EPRI ELECTRIC POWER RESEARCH INSTITUTE

THE ROLE OF DISTRIBUTION UTILITIES IN ENABLING MARKET PARTICIPATION FOR DISTRIBUTED ENERGY RESOURCE AGGREGATIONS

An EPRI FO2222 Phase 1 Collaborative Report

- Wholesale Market Operations & Design
- Distribution Reliability & Safety
- Transmission Operations & Planning
- Transmission, Distribution & Aggregator Coordination
- Information, Communication, Cyber Security
- Customer Technologies & Retail Programs

Bringing together key stakeholders to ensure the reliable and economic participation of distributed energy resources in wholesale electricity markets and establishing a research and development roadmap

June 2021

In September 2020, the Federal Energy Regulatory Commission (FERC) issued Order 2222: *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*[1]. The Order requires Independent System Operators and Regional Transmission Organizations (ISOs/RTOs) to make changes that allow for aggregations of distributed energy resources (DERs) to participate in the wholesale markets that ISOs/RTOs administer. The Order directs the ISOs/RTOs to include in their compliance filing, among other things, the role of distribution utilities and the coordination between those organizations, the ISO/RTO, relevant retail regulatory authorities, and the DER Aggregators (DERA) to ensure reliability of both the distribution and bulk power systems. This technical brief describes the roles of distribution utilities in maintaining safety and reliability as outlined in the Order, including a discussion of the challenges and possible frameworks for meeting Order requirements.

This technical brief outlines the roles and functions of distribution utilities required in O2222 in three distinct timeframes: interconnection, technical review during market registration, and ongoing operational coordination. Several introductory frameworks are presented that address implementing these new and evolving functions with existing and emerging technology, processes, data, and tools. The paper discusses the continuing challenges faced by distribution utilities in hosting DER as well as the developing challenges they face in supporting DER participation in wholesale electricity markets through DERA. Finally, it documents some of the challenges and gaps in DER and grid management that enable further coordinating with ISOs/RTOs, transmission system operators, DERA, and relevant retail regulatory authorities. The goal of this brief is to summarize for all stakeholders what is required of distribution utilities and the implications across the key areas impacted. Subsequent reports will address more detailed implementation solutions for individual issues presented in this document.

Introduction

FERC Order 2222 (O2222) has considerable implications on how both the distribution and bulk power systems are planned and operated. Because the definition DER contained within O2222 pertains to those resources interconnected to the distribution system, the role of the distribution utilities is critical in ensuring that ISOs/RTOs meet the compliance requirements outlined in the Order. Distribution utilities will continue to be focused on providing safe and reliable electricity to residential, commercial, and industrial customers, but must also support DER participation in wholesale markets through a DERA without imposing undue barriers to individual DER owners or DER Aggregators. While individual DER owners are currently permitted to participate in wholesale markets, these, often large and singular systems, are typically studied and monitored more rigorously than the widespread small DER that can be aggregated under O2222. There are also significant challenges for electricity market operations, transmission system planning and operations, communications and information technology, and cyber security that are being considered in parallel efforts within this EPRI collaborative effort.

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[1] Federal Energy Regulatory Commission, "Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators," Order No. 2222, issued September 17, 2020. https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf

O2222 Requirements Pertaining to the Role of Distribution Utilities

Interconnection

Key Takeaway

The interconnection of DER to the distribution system for the purpose of participating in wholesale markets through DER Aggregators is not subject to FERC jurisdiction. Distribution utilities can review their processes to ensure they capture the impact of DER aggregations delivering bulk system services and also prepare for possible increased application volumes.

