INDIANA MICHIGAN POWER COMPANY
FEBRUARY 2, 2023 COMMENTS
ON IURC IMPLEMENTATION OF FERC ORDER 2222

Indiana Michigan Power (I&M or Company) is the only Indiana investor-owned utility regulated by the Indiana Utility Regulatory Commission's (IURC or Commission) that participates in the PJM Regional Transmission Organization (RTO). I&M appreciates the opportunity to provide comments in this proceeding, in compliance with the legislative mandate in Ind. Code § 8-1-40.1-4, to consider stakeholder comments on issues related to the IURC's implementation of Federal Energy Regulatory Commission (FERC) Order 2222.

I. INTRODUCTION

The future of the electric industry is relying more and more on distributed generation. As an electric distribution company (EDC), I&M recognizes its unique and important role as an enabler to connect individual distributed generation facilities to the distribution grid and support reliable supply of their aggregated energy into the wholesale markets. Generally, the IURC rules for FERC Order 2222 should:

- Ensure fairness to all participants;
- Develop a common implementation schedule across the state;
- Provide equitable allocation of costs to participants and non-participants;
- Maintain operational reliability of the transmission and distribution grid, ensuring safe and reliable service to all customers; and
- Preserve the utility's ability to prioritize outage restoration and to take sections of the electric system out of service if there is a safety, maintenance or system operational issue.

FERC Order 2222[1] allows for participation of Distributed Energy Resource (DER) aggregations in wholesale capacity, energy and ancillary services markets operated by Independent System Operators (ISO)/RTOs. DERs have the capability to – and have traditionally – reduced load. However, with the introduction of FERC Order 2222, the aggregation of the DERs will become suppliers of energy to the grid. This represents a change from the traditional utility model where the electric system is designed for one-way power flows and two-way power flows are being introduced, which can affect the reliability and resiliency of the distribution system for real-time operation of supply. Additionally, the participation will change the use of an existing connected DER from a load program, managed under state retail tariffs, to injectable real-time energy supply into the RTO markets. As more DERs connect to distribution wires, there will be a corresponding need for increased visibility into, the real-time monitoring of, and control of these assets. The interconnecting utility, both distribution and transmission, must be involved in the planning and control processes because it has the obligation to serve and maintain system reliability and customer quality of service.

As a result of FERC Order 2222, PJM submitted tariff changes to FERC to allow DER aggregations to participate in its wholesale markets, including establishing a coordination process to register component DERs that participate in aggregations and to examine/review the proposed DER aggregation for reliability impacts. That proposal is still pending before FERC.[2] The IURC has a role in coordinating the participation of aggregated DERs in PJM's market, including: setting retail rates at the distribution level; supervising utility review of DER participation in aggregations; evaluating DER interconnection; sharing of retail customer data into the RTO management systems; and overseeing issues regarding distribution system operation, reliability and cost allocation.[3]

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[1] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 2222, 85 FR 67094 (Oct. 1, 2020), 172 FERC ¶ 61,247, (2020), *corrected*, 85 FR 68450 (Oct. 29, 2020) ("Order 2222"), *order on reh'g*, Order No. 2222-A, 86 FR 16511 (Mar. 24, 2011), 174 FERC ¶ 61,197 (2021), *order on reh'g, final rule*, Order No. 2222-B, 86 FR 33853 (Aug. 27, 2021), 175 FERC ¶ 61,227 (2021).
[2] *PJM Interconnection, L.L.C.*, Order No. 2222 Compliance Filing of PJM Interconnection, L.L.C., Motion for Extended Comment Period, Docket No. ER22-962 (Feb. 1, 2022).
[3] Order 2222 at P 324.

