June 13, 2025

INDIANA RURAL ELECTRIC MEMBERSHIP COOPERATIVES
POST-STAKEHOLDER MEETING COMMENTS
ON FERC ORDER 2222 IMPLEMENTATION

Northeastern Rural Electric Membership Corporation ("NREMC"), Johnson County Rural Electric Membership Corporation ("JCREMC") Tipmont Rural Electric Membership Corporation ("Tipmont"), and Bartholomew County Rural Electric Membership Corporation ("BCREMC") (collectively the "named Indiana REMCs" or "REMCs"), respectfully submit the following comments in response to the May 28, 2025, stakeholder meeting regarding the implementation of FERC Order 2222. The REMCs appreciate the opportunity to comment on the issues raised during the stakeholder meeting and thank the Commission for providing a forum and opportunity to discuss the important issues related to the implementation of FERC Order 2222.

I. INTRODUCTION AND BACKGROUND

The REMCs provide these comments from the perspective of non-profit, member-owned electric distribution utilities organized and existing pursuant to the laws of the State of Indiana. NREMC's service territory is within the PJM RTO. NREMC is a direct market participant in the PJM energy, capacity, and ancillary service markets as a Load-Serving Entity and purchases transmission service under the PJM Open Access Transmission Tariff in the AEP transmission zone of the PJM region. JCREMC, BCREMC, and Tipmont's service territories are within the MISO RTO. JCREMC and Tipmont are (or will be) direct market participants in the MISO energy, capacity, and ancillary service markets as Load-Serving Entities and purchase transmission service under the MISO Open Access Transmission Tariff in the Zone 6 transmission zone of the MISO region.

II. COMMENTS

1. Registration of DER Aggregation

    A. Data Requirements
    Data requirements for DER Aggregation registration should align with the standards currently being developed by the RTOs. Although guidance continues to evolve, PJM's current proposal requires DER Aggregators to provide the following data upon initial registration: LSE account number, physical address, transmission zone, LSE, LSE, DER type, PJM telemetry setup, LSE interval meter, CSP interval meter, RERRA evidence, transmission node, pricing point, max load, max injection, max market eligibility, load reduction method, generator details, LSE interconnection ID, retail agreements, peak load contribution, loss factor, registration start / end date, registration status, market, LSE reliability issue(s). Maintaining alignment with RTO data requirements is critical for consistency, interoperability, and effective coordination between state and RTO processes.

    B. Timelines
    MISO and PJM both provide a 60-day window for LSEs to review proposed DER aggregations. PJM further subdivides this window into 15 days to verify locational data and 45 days to perform reliability assessments.

    These timelines are not sufficient for comprehensive review of all potential projects. DER Aggregations may participate in capacity, energy, and ancillary services markets, and each market presents unique operational characteristics. Effective reliability studies require sufficient time to analyze how aggregated resources will perform across these markets.

    Establishing a state-level registration process that allows utilities an additional 30 days to evaluate the data before registration approval would support more rigorous reliability reviews and ensure grid integrity.

    C. Differentiated Review for Ancillary Services Participation
    Imposing fixed thresholds based on aggregation size would be arbitrary and unrepresentative of actual system impacts. System impacts are more accurately tied to resource type, operational characteristics, and market participation, rather than size alone.

    In particular, resources participating in ancillary services markets warrant additional review time. These resources often have bidirectional capabilities, rapid ramping, and sub-hourly responsiveness, which make their reliability impacts more difficult to model.

An additional 30-day review period (for a total of 60 days under state authority) for aggregations intending to participate in ancillary services markets would help ensure that appropriate operational modeling, impact assessments, and reliability studies can be completed.

2. Pre-Registration of DER Resources

The REMCs strongly oppose any requirement for utilities to proactively register individual DERS on their systems. The responsibility to register DERs appropriately rests solely on the DER Aggregator, not the LSEs. A pre-registration system might save DER aggregators time in soliciting customers but unfairly shifts the administrative burden to the utilities.