What O2222 Specifies

In Order 2222, FERC declined to exercise jurisdiction over the interconnection of DERs to the distribution system for the purpose of participating in wholesale markets as part of DER aggregations. This is a notable shift from the prior stance that the interconnection of DERs that participated directly in wholesale markets is within FERC jurisdiction. In addition to not claiming jurisdiction, FERC also declined to impose any standardization of reliability or safety criteria onto state and local interconnection procedures or agreements. Additional relevant material pertaining to interconnection are listed below:

- State and local regulatory bodies maintain the authority over the interconnection procedures and agreements for DERs on the distribution system that are not *directly* engaging in wholesale markets.
- The interconnection of DER for the intent of participating in wholesale markets through DERA does not trip the "first use" test established under Order Nos. 2003[2] and 2006[3].
- The ruling does not impact or require modifications to the pro forma Generator Interconnection Procedures or Generator Interconnection Agreements described in Order Nos. 2003 and 2006.
- States and local authorities are permitted to both update existing interconnection procedures and agreements and require additional studies to capture the impact of a DER joining a DER aggregation that will participate in wholesale markets.
- The interconnection of Qualifying Facilities[4] (QFs) that plan to participate in wholesale markets exclusively through a DERA is not be subject to FERC jurisdiction. This jurisdiction applies to both new and existing QFs.
- DER that are already interconnected under FERC jurisdiction procedures and agreements do not need to convert to state or local interconnection agreements when participating in DER aggregations.
- Standard interconnection tariffs are not required for DER that participate in DER aggregations in states that do not currently impose interconnection tariffs for DERs that are not QFs.

Implications for Distribution Utilities

Order 2222 is part of a broad sweeping effort to remove barriers to the participation of DER in wholesale markets. One such barrier is the time and cost associated with the interconnection of individual resources. FERC noted in the Order that current RTO/ISO processes for interconnection can be prohibitively expensive, especially for smaller resources, when compared to state and local practices. Moreover, the Commission stated that it would revisit the decision over jurisdiction if it found that the distribution interconnection process was being abused or used as a barrier to that participation. Therefore, distribution utilities could face continued or increased scrutiny over the efficiency and efficacy of their interconnection practices and agreements.

FERC noted that allowing DERs to participate in wholesale markets through DERA could result in a substantial influx in DER interconnection requests which could be burdensome to RTO/ISOs. On the other hand, that places the burden of regulating DER interconnections on state and local authorities, with the burden of processing the sustained high and possibly increasing volume of interconnection applications falling on distribution utilities. One possible silver lining is that the ruling removes any uncertainty about the jurisdiction of those interconnections which could have otherwise resulted in delays in the interconnection process.

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[2] Federal Energy Regulatory Commission, "Standardization of Generator Interconnection Agreements and Procedures," Order No. 2003, issued July 24, 2003. https://www.ferc.gov/sites/default/files/2020-06/order-2003.pdf

[3] Federal Energy Regulatory Commission, "Standardization of Small Generator Interconnection Agreements and Procedures," Order No. 2006, issued May 12, 2005. https://www.ferc.gov/sites/default/files/2020-05/20050512110357-order2006.pdf

[4] Qualifying Facilities are small generating facilities with a total maximum net output of 1-80 MW as defined under the Public Utility Regulatory Policy Act (PURPA) of 1978.

The interconnection of distributed generation has typically been handled by distribution utilities, which have developed the requisite experience and systems for handling high volumes of applications. Still, utilities are continually seeking to update, improve, and expedite their processes. The combination of potentially rising application volumes with DERs offering services that differ from those traditionally studied will intensify the challenges in balancing the parallel goals of efficiently processing interconnection applications and maintaining grid safety and reliability. As shown in Figure 1, utilities currently use DER interconnection processes—comprised of screens, technical reviews, and detailed analyses—to determine if a requested resource will negatively impact distribution system operations.