Although "DER" is a common term in the energy industry, there is no clear consensus among industry stakeholders on its definition. The term can refer to a broad range of operational assets for electricity generation, energy storage, load management, and various types of control systems that connect physically to the electricity system at the distribution level rather than to the bulk power system. For example, the North American Electric Reliability Corporation (NERC) defines DER as, "Any Source of Electric Power located on the Distribution System." *See* North American Electric Reliability Corporation, Quick Reference Guide: Distributed Energy Resource Activities (June 2022). FERC defines a DER as "any resource located on the distribution system, any subsystem thereof or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment."[4] The IURC should consider whether to adopt a broad definition of DERs that takes into account other resources beyond the definition of distributed generation, such as energy storage resources, demand response and electric vehicles and their charging equipment.

The remainder of I&M's comments are intended to address the areas of discussion suggested by the IURC in its request for comments.

II. COMMENTS

A. IURC-Specific Comments

1. The appropriate or preferred process or processes to utilize in the development of rules implementing FERC's Order 2222 (informal, formal rulemaking, and/or formal investigation).

Some issues may be appropriate for informal/formal rulemaking proceedings while other issues may be addressed on an individual company basis. For example, as discussed below, the IURC should permit an individual company to file for approval of its standard interconnection agreements and procedures. A generic rulemaking proceeding requiring all Indiana utilities to adopt the same interconnection agreement language is not necessary and may not be appropriate given some utilities are in PJM and others in MISO.

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[4] *Id.* at n. 1.

The IURC should require implementation of any rulemakings on a state-wide basis, even if one RTO is able to implement FERC Order 2222 sooner than the other. It seems appropriate to have aggregation of DERs available statewide at the same time in all utility service territories. If there is not a common timeline across the state, there may be instances where a DER attempts to interconnect into a utility service territory simply to have access to a given RTO wholesale market. Contracts between the DER Aggregator and the local distribution utility – similar to the Small Power Producer agreements – define roles and responsibilities between the parties and should also be considered. The DER Aggregator will be registering directly with the RTO under a separate wholesale market agreement.

2. Interconnection of component DERs to the distribution system.

It would be appropriate for the IURC to require a utility to submit an updated interconnection agreement and procedures for approval, incorporating obligations and requirements for DERs and DER aggregations specific for wholesale market participation under FERC Order 2222.

As more DERs connect to distribution wires, there will be a corresponding need for increased visibility into, real-time monitoring of, and control of these assets. The increasing presence of DERs will introduce new reliability and resiliency issues that require new equipment, processes, and standards to allow for further DER participation through an aggregation. These elements should be incorporated into updated customer interconnection agreements and procedures. Monitoring, metering, telemetry, bidirectional devices, voltage regulation and reclosing/curtailment devices are examples of equipment that will become increasingly important to maintain grid balance, power quality and reliability. This equipment will need to tie together with existing operational and support systems to model and forecast effects of DERs on the system. Additionally, backend and frontend systems will be needed for data integration of devices and equipment on the distribution and transmission systems.

Each ISO/RTO may have different metering, telemetry and other requirements to enable wholesale market participation. Accordingly, I&M may need to incorporate different processes, procedures and equipment requirements into its interconnection agreement and procedure requirements than a utility operating in MISO. Similarly, there is no need for a single statewide interconnection agreement.

As mentioned above, there is a lack of a clear definition of DER in the industry. As such, gaps exist concerning exactly what types of systems and technologies are covered under current interconnection procedures, interconnection rules, and interconnection agreements. For instance, the IURC and the Company have clear interconnection rules that were designed for Distributed Generation systems connecting to the Distribution System, and only contemplates small renewable systems like Solar and Wind, or small cogeneration facilities less than 100 kW. The current rules do not cover non-renewable generation such as larger cogeneration facilities or other alternative Distributed Energy Resources, such as energy storage systems, electric vehicles and chargers, or demand response programs – especially those with injection capabilities. DERs, as contemplated within FERC Order 2222, constitute a much larger range of technologies, which might require different interconnection rules and standards than those designed solely for distributed generation. Establishing interconnection requirements for various types of DERs will streamline the interconnection process for all types of covered DERs. Further, establishing a state-approved list of customer-required DER equipment and technical attributes could significantly accelerate the DER interconnection process on distribution systems throughout the state.