Furthermore, utilities such as REMCs that are exempt from FERC Order 2222 under the small utility exemption[1] should not be required to submit customer data for aggregator solicitation, as doing so would effectively circumvent their ability to opt out. Customers of exempt utilities should not be targeted by DER Aggregators for participation in market programs that are not authorized or offered by their utility.

3. Consumer Protections

The REMCs strongly support robust consumer protections, including:

A. Compensation for EDG / Net-Metering
It is important to clearly distinguish between compensation for DER Aggregators and customers participating in Net Metering or EDG programs. Double compensation—where a customer receives both full retail credit and market compensation for the same exported energy—must be avoided. Clear policies must be established to ensure participants are compensated under one program at a time, in alignment with the principle of cost causation and fairness to all ratepayers.

B. Affirmative Opt-Out Requirements
Customers must be required to directly contact their distribution provider to affirmatively opt out of their current retail rate or tariff before enrolling with a DER Aggregator. Passive enrollment—such as enrollment initiated by an Aggregator without direct utility contact—fails to ensure that customers are making fully informed decisions. Only the distribution provider can accurately explain what a customer may forfeit by exiting a

[1] Order No. 2222, 172 FERC P 61, 247 at P 64. "Recognizing this potentially greater burden on small utility systems, we will exercise our discretion to include in this final rule an opt-in mechanism for small utilities similar to that provided in Order No. 719-A. Specifically, we determine that customers of utilities that distributed 4 million MWh or less in the previous fiscal year may not participate in distributed energy resource aggregations unless the relevant electric retail regulatory authority affirmatively allows such customers to participate in distributed energy resource aggregations."

particular tariff—such as legacy net metering status, bill credits, or other benefits—and ensure the customer understands the potential loss of those advantages. Affirmative, direct interaction between the customer and their utility is necessary to confirm customer awareness and understanding of the implications of leaving an existing rate or tariff.

C. Limits on Program Switching
Switching restrictions should mirror RTO market participation commitment periods. Once a customer exits an aggregation program or ceases wholesale market participation, they should not be permitted to re-enter legacy or grandfathered retail programs.

To prevent market volatility and facilitate utility planning, customers should not be allowed to move between RTO and retail programs more than once annually. A longer restriction period would further support grid reliability and rate stability.

D. Cost Allocation for Non-Participating Customers
Policies must also protect customers who do not participate in DER Aggregations. For instance, if a DER Aggregator charges a battery during a peak demand period due to following ancillary service market signals, cost allocation methods must ensure those costs are not unfairly borne by non-participating customers. A thorough review of cost causation principles should be conducted to ensure fairness and transparency in any rate impacts caused by DER Aggregator operations.

4. Jurisdictional Clarity and Dispute Resolution

The REMCs support continued use of the existing CAD process to resolve disputes related to DER Aggregation, with confirmation that the CAD process can address all such disputes left to state authority of the state commissions and that the Commission has jurisdiction over DER Aggregators. Ensuring the Commission can serve as a venue for resolving the issues left to state authority is essential to maintaining and protecting regulatory continuity.

PJM specifically delineated authority and jurisdiction to the state commissions over a variety of disputes in its FERC 2222 compliance filing, including: "(1) interconnection of Component DER; (2) adjudication of disputes in pre-registration bilateral coordination between the DER Aggregator and the distribution utility; (3) an option for adjudication of disputes in the registration process, if applicable; (4) an option to directly influence and oversee the operational relationship between the distribution utility, the DER Aggregator, and the Component DER, for purposes of physically dispatching DER Aggregation Resources and/or the Component DER therein; and (5) an option to oversee the conditions under which a distribution utility may override PJM's dispatch for purposes of preserving distribution system reliability, and the ability to adjudicate disputes arising under that oversight."[2] And "[a]ny disputes regarding an electric distribution company's exercise of its ability to override the physical operation of a DER Aggregation Resource or individual Component DER within a DER Aggregation Resource, for purposes of maintaining safe and reliable operation of distribution facilities, pursuant to any applicable tariffs, agreements, and operating procedures of the electric distribution company, and/or the rules and regulations of any Relevant Electric Retail Regulatory Authority, shall be addressed in accordance with applicable state or local law, and shall not be arbitrated or in any way resolved by the Office of the Interconnection or through the dispute resolution processes under Operating Agreement, Schedule 5."[3]