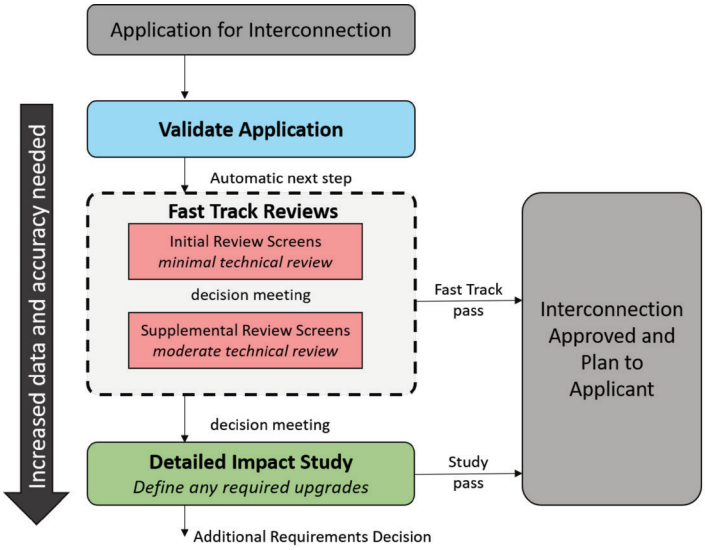

Figure 1 – High-level flow diagram of the utility interconnection review process modeled after the FERC SGIP

To date, the interconnection screening and technical review of DER applications continues to be a mostly manual process on the part of distribution utilities. This is due, in part, to the fact that the information provided by a customer or developer in the interconnection application is largely insufficient to comprehensively screen the application for safety and reliability with automated methods. Therefore, utilities have had to gather and validate additional data that may reside in decentralized utility repositories and files, prior to evaluating the technical impact of a proposed DER. Manual data gathering combined with growing application volumes is one of the underlying causes of slower processing times.

To combat the inefficiencies of the interconnection process, many utilities have adopted a tiered approach that includes an expedited or fast track process. While individual processes, screens, and requirements vary between states and among utilities[5], the fast track processes can be generalized by abridged screens with pass/fail criteria, aiming to identify the subset of applications that require further analysis and expedite the processing of applications that do not. The tiered process has streamlined the interconnection of small, mostly residential, DER; however, rising DER penetration and increasing complexity of the distribution system has resulted in more DER that require detailed impact studies, which are both costly and time intensive. Because of these factors, utilities are progressively pursuing options to improve their DER grid interconnection processes to incorporate novel technology, enable transparency, and reflect evolving technical standards and requirements.

One of the challenges posed by Order 2222 will be capturing the potential impacts from DER aggregations providing bulk system services during the interconnection process. Although there are regional differences, much of the DER connected to the distribution system today is non-dispatchable and largely uncontrolled. As a result, utilities have focused on impacts related to the potential intermittency of DER as opposed to the impact of multiple individual devices being dispatched in concert. To overcome this gap, a practical first step is for distribution utilities to work with RTOs/ISO to document and standardize the performance requirements for various wholesale services. Those performance requirements can then be translated into technical studies to determine if DER providing specific services will cause adverse impacts to safety or reliability. Clearly defined studies pertaining to various market services will not only ensure system reliability but will also aid in expediting the registration and review process, discussed later in this report.

In addition to expanding the use cases examined in interconnection, utilities are also seeking improvements to the efficiency and transparency of their processes, which FERC noted as a possible barrier to DER participation in wholesale markets. Two common themes that have emerged in recent years are the use of

[5] *Improving DER Interconnection Processes and Procedures: Common Issues and Leading Practices.* EPRI, Palo Alto, CA: 2020. 3002013852.

automation and the integration of hosting capacity analysis in the interconnection technical review process[6]. Automation can unlock significant gains in process efficiency; however, an end-to-end automated approach may not be technically feasible or appropriate for all aspects of the interconnection process. Similarly, hosting capacity—the amount of DER that can be accommodated on the distribution system without causing adverse impacts and without requiring infrastructure upgrades—is a valuable analytical result but may not align with all technical screens and criteria examined during the interconnection process. While the use of hosting capacity and automation do align with the spirit of FERC Order 2222, they are more likely long term goals due to requirements for more accurate and comprehensive distribution system models, data collection, validation, and governance processes, and integration of back-office applications and systems.[7]

By not exercising jurisdiction over interconnection, FERC intended to remove barriers to DER participation in wholesale markets through DER aggregators. The Commission went so far as to note that the non-discriminatory, reliable, and cost-effective integration of new energy resources on the distribution system would be possible without exercising jurisdiction or requiring standardized safety and reliability criteria. It was also recognized that because interconnection practices vary from state to state and between utilities, additional technical studies or modifications to existing interconnection processes may be needed to assess the impact of DER aggregations participating in wholesale markets. As a result, distribution utilities have added motivation and opportunity to re-examine and enhance interconnection processes to include potential impacts from DER aggregations providing traditional and ancillary services, which can better meet the needs of customers and DER developers who now have additional opportunities to participate in wholesale markets.

