM, capacity market participants must offer energy, which in the case of a NEM resource cannot be compensated in the wholesale market since it is already compensated via retail rate. AEMA argues that PJM hasn't considered options for NEM DER, such as not compensating these assets for energy or sub-metering solutions.

NYISO's DER model explicitly prohibits NEM DER[15] and will prohibit aggregations to provide only those services that all resources within it are qualified to provide. Yet, NYISO's model also allows DERs to bid below the Net Benefits Threshold and be scheduled for energy but not receive energy compensation when dispatched. In other words, it is possible for DERs to have an energy offer and not receive energy compensation while still being able to comply with the NYISO's dispatch instructions.

MISO's concern regarding the participation of DER[16] as capacity is focused on determining a mechanism for deliverability credit in the Capacity Market. At present, they seem to be concerned only about deliverability of "net injections," which would have to obtain firm

[15] On pages 38-39 of the filing letter (in the Interconnection section), Attachment III (in the first paragraph of section 32.1.1.1 at p. 105 of the filing letter), definition of Small Generating Facility (at p. 125 of the PDF), New York Independent System Operator, Inc., July 19, 2021.
https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20210719-5126&optimized=false

[16] A DEAR can demonstrate deliverability for the capacity market by going through the EDC review process and procuring E-NRIS or firm Transmission Service, Meeting Materials for the January 13, 2022, Midcontinent Independent System Operator, Inc., Distributed Energy Resource Task Force (Item No. 4) at Page 72, *available at* ,
https://cdn.misoenergy.org/20220113%20DERTF%20Item%2004%20Compliance%20Framework%20-%20Iteration%207617870.pdf

transmission service in order to qualify for the Planning Auction. This is a very nuanced element for MISO but is similar to treatment of other "non-network service" resources.

5. Metering & Submetering

The Commission did not mandate specific metering requirements because it did not want to impose unnecessary costs on the RTOs/ISOs, DER Aggregators, and the individual DERs.[17] While there are some commonalities in how RTOs/ISOs approach compliance with Order 2222 on metering and submetering aspects, at least one market proposes restrictions and unreasonable costs.

Sub-metering is effectively prohibited at ISO-NE because the distribution utilities do not support it and ISO-NE does not allow for third-party metering. As a result, all DERA models require participation at the retail delivery point, which translates into separate resources at a site needing separate retail billing meters. These impose additional costs on DER aggregations, and effectively precludes any residential customer.

The prohibition of submetering forces BTM DERs to either (a) participate as demand response (which may limit the services they can provide and/or which they may be unable to do, especially given that lack of flexibility with respect to calculation of baselines in the existing DRR model and the newly proposed DRDERA (Demand Response DER Aggregation) model. This prevents important categories of DERs that could otherwise offer their services as demand response from doing so and strands assets that otherwise could provide valuable grid services today); or (b) participate at the Retail Delivery Point (RDP), which is unworkable for many

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[17] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 2222, ¶ 265, 172 FERC ¶ 61,247 (2020), *order on reh'g*, Order No. 2222-A, 174 FERC ¶ 61,197 (2021), *order on reh'g*, Order No. 2222-B, 175 FERC ¶ 61,227 (2021).

DERs because it obfuscates actual DER performance and makes the facility, not the DER aggregation, the asset. Even if this were workable for certain (uncommon) business models, in many cases this is not possible due to lack of meters suitable for wholesale market participation at the RDP, that may only be installed by distribution utilities, for most residential and small commercial facilities in ISO-NE.

6. Settlement

MISO's current recommendation for its Order 2222 compliance plan[18] leverages the existing Attachment TT utilized for MISO's demand response programs, which allows data for settlement to be submitted up to 103 days following the operating day for dispatched energy, and up to five days for ancillary services.[19] At MISO, settlement data is submitted during existing market registration cycles. Metering submission is aggregated at the Distributed Energy Aggregated Resource ("DEAR") Sub-Groups of homogenous or like DERs. For example, all DR from a residential water heater or thermostat program utilizing the same measurement and verification ("M&V") methodology is aggregated to a Sub-Group. MISO aggregates Sub-Group for settlements and performance evaluation.

