

# DER Aggregation Participation in Electricity Markets

## EPRI Collaborative Forum Final Report and FERC Order 2222 Roadmap



- 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*

### 2022 TECHNICAL REPORT



# DER Aggregation Participation in Electricity Markets

*EPRI Collaborative Forum Final Report  
and FERC Order 2222 Roadmap*

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## Abstract

In September of 2020, FERC issued Order 2222, which set a path forward for independent system operators (ISOs) and regional transmission organizations (RTOs) to work with distribution utilities, distributed energy resource aggregators, and relevant electric retail regulatory authorities to enable participation of DERs in the wholesale electricity markets that ISO/RTOs manage. In the following year, the Electric Power Research Institute (EPRI) engaged with these key stakeholders across the United States and others abroad in a collaborative forum to discuss the challenges that Order 2222 poses, and possible solutions. The forum encompassed six workstreams on challenging, technical topics that could benefit from collaborative discussions and a research roadmap. This report summarizes the discussions that took place throughout the project. It includes an up-to-date summary of design features in place at each FERC jurisdictional ISO/RTO, key challenge areas and recommendations for each workstream, and overarching conclusions and actions.

### Keywords

Aggregation

Distributed energy resources

Electricity markets

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**PRIMARY AUDIENCE:** Independent system operators and regional transmission organizations, distribution utilities, transmission utilities, distributed energy resource aggregators, wholesale and retail regulators

**SECONDARY AUDIENCE:** International market operators, international utilities, consumer advocates, researchers

## KEY RESEARCH QUESTION

In September 2020, the Federal Energy Regulatory Commission (FERC) issued Order 2222, which set a path forward for independent system operators (ISOs) and regional transmission organizations (RTOs) to work with distribution utilities, distributed energy resource (DER) aggregators, and relevant electric retail regulatory authorities to enable participation of DERs in the wholesale electricity markets that ISO/RTOs manage. This EPRI research seeks to identify the key challenges facing FERC Order No. 2222 implementation; highlight gaps within the order that must be addressed; and establish a roadmap with recommendations that can promote economic efficiency while reliably integrating DERs into the wholesale market.

## RESEARCH OVERVIEW

At the end of 2020, EPRI initiated the FERC Order 2222 Collaborative Forum (FO2222). The forum consisted of all seven U.S. ISO/RTOs, a Canadian ISO/RTO, and over 25 utilities of differing types, sizes, and locations from the United States and worldwide. The project held many webcasts throughout the project focusing on various topics and updates of interest to all participants. The project also held focused discussions in six areas (workstreams) to address specific issues relevant to focused participants. This report summarizes the key challenges and recommendations across the different workstreams discussed within those sessions. It also provides a working roadmap for stakeholders to consider, facilitates continued collaboration across regional and technical boundaries, and aids development of working solutions.

## KEY FINDINGS

- The research contains important considerations, current information or process gaps, and recommendations for six key challenge areas:
  - Wholesale electricity market design and operation
  - Distribution system reliability and safety
  - Transmission operations and planning
  - Transmission, distribution, and aggregator coordination
  - Metering, telemetry, information, and cyber security
  - Wholesale and retail interactions
- Each of the workstreams explored new tools or methods that stakeholders had not yet adequately considered. Examples include tools to evolve distribution utilities to distribution system operators, coordination frameworks that appropriately manage data and decision making, participation models that can incorporate the unique characteristics of DER aggregations, low-cost metering and telemetry infrastructure that can allow DER adoption, transmission planning study frameworks that adequately anticipate system needs to accommodate DERs, and alignment of retail billing structures with grid-level cost drivers.

- To ensure continued exchange of information and best practices and to promote understanding across two otherwise different “worlds” in transmission and distribution, the report recommends stakeholder collaboration, continued education, and coordination among all parties in the process. These parties include ISO/RTOs, distribution utilities, DER aggregators, and relevant electric retail regulatory authorities (RERRAs).
- Terminology may need to evolve to promote effective communication. Various stakeholders that rarely interacted with each other in the past need to clarify terms that may have had historical meanings that differed across unique stakeholder groups.
- A bottoms-up approach may be the most helpful way of determining specific mitigation strategies for effective DER integration. DER aggregations assume thousands of different forms and permutations. Understanding the potential challenge to address is difficult to comprehend in general terms.
- DER technologies, business models, and market models will continue to evolve in potentially unpredictable ways. Developing flexible DER integration tools and solutions that can adapt to future changes will facilitate support of future needs and requirements.
- Ongoing communication and collaboration among all stakeholders—including peer stakeholders such as various ISO/RTOs—can result in greater benefits across the industry.

## WHY THIS MATTERS

FERC Order 2222 is one of the most impactful decisions impacting electricity policy over the last several years. It is paving the way for new opportunities to enable the participation of electricity customers and owners of small existing and innovative technologies, as well as organizations who can create software and business models to aggregate them together, to help support the growing need for electricity in an affordable and reliable manner. The Order was indeed significant, but did not prescribe all of the ways in which ISO/RTOs, and the many organizations participating in their markets, would specifically address the directives. The Order requires ISO/RTOs to develop adequate participation models for heterogeneous DER aggregations through potential tariff changes and to establish coordination rules that ensure bulk system and distribution system reliability. All of this calls for greater coordination and communication across these organizations and roles. This rule can impact almost every stakeholder in the electricity sector—from a single homeowner with a small amount of rooftop solar—to FERC itself. To aid this process, this EPRI project brought together one of the largest and most diverse collaborative forums of its kind. EPRI with its stakeholders identified key challenges and recommended actions across six focused workstreams, as well as developed a roadmap to help stakeholders design and adopt new tools and strategies to efficiently and effectively support DER aggregations in the market.

## HOW TO APPLY RESULTS

Section 2 of the report reviews Order 2222 and FERC follow-up decisions. This section also describes and compares the major market design features and compliance filings to date of six North American ISO/RTOs that were required to respond. Section 3 can be reviewed by stakeholders that have specific interests in particular areas relevant to the order and DER integration generally. The section presents findings and possible needed actions.

## LEARNING AND ENGAGEMENT OPPORTUNITIES

- The end of section 3 of this report describes an advanced, dynamic survey form called the DERA Market Participation Use Case Survey Tool that the project team developed. Users can submit information into this tool, and EPRI compiles the information and shares it with stakeholders to

determine whether solutions or changes may be needed. To learn more, see EPRI deliverable 3002022890, November 2021, <https://www.epri.com/research/products/000000003002022890>.

- Additional project and related EPRI reports are included below:
  - *Distributed Energy Resource Aggregation Participation in Organized Markets: Federal Energy Regulatory Commission Order 2222 Summary, Current State-of-the-Art, and Further Research Needs*. EPRI, Palo Alto, CA: 2021. 3002020586.  
<https://www.epri.com/research/products/000000003002020586>.
  - *TSO-DSO Coordination Functions for DER*. EPRI, Palo Alto, CA: 2022. 3002021985.  
<https://www.epri.com/research/products/000000003002021985>.
  - *Activation of Distributed Energy Resources in the Energy Market: EPRI Report for the Australian Energy Market Operator*. EPRI, Palo Alto, CA: 2019.  
<https://aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/Standards-Protocols/EPRI-Activation-of-DER-in-the-Energy-Market-Report.pdf>.
- This project is a collaboration of many different EPRI Research Programs (see <https://www.epri.com/research/index>) including but not limited to the following:
  - Program 39: Transmission and Market Operations
  - Program 174: DER Integration
  - Program 173: Bulk System Integration of Renewables and Distributed Energy Resources
  - Program 200: Distribution Operations and Planning
  - Program 161: Information and Communication Technology
  - Program 170: Customer Technologies
  - Program 182: Customer Insights
  - Program 40: Transmission Planning
  - Program 183: Cyber Security for Power Delivery and Utilization
  - Program 94: Energy Storage and Distributed Generation
  - Program 18: Electric Vehicles
  - Program 204 Advanced Buildings
- The EPRI Team coordinated with other collaborative groups organized by other entities throughout the project as well. Project reports of those are shown here:
  - *Distributed Energy Resources Task Force. 2022. DER Integration into Wholesale Markets and Operations*. Reston, VA: Energy Systems Integration Group. [ESIG-DER-Integration-Wholesale-Markets-2022.pdf](#).
  - *Advanced Energy Economy and GridLab, FERC Order 2222 Implementation: Preparing the Distribution System for DER Participation in Wholesale Markets*. January 2022.  
<https://info.aee.net/ferc-order-2222-implementation-preparing-the-distribution-system-for-der-participation-in-wholesale>.

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## Acronyms and Abbreviations

ATRR	alternative technology regulation resource
BSF	binary storage facility
CAISO	California Independent System Operator
CPnode	commercial price node
CSF	continuous storage facility
DER	distributed energy resource
DERA	DER aggregation
DERMS	DER management system
DERP	DER provider
DF	distribution factor
DG	distributed generation
DIR	dispatchable intermittent resource
DR	demand response
DRDERA	demand response DERA
DRR	demand response resource
DSO	distribution system operator
EMT	electromagnetic transient
EPnode	elemental price node
EPRI	Electric Power Research Institute
ESPI	Energy Services Provider Interface
ESR	electric storage resources
FCM	forward capacity market
FERC	Federal Energy Regulatory Commission
IESO	Independent Electricity System Operator
ISO	independent system operator
ISO-NE	ISO New England
LAP	load aggregation point

LBMP	locational based marginal price
LMP	locational marginal price
LSE	load-serving entity
MISO	Midcontinent ISO
NAESB	North American Energy Standards Board
NBT	net benefits test
NEM	net energy metering
NERC	North American Electric Reliability Corporation
NOPR	Notice of Proposed Rulemaking
NYISO	New York Independent System Operator
NYTO	New York Transmission Owner
PV	photovoltaic
RERRA	relevant electric retail regulatory authority
RTO	regional transmission organization
RUC	reliability unit commitment
SOC	state of charge
SODERA	settlement-only DERA
SPP	Southwest Power Pool
T&D	transmission and distribution
TIRR	technical interconnection and interoperability requirements
TSO-DSO	transmission system operator-distribution system operator
URP	utility-required profile
VER	variable energy resource



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# Section 1: Introduction



This EPRI collaborative included 32 participating companies and over 600 individuals participating in over 40 webcast sessions throughout 2021. Eleven workstream guides were produced throughout the project.

On September 17, 2020, the Federal Energy Regulatory Commission (FERC) released Order No. 2222, which aimed to enable participation of distributed energy resource (s) aggregations in energy, ancillary services, and capacity markets operated by independent system operators (ISO) and regional transmission organizations (RTOs). The order directed ISO/RTOs to ensure existence of adequate participation models for heterogeneous DER aggregations through potential tariff changes, while establishing any needed rules for coordination to ensure bulk system and distribution system reliability. Due to its strong relationships with both distribution utilities and ISOs/RTOs, EPRI initiated the FERC Order 2222 Collaborative Forum (FO2222) at the end of 2020 to assemble these entities across the country and worldwide to:

- Discuss key challenges associated with the order
- Identify any remaining gaps across the different focus areas of the order
- Establish a roadmap for reliable and economically efficient stakeholder compliance with the order, through panel sessions, six workstream discussion sessions, educational sessions, and engagement with other stakeholders

This report summarizes these activities and provides the roadmap, including upcoming challenges prior to implementation.