Review of New or Modified DER Aggregations

Key Takeaway

Upon registration or modification of a DER Aggregation in an RTO/ISO market, the relevant distribution utility will review the individual DERs within the aggregation to determine whether:

1. Each DER is eligible to participate in the wholesale market through a DER aggregation.
2. The individual DERs are technically capable of participating in an aggregation without posing significant risks to the reliable and safe operation of the distribution system.

Distribution utilities can work with ISOs/RTOs, relevant retail regulatory authorities, as well as internal teams to identify the program compatibility, safety, and reliability criteria that will be used to review newly registered or modified DER aggregations.

What O2222 Specifies

FERC granted distribution utilities the opportunity to review the eligibility and technical feasibility of the individual DERs participating in DER aggregations. The review process, including proposed timeline and specific review criteria, must be included in compliance filings that each ISO/RTO will submit. In a clarification to the original ruling[8], FERC specified that the safety and reliability criteria in the review should be limited to the subset of potential impacts caused by participation in a DER aggregation that were not previously investigated in the interconnection study process. Because the review process allows the distribution utility to identify conflicts or concerns, the Order requires that RTOs/ISOs include a dispute resolution process as part of the distribution utility review. Additional pertinent details about the distribution utility review process are shown below:

- *The eligibility review is intended to determine whether the individual DERs within an aggregation are participating in retail programs or tariffs that explicitly bar the dual participation in wholesale markets through DER aggregations.* This review is not a decision on the part of the distribution utility, rather an examination of the terms and conditions of the retail program(s) that a DER is participating in. While the eligibility review is similar to

[6] *Integrating Hosting Capacity Analysis into the Utility Interconnection Technical Review Process.* EPRI, Palo Alto, CA: 2020. 3002018644.

[7] *Defining a Roadmap for Integrating Hosting Capacity in the Interconnection Process.* EPRI, Palo Alto, CA: 2020. 3002020010.

[8] Federal Energy Regulatory Commission, "Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators," Order No. 2222-A, issued March 18, 2021. https://www.ferc.gov/sites/default/files/2021-03/E-1.pdf

the requirement to avoid double compensation, there is no clear directive in the Order signifying that the eligibility review is the intended venue for determining whether a DER participating in a DER aggregation would result in double compensation.

- *The technical review is not intended to be a new study or analysis, but rather an examination of prior studies or analyses, such as those conducted during interconnection.* In fact, the Order explicitly states that the studies performed during interconnection should be sufficient to *inform* the review process. According to the clarification issued in Order 2222-A, the intent of the technical review is to determine whether the expected or potential behavior of the DER participating in the DER aggregation was considered in the original interconnection study. Specifically, the distribution utility is responsible for determining whether individual DER can respond to dispatch instructions without posing risks to the safe and reliable operation of the distribution system.
- *The Order does not grant distribution utilities the authority or decision-making power to directly permit or deny the individual DERs from joining aggregations during the registration review process*. Any reliability concerns identified during the review process can be reported to the relevant RTO/ISO. The Order also suggests that distribution utilities can *recommend* operational constraints or removal of individual DERs but not directly *impose* those constraints at the time of the technical review. The ISOs/RTOs ultimately have the authority to decide whether individual DERs can participate in aggregations, and whether an aggregation can participate in a market. The Order does not require distribution utilities to revisit or modify the interconnection agreement for any DERs for which there are safety and reliability concerns, stating that the related conflict resolution process is the appropriate venue for addressing and mitigating those concerns.