In stark contrast, NYISO's filing requires all participating DERs to have revenue grade metering, and settlement data must be submitted by 12 p.m. of the following operating day with separate groupings for load curtailment, injections, and withdrawals (to comply with FERC Order 745). The requirement to submit meter data by the following operating day is a barrier that

[18] *See*, Meeting Materials for the November 29, 2021, Midcontinent Independent System Operator, Inc., Distributed Energy Resource Task Force (Item No. 3) at Page 79, *available at*, https://www.misoenergy.org/events/distributed-energy-resources-task-force-dertf---november-29-2021/

[19] *See*, Midcontinent System Operator, Inc. Tariff Attachment TT, Section 4.

will prevent Aggregators from utilizing Member System metering and data, resulting in duplicate metering equipment and associated costs.

PJM has a similar requirement to NYISO that settlement data must be submitted the following day using existing settlement tools. PJM has not yet explained if or how the process would work with estimated data if the utility meter data were used for settlements.

At SPP, settlement data would be submitted the same as any other resource participating in the market. The metering submission is at the aggregation level with an understanding that sub-metering is needed for any audits. To ensure compliance with FERC Order 745 on DR compensation, SPP requires any DR load reduction to be submitted separately.

AEMA argues all stakeholders are best served by discussing the range of metering solutions at a technical conference.

7. Telemetry

The Commission did not mandate specific telemetry requirements, but the current compliance discussions at ISOs impose an additional burden for aggregators. NYISO, for example, requires six-second telemetry at the aggregation level, regardless of the products provided by the aggregation, with separate feeds for injection/withdrawal, curtailment, and total amount via ICCP or SD-WAN (the latter is an option only if the DER Aggregator represents less than 100 MW of DER aggregations) to both the Transmission Owner ("TO") and the NYISO. While the telemetry requirement is imposed at the aggregation level, NYISO effectively requires all individual facilities greater than 100 kW to be directly telemetered to the DER Aggregator. An alternate telemetry method may be used for DERs providing less than 100kW but must be calculated based upon five-minute data (which likely will require aggregators to install metering equipment, adding to costs).

At ISO-NE, five-minute telemetry must be provided at the aggregation level for dispatchable DERAs, and four-second telemetry is required for regulation services. At PJM, a potentially acceptable resolution with "calculated" values is permitted for DERs.

Like metering, SPP requires real time telemetry through ICCP for all DERs, even though DERs are not large generating assets. DR must be submitted separately and in addition to other responses.

MISO also requires real time telemetry, based on the products provided through ICCP.[20] Even though its task force is examining some relaxed intervals, only slight changes are discussed (e.g., 6 second and 10 second intervals).

A Technical Conference would allow all parties to explore the need for unique telemetry requirements by ISO.

8. The Role of the Distribution Utilities in Registration and Dispatch

The Commission recognized that the operational coordination among ISOs, aggregators and distribution utilities is crucial.[21] The fact that many implementation details will be left to manuals however hinders coordination.

At NYISO, the details regarding operational coordination have not yet been discussed with stakeholders, and NYISO intends to work through these details in 2022 during the Manual

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[20] Telemetry is required based on products provided, Meeting Materials for the January 13, 2022, Midcontinent Independent System Operator, Inc., Distributed Energy Resource Task Force (Item No. 4) at Page 80, *available at* , https://cdn.misoenergy.org/20220113%20DERTF%20Item%2004%20Compliance%20Framework%20-%20Iteration%207617870.pdf
And ICCP via Private WAN is required even though small DERs that do not provide regulation are exempt, Meeting Materials for the May 18, 2021, Midcontinent Independent System Operator, Inc., DER Distribution Company Workshop (Item No. 3c) at https://cdn.misoenergy.org/20210518%20DER%20DC%20Item%2003c%20Telemetry%20Considerations551717.pdf