The forum consisted of all seven U.S. ISO/RTOs, a Canadian ISO/RTO, and more than 25 utilities of differing types, sizes, and locations from the United States and worldwide. The project held 18 “full participant” webcasts during the year, focusing on different topics and updates of interest to all participants. In addition, focused discussions on six workstreams covered particular areas relevant to the order, which led to a total of over 45 webcasts<sup>1</sup> Following are the six workstreams (see Figure 1-1):

---

<sup>1</sup> Due to the COVID-19 pandemic, no in-person engagements were held as part of the project.

1. **Wholesale Market Operations and Design** covered topics related to wholesale market design and operation from the ISO/RTO perspective, including DER aggregation participation models, market rules for different services, and geographically broad aggregations.
2. **Distribution Reliability and Safety** covered topics related to maintaining distribution system reliability from the distribution utility perspective, including distribution planning mechanisms to ensure DERs could reliability participate in aggregations, and reliability override of dispatch in operation if needed to ensure distribution system reliability.
3. **Transmission System Operations and Planning** covered topics related to maintaining transmission system reliability from the transmission owner or ISO/RTO perspective, including transmission operations tools and transmission planning assessments with active DERs.
4. **Transmission Distribution and Aggregator Coordination** covered topics related to coordination from ISO/RTO, distribution utility, transmission utility, DER aggregator, and electric retail regulatory authority perspectives, including communication and process needs during situations that require coordination across multiple entities.
5. **Information, Communication, and Cyber Security** covered topics related to data exchange, cyber security, and metering and telemetry hardware and software needs to meet evolving needs of DERA participation in wholesale markets.
6. **Customer Technologies and Retail Programs** covered topics including the types of DERs likely to be adopted across the country, and issues related to retail participation such as dual participation and double counting prevention.



 *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*

*Figure 1-1  
The FO2222 collaborative included a broad array of stakeholders to develop this roadmap. It consisted of six topical workstreams.*

Project discussions included a variety of sessions (see Figure 1-2). Four educational sessions aimed to educate stakeholders “on the other side of the substation”:

- ISO/RTO Markets for Distribution Utility Staff 101
- ISO/RTO Markets for Distribution Utility Staff 201
- Distribution Systems for ISO/RTO and Transmission Staff 101
- Distribution Systems for ISO/RTO and Transmission Staff 201

Stakeholder sessions were also held with DER aggregators, European system operators, the North American Electric Reliability Corporation (NERC), technology companies, and state public utility commissions.<sup>2</sup> Other sessions included updates from ISO/RTOs, distribution utilities, and research entities on various topics.

<sup>2</sup> See [https://www.youtube.com/watch?v=Qb-8\\_4cUcyw&t=23s](https://www.youtube.com/watch?v=Qb-8_4cUcyw&t=23s)

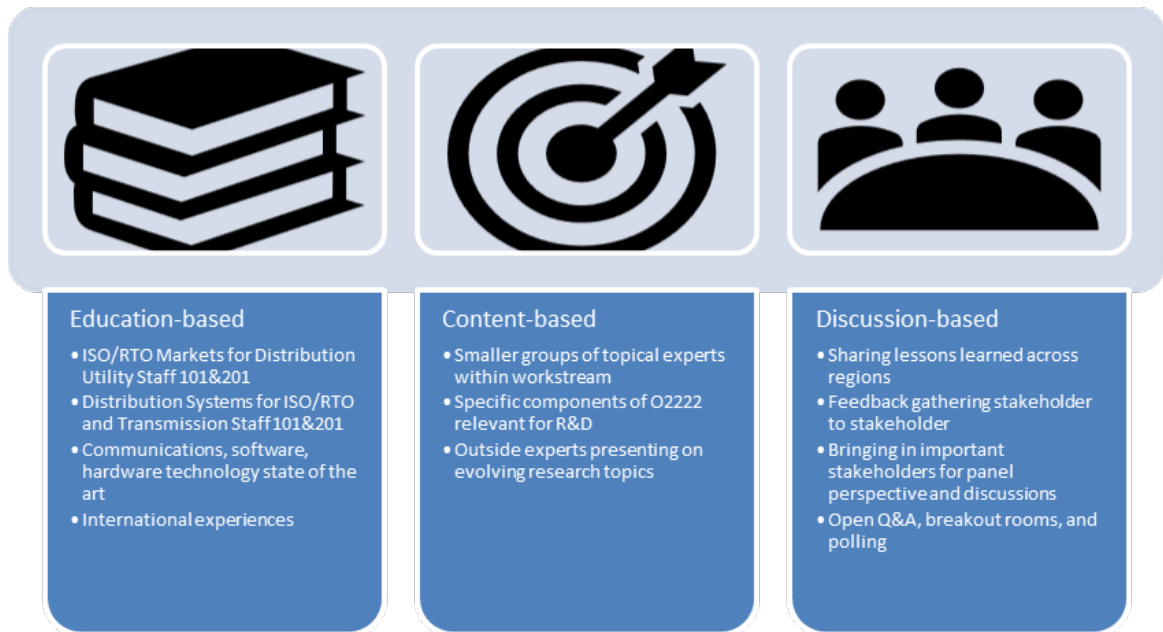


Figure 1-2  
 Project discussions included education-based, specific content-based, and discussion-focused sessions.

This final report summarizes project discussions to provide a roadmap across the different areas and support needed stakeholder actions. While all compliance filings from the ISO/RTOs and design discussions occurred during the project and are nearly complete, implementation of Order 2222 is not anticipated to occur in many regions for a few years. Implementing the new tools and practices to ensure reliable and practical DER participation at scale in wholesale markets will require additional steps. Section 2 reviews Order 2222, additional clarifications, and ISO/RTO designs to date. Section 3 summarizes discussions and possible needed actions to implement each workstream, as well as cross-cutting areas. Section 4 concludes the report and includes recommended next steps.



## Section 2: FERC Order 2222 and DER Market Participation Activities

This section provides background information on FERC Order No. 2222, follow-up activities from FERC, and up-to-date design discussions from each ISO/RTO to comply with the order. This detailed review shows that DER participation in wholesale markets can be addressed in multiple ways. It also shows that each region has unique characteristics that call for different designs and rules.

The information in this review is timely for the following reasons:

- As of December 2021, all but two ISO/RTOs had not submitted final filings to FERC.
- FERC may reject portions of some submitted filings.
- All design features are subject to change.

### FERC Order No. 2222 Summary and History

The long evolving history of FERC Order No. 2222 began with inquiries regarding the participation of electric storage resources into electricity markets, with the possibility of electric storage resources being located on the distribution system (Figure 2-1). FERC opened an inquiry on electric storage resources in November 2015, but the comments received on the docket were also related to DERs and their participation in ISO/RTO markets. In November 2016, FERC issued a Notice of Proposed Rulemaking (NOPR) on ESRs and DER aggregations (DERAs) and received 109 comments [1]. In February 2018, FERC issued Order No. 841, which provided a final ruling for ESRs, but did not provide final rulings on DERAs due to lack of information [2]. Some parties filed for clarification or rehearing on some elements of Order No. 841, primarily concerned with whether electric storage resources located on the distribution system can participate in wholesale markets or whether states could allow for an opt-out. In May 2019, Order No. 841-A on rehearing and clarification confirmed FERC jurisdiction [3].

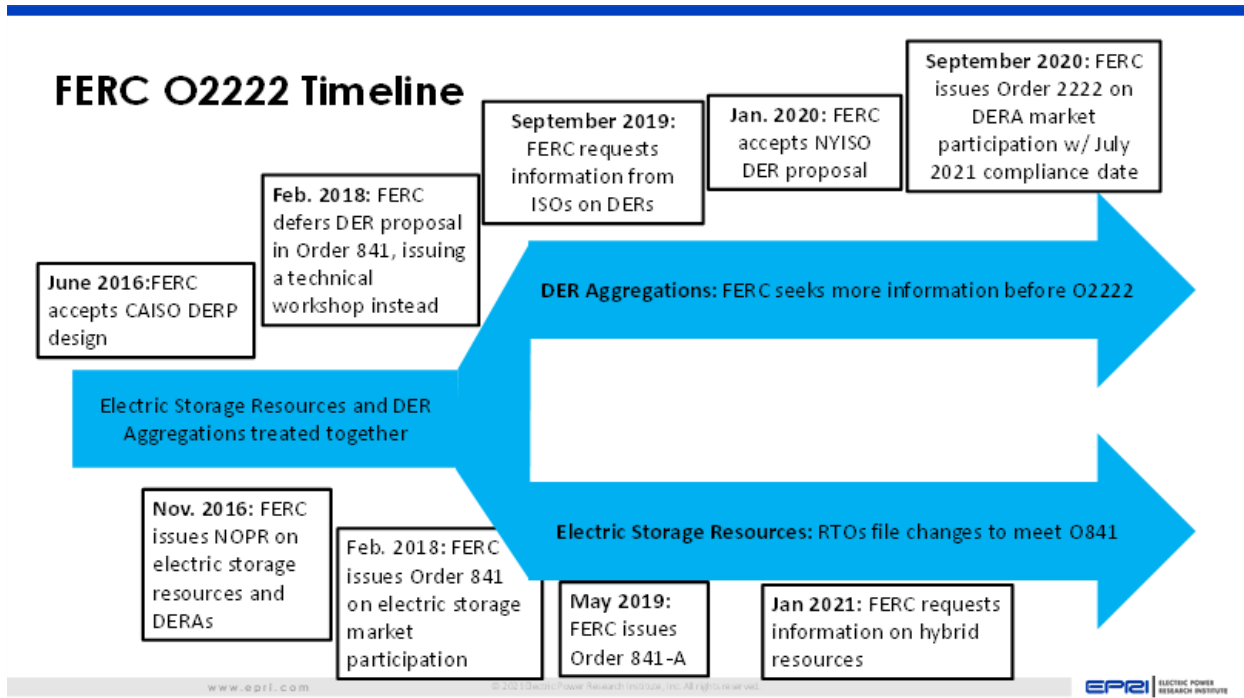


Figure 2-1  
 The FERC Order 2222 timeline began with activities at CAISO and the NOPR on DERs and electric storage resources

In a new separate DERA docket opened at the time FERC issued Order No. 841, FERC held a technical conference in April 2018, which focused on several aspects of DERAs, including locational requirements, regulatory concerns, compensation for multiple services, coordination of DERAs, and ongoing operational coordination [4]. EPRi and many other organizations submitted comments on several of these aspects. In September 2019, FERC requested information regarding policies and procedures affecting interconnection of DERs from ISO/RTOs.