3. Adjudication of (pre-registration/aggregation registration) disputes.

As part of its compliance filings with FERC, PJM proposed a process by which DER aggregators must register their aggregations of component DERs with the RTO.[5] The registration process, as proposed, permits the EDC 60 days to properly determine that a DER aggregation will not pose a risk to distribution system reliability or operations. The nature of the review process will largely depend on the number and characteristics of component DERs within the aggregation or overall size of the aggregation, the location and size of all existing DERs on the relevant circuit, additional proposed DER

[5] By contrast, the Pre-Registration Process is a precursor to the 60-day Registration review process, which allows DER Aggregators, EDCs, TOs and PJM to collect, share, and validate relevant component DER data and to evaluate and determine retail program participation by component DER. The Pre-Registration Process does not have a defined time limit.

aggregations, and the circuit's hosting capacity. Each DER Aggregator's registration will likely pose unique arrangements. It is appropriate to provide deference to the EDC's decisions regarding its assessment of the DER aggregation's impact and on the operation of its own distribution facilities in order for the EDC to maintain system safety and reliability for all of its customers. Depending on the outcome of the distribution utility's review of a DER aggregation request (including a requirement to pay any costs required to modify the grid to accommodate the request), the DER Aggregator may dispute the utility's determination not to approve the aggregation. The Commission will need to develop procedures to adjudicate pre-registration/registration disputes between a DER Aggregator and the distribution utility.

4. Operational oversight and control of DERs.

While DERs can offer many benefits, the proliferation of DERs can also affect the reliability and resiliency of the distribution grid and the bulk power system through impacts to operations and planning. Many of these issues can be effectively managed by allowing increased visibility into, real-time monitoring of, and control of these assets. The Commission could consider updating DER performance standards, modeling requirements, and data requirements to help minimize the impact of DER interconnections on customer, distribution, and transmission reliability. Similarly, the Commission could consider updating operational requirements and incorporating them into interconnection standards to help ensure distribution and transmission grid reliability, including proper voltage and frequency disturbance ride-through capabilities.

5. Distribution utility overrides of DERs to maintain reliability, and disputes arising therefrom.

While State commissions and other Relevant Electric Retail Regulatory Authorities (RERRAs) have jurisdiction over the reliability of distribution systems, EDCs have an obligation to provide safe and reliable service to all customers. While the customer and its aggregator will work directly with the RTO and must abide by the RTO standards for reliability and accountability, the distribution company maintains oversight, complete authority, and preemption rights for the protection of the distribution system. The DER Aggregator, as a supplier to the markets, should be responsible for the generation supply modeling. EDCs must have the ability to override DER aggregator instructions to maintain reliability of the distribution system. This includes installing equipment such as remote-control and real-time monitoring devices on component DERs, circuits or other locations on the distribution system, as necessary to maintain system reliability. Supervisory control override capability at the point of interconnection is critical for the interconnecting utility to properly isolate any DERs identified as creating real-time reliability or power quality disturbances for the customers served from the distribution system in that area. FERC expressly contemplated this type of override capability in FERC Order 2222.[6]

Since the EDC is responsible for safe and reliable operation of the distribution grid, it needs to maintain the ability to take circuits out of service for normal maintenance, replacement, and customer specific projects. The fact that a component DER is located on a given circuit, and that DER is part of an approved aggregation, should not interfere with the EDC's ability to operate the system. This is true for normal operations as well as during storm restoration efforts. The Commission's rules should be clear that the location and/or operation of a DER or DER aggregation should not inhibit the EDCs ability to determine the safest and fastest way to restore service to critical customers after a weather event or any other situation that could impact the electric system.

As entities responsible for planning and control of distribution and transmission systems, with increased penetration of DERs, electric utilities need accurate, granular historical and real-time data to develop system models, validate results, and perform real-time and long-term analysis and planning. The Commission could consider whether the interconnection, operations, and planning processes for DERs could reflect those of large generators connected to the transmission system. Since safety and reliability of the distribution grid is the responsibility of the EDC, the Commission could enhance the utility's visibility into DERs participating in the market by requiring more granular, real-time information from DERs and DER Aggregators.