[21] Order 2222, ¶ 293 (directing that each RTOs'/ISOs' "proposed distribution utility review process is transparent, provides specific review criteria that the distribution utilities should use, and provides adequate and reasonable time for distribution utility review.")

development process. Some information regarding data to be shared between NYISO, utilities, and aggregators was included in NYISO's response to FERC, such as system outage, DER outage, DER schedules, utility overrides. However, companies interested in becoming DER Aggregators have not been involved in developing these coordination methods and requirements. Distribution utilities are developing a separate set of registration requirements for DER Aggregators seeking to represent DERs in the NYISO market, however little information is available as of yet available to know if, or how, onerous these requirements may be. As noted in Section 7 above, the requirement for DER Aggregators to provide telemetry data to the TO is unique to the NYISO, and requirements to integrate with TOs has not yet been shared.

Details are still being refined at PJM. PJM has proposed a "dispatch agent" function to provide this coordination. Conceptually this function can be provided by the aggregator, the electric distribution company ("EDC"), or a third party. However, PJM's proposed tariff changes allow room for the Distribution Utility ("DU") manuals to define which parties can register as an Aggregator, creating potential barriers to customer participation.

At both SPP and MISO, the operational coordination details are deferential to the DU. At SPP, the proposed tariff indicates that DERA must meet the DU requirements. SPP proposes language that is somewhat vague related to Operational Coordination between the Distribution Utility, the DERA, and the Transmission Provider. In theory, a Distribution Utility could repeatedly override the dispatch of DER Aggregation, which pushes penalties to the DERA for non-performance. It is unclear that there is a mechanism to resolve situations where a DU is abusing this situation. SPP will supply market ICCP dispatch signals directly to the DU as requested by the DU.

At SPP, the entire set of attestations would allow a DU or load serving entity ("LSE") to simply not respond to the DERA and the registration could not proceed. AEMA does not believe there is anything like this for Transmission level registrations, so this would potentially be a barrier above and beyond other resources.

At MISO, the details of operational coordination have been mapped between the DER Aggregation, TO, and Local Balancing Authority ("LBA"), with the specifics left to the EDC.

If ISOs leave operational coordination details to the manuals after the compliance filing, the DU review process will not be transparent because the aggregators do not know the specific DU review criteria in some markets. AEMA argues a technical conference would provide some much-needed transparency and guidance on this issue. In addition, a technical conference can discuss appropriate and consistent timelines for DERA registrations and how to minimize administrative burden.

All rates, terms, and conditions of service in FERC-jurisdictional programs such as these must be included in FERC-approved tariffs and agreements. A technical conference may help to clarify why it is that key conditions of service should be relegated to unreviewed and unapproved manuals or other documents and delegated to non-jurisdictional entities.

9. Role of Relevant Electric Retail Regulatory Authorities

As we have mentioned in the AEMA comments filed in response to NYISO's reply to FERC's deficiency letter,[22] the Relevant Electric Retail Regulatory Authority ("RERRA") is the appropriate jurisdictional entity to decide issues such as the potential double counting of identical retail and wholesale services. NYISO's approach to identify retail products and services

[22] AEMA Comments on NYISO Letter to FERC, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20211210-5066&optimized=false

that are incompatible with wholesale market products is both unnecessary and inconsistent with the necessary jurisdictional boundaries since it fails to provide any role for the RERRA or the aggregator. Moreover, as noted in AEMA's Protest, this 'matrix development' is unnecessary given the numerous mechanisms at the NYISO and state-level that already exist and are in place to avoid double counting.[23]

SPP has proposed an overly complex registration process that requires attestation of multiple items including "written documentation from the relevant electric retail regulatory authority indicating that affirmative action has been taken that allows participation of the relevant DERs"[24] regarding participation. Additionally, the DERA must submit an attestation that the "if applicable, the relevant electric retail regulatory authority affirmed that it does not prohibit the participation of load reduction demand response in the Energy and Operating Reserve Markets of a Distribution Utility that distributed more than 4 million Megawatt hours ("MWh") in the previous fiscal year."[25]

A Technical Conference could help define boundaries for the appropriate role of the RERRA.