FERC issued Order No. 2222 on September 17, 2020, to facilitate participation of DERAs in the capacity, energy, and ancillary service markets operated by ISO/RTOs [5]. The order specifically addressed barriers to DER participation related to ISO/RTO minimum size and performance requirements, thereby enhancing competition and producing just and reasonable rates. The order requires ISO/RTOs to file tariff modifications to comply with the order by July 19, 2021. Notably, two ISO/RTOs had already filed with FERC designs regarding DERA participation, and FERC had accepted those designs before the order was issued:

FERC issued Order No. 2222 on September 17, 2020, to facilitate participation of DERAs in the capacity, energy, and ancillary service markets operated by ISO/RTOs [5].

- The California Independent System Operator (CAISO) filed tariff revisions in March 2016 and received FERC acceptance in June 2016 [6].
- The New York Independent System Operator (NYISO) filed tariff modifications in June 2019, followed by FERC approval of those changes in January 2020 [7].

These two ISO/RTOs may still need to propose tariff changes to comply with Order No. 2222. In addition, ISO New England (ISO-NE) currently allows DERAs to participate in wholesale markets as demand response (DR) resources or settlement only resources [8].

In general, the rules adopted in Order No. 2222 were proposed in the NOPR [1], but with specific modifications in response to:

- Comments received on the NOPR
- Feedback to the FERC technical conference in April 2018 [4]
- Responses to a post-technical conference notice
- Replies ISO/RTO provided to FERC's September 2019 data requests regarding the policies and procedures impacting the interconnection of DERs

The specific directives are summarized below.

**Jurisdiction.** FERC referred to sections 201, 205, and 206 of the Federal Power Act (FPA) to argue its legal authority in making rules and regulations regarding the participation of DERAs in ISO/RTO markets. FERC's argument is two-fold:

- FERC contends that sales of energy by a DERA in ISO/RTO markets are wholesale sales and therefore are under FERC legal authority.
- FERC asserts that the U.S. Supreme Court ruling that confirmed FERC's legal authority over sale of DR resources in ISO/RTO markets can be extended and equally applied to the sale of DERAs in ISO/RTO markets.

**Opt-out and Opt-in.** FERC referred to its jurisdiction over wholesale markets and decided not to include an opt-out option for relevant electric retail regulatory authorities (RERRAs) to prohibit all DERs from participating in ISO/RTO markets. However, it includes an opt-in option similar to Order No. 719-A by which:

- Small utilities (less than 4 million MWh annually) must opt-in for ISO/RTOs to accept bids or offers from DERs that are their customers. Otherwise, ISO/RTOs cannot accept those bids or offers.

- For DERs located in larger utilities, ISO/RTOs must automatically accept bids or offers.
- Each ISO/RTO must explain how it will implement the small utility opt-in.

**Interconnection.** FERC declined to exercise jurisdiction over the interconnection of DERs to distribution networks for those DERs seeking to participate in ISO/RTO markets only as part of a DERA. Thus, state and local utilities would be responsible for overseeing such interconnections. FERC asserted that DER participation in ISO/RTO markets through a DERA would not establish a first interconnection for the purpose of making wholesale sales under the “first use” test. However, the interconnection of a DER for the purpose of directly participating in wholesale markets not through DERA would constitute a “first use.” Thus, any subsequent DER interconnection for the purpose of directly engaging in wholesale market would be under FERC jurisdiction. FERC also stated that any existing interconnection agreements for DERs that were under FERC jurisdictional procedures (i.e., in CAISO) do not need to convert to state or local interconnection agreements.

**DER and DERA Definitions.** In Order 2222, FERC defined a DER as “*any resource located on the distribution system, any subsystem thereof or behind a customer meter.*” FERC mentioned that using “source or sink” in the NOPR definition may have caused confusion and inadvertently excluded resources (e.g., selling ancillary services may mean it is not a source or sink). FERC clarified that in this definition, resources that are in front of or behind the customer meter, ESRs, intermittent generation, distributed generation, DR, energy efficiency, thermal storage, electric vehicle, and their supply equipment are examples of DERs as long as the resource is “located on the distribution system, any subsystem thereof or behind a customer meter.” FERC defined a DER aggregator as “*the entity that aggregates one or more distributed energy resources for purposes of participation in the capacity, energy and/or ancillary service markets of the regional transmission organizations and/or independent system operators.*”

**DER Technology Types.** FERC requires each ISO/RTO to modify its tariff to allow single aggregations that consist of different DER technologies (i.e., heterogeneous aggregations). Regarding a concern raised by ISO-NE on settlement of DR resources in an aggregation, FERC asserted that Order No. 745 would apply to DR resources participating in heterogeneous aggregations.

**Double Counting of Services.** FERC allowed ISO/RTOs to limit the participation of DERs through DERA for DERs that are compensated for the same service through another program. However, FERC required each ISO/RTO to modify its tariff to:

- Allow DERs participating in one or more retail programs to participate in wholesale markets
- Allow DERs to provide multiple wholesale services
- Include any appropriate limitations on the DER participation in ISO/RTO markets through DERA if service provided is counted more than once, for which FERC provided two examples:
  - A DER that is offered in a wholesale market but not added back to a utility or load-serving entity (LSE) load profile
  - A DER that is registered to provide the same service twice in the wholesale market (e.g., in multiple DERAs, or in a DERA and a DR program)

FERC notes that these limitations are similar to those imposed in Order No. 719 for aggregations of DR resources.

**Participation Model.** FERC required each ISO/RTO to modify its tariff and define a DER aggregator as a market participant, allowing it to register its aggregated DERs under one or more participation models that fits its aggregated DERs' physical and operational characteristics. FERC stated that ISO/RTOs can determine how they need to adjust existing participation models or create one or more new participation models for DERAs. ISO/RTOs can also choose a mixture of these two approaches.

**Minimum and Maximum Aggregation Size.** FERC required each ISO/RTO to revise its tariff to impose a minimum size requirement not to exceed 100 kW for all DERAs, regardless of their participation through existing or newly proposed participation models. FERC did not institute a maximum size requirement for multi-node aggregations. However, FERC stated that it does not explicitly require ISO/RTOs to allow multi-node aggregations of DERs in their markets.

**Single Resource Aggregation.** FERC asserted that a single DER as an aggregation is allowed with no difference in minimum size requirements.

**Bulk System Locational Requirements.** FERC required ISO/RTOs to modify their tariff to describe the locational requirements for DERs participating in DERAs that are as geographically broad as technically feasible. To comply with the order, FERC required each ISO/RTO to describe the geographical scope of its proposed locational requirements, including specific topology of the region and congestion patterns that explain any limits on multi-node aggregations. While FERC acknowledged the benefits of single-node aggregations given potential cost savings from separate telemetry and potential reliability benefits from improved congestion management, it asserted that multi-node aggregations can provide greater participation and enhance the services the aggregated DERs can provide.

**Distribution Factors and Bidding Parameters.** FERC requires ISO/RTOs that allow multi-node aggregations to:

- Require DERAs to give ISO/RTO the allocation from each pricing node (i.e., distribution factors) at initial registration and any time they change.
- Incorporate bidding parameters into participation models to account for physical and operational characteristics of aggregated DERs.

In complying with the latter requirement, each ISO/RTO must either include the needed bidding characteristics as part of its new participation model or adjust bidding parameters of existing participation models.

**Information and Data Requirements.** FERC required each ISO/RTO to revise its tariff to:

- Define the information and data requirements that a DERA must provide about its physical and operational characteristics
- Require DER aggregators to provide a list of DERs in their aggregation and update the list as the DERs in the aggregation change
- Define any information required to be submitted for individual DERs
- Require each DER aggregator to provide aggregate settlement data and retain performance data for individual DERs

In addition, FERC clarified that each DER aggregator is the single point of contact with the ISO/RTO and is therefore responsible for metering, managing, dispatch, and settlement of individual DERs in its aggregation.

**Metering and Telemetry System Requirements.** FERC required each ISO/RTO to create market rules that address metering and telemetry hardware and software requirements for DERAs in its compliance filing. FERC gave ISO/RTOs the flexibility to propose metering and telemetry requirements for both individual DERs and the DERAs. However, ISO/RTOs should explain in their compliance filings why requirements are just and reasonable and do not impose unnecessary and undue barrier to individual DERs within an aggregation. FERC also required ISO/RTOs to explain whether their proposed requirements are close to those for other resources participating in the same service. However, FERC did not require that the requirements be identical to those of existing resources or that they be different.

**Market Rules on Coordination.** FERC modified the NOPR by adding RERRAs to the coordination framework. Therefore, FERC required each ISO/RTO to modify its tariff to create market rules for coordination between the ISO/RTO, the DER aggregator, the distribution utility, and the RERRAs.

**Role of Distribution Utilities in Coordination.** FERC required each ISO/RTO to modify its tariff to include a comprehensive and non-discriminatory process for timely review by distribution utilities (DUs) of individual DERs in a DERA, triggered by registration of DERA in the ISO/RTO market or incremental change (addition or removal of DERs) to the DERA already in the market. To comply with the order, ISO/RTOs are required to coordinate with DUs to determine criteria that DUs would use to determine whether each DER is eligible to participate in the DERA, and if the participation of a DER in a DERA would pose significant risks to the reliable and safe operation of the distribution system. In addition, FERC required ISO/RTOs to demonstrate in their compliance filings that the distribution utility review process is transparent, includes specific criteria, and is conducted in a timely manner. FERC required each ISO/RTO to put a reasonable time limit for distribution utility review process to be completed. FERC specified that this time limit should not exceed 60 days. Finally, FERC required any disputes between ISO/RTO, the distribution utilities, and the DERAs to be processed according to the dispute resolution provisions in the ISO/RTO tariff as part of a proposed distribution utility review process.

**Ongoing Operational Coordination.** Recognizing the need for real-time coordination to ensure safe and reliable operation of transmission and distribution (T&D) systems, FERC required each ISO/RTO to create a process for ongoing coordination that addresses data flow and communication among itself, the DER aggregator, and the distribution utility. Each ISO/RTO must also require the DER aggregator to report to the ISO/RTO any changes to offered quantity and the relevant distribution factors that is caused by distribution system outages. Furthermore, each ISO/RTO must include coordination protocols and processes for the operating day that can allow distribution utilities to override the ISO/RTO dispatch of a DERA when such override is necessary to maintain the reliable and safe operation of the distribution system. The override processes must be in the tariff, be non-discriminatory, and be transparent. Each ISO/RTO is also required to apply existing resource non-performance penalties to DER aggregators when the DERA does not perform because of an override.

**Role of Relevant Electric Retail Regulatory Authorities.** FERC required each ISO/RTO to explain in its tariff how they involve RERRAs in coordinating the participation of DERAs in its market.

**Coordination Frameworks.** FERC encouraged but did not require ISO/RTOs to develop coordination frameworks that address the needs of its region. FERC noted that the coordination framework was not fully considered in the record and is still developing.