Implications for Distribution Utilities

The distributed energy resources affected by Order 2222 are, by definition, interconnected to the distribution system, therefore it is reasonable and appropriate that the distribution utility is allotted the opportunity to review the eligibility and proposed behavior of those DER when they join a DER aggregation. The distribution utility that oversaw the interconnection study and agreement is particularly well positioned to review the impacts to safety and reliability, as well as the regulations surrounding any retail programs that a DER is participating in.

FERC is allowing for regional flexibility in the timeline for distribution utility review, however it stated that the process should be completed within 60 days. The combination of a short timeframe and the possibility that a single DER aggregation may contain numerous individual DERs subject to review implies that distribution utilities will benefit from developing efficient processes or tools for completing the review within the defined timeline.

One such tool that has been proposed to expedite the eligibility review is a DER program compatibility matrix[9]. This tool can be loosely defined as reconciliation of retail and wholesale programs or tariffs that are available for DERs to participate in, both individually and simultaneously. One possible arrangement is to place the retail programs on one axis and the various wholesale programs on the opposite axis, with the entries in the matrix indicating whether a retail program permits dual participation in the corresponding ISO market. The options for each entry could include 'Allowed', 'Prohibited', and possibly 'Conditionally Allowed' for cases in which there are additional coordination requirements to facilitate dual participation. One example of a conditional dual participation could be the intersection of a retail program to provide capacity relief to the distribution system and a wholesale market for reserve capacity. A DER could potentially register to provide both services at different times but would not be able to simultaneously provide both services. In that case the dual participation would be conditionally allowed if properly coordinated. An example of a DER program compatibility matrix is shown in Table 1.

Table 1 – Example DER program compatibility matrix

		ISO Services / Markets			
		ISO-S1	**ISO-S2**	**…**	**ISO-SX**
Retail Programs / Tariffs	**Retail-P1**	Allowed	Allowed	…	Conditional
	Retail-P2	Allowed	Prohibited	…	Allowed
	…	…	…	…	…
	Retail-PX	Prohibited	Conditional	…	Prohibited

[9] *DER Group Management for Coordinated Operations Across the T&D Interface*, EPRI, Palo Alto, CA December 2020: 3002016174.

A DER compatibility matrix can be constructed through meetings and agreements between the distribution utility, relevant retail regulatory authority, and ISO/RTO, and can be updated over time as regulations evolve or new markets emerge. In some cases a single compatibility matrix may be uniformly applied to all DER types, however it is likely that some retail programs and ISO markets have terms and conditions that vary depending on the type of resource that is participating, which would then require individual matrices for each DER type. The matrix can be as simple as a static spreadsheet or document that all entities can reference, or it can take on a more complex form such as a programmatic interface linked to queryable data sources (e.g., DER registry and settings database). Regardless of the implementation, the compatibility matrix is a tool that can simplify and expedite the process for determining eligibility (and any coordination requirements) of individual DERs to join a DER aggregation, which is a required step in the distribution utility review under Order 2222.

It is possible that a similar approach could be feasible for the technical review, given that the requirement in the Order is to determine whether or not the interconnection study (or other prior studies) considered the impacts associated with participating in various wholesale markets, and if those impacts pose threats to the safe and reliable operation of the distribution system. Some parts of the interconnection process are highly standardized, such as the fast track and supplemental review screens depicted above in Figure 1. In many cases these screens are designed to be uniformly applied to all DER, or DER of the same class (e.g., solar PV, synchronous generator, storage, etc.), that meet certain size and location requirements; therefore, the impacts or behaviors considered by the screens can be summarized for most DERs. However, detailed impact studies tend to be more nuanced and one-off in nature, which could be more difficult to capture in a standard template that applies to many different DER.

One option for capturing and categorizing the possible impacts that result from participation in DER aggregations as well as those considered during interconnection or other prior studies is a DER services impact matrix. This tool contains the standard screens that the distribution utility applies to a DER during interconnection, as well as the expected behaviors for each of the ISO markets that a DER can participate in. By placing the interconnection screens or study steps on one axis and the behaviors from ISO market participation on the other axis, the entries in the matrix could quickly show which behaviors have or have not been previously considered in a study. The options for entries in this matrix would include 'Considered' and 'Not Considered'; while 'Not Applicable' might seem like a possible entry that response can be lumped under the 'Not Considered' category. An example DER services impact matrix is shown in Table 2.