5. Existing DR Tariff 43566 and Current Rulemaking

   The existing DR tariff under Cause No. 43566 should remain intact and continue to serve its designated purpose as demand response is very distinct from distributed energy resources. DERs are physical resources capable of generation or load modification, while DR is only a load reduction mechanism. New DER aggregation frameworks should be developed in parallel and designed around existing DR constructs.

6. Resource Adequacy Implications

   The effects of DER aggregation must be fully accounted for in the resource planning process. When distributed energy resources are aggregated and virtually bid into the wholesale market, they not only serve as a supply-side resource but also fundamentally alter the metered load of the LSE. This dual impact—reducing LSE load while contributing to market supply—affects both sides of the resource adequacy equation. To ensure accurate forecasting and maintain reliability, these effects must be explicitly incorporated into utility planning.

7. Auction Timeline Misalignment Between PJM & MISO

   It is essential to recognize and address the operational and planning challenges posed by the differing capacity auction timelines between PJM and MISO. State policies must accommodate these differences and ensure that planning and compliance processes remain workable across both RTO footprints.

   In particular, state deadlines for aggregator registration and participation confirmation should align with each RTO's specific auction timeline requirements—ensuring that utilities receive timely and accurate information on the volume and type of DERs committed to wholesale markets. This alignment is

[2] Order No. 2222 Compliance Filing of PJM Interconnection, L.L.C. Motion for Extended Comment Period, Docket No. ER22-962-000 (Feb. 1, 2022), at p. 12.
[3] *Id* at p. 77.

critical to support effective utility forecasting and enable sound resource adequacy planning.

III. CONCLUSION

The REMCs thank the Commission for the opportunity to provide comments on these critical issues of FERC 2222 implementation. As the Commission looks to address the many new issues that come with DER aggregation, the REMCs respectfully request that the Commission:

(1) Establish a state-level DER Aggregation registration process that aligns data requirements with evolving RTO standards and provides utilities with an additional 30 days beyond the RTO timeline to conduct thorough reliability reviews. For DER Aggregations proposing to participate in ancillary service markets, which require more complex and sub-hourly operational studies, provide a total of 60 days at the state level to ensure robust reliability assessments and grid protection.

(2) Reject any proposal requiring utilities to proactively register DERs on their systems. Clarify that DER registration obligations rest solely with aggregators and explicitly exempt utilities covered by the FERC small utility exemption from any pre-registration requirements.

(3) Adopt strong consumer protection rules that: (a) prohibit double compensation for DERs by ensuring customers cannot simultaneously receive both full retail rate credit (e.g., under net metering or EDG programs) and wholesale market compensation for the same exported energy; (b) require affirmative customer opt-out through direct contact with their utility; (c) mirror the RTO's market participation requirements for minimum enrollment duration and restrict state to wholesale program switching to no more than once per year (or the RTO duration, if higher), and (d) ensure non-participating customers are protected from cross-subsidization through proper cost allocation mechanisms.

(4) Affirm Commission jurisdiction over DER Aggregators and ensure that the CAD process explicitly covers all issues ceded to state commissions by the RTOs and FERC.

(5) Design DER aggregation rules to around the existing Demand Response Tariff 43566.

(6) Require that utilities adjust their forecasting and planning processes to account for the dual impact of DER Aggregation—both as a supply resource in the wholesale market and as a modifier of LSE load—by incorporating the associated capacity impacts into their resource adequacy assessments.

(7) Develop flexible rules that accommodate the differing capacity auction timelines of PJM and MISO and align state-level deadlines for confirming aggregator participation with RTO-specific auction timelines.

Respectfully submitted, on behalf of
the named Indiana REMCs

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