**Modifications to the List of DERs in an Aggregation.** FERC required each ISO/RTO to establish rules that address modification to the list of DERs in a DERA. In addition, the DER aggregator must update the

list of DERs in each aggregation, and any relevant information and data, but the DER aggregator does not have to reregister or re-qualify the aggregation. FERC emphasized that any modification to the list will trigger the distribution utility review process. However, FERC believed that each entry and exit will have minimal impact on the distribution system and suggested that an abbreviated review process is sufficient, compared to the beginning review process.

**Market Participation Agreements.** FERC required ISO/RTOs to establish rules that address market participation agreements for DER aggregators, including a standard market participation agreement defining the DER aggregator role and responsibilities, and the DERA relationship with the ISO/RTO. The DER aggregator must execute this agreement before participating in an ISO/RTO market. The agreement must also attest that the aggregation is compliant with the tariffs and operating procedures of the distribution utilities and rules/regulations of any RERRA. The participation agreements must not limit the business models under which the DER aggregator can operate (i.e., not exclusive to third-party aggregator companies). No other requirements are stated for the agreement, and FERC allowed ISO/RTOs and stakeholders to develop the agreements based on specific needs.

**Compliance Timeline.** FERC required each ISO/RTO to submit tariff changes within 270 days from when the final rule was made effective in the Federal Register. Therefore, tariff filings were originally due by July 19, 2021.<sup>3</sup> Rather than specifying the implementation date, FERC allowed each ISO/RTO to propose a final implementation date in its compliance filing.

#### Order 2222-A and Order 2222-B

FERC issued Order No. 2222-A in March 2021 to address the arguments raised on rehearing and to provide clarifications on the final rules of Order No. 2222. Notably, FERC clarified in Order No. 2222-A that while the opt-out requirement of Order Nos. 719 and 719-A continues to apply to aggregations made solely of DR resources, it did not intend to extend this requirement to DR resources participating in heterogeneous DERAs. More of what was included in this order of rehearing, set aside, and clarification are provided below:

- It removed the opt-out option from relevant electric retail regulatory authorities for heterogeneous DER aggregations that include DR. The opt-out would continue to apply to aggregations made up solely of resources that participate as DR resources, based on the ruling of

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<sup>3</sup> As discussed later, four of the six ISO/RTOs were granted extensions in their compliance deadlines out to February and April 2022.

FERC Order 719. Thus, DR resources in states that have the opt-out could participate in heterogeneous DER aggregations that include other resources. (Note that this was set aside in Order 2222-B.)

- It confirmed its use of the 4 million MWh small utility threshold opt-in of Order 2222.
- It clarified that FERC declined to exercise jurisdiction over interconnections of DERs, including interconnections of qualified facilities.
- It confirmed the flexibility for which ISO/RTOs establish new or modify existing participation models for DER aggregations.
- It clarified that ISO/RTOs may not need to make additional changes to rules or new restrictions to prevent double counting, if for example, existing restrictions meet the requirements.
- It clarified that energy efficiency resources can also require a distribution utility review when part of an aggregation participating in the wholesale market, and that only the distribution utility hosting the DER is given the opportunity to review the addition of that resource to an aggregation.
- It clarified that the specific information shared on the DER from an ISO/RTO to a distribution utility as part of the distribution utility review process, should also be shared with the DER aggregator. It also clarified that when a distribution utility recommends removal of a DER from an aggregation due to a reliability concern, the ISO/RTO should not remove the DER without showing that the participation presents a threat to distribution system reliability.
- It clarified that when ISO/RTOs include impacts on distribution system reliability as a criterion in distribution utility DU review process, these would refer specifically to incremental impacts from the DER participation in the aggregation that were not previously considered by the distribution utility during the interconnection study process for that resource.

On June 17, 2021, FERC released the final rule in Order No. 2222, which among some clarifications, reversed the finding in Order No. 2222-A and allowed RERRAs to prohibit participation of DR in any DERA. FERC inserted these issues in a new separate docket through a notice of inquiry that explored whether to remove the opt-out of DR in Order No. 719. Thus, the opt-out is still applicable to DR resources that participate in DER aggregations.

In addition, Order No. 2222-B provided certain other clarifications. It clarified that the requirements of FERC Order No. 745, which allows DR resources to be paid the locational marginal price (LMP) when the appropriate net benefits test (NBT) has been passed, can apply to DERs that act as DR resources within a DER aggregation. This also means that a

behind-the-meter generator may participate within a DER aggregation as a DR resource in which case Order No. 745 requirements would apply. This was the final ruling.

## ISO/RTO Designs and Compliance Filings

CAISO and NYISO submitted their compliance filings prior to the July 19, 2021, deadline and received several comments from FERC to address. While other jurisdictional ISO/RTOs have not yet filed compliance filings to FERC, they have been discussing their main design proposals with their stakeholders. The following subsection reviews the major market design features ISO/RTOs have proposed for integration of DERAs in wholesale electricity markets.

### NYISO

NYISO received FERC approval on its “DER and Aggregations” participation model on January 23, 2020, around eight months before FERC issued Order No. 2222 [7]. The “DER and Aggregations” participation model established requirements for DERAs to participate in NYISO-administered energy, ancillary services, and installed capacity markets. NYISO submitted Order No. 2222 compliance filing on July 19, 2021, stating that their “DER and Aggregation” participation model is compliant with most of the order’s requirements while proposing certain modifications to establish full compliance [9]. In what follows we summarize major DERA market design proposals in the NYISO compliance filing:

*Participation Model:* NYISO proposes to permit aggregations of a single resource in compliance with Order No. 2222. Note that the initial “DER and Aggregation” model required two or more individual resources in an aggregation. A size limit applies to each individual DER in an aggregation of 20 MW. Each transaction offered in the energy, ancillary services, and installed capacity markets must have a minimum offer of 100 kW. Minimum eligibility and performance requirements are enforced at the aggregation level except for the provision of ancillary services, which requires all individual DERs in the aggregation to be qualified to provide that service. Aggregations are prohibited from providing voltage support service. NYISO has established eligibility, qualification, and participation rules for DERAs to participate in an installed capacity market.

*Locational Requirements:* Individual DERs within an aggregation must be connected to the same NYISO-identified transmission node. NYISO believes that this requirement will help grid operators better manage transmission constraints and encourage DERs to locate strategically.

*Compliance with Order No. 745:* NYISO’s participation model for aggregations that include both DR and non-DR resources ensures compliance with Order No. 745. While the aggregation is not required to

report what portion of its day-ahead or real-time offer constitutes demand reductions, NYISO evaluates each aggregation's performance after the fact to compensate the demand reductions portion only when real-time LBMP meets or exceeds the NBT threshold.

*Bidding Parameters:* Aggregators are not required to provide distribution factors (DFs). Aggregations will not be eligible to submit commitment costs and will be modeled as "dispatch-only" resources. Homogeneous aggregations may elect the participation model associated with the resource type.

*Registration:* Aggregators are required to provide information about the aggregation (e.g., location of DERA, meter authority that will serve the aggregation, upper/lower operating limits, etc.) and individual DERs (e.g., upper and lower operating limits, resource and fuel type, etc.) at the time of registration.

*Metering and Telemetry:* The aggregator must provide real-time telemetry and after-the-fact revenue-quality meter data for the Aggregation's energy injections, energy withdrawals, and demand reductions. These multiple streams of data will allow the NYISO to ensure compliance with Order No. 745 requirements among other things. Measurements for metering and telemetry of individual DERs could be obtained from either directly measured or calculated values, or a combination thereof, according to requirements in NYISO Procedures.

*Dual Participation:* In coordination with the New York Transmission Owners (NYTOs), NYISO has developed rules and operational coordination procedures which allow for dual participation of resources in both wholesale and distribution services.<sup>4</sup> However, to prevent double counting, NYISO prohibits a DER that provides a service (e.g., energy, ancillary services, capacity) to a distribution utility from providing the same, or a functionally similar service in the NYISO wholesale markets.

*Ongoing Coordination:* Existing coordination mechanisms at NYISO allows NYTOs to directly contact the NYISO requesting that specific resources be scheduled in a way that satisfies a local reliability need. NYISO also proposes tariff modifications to address coordination needs between NYISO, distribution utilities, and aggregators. The aggregator is responsible for notifying the distribution utility of its device-level plans. The distribution utility may use this data to inform the Aggregator on any derates caused by distribution system conditions. Aggregator must update its day-ahead and real-time market bids to address individual DER derates.

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<sup>4</sup> In New York, the NYTOs are generally the same companies as the DUs that also own and operate the distribution system.

*Effective Implementation Date:* NYISO proposes to implement its DER and aggregation participation model in the fourth quarter of 2022.

## CAISO

CAISO implemented its FERC-approved DERA participation model in 2016 [6]. However, there has not been known participants since it was implemented. CAISO has identified two potential reasons for lack of participation: (1) DERs providing the net energy metering service are not allowed to provide wholesale market services, and since net energy metering rates have been considerably higher than average wholesale market rates, they always choose net energy metering over wholesale. (2) Resource adequacy (RA) qualifying-capacity counting rules for DERAs do not exist in California, which incentivizes resources to participate as standalone or DR resources in CAISO markets. The following summarizes major DERA market design proposals in the CAISO compliance filing [10]:

*Participation Models:* CAISO proposes to lower the minimum capacity requirements for DERAs from 500 kW to 100 kW. Individual DERs seeking to participate in a DERA must be smaller than 1 MW. Allowed participation models for DERAs are generator resource, non-generator resource (NGR), DER provider (DERP), and the newly introduced “heterogeneous DERA” which can allow aggregation of DR resources with others.

*Compliance with Order 745:* CAISO proposes to implement a new participation model called “heterogeneous DERA” that allows aggregation of DR and non-DR resources. The scheduling coordinator for such DERA submits ancillary service and energy bids on the aggregation’s behalf. To establish compliance with Order No. 745, CAISO requires that the bid must be above the market clearing price established by the NBT This requirement would apply to both injecting DERs and DRs in the aggregation.

*Locational Requirements:* The CAISO allows individual DERs within an aggregation to aggregate across a single sub-load aggregation point (sub-LAP), which is geographically broad. For comparison, CAISO generally has over 12,000 transmission pricing nodes but approximately 23 sub-LAPs at any time.

*Bidding Parameters:* The CAISO requires DERs aggregating across multiple pricing nodes in a DERA to submit and follow DFs. All DERAs are required to provide common bid parameters for supply resources and other parameters required for aggregations including ramp rate, min and max operating limits, energy limits, contingency flag, etc.

*Dual Participation:* To prevent double-counting of the same service, the CAISO proposes that “a DERA may not receive compensation from retail programs for capacity, Energy, or other services it provides the CAISO Markets” [10]. The CAISO proposes to identify such instances in collaboration with the applicable distribution utility.