Using the framework of the DER services impact matrix, a distribution utility could quickly determine which behaviors from various market services had been considered for a DER depending on the interconnection screens or studies that were applied to that DER during the interconnection process. As described in Order 2222-A, a behavior or scenario that was not previously considered could justify a reasonable safety or reliability risk to the distribution system.

Table 2 – Example DER services impact matrix

			ISO/RTO Services / Markets								
			ISO-S1		ISO-S2			…	ISO-SN		
			S1-B1	S1-B2	S2-B1	…	S2-BN	…	SN-B1	SN-B2	SN-B3
Interconnection Study / Screen	Fast Track Screen	FT-S1	✓	✗	✓	…	✗	…	✓	✗	✗
		FT-S2	✗	✗	✗	…	✗	…	✗	✗	✗
		…	…	…	…	…	…	…	…	…	…
		FT-SN	✓	✗	✗	…	✗	…	✓	✗	✗
	Supplemental Review Screen	SR-S1	✓	✗	✓	…	✗	…	✓	✗	✗
		SR-S2	✓	✓	✓	…	✗	…	✓	✓	✗
		…	…	…	…	…	…	…	…	…	…
		SR-SN	✓	✓	✓	…	✗	…	✓	✓	✓

✓ = Considered ✗ = Not Considered

The framework can only identify if a behavior was previously considered; however, because it does not contain the results of the individual studies or screens, the matrix cannot identify if a behavior will or will not impact safety or reliability. A distribution utility would need to review the results of the individual studies, as well as the associated interconnection agreement, to determine if any concerns were identified during interconnection, and if the interconnection agreement specifically prohibits those behaviors. Examples of previously defined behaviors that could preclude participation in an aggregation include ramp rates and maximum generation (or demand for resources such as energy storage or electric vehicles), which may be globally applied to all circumstances, or may be provisioned for certain times of the day, loading conditions, or grid topologies. Because FERC declined to exercise jurisdiction over interconnection, the terms and conditions defined in existing interconnection agreements will be pivotal in determining eligibility to participate in DER aggregations.

This framework is limited to the standardized portions of the interconnection study process, but it may not be capable of capturing all the studies that a DER is subject to, such as the detailed impact studies discussed above. Depending on factors such as the DER size, type, location, and feeder specific circumstances, a DER may be subject to different screening and study requirements. For those instances where a non-standard study was performed, a manual review of the individual study process and results would be required to determine whether individual behaviors were considered. Because these studies are often unique for each DER, there may not be a standardized or streamlined approach to determine whether a particular behavior was considered, and if a reliability concern was identified.

Given that FERC declined to exercise jurisdiction over the interconnection of DER that participate in aggregations, the terms and conditions contained in interconnection agreements and retail programs or tariffs will play a significant role in the access that DER have to participation in aggregations. The review of newly registered or modified DER aggregation described in Order 2222 presents the relevant distribution utility the opportunity to investigate both the program eligibility and technical feasibility of DERs, but it is not intended to be a comprehensive study or re-negotiation of the interconnection agreement or retail structure. Therefore, to ensure a viable path forward towards compliance with the Order, distribution utilities will need to work closely with internal teams, state and local regulatory authorities, and ISOs/RTOs to clearly define the eligibility, safety and reliability criteria that will be considered in the review process. From those agreed upon definitions, utilities can begin to develop tools and systems that will enable an efficient and effective review.

Ongoing Operational Coordination

Key Takeaway

As part of the requirements to establish ongoing operational coordination, RTOs/ISOs must address in their compliance filings:

1. Data flows and communication between themselves, distribution utilities, and DER aggregators.
2. Requirements for DER Aggregators to report changes in offered quantities due to distribution outages.
3. Protocols with specific criteria that allow distribution utilities to override the dispatch of DER aggregations.