Granular information is necessary to accurately model DERs in transmission and distribution planning studies, separate from operational studies. These planning studies

[6] *See* Order No. 2222 at P 310.

allow planners to understand the potential opportunities and challenges that relate to bulk system reliability in terms of voltage and frequency performance. As the penetration of DERs on the system increases, there is a need for new processes, for both distribution and transmission, to study potential control instabilities.

6. Cost allocations (issues re: technical review costs/upgrades/needed technology/considerations of subsidizations, etc.).

The increasing presence of DERs creates some complex cost recovery and cost allocation issues. For example, cost structures for different types of DERs vary and DERs may have both retail and wholesale characteristics that will need to be individually studied. Costs to facilitate DERs generally will fall into three categories: (1) hardware costs (e.g., metering, telecommunications, general infrastructure, Automated Data Management Systems (ADMS), and interconnection upgrades); (2) information technology and operational technology software costs such as updated billing and customer tracking systems and modeling upgrades to incorporate component DER and DER aggregation forecasts and behaviors into studies; and (3) administrative costs such as staff and analytical support needed to accommodate incremental volume of interconnection requests and the increasing complexity of DER interconnection studies and real-time operations.

Because the future of DERs depends on multiple variables, I&M has not quantified the level of investment needed at this time. Cost allocation responsibilities for component DERs should be addressed in the Interconnection Agreement(s). This includes potential network upgrades for interconnection, metering requirements and other technical requirements. In addition, the Company may decide to propose additional tariffs or services for DERs that participate in wholesale aggregations.

7. Dual participation (retail and wholesale participation) and double-counting concerns or challenges.

EDCs have an opportunity to review which retail and wholesale services a component DER participates in as part of the DER aggregation Pre-registration and Registration Processes. Only the EDC is equipped with the information necessary to confirm that a DER does not have performance obligations for the same megawatt-hour (MWh) at retail that the DER will be providing at wholesale at the same time. Reviewing retail and wholesale participation for financial double compensation concerns alone does not acknowledge the reliability concerns that may result if resources providing the same service at the same time have been double counted. The Commission could establish procedures to adjudicate disputes regarding double counting should they arise. In addition, the Commission could consider processes to streamline the program review process. Specifically, the Commission could require customers to participate in either a retail or wholesale tariff, which may be a simpler solution.

Further, the Commission could consider limiting DERs to a single tariff or service for a one-year minimum. Such a requirement will reduce the real-time decision-making impact associated with DERs continually changing service types, which affects how DERs are viewed in real-time contingency analysis. Each change in service type will cause additional work related to setup, configuration, and modeling in the real-time monitoring systems/tools.

8. State vs. Federal jurisdictional issues.

FERC Order 2222 directed each RTO/ISO to revise its tariff to ensure its market rules facilitate the participation of DER aggregations. The Order does not direct any particular actions on the part of the EDC to which the DERs would be interconnected. The absence of such direction is consistent with the limitations on FERC's jurisdiction that it recognized in the Order. Additionally, in several places throughout the Order, FERC clarified that it was not asserting jurisdiction over the planning or operation of the distribution system or retail programs in which DERs may participate. Specifically, FERC noted the following:

- FERC would not exercise jurisdiction "over the interconnections of [DERs] to distribution facilities for the purpose of participating in RTO/ISO markets exclusively as part of a distributed energy resource aggregation." [7]

[7] *Id.* at P 96.

- Nothing in [Order 2222] preempts the right of states and local authorities to regulate the safety and reliability of the distribution system and that all distributed energy resources must comply with any applicable interconnection and operating requirements.[8]
- Relevant Electric Retail Regulatory Authorities continue to have authority to condition participation in their retail distributed energy resource programs on those resources not also participating in RTO/ISO markets, which should allow them to mitigate any double-compensation concerns.[9]

Finally, it is important to note that utilities must still comply with basic retail service obligations under state law regardless of the implications of FERC Order 2222.