*Metering and Telemetry:* DERAs must submit aggregate settlement quality meter data for the DERA to CAISO. Individual DERs within an aggregation must be directly metered under a meter that complies with the distribution utility tariff and any standards of the local regulatory authorities. For a heterogeneous DERA consisting of both DR and non-DR resources, the CAISO requires the following data in each settlement interval: (1) net injection or withdrawal from non-DR resources, (2) demand curtailment from DR resources, (3) the customer load baseline or generator output baseline, and (4) actual consumption or energy during all hourly intervals used in developing the baselines. Only DERAs larger than 10 MW or providing ancillary services must submit direct telemetry to CAISO (aggregate level).

*Distribution Utility Review:* CAISO proposes to allow 30 days for distribution utility review of the DERA. The distribution utility may raise concerns if it has identified that any DERs (1) participate in another DERA, (2) participate through DR participation model, (3) participate in a net-energy metering program that does not explicitly allow for wholesale market participation, (4) do not comply with the distribution utility or RERRA requirements, (5) may adversely impact the safety and reliability of the distribution system if operated as part of a DERA, and (6) causes a double counting issue. The DERP will get a chance to resolve the issues with the distribution utility before it is allowed for wholesale market participation.

*Ongoing Coordination:* CAISO coordinates with the applicable distribution utility on an ongoing basis, e.g., through sharing DERA dispatch instructions, to avoid conflicting operational directives. It also requires the DERP to operate “consistent with limitations or operating orders established by the DU”, and to submit outages to the CAISO reflecting any distribution constraints impacting a DER within the aggregation.

*Effective Implementation Date:* CAISO proposes an effective date no later than Nov. 1, 2022, for implementation of the changes proposed in the compliance filing.

## MISO

MISO's compliance filing due date was extended to April 18, 2022. However, MISO has discussed several aspects of its DERA design proposal with its stakeholders. The following is a summary of major DERA design proposals at MISO [11]. The descriptions below may be subject to change before finalized.

*Participation Models:* MISO allows DERAs to participate through two of its existing participation models: dispatchable intermittent resource and energy storage resource. The minimum size requirement for an aggregation is 100 kW. There is no minimum/maximum size requirement on each individual DER. MISO requires small DERAs (<1 MW) to self-commit.

*Locational Requirements:* DERs within an aggregation must be located at a single transmission pricing node (EPNode) for the purpose of participation in wholesale markets.

*Metering and Telemetry:* MISO defines a "DER Group" as a subset of DERs in an aggregation that are homogeneous and utilize the same measurement and verification methodology. DER aggregators must submit meter data for each individual non-grouped DER and DER group in a DERA. In any case, aggregators must retain individual DER meter data for auditing purposes. Using the abovementioned data, MISO calculates the aggregation response to verify performance. For each individual DR or DR DER Group, MISO calculates baseline and performs measurement and verification. MISO is considering two options for telemetry: (1) 2 s granularity from all dispatchable DERAs, (2) relaxed scan rate, e.g., 10-30 s, for non-regulation qualified dispatchable DERs less than 5 MW in size.

*Compliance with Order 745:* The DR portion of the meter data provided by the DER Aggregator will be settled under existing settlement rules at MISO to ensure compliance with Order No. 745. To ensure appropriate load reconstitution, the DR portion MW will be reconstituted to the applicable load-serving entity when the "locational marginal price (LMP) is less than the NBT threshold," and to the applicable reserve zone(s) otherwise. In such DERAs, DERs will be limited to one LSE.

*Dual Participation:* MISO has identified a few examples of double counting, e.g., a DERA that simultaneously provides energy to the ISO and reduces LSE energy purchase from the ISO. Stakeholders are discussing a few ideas track dual participation of resources in retail programs and MISO markets to prevent double counting of the same service.

## PJM

PJM's compliance filing on Order No. 2222 was extended to February 1, 2022. In collaboration with stakeholders, PJM has developed the main pieces of DERA wholesale market participation. The following is a review of PJM major market design proposals [12]. The descriptions below may change before they are finalized.

*Participation Models:* While DERAs are allowed to use several existing participation models (generator, electric storage resource, DR, and energy efficiency), a new "DERA" participation model is created to better model the physical and operational capabilities of DERAs. There are no minimum /maximum size requirement for each individual DER. A minimum size requirement of 0.1 is imposed on the aggregation. Commitment variables are not required for DERAs (dispatch-only model). Settlement of the DR portion in a DERA will be based on Order No. 745 requirements. Available wholesale services for DERAs include energy, ancillary services (regulation, synchronized reserve, black start), and capacity. DERAs are allowed to self-schedule in day-ahead and real-time energy markets. In this case, they must submit 0\$ cost-based offers and are not eligible for lost-opportunity-cost and make-whole payments.

*Locational Requirements:* All DERs within an aggregation are required to primarily map to the same node. PJM does not require distribution factors because DERA is modeled at a single pricing node to align with PJM dispatch and pricing.

*Telemetry Requirements:* PJM proposes to require real-time telemetry data on an aggregate level with 1-min scan rate for all DERAs providing reserves and capacity service. Energy-only resources are required to provide 1-min telemetry data if the aggregation size is larger than 10 MW. Aggregations providing regulation are required to provide more granular telemetry data (2 s for Reg-D and 10 s for Reg-A). Telemetered data includes MW response, state of charge (SoC) for DERAs using ESR participation model, and meteorological data (radiance and back panel temperature) at 5 min intervals for aggregated solar larger than 3 MW. Accuracy requirement for telemetry is  $\pm 2\%$  and alternative approaches such as calculated values are allowed for individual DERs.

*Metering Requirements:* PJM proposes to require meter data on an individual DER level with 5-min or 1-hour granularity in accordance with PJM manuals. Certain DERs are allowed or required to be sub-metered, e.g., regulation-only DR or behind-the-meter DER). PJM asserts that meter data at individual DER level is required to ensure proper settlement for different DER types and accurate wholesale/retail settlements.

*Registration:* PJM has developed a DERA registration framework in which it has determined the roles and responsibilities of different entities including RERRA, DER aggregator, distribution utilities, PJM, and LSE. DERA registration data in PJM proposal is similar to the data PJM requires from DR aggregations.

*Distribution Utility Review:* In PJM's proposal, the distribution utility review process will have a major role in identifying double counting issues, e.g., wholesale market eligibility for resources participating in net energy metering programs. To resolve any double-counting concerns that could arise for DERAs providing distribution-level services, the DER aggregator must self-schedule for energy in the PJM market.

*Ongoing Coordination:* Ongoing day-ahead operational coordination proposal at PJM requires distribution utilities to coordinate with the aggregator on planned maintenance and other distribution work that impacts DERA operation prior to the day-ahead market. Accordingly, the aggregator is required to accurately reflect the DERA capability in the day-ahead market. After the day-ahead market is cleared, day-ahead schedules will be provided to the distribution utility for further analysis. The DER aggregator can update allowable bid parameters through reliability unit commitment (RUC) rebid procedure. In real-time, the DER aggregator must submit telemetry to both the ISO/RTO and the distribution utility. This gives the distribution utility the opportunity to send override commands to the aggregator to reflect unplanned outages and distribution safety and reliability concerns.

## ISO-NE

Compliance filing for ISO-NE was extended to February 2, 2022. The following is a summary of ISO-NE's major market design proposals [13]. The descriptions below may change before they are finalized.

*Participation Models:* DERAs are allowed to use several existing participation models including continuous storage facility (CSF), generator asset, binary storage facility (BSF), DR resource (DRR) and alternative technology regulation resource (ATRR). In addition, two new participation models are proposed: (1) DR DERA (DRDERA) which allows aggregation of DR with non-DR resources, and (2) Settlement-only DERA (SODERA) which allows self-scheduling. Wholesale services available to DERAs are energy, ancillary services (reserves and regulation), and forward capacity. The minimum size requirement for an aggregation is 100 kW. If an individual DER size is larger than 5 MW, it must be the only DER in the aggregation. SODERA is allowed to participate in forward capacity market (FCM) but not in reserves or regulation. SODERA participation in the day-ahead energy market is optional. To use the SODERA model, the maximum energy injection capability of each individual DER must be less than 5 MW.

*Compliance with Order 745:* To establish compliance with Order No. 745, a DRDERA must submit an offer that is higher than or equal to the NBT threshold price. However, the energy injection portion of the aggregation may self-schedule and get paid the LMP if the DRDERA does not clear the market.

*Locational Requirements:* All constituent DERs within an aggregation must be within the same DRR Aggregation Zone. For Gen Asset, BSF, CSF, SODERA, and DRDERA, a stricter locational requirement is proposed: the intersection of metering domain and DRR Aggregation Zone. If the injection capability of a group of DERs at a single transmission node is more than 5 MW, this group of DERs cannot aggregate with DERs at other nodes.

*Metering and Telemetry:* Hourly Revenue Quality Meter (RQM) data on an aggregate level must be submitted to ISO-NE according to existing requirements (Manual M-28). Alternatives for sub-hourly settlement are telemetry data (if exists) or 5-min RQM data (optional). There is no telemetry requirement for SODERA. If DERA provides regulation through ATRR or other participation models, 4 s telemetry is required on an aggregate level. If DERA uses Generator Asset, BSF or CSF but does not provide regulation, it requires to submit 10 s telemetry on an aggregate level. If participation is through DR or DRDERA, individual resource telemetry data is required (1 min latency if providing 10-min reserve; 5 min latency otherwise).

*Registration:* The DER aggregator notifies both ISO-NE and the applicable distribution utility that it intends to register a DERA. Parameters include contact information, individual DER data (location, size, DER technology type), and DERA market information (desired markets, participation models, and target date). If required by state law, each DER must have an executed interconnection agreement prior to submitting registration request.

*Distribution Utility Review:* The distribution utility will have 60 calendar days to complete the distribution review to ensure (1) distribution system safety and reliability, and (2) DER eligibility according to ISO-NE criteria (e.g., not participating in a retail program that prohibits wholesale participation).

### *Southwest Power Pool*

Southwest Power Pool's (SPP's) compliance filing was extended to April 28, 2022. The descriptions below may be subject to change before finalized. The following is a review of SPP's latest DERA market design proposal [14] :

*Participation Models:* Minimum DERA size for participation is 100 kW. There are no minimum or maximum size limits on individual DERs that are part of an aggregation. DERAs may register and operate under any existing participation model that meets the physical and operational characteristics of the aggregation. A heterogeneous DERA including at least one ESR is eligible to elect the ESR participation model.

*Locational Requirements:* Individual DERs that are part of an aggregation seeking to participate in SPP's energy and ancillary service markets must be located at a single transmission node.

*Bidding Parameters:* Since multiple transmission node aggregation is not allowed, DER aggregators are not required to submit DFs. As for other bidding parameters, SPP states that DER aggregators must submit the bidding parameters of their elected participation model.

*Dual Participation:* Dual retail and wholesale market participation is allowed if the DER (1) does not reduce the LSE's obligation to purchase services from the ISO, (2) does not receive compensation for the same service they intend to provide to the ISO.