Distribution utilities can work with internal teams, DER Aggregators, and RTOs/ISOs to define the necessary data flows, communication standards, and safety and reliability criteria that provide the needed visibility and coordination between all stakeholders.

What O2222 Specifies

Maintaining the safe and reliable operation of the transmission and distribution systems under the market and dispatch structure defined in Order 2222 will require well-orchestrated communication and coordination between RTOs/ISOs, DER aggregators, and distribution utilities. FERC did not impose any specific processes and protocols for coordination or communication in the Order, other than requiring that those processes and protocols be defined in compliance filings. The stipulations related to ongoing operational coordination explicitly defined in the order are listed below:

- The RTOs/ISOs are required to outline the structure, format, and pathways for data or other communications needed for ongoing operational coordination between themselves, distribution utilities and DER aggregators.
- DER Aggregators are mandated to report to the RTO/ISO changes in offered quantities or distribution factors resulting from distribution outages or faults.
- Distribution utilities can override the RTO/ISO dispatch of DER aggregations, however the criteria and circumstances that trigger the override process must be transparent, non-discriminatory, and clearly defined in the compliance filings.

- RTOs/ISOs are required to apply existing non-performance penalties to DER aggregations for the case that the aggregation does not meet performance agreements due to an override by the distribution utility.
- The Order does not impose any specific liability protections for distribution utilities related to the override of DER aggregations, nor are there requirements or restrictions for RTOs/ISOs establish those provisions.

Implications for Distribution Utilities

FERC noted in the original notice of public record (NOPR) that the intent of coordination and data sharing requirements is to ensure that the dispatch of individual DERs by aggregators is conducted in a way that is not detrimental to the distribution system. Likewise, the requirement for DER Aggregators to notify the RTO/ISO of changes in offered quantities is intended to safeguard the operation of the bulk power system. Both of these requirements are squarely aimed at creating and maintaining open lines of communication between the RTO/ISO, the distribution utility, and DER aggregators in the name of maximizing the availability of DER aggregations while maintaining the safe and reliable operation of the power grid.

Because unforeseen situations can and do arise on the distribution system, FERC also ruled that distribution utilities may need to override the dispatch of DER aggregations in order to maintain physical and operational limits. However, the requirement to extend non-performance penalties to DER aggregations in the case of an override, combined with the potential for liability for distribution utilities performing the override, creates the need to deploy coordination schemes that minimize the occurrence of situations that require override or curtailment. In fact, FERC stated in the Order that the intent of these requirements is to motivate DER aggregators to recruit DERs that are connected to areas of the distribution system with fewer constraints.

The operational coordination requirements outlined in Order 2222 will undoubtably involve new data streams and communication between ISOs/RTOs, distribution utilities, DER aggregators, as well as individual DERs. Several relevant considerations are presented below:

- *Distribution utilities will need transparent access to planned dispatch schedules during operational timeframes.* This involves both the aggregation level dispatch between ISOs/RTOs and DER aggregators, as well as the device level dispatch instructions issued by DER aggregators to individual DERs. Without visibility into the planned behavior of resources in the day-ahead and day-of timeframes, distribution utilities cannot identify potential constraints to safety and reliability and will instead have to rely on prior studies and more conservative approaches to DER management. Therefore, ongoing and open communication surrounding the dispatch of DER aggregations will be key to fully realizing the potential of DERs to participate in aggregations.
- *Distribution utilities can continue to notify customers well in advance of planned outages or grid conditions that require curtailment of generation.* This practice, which is already standard in the industry, will enable the successful implementation of the Order and will minimize curtailments or overrides on the operating day. Distribution utilities strive to minimize the service interruptions that each customer experiences, and there are very few circumstances that require utilities to intentionally de-energize customers. Advanced notification of planned outages allows owners of DERs participating in aggregations to inform aggregators, who can then make appropriate adjustments to bids or market offerings.
- *Increased monitoring of individual DER devices will enable less-conservative approaches to the operation of DER in abnormal or constrained situations and could even minimize the override of ISO/RTO dispatch signals.* Currently, distribution utilities have minimal visibility into the operation of most DERs, although practices vary between jurisdictions depending on regulatory and policy decisions[10]. In addition to visibility of planned behaviors, distribution utilities will require visibility of real-time behavior in order to identify eminent constraints or safety concerns. Without this visibility distribution utilities will have to rely on more conservative approaches to DER management that may not maximize DER availability.
- *Customer notification systems can expedite the communication of unplanned or emergent outages that cause DERs to become unavailable.* Customer notification systems are advanced functions in modern outage management systems (OMS) and require high accuracy customer and electrical connectivity models in order to