10. Review of Aggregations

FERC requires a review of DER Aggregation registrations to be less than 60 days even though CAISO distribution utilities are already meeting a 30-day deadline. Some EDCs have

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[23] AEMA Protest at pages 4-7. https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20210823-5065&optimized=false

[24] Registration section 2.2, 20 d (2) and (4), RR 468 Recommendation Report, Southwest Power Pool Markets and Operations Policy Committee (MOPC) January 10, 2022 Approved https://www.spp.org/spp-documents-filings/?id=21069

[25] Registration section 2.2, 20 d (2) and (4) , RR 468 Recommendation Report, Southwest Power Pool Markets and Operations Policy Committee (MOPC) January 10, 2022 Approved https://www.spp.org/spp-documents-filings/?id=21069

expressed significant concern with the ability to meet the 60-day deadline. In response, PJM proposes a “pre-registration process” where data is verified. The 60-day clock does not start until account numbers, locations, metering requirements, evidence of approval to interconnect, and confirmation that DER will not be compensated twice via a local retail program. PJM created this pre-registration process in part because the EDCs stated new analysis would be required, which could not be accomplished in 60 days.

AMEA suggests FERC consider dedicating a panel to determine the additional analysis that would be required considering that every DER included in an aggregation has either already been studied as part of the interconnection process or is simply an existing load that is accounted for in the distribution system plan. The sum of all approved DER assets is what rolls up to the registered Aggregation. Additionally, it would be helpful to understand how the EDCs in California are meeting the 30-day requirement and the tools and processes that have been put into place to enable automation.

11. Implementation Dates

AEMA notes that some ISOs have announced implementation dates, whereas others have not. NYISO’s current implementation date is the 4^{th} quarter of 2022. PJM has communicated that it is considering an implementation date in the 2^{nd} quarter of 2025. ISO-NE has a multi-phase implementation approach planned for the energy and ancillary services market in the 4^{th} quarter of 2026 and capacity market implementation scheduled in the 2^{nd} quarter of 2027.

SPP has indicated the earliest implementation date is Spring, 2024 while MISO has provided no information at all. A technical conference would provide a forum to discuss the considerations driving the range of implementation dates.

12. Market Mitigation

SPP proposes market mitigation measures for DER aggregation including Demand Response. While SPP has proposed an exemption of 2 MW, the default threshold is $25/MW or 10 times the Henry Hub. For Demand Response, these thresholds are likely to be far too low, which would then require a DERA to develop, submit and receive an approved mitigated offer methodology. The effort of developing this methodology and potentially updating as the elements of the DER Aggregation change could be onerous.

In contrast, MISO does not propose to monitor/mitigate DERA with less than 10 MW of injection capability. Above this limit, the DERA would be subject to mitigation as similar resources, but DR by load reduction is not subject mitigation.

III. Conclusion

While AEMA understands that regional differences may justify differing approaches and FERC has not mandated the adoption of identical participation models, that does not mean that FERC should permit the proverbial thousand flowers to bloom either. For the significant promise of Order 2222 to be realized, the DER industry requires at least some level of consistency, if not in the rules, at least in their justifications.

WHEREFORE, the AEMA respectfully requests that the Commission grant the request for a technical conference on the RTOs/ISOs Order No. 2222 compliance proposals. Thank you for consideration of these comments.

Respectfully submitted,

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February 07, 2022

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document via electronic means upon each person designated on the official service list compiled by the Secretary in these proceedings.

This the 7th day of February, 2022.

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