*Metering and Telemetry:* DERA must provide after-the-fact aggregated revenue (settlement) quality meter data to the ISO/RTO. The data must be available for LSE to review as well. Real-time telemetry is required at the aggregation level to communicate real-time MW values through Inter-Control Center Communications Protocol (ICCP).

*Ongoing Coordination:* The distribution utility should notify the DER aggregator of any override request that is necessary to maintain the reliability and safety of the distribution system. DERA must update future day-ahead, RUC, and real-time market offers accordingly.

### *Order 2222 Compliance Summary Tables*

Table 2-1 provides a summary comparison of the main market design aspects for DERAs across the six FERC jurisdictional ISO/RTOs.

Table 2-1 provides a summary comparison of the main market design aspects for DERAs across the six FERC jurisdictional ISO/RTOs. The top gray box in each category includes the general approach with unique aspects for each ISO following in the white columns. Readers are reminded that many of the designs are not finalized yet and this status is as of the end of 2021.

Table 2-1  
Summary of ISO/RTO distributed energy resource aggregation market design proposals

FERC Order No. 2222 Aspect	NYISO	PJM	SPP	ISO-NE	MISO	CAISO
Participation Model	Most ISO/RTOs are proposing a new participation model to allow for aggregations of DR with non-DR resources.					
	<p>New: <b>"DER and Aggregation"</b></p> <p>Existing: Homogeneous aggregations may elect existing models.</p>	<p>New: <b>DERA</b></p> <p>Existing: <b>GEN, ESR, DR, EE</b></p>	<p>Existing: <b>DDR, BDR, GEN, MSR, MCR, DVER</b> for homogeneous; <b>GEN, MSR</b> for heterogeneous</p>	<p>New: <b>SODERA, DRDERA</b></p> <p>Existing: <b>GEN, CSF, BSF, DRR, ATRR</b></p>	<p>Existing: <b>DIR, ESR</b></p>	<p>New: <b>DERP, "Heterogeneous DERA"</b></p> <p>Existing: <b>GEN, NGR</b></p>
Eligible Wholesale Market Services	All ISO/RTOs are proposing to allow DERAs provide wholesale energy service.					
	<p><b>Energy, Ancillary Services (AS), Installed Capacity Market.</b></p> <p>Not eligible for Voltage Support. To be eligible for AS, each DER must be eligible.</p>	<p><b>Energy, AS (Regulation, Synchronized Reserve, Black Start).</b></p> <p>Not eligible for Non-Synchronized Reserve.</p>	<p><b>Energy, AS (Reserves and Regulation).</b></p>	<p><b>Energy, AS (Reserves and Regulation), Forward Capacity Market (FCM).</b></p>	<p><b>Energy, AS (Reserves and Regulation).</b></p>	<p><b>Energy, AS (Reserves and Regulation).</b></p> <p>Not eligible for Resource Adequacy (RA) as qualifying capacity counting rules do not exist for DERAs in California.</p>
Locational Requirements	Most ISO/RTOs are proposing single transmission pricing node aggregations.					
	<p><b>Single Trans. Pricing Node</b></p> <p>Similar to a hybrid approach. NYISO identifies the nodes in coordination with NYTOs.</p>	<p><b>Single Trans. Pricing Node</b></p> <p>Must be primarily mapped to the same node</p>	<p><b>Single Trans. Pricing Node</b></p>	<p><b>Multiple Trans. Pricing Nodes</b></p> <p>Intersection of DRR Aggregation Zone and Metering Domain</p>	<p><b>Single Trans. Pricing Node</b></p>	<p><b>Multiple Trans. Pricing Nodes</b></p> <p>Single Sub-Load Aggregation Point (Sub-LAP)</p>

Table 2-1, continued  
 Summary of ISO/RTO distributed energy resource aggregation market  
 design proposals

FERC Order No. 2222 Aspect	NYISO	PJM	SPP	ISO-NE	MISO	CAISO
Metering Requirements	All ISO/RTOs except for PJM and MISO require aggregate-level meter data.					
	<p><b>Aggregated Revenue Quality Meter data</b></p> <p>Multiple streams (energy injections, energy withdrawals, and demand reductions).</p> <p>Individual DER data could be directly measured or calculated values.</p>	<p><b>Individual DER Settlement Quality Meter data</b></p> <p>Hourly or 5-min granularity.</p>	<p><b>Aggregated Revenue Quality Meter data</b></p>	<p><b>Aggregated Revenue Quality Meter data</b></p> <p>Hourly or 5-min (optional) granularity.</p>	<p><b>Individual DER and "DER Group" Settlement Quality Meter data</b></p> <p>A "DER Group" is a subset of DERs that are homogeneous and have the same M&amp;V.</p>	<p><b>Aggregated Settlement Quality Meter data</b></p> <p>Multiple streams (energy injections, withdrawals, and demand reductions). Individual DERs must be directly metered.</p>
Telemetry Requirements	Most ISO/RTOs require aggregate-level real-time telemetry from all DERAs.					
	<p><b>Aggregated Real-Time Telemetry</b></p> <p>Multiple streams (energy injections, energy withdrawals, and demand reductions).</p> <p>Individual DER data could be directly measured or calculated values.</p>	<p><b>Aggregated Real-Time Telemetry</b></p> <p>Scan rate 2s for Reg-D, 10s for Reg-A, 1-min for other AS and Capacity, 1-min for Energy if larger than 10 MW.</p> <p>Calculated values are acceptable for individual DERs.</p>	<p><b>Aggregated Real-Time Telemetry</b></p>	<p><b>Aggregated Real-Time Telemetry</b></p> <p>SODERA: no requirements</p> <p>GEN, BSF, CSF: 10s or 2s (if providing regulation)</p> <p>DR, DRDERA: individual DER telemetry at 1- or 5-min rate</p>	<p><b>Aggregated Real-Time Telemetry</b></p> <p>Scan rate either 2s for all DERAs; or relax to 10-30 s only for non-regulation DERs smaller than 5 MW</p>	<p><b>Aggregated Real-Time Telemetry</b></p> <p>Only if DERA size is larger than 10 MW or provides Ancillary Services.</p>

Table 2-1, continued  
 Summary of ISO/RTO distributed energy resource aggregation market  
 design proposals

FERC Order No. 841 Aspect	NYISO	PJM	SPP	ISO-NE	MISO	CAISO
Application of NBT (Order No. 745) to Heterogeneous DERs (DR + non-DR)	Most ISO/RTOs apply the NBT in after-the-fact settlement stage.					
	<b>Settlement Adjustment</b>  Only applies to DR DERs within a DERA.	<b>Settlement Adjustment</b>  Only applies to DR DERs within a DERA.	<b>Settlement Adjustment</b>  Only applies to DR DERs within a DERA.	<b>Bid-Floor Approach</b>  Applies to both injecting DERs and DR DERs within a DRDERA. Injecting DERs can self-schedule and get paid at LMP if do not clear the market.	<b>Settlement Adjustment</b>  Only applies to DRs within a DERA. DRs must be within the same LSE territory.	<b>Bid-Floor Approach</b>  Applies to both injecting DERs and DR DERs within a DRDERA. Cannot provide services if not cleared.
Maximum Size (Individual DERs)	Most ISO/RTOs require larger DERs to participate as stand-alone resources or be the only resource in the DERA.					
	<b>20 MW</b>	<b>5 MW</b>		<b>SODERA: 5 MW</b>  Other models: If larger than 5 MW, must be its own DERA		<b>1 MW</b>
Maximum Size (DERA)	Only ISO/RTOs allowing multiple pricing node aggregations impose size requirements on aggregations.					
				<b>5 MW</b> on total DER size at each pricing node if aggregated across multiple pricing node		<b>20 MW</b> if aggregated across multiple pricing nodes

*Other ISO/RTO Regions*

**ERCOT:** ERCOT refers to DER as distributed generation (DG) and defines it as “an electrical generating facility located at a customer’s point of delivery (point of common coupling), 10 megawatts (MW) or less, and

connected at a voltage less than or equal to 60 kilovolts (kV), which may be connected in parallel operation to the utility system.” This definition does not include DR. There are three types of DGs in ERCOT [15]:

- **Unregistered DG:** These resources are typically less than 1 MW and are not required to be registered with ERCOT. Resources that are greater than 1 MW but do not inject into the grid also fall in this category. They are not compensated by ERCOT but may be compensated by their electric provider. In 2019, ERCOT estimated these resources at 850 MW, of that 710 MW is rooftop solar.
- **Settlement-Only Distributed Generation:** These resources are self-dispatched resources greater than 1 MW and can inject energy to the grid. They are compensated by ERCOT for the energy they export to the grid. These resources include utility-scale solar, commercial solar, gas-fired generators, and diesel generators. In 2019, ERCOT estimated these resources at 849 MW.
- **Distribution Generation Resource:** These resources are bid into the markets and are compensated for energy and/or ancillary services. Currently, all resources in this category are batteries. In 2019, ERCOT estimated these resources at 2 MW (operational) with an additional 374 MW in interconnection queue.

*IESO:* In September 2020, IESO published a report in which it estimated that more than 4,000 MW of DERs have been contracted or installed over the past ten years in Ontario, with solar accounting for more than half of the total DER capacity [16]. As DER deployment is expected to grow even higher in the coming years, IESO has developed a series of white papers and started pilot programs to understand the impacts of DERs on the transmission-distribution interface. In a 2019 white paper, IESO presented existing participation models for DERs and potential options to expand the models in the future [17]. The white paper also identifies several barriers that may hinder the participation of DERs in the wholesale market. In a separate white paper, IESO investigates the coordination necessary for DERs to provide distribution services through non-wires alternatives and also participate in transmission-level markets [18]. A transmission-distribution interoperability framework is developed in [19] to maximize the potential of DERs in providing services.

The IESO initiated a non-wires alternative demonstration project in York Region to explore market-based approaches in which DERs can provide energy and capacity services. The project is funded by the IESO’s Grid Innovation Fund and Natural Resources Canada, and will be delivered by Alectra Utilities. IESO ran the first local capacity auction in November 2020 in which 10 MW were cleared from seven customers including aggregated residential customers with controllable smart thermostats, industrial customers, and small-scale generators [20].

# Section 3: Mapping Key Challenge Areas

The collaborative forum used the six topical workstreams to focus on particular gaps and possible solutions with experts from various stakeholder groups. As part of the workstream discussions and research, the project team produced technical guides for each of the workstreams (see Table 3-1). These guides contain more detailed reviews of each workstream discussions.