[10] *Making the Connection: The Importance of DER Visibility to Grid Support and Modernization.* EPRI, Palo Alto, CA: 2018. 3002013388.

function properly. These systems send automated text messages or emails to customers experiencing sustained service interruptions, and often include estimated repair times based on the location and extent of the outage. The information provided to DER owners is the first step in enabling DER aggregators to adjust planned output and notify ISOs/RTOs. While systems are commercially available, there is not currently widespread deployment among distribution utilities.

Current distribution planning and interconnection practices focus on ensuring that the DER does not cause any adverse impacts under any operating conditions, and generally capture and study the most constrained situations that the DER is expected to encounter[11]. This paradigm is coined 'Firm Interconnection', meaning that DER owners are given a firm capacity up to which they can generate and not anticipate curtailment from the utility. Therefore, while distribution utilities continue to use firm interconnection practices it is expected that there will be minimal need for distribution utilities to override the dispatch of DER aggregations. In the future, as planning and interconnection standards evolve, the operation of the distribution system will require more active management of DER[12], including curtailment or override of ISO dispatch. Utilities can proactively work with ISOs/RTOs, DER aggregators, and state and local regulatory authorities to identify and deploy the telemetry and communications infrastructure that will enable the operational coordination needed to maximize the availability of DER to wholesale markets and ensure the safe and reliable operation of the grid.

Summary

FERC Order 2222 paved the way for distributed energy resources to access wholesale markets by requiring ISOs/RTOs to modify or create participation models for aggregations of DER. Prior to this landmark ruling, most markets only permitted large DER to transact their services in interstate commerce, relegating the small distributed resources to retail tariffs and programs. Distribution utilities, who manage the systems where these resources are connected, will play a vital role in enabling DERs to join aggregations and participate in wholesale markets.

Three key utility functions—interconnection, technical-compatibility review, and operational coordination—will require new or revamped processes, capabilities, and resources to overcome the challenges imposed by Order 2222. Many of today's interconnection practices were not designed to capture the coordinated behavior of DERs providing services to the bulk system. New or modified studies may be needed to ensure that DER aggregations do not cause adverse impacts to the operation of the distribution system. Furthermore, the retail programs that are available to DERs have varying levels of compatibility with wholesale markets. Consensus is needed between ISOs/RTOs, distribution utilities, and state and local regulatory authorities on specific use cases that permit dual participation but avoid dual compensation. Finally, to ensure the safe and reliable operation of both the distribution and bulk power systems, formal protocols and communication standards are needed to give distribution utilities visibility of expected and actual behavior of DER aggregations, while giving market operators and DER aggregators visibility of real-time grid conditions.

Current planning standards and firm interconnection practices give utilities some breathing room to support DER aggregations while new data, tools, and systems evolve to enable a more dynamic and transactive energy future. The frameworks outlined in this paper provide possible pathways towards achieving that future state, but will likely take on many different adaptations, varying from utility to utility and across regions. While individual implementations will require bespoke solutions, the roles that utilities play will be united by the common goal of supporting DER aggregations participating in wholesale markets.

[11] *The Hosting Capacity Process.* EPRI, Palo Alto, CA: 2020. 3002019750.

[12] *Modernizing Distribution Control Center Operations: Evolving Operator Roles and Responsibilities.* EPRI, Palo Alto, CA: 2020. 3002019511.

Note

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EPRI RESOURCES

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Distribution Operations and Planning

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