9. DER aggregators as "public utilities."

Treating DER Aggregators as public utilities presents a broad range of issues that would need to be thoughtfully considered. DER aggregators are not public utilities and should not be relied on to provide public utility services. However, since FERC Order 2222 shifts the treatment of DERs from a load offset to a supplier of generation, that brings with it certain responsibilities and requirements. The Commission's rules should require DER aggregators and their members to provide safe and reliable service, to maintain their equipment and operate so as to not harm the general public or interfere with service to any other customer on the distribution system. Further, DER aggregators and their members should be required to maintain their IT communications with the EDC and the RTO with an awareness to minimize or reduce cyber threats to the electric grid.

10. IEEE 1547-2018 standardization.

The Commission could consider updating DER performance standards, modeling requirements, and data requirements to help minimize the impact of DER interconnections on customer, distribution, and transmission reliability. Similarly, the Commission could consider updating operational requirements and incorporating them into interconnection standards to help ensure distribution and transmission grid reliability,

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[8] *Id.* at P 44.

[9] *Id.* at P 162.

including proper voltage and frequency disturbance ride-through capabilities. The IEEE Standard 1547TM-2018 was published in pursuit of this objective, and multiple states have adopted, referenced, or used the IEEE Standard 1547TM to develop their own interconnection rules.[10] The Company notes that the adoption of the IEEE 1547-2018 standard addresses both intentional and unintentional islanding of DERs, as well as standardizes the technical requirements for DERs connected to any distribution utility. According to the National Renewable Energy Laboratory, the IEEE Standard 1547-2018 provides functional technical requirements that are universally needed to help ensure a technically sound interconnection.[11] Functional requirements "allow flexibility and innovation and state the required outcome, not how to achieve that or the equipment or methods that must be used to satisfy the requirements."[12] The IURC should consider adopting the IEEE in its interconnection rules.

11. Coordination among RTO/utility/aggregator/IURC.

The coordination among the RTO, utility, DER Aggregator, and IURC is important with respect to the reliability of the distribution grid. Also, Data Access and Accessibility is a key area that the Commission can provide guidance on to protect the parties. Utilities need accurate, granular historical and real-time data to develop system models, validate results, and perform real-time and long-term analysis and planning. A more thorough discussion on data sharing is warranted, especially given security concerns.

Another important area where the Commission could provide guidance is regarding consumer education and protection. With many types of customers with varying levels of sophistication investing in DERs, the Commission should consider how to advance consumer education and protection measures to ensure that any customer opting to invest in DERs understands the potential benefits and costs of installing and operating such systems.

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[10] Thomas Basso, Nat'l Renewable Energy Lab., IEEE 1547 and 2030 Standards for Distributed Energy Resources Interconnection and Interoperability with the Electricity Grid at 2.
[11] Order No. 2222 at 4.
[12] *Id.*

B. Additional Comments

As an increasing amount of DERs interconnect to the distribution system, there is a corresponding need to have processes and procedures in place to maintain the safe and reliable operation of the system. In anticipating this trend, it is imperative to ensure DER performance standards are in place today so that as DER interconnections proceed, reliability is not degraded by significant quantities of DER being interconnected without reliability requirements. The Commission could consider rulemakings to address these specific concerns.

Finally, as more DERs connect to distribution, there will be a corresponding need for increased visibility into, the real-time monitoring of and, possibly, control of, these assets. DERs have the capability to reduce load or supply energy to the grid. This reduction of one-way flows and introduction of two-way flows are a change from the traditional utility model and can affect the reliability and resiliency of the distribution grid. But DERs might not be equally valuable to the grid with respect to their contributions and the costs imposed, and the performance of some might have more of an impact on the reliability and operations of the bulk power system than others.

III. CONCLUSION

Finally, I&M must be involved in the planning and control processes because it has the obligation to serve and maintain system reliability and customer quality of service. Additionally, the Commission will continue to play an essential role in establishing and governing these processes.