Table 3-1  
Project deliverables and links organized by workstream

Product	Title	Workstream
<a href="#"><u>3002020586</u></a>	DERA Participation in Organized Markets: FO2222 Summary State-of-the-Art and Research Needs	All
<a href="#"><u>3002020587</u></a>	Market Participation Model Design Considerations for DERAs	Market Design & Operation
<a href="#"><u>3002020588</u></a>	Technical Feasibility for Enabling DERAs across Broad Geographical Transmission Locations for Wholesale Market Participation	Market Design & Operation
<a href="#"><u>3002020589</u></a>	The Role of Distribution Utilities in Enabling Market Participation for DERAs	Distribution Reliability
<a href="#"><u>3002020590</u></a>	Evolving Distribution Analytics and Tools	Distribution Reliability
<a href="#"><u>3002020591</u></a>	DER Market Participation Considerations for Transmission Operators	Transmission
<a href="#"><u>3002020592</u></a>	Transmission Planning Considerations For DER Wholesale Market Participation	Transmission
<a href="#"><u>3002020593</u></a>	Coordination Frameworks to Meet Needs of FERC Order 2222	Coordination
<a href="#"><u>3002020596</u></a>	Metering, Data, and Information, and Telemetry	Information, Communication, & Cyber Security

Table 3-1, continued  
 Project deliverables and links organized by workstream

Product	Title	Workstream
<u>3002020597</u>	Systems Interoperability and Cyber Security	Information, Communication, & Cyber Security
<u>3002020598</u>	DER Technology Insights	Customer Technologies & Retail Programs
<u>3002023292</u>	Dual Participation and Double Counting Perspectives	Customer Technologies & Retail Programs
<u>3002022890</u>	FERC Order 2222 Use Case and Activities Challenges Matrix Tool	All

Each workstream section in this report describes the activities and discussions within the workstream, which consisted of several workstream webcasts with a subset of the participants with particular expertise and interest in the subject area. Gaps related to the design of FERC Order No. 2222 are also described, along with recommendations that the project team developed in consultation with project participants. In some cases, additional next steps are also described. These recommendations and next steps can be used as a roadmap from design to implementation to improve integration of DERs participating in wholesale markets through aggregators. These actions can also help ensure efficient and reliable implementation of designs that are part of Order No. 2222 compliance.

### Wholesale Electricity Market Design and Operations

The primary objective of the Wholesale Market Operations and Design Workstream is to support FERC jurisdictional ISO/RTOs and other stakeholders as they change wholesale electricity market design, operations, and market clearing software to comply with the order. In particular, the efforts focused on addressing the challenges of DER aggregation participation models and the potential for geographically broad DERA locational requirements [21,22]. Other aspects, such as ancillary service market and capacity market eligibility, were also discussed. However, because of each ISO/RTO's differences across these market products, the team decided not to incorporate general guidance or recommendations in these areas at this time, and further work will examine these aspects as they evolve. The main goal of this workstream's dialogues was to provide stakeholders the opportunity to discuss the benefits and potential challenges of the numerous proposed approaches to DERA participation models and locational requirements. The following subsections review the main discussions and findings across these topics.

The primary objective of the Wholesale Market Operations and Design Workstream is to support FERC jurisdictional ISO/RTOs and other stakeholders as they change wholesale electricity market design, operations, and market clearing software to comply with the order.

## Participation Models

Challenge:  
Heterogeneous  
aggregation  
participation models are  
not well understood and  
can lead to potential  
reliability or settlement  
concerns.

Per Order No. 2222, FERC required each ISO/RTO to modify its market rules and tariffs to establish DER aggregators as market participants, allowing them to register DER aggregations (DERAs) under one or more participation models that appropriately accommodate their physical and operational characteristics. FERC stated that ISO/RTOs can determine whether and how they adjust their existing participation models or create more new participation models for DERAs. FERC also provided ISO/RTOs the option to choose between a mixture of the two approaches. Given the associated complexities, ISO/RTO-proposed participation models may not capture all the physical and operational characteristics of each DER type that constitutes the DERA. However, to account for unique characteristics, ISO/RTOs must determine the parameters to be submitted with the corresponding participation models. By submitting an offer to the ISO, the aggregator asserts that the DERA will be able to perform as scheduled or dispatched by the ISO or will be penalized for uninstructed deviations if it does not. FERC also required each ISO/RTO to modify its tariff to allow DERAs comprised of different DER technologies (i.e., heterogeneous DERAs) to participate in its energy, ancillary services, and capacity markets (when applicable and when technically viable).

While individual ISO/RTOs used the term “participation model” with slightly different meanings in the past, FERC first broadly introduced the term in its NOPR on energy storage and DERA participation in wholesale markets [1]. FERC defined a participation model as a “set of tariff provisions that accommodate the participation of resources with particular physical and operational characteristics in the organized wholesale electric markets of the RTOs and ISOs.” FERC Order No. 841 slightly revised the definition as “tariff revisions that consist of market rules that, recognizing the physical and operational characteristics of the resource, facilitates their participation in ISO/RTO markets” [2]. EPRI submitted comments to the NOPR, adding that the “definition of a participation model also includes the set of market clearing software provisions required to represent the physical and operational characteristics of the resource” [23]. Generally, ISO/RTOs may consider new participation models when unique characteristics of new technologies require changes to participation or settlement rules (e.g., electric storage resource models) or when characteristics could be incorporated to operate existing resources more efficiently (e.g., advanced combined-cycle models).

Participation models  
reflect characteristics of  
specific supply  
technologies (including  
DR) and are named  
after those technologies.  
However, participation  
models do not typically  
require that each  
technology use the  
participation model  
aligned with the  
technology; some  
technologies can use  
different technology-  
specific participation  
models.

Participation models reflect characteristics of specific supply technologies (including DR) and are named after those technologies. However, participation models do not typically require that each technology use the participation model aligned with the technology; some technologies can use different technology-specific participation models.

Several stakeholders commented that using existing participation models as-is (without incorporating new modifications or with slight modifications) is potentially the quickest path to accommodate DERAs. Some adjustments to existing participation models may become necessary, including but not restricted to:

- Introducing transmission distribution factors (DFs) for DERAs aggregating over multiple pricing nodes
- Modifying minimum resource size requirements
- Modifying commitment decisions (e.g., self-commitment or committed by the ISO/RTO) to be compliant with Order No. 2222 requirements

Other possible reasons for modification include fairness with other participation models, unique features of the ISO/RTO, and the computational tractability of scheduling algorithms, particularly with large numbers of small resources. Additionally, if DERA operation is significantly different than existing participation model options, existing participation models may result in inefficient DERA operation. Furthermore, if DERA's reliability benefits cannot be accommodated and valued appropriately through existing participation model options, new participation models may be needed. However, introducing new participation models is costly and requires significant time and effort. Therefore, a thorough analysis is required to ensure that the new participation model is necessary and offers benefits that outweigh implementation costs (see Figure 3-1).

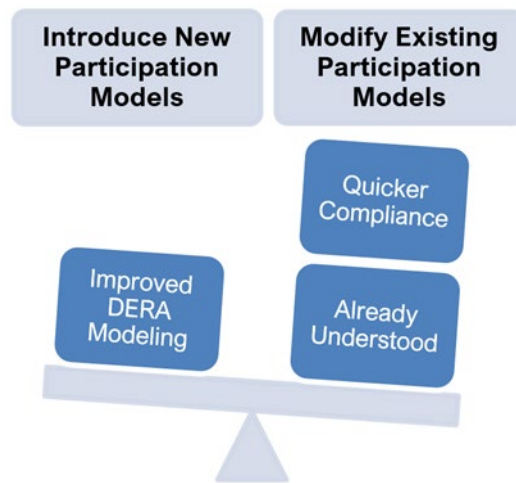


Figure 3-1  
The decision to introduce new participation models or modify existing ones.

Introducing participation models for heterogeneous DERAs poses numerous challenges that warrant further research and development, including demand response (DR) resources, electric storage resources,

and variable energy resources (VERs). This subsection focuses on these three types of heterogeneous aggregations and the challenges and possible mitigation of market participation model development.

### Heterogeneous DERAs Including DR

In Order No. 2222, FERC stated that DR aggregations are subject to the opt-out requirements of Order No. 719. In Order No. 2222-A, FERC clarified that only homogeneous DR aggregations are subject to such requirements [24]. However, Order No. 2222-B reversed this finding and stated that a relevant electric retail regulatory authority (RERRA) may disallow the wholesale market participation of DR resources within any DERAs. Order No. 2222-B also clarified that it defines DR as a service and that individual DR resources could be injecting generators, as long as they reduce demand from a baseline.

Regarding the settlement of DR resources in a DERA, FERC asserted that Order No. 745 still applies to DR resources participating in heterogeneous aggregations. FERC issued Order No. 745 in March 2011 to standardize the compensation of DR resources that participate in wholesale energy markets administered by ISO/RTOs [25]. Order No. 745 stated that when a DR resource participating in the energy market can balance supply and demand as an alternative to generation, and when dispatch of the resource is cost-effective as determined by an NBT, the resource must be compensated for its demand reduction in the energy market at the locational marginal price (LMP). Order No. 745 established requirements for an NBT, required the review and modification (if necessary) of measurement and verification procedures including baseline estimates, and required a method for allocating the costs of DR payments among the loads that benefit from load reductions performed by DR resources.

When developing new rules and participation models for Order No. 2222, ISO/RTOs must ensure compliance with Order No. 745. This is challenging because complicated settlement procedures may be involved. If the NBT has not passed, it may mean that some DERs within the DERA receive LMP payments while others do not. This may also cause further confusion about what constitutes DR. In Order No. 745, FERC did not differentiate between DR resources and DR aggregations or aggregators as in Order No. 2222, which causes some confusion about how rules may be applied. As loads become less predictable and more volatile, the future of baselining methodologies and their effectiveness may become more important.

ISO/RTOs are developing concepts and models to address this issue. For example, NYISO created a FERC-approved DER aggregation participation model that is compliant with Order No. 745. In this DER aggregation model, NYISO treats demand reduction as supply when calculating the total aggregation response. However, the demand reduction part is compensated only if the real-time LMP for the corresponding interval

meets or exceeds the monthly NBT threshold price. Since the DR response is considered as supply, it can help the DERA avoid non-performance penalties even if the DR response is not paid (i.e., because of not satisfying the NBT). CAISO and ISO-NE have recently introduced new participation models to establish compliance with Order No. 745.

These new participation models require the DERA to bid above the NBT threshold price. Since the DERA is the market participant, both ISO/RTOs have indicated that they cannot receive separate bids for injecting DERs versus DRs within the aggregation. Therefore, the bid floor requirement applies to any technologies within a heterogeneous DER aggregation containing at least one DR. One small but important difference between these models is that ISO-NE allows non-DR resources within such an aggregation to self-schedule and be paid at the LMP even if the DERA does not clear the market.

### Heterogeneous DERAs Including ESRs

FERC required ISO/RTOs to allow heterogeneous aggregations of DERs, but it did not establish explicit requirements for heterogeneous DER aggregations that consist of electric storage resources. For DERAs that include electric storage resources (ESRs) within the aggregation, there are operational and market design challenges related to state-of-charge (SOC).

Some ISO/RTOs have stated that SOC information from electric storage resources is crucial to ensure feasible and efficient grid operation. The information is used to maintain reliability and to ensure that the ISO is not relying on a schedule from an electric storage resource that it may not meet because it has run out of charge or has no more capacity to charge. In some cases, this information is also used to optimize the resource to ensure it can reduce costs across a time horizon. Providing SOC information through bidding parameters and telemetry for the electric storage resource portion of DER aggregations may help the DER aggregator maintain feasible SOC levels and feasible energy or ancillary service schedules. Challenges include understanding how SOC can be telemetered or provided through as a bidding parameter if it only represents a portion of the resource, and how the ISO/RTO can use that data. Another challenge is whether and how telemetry may be required and whether it is available from many small devices.

Per the DER provider (DERP) provisions, CAISO intends to consider SOC at an aggregate level, but does not intend to collect or monitor SOC information for the DERs that constitute the DERA. Some ISO/RTOs think that heterogeneous DERAs that consist of electric storage resources might use existing participation models for electric storage resources, such as the Southwest Power Pool's (SPP) market storage resource, which FERC approved as part of Order No. 841 in most regions. Accordingly, because resources using the ESR participation model are required to

submit SOC information, the requirement will also apply to DERAs that use the electric storage resource model despite the ISO/RTO's overarching goal to be technology-agnostic.

Given the imminent deadline to comply with Order No. 2222, some ISO/RTOs have stated that monitoring and considering SOC for heterogeneous DERAs that consist of electric storage resources (ESRs) requires a separate undertaking that they may not propose or design as part of their Order No. 2222 compliance filings. According to these ISO/RTOs, challenges include determining how SOC is impacted when ESRs aggregate with other DER technologies, and whether there is a near-term need to monitor and consider SOC accordingly. If the ISO/RTOs were to introduce the SOC offer parameter, questions arise as to who manages the SOC of such heterogeneous DER aggregations. Most ISO/RTOs lean toward aggregator self-management of SOC.

Midcontinent ISO (MISO) is presently considering a fully flexible ESR-capability-based DERA resource that is as a potential participation model option for heterogeneous DERAs that include ESRs and for DERAs that would like to both withdraw and inject. (MISO's ESR model is a future planned resource type that is not yet implemented.) The planned participation model is proposed to be potentially eligible to provide all market products. It is dispatchable, but does not include commitment decisions, so selecting this option requires the DER aggregator to self-commit. However, SOC will not be provided as an offer parameter and will be reserved only for ESRs or homogeneous DER aggregations of ESRs.

Unlike FERC Order No. 841, Order No.2222 did not require ISO/RTOs to consider and monitor the SOC of DERAs that include ESRs. Given the complexities associated with market operating procedures that include SOC management, most ISO/RTOs may adopt this potential modeling option or pathway for these DER configurations in the near future. This option may also change as ISO/RTOs gain experience with standalone ESR participation models introduced to comply with FERC Order 841. Under this fully flexible option, the DERA will be allowed to inject, withdraw, or both. MISO has preliminarily advised that heterogeneous DER aggregations that need SOC consideration use the ESR participation model.

### Heterogeneous DERAs Including VERs

In Order No. 2222, FERC did not establish explicit requirements for heterogeneous DERAs that include VERs. Transmission-connected, stand-alone VERs have unique participation models that support forecast integration with offers; settlement rules such as waived deviation penalties; and, in some cases, additional meteorological telemetry to aid in forecasting. These rules are critical for reliability and to ensure fairness.

For DERAs that include VERs, such as rooftop solar, challenges arise as to who provides forecasts for the aggregated VER components: the ISO/RTO, the aggregator, or an independent provider. Another uncertainty is the suggested participation model's ability to allow automatic dynamic update of the aggregated VER component's forecasted maximum injection capability or upper economic limit in real time based on short-term forecasts. Another concern is whether these resources can qualify for ancillary services provision. (At this time, most ISO/RTOs do not allow transmission-connected, stand-alone solar and wind to provide reserves.) A final question is whether and how uninstructed deviation penalties should be applied to aggregations or the portions of aggregations that represent VERs.

Further complexities arise when VERs aggregate with ESRs. One difficulty is the ISO/RTO's ability and potential need to allow subsequent updating of bids or offers in real time (potentially intra-hour), given forecast deviations from the aggregated VER component (or SOC limitations). Concerns also arise regarding mitigation of such dynamic offers on an intra-hour basis because of the computational complexity associated with some of the mitigation processes. Other complexities include:

- Whether the aggregator should provide the SOC telemetry of the underlying aggregated ESR components to ensure feasibility during critical time periods
- How such aggregations may be treated in reliability unit commitment procedures
- Validation of offer parameters such as ramp rates
- The software's ability to accommodate dynamic ramp rates (if needed)

These issues are similar to current continent-wide discussions about hybrid resources that include utility-scale VER and ESR at the same location. Across these initiatives, similar approaches are being considered that may be used for each type. Meanwhile, ISO/RTOs may propose participation models that defer the responsibility of addressing these complexities to DER aggregators.

### *Recommendations*

The design of participation models includes a delicate balance across simplicity and reliability, while attempting to provide technology neutrality. New participation models are developed either because existing participation models are not feasible for a new resource type, or because they enable more cost-effective operation of a new or existing resource type. Most analyses have shown that more granular participation models that include greater use of resource operational characteristics as parameters of the resource type to determine the optimal scheduling of the resource provide both reliability and economic efficiency benefits. However, they are expensive to develop, and may be perceived to give less

control to a resource offer strategy. As new DER technologies become prevalent, new types of DERAs are formed. As changes to participation eligibility are in effect, ISO/RTOs will need to work with their stakeholders to determine the best paths forward.

The following recommendations are provided on the future of participation model design for DERA resource types:

- Assess the market clearing time impact of different participation models within the market clearing software to determine any negative impacts. For those that have substantial impacts, determine solutions that can reduce solution times. Determine whether unit commitment constraints for DERAs are physically needed or if they will be useful; if so, will they be feasible given computation limits?
- Determine whether there are parameters associated with distribution systems that may be useful for the ISO/RTO market clearing software to have visibility when scheduling DERAs. One example is distribution losses, and whether similar cost DERAs can be dispatched based on their effective reduction in distribution system losses.
- Determine appropriate modeling in real-time (e.g., the need for multi-interval optimization for DERAs that have storage + renewables).
- Determine the eligibility of heterogeneous DERAs with VERs to deliver reserves. What reserve types could be economically and reliably provided? Are there aggregation benefits in which the aggregation of many resources that may not be eligible to provide the service individually can do so in aggregate large numbers?
- Conduct studies with simple heterogeneous DERA market clearing (e.g., offer curve, min/max capacity, ramp rate) to understand the reliability implications of high DERA penetrations.
- Consider alternative methods for modeling DR flexibility in the market (e.g., DR is subject to wholesale prices for any consumption, as opposed to DR is modeled as a supply resource per Order 745).

### *Bulk System Locational Requirements for Aggregations*

In Order No. 2222, FERC required each ISO/RTO to modify its market rules and tariffs to establish locational requirements for DERs to participate in a DERAs that are “as geographically broad as technically feasible.” ISO/RTOs are required to provide a detailed, technical explanation to demonstrate that their proposed approach meets this requirement. FERC’s examples of a detailed, technical explanation include an explanation of system topology and congestion patterns in the specific ISO/RTO region. The ISO/RTO’s two main choices in establishing these requirements are single transmission (pricing) node aggregations and multiple transmission (pricing) node aggregations.

Challenge: Multi-node aggregations can create dispatch and pricing challenges that must be addressed if implemented. There is no consensus or agreed-upon method for proving that the requirement is as broad as technically feasible.

In the 2016 NOPR on energy storage and DERA participation in wholesale markets, FERC stated that single transmission node aggregations may unnecessarily limit the opportunities for DERs to participate in a DERA [1]. In addition, FERC argued that improved situational awareness due to recent enhancements in metering, telemetry, and communication technology can enable geographically broader aggregations, such as multiple transmission node (pricing) aggregations. However, FERC did not require ISO/RTOs to adopt consistent locational requirements. Instead, FERC provided ISO/RTOs flexibility to propose requirements that allow for dispersed aggregation where feasible and account for unique aspects of the region's transmission system and its modeling and dispatch processes.

Generally, ISO/RTOs have either allowed a single aggregation to spread across multiple transmission pricing nodes, or require all DERs within an aggregation to effectively be located under the same transmission pricing node. Some believe that forcing all DERs to be located under one node may limit participation, as DERs may not always be able to aggregate up to 100 kW with other resources under the same pricing node. Other than this potential participation impact, single-node DER aggregations present limited technical challenges because they are the status quo for other technologies that participate in today's wholesale markets.

For multi-node aggregations, several technical challenges exist. For example, how will resources be dispatched if transmission congestion is prevalent within the aggregation (e.g., lines connecting two nodes that each contain DERs of the same aggregation)? What price will DER aggregations receive if there are multiple prices? Another challenge is that it is not well understood how an ISO can "prove" to FERC that an aggregation is as geographically broad as technically feasible. Several other pros and cons to each of the approaches were raised in comments to the 2016 NOPR and the April 2018 technical conference [26].

### Multiple Transmission Pricing Node Aggregation

Increased participation is the main benefit of allowing geographically broader aggregations such as multiple transmission pricing node aggregations. This can help establish larger aggregations to ensure compliance with the minimum size and eligibility requirements, lower the chance of underperformance, improve competition, and enhance DERA services. Several ISO/RTOs including PJM, NYISO, CAISO, and ISO-NE currently allow geographically broad aggregations of behind-the-meter resources over multiple transmission nodes, mostly in the context of DR participation. CAISO's current DERA participation model allows for multiple transmission pricing node aggregations, but lack of participation beyond DR resources limits the ability to evaluate the performance and challenges of the proposed geographical scope of aggregation for DERAs.

Industry experts are concerned about the implications of geographically broad DERAs that have injection capabilities past the applicable retail meters.

The main challenges of multiple transmission pricing node aggregations include potential impacts on system reliability, dispatch, pricing, and settlement of resources. ISO/RTOs are concerned about adverse reliability and pricing impacts when DERs are aggregated on both sides of a binding transmission constraint, especially with increasing DER penetration. One potential compromise to enable aggregations beyond a single pricing node is to allow aggregations across a pre-defined set of pricing nodes that are unlikely to have internal congestion between them. CAISO maintains that their current DERA participation model allows DERs to aggregate across multiple transmission pricing nodes within a single sub-load aggregation point (sub-LAP). CAISO defines a sub-LAP as a subset of pricing nodes within a default LAP with minimal historical price differentiation between the nodes, which implies lack of persistent transmission congestion. To illustrate how broad the aggregations could be, CAISO generally has over 12,000 pricing nodes but about 23 sub-LAPs [10].

Aggregation zones may require updates to account for changing grid conditions. CAISO states that it regularly studies the sub-LAPs and will establish new sub-LAPs if it determines that price differentiation between nodes in a sub-LAP exceeds a threshold to ensure that aggregations do not exacerbate transmission constraints. Frequent updates to aggregation zones could have potential implications for DER aggregators that participate in ISO/RTO markets. However, CAISO's sub-LAPs were fixed for nearly eight years since their introduction in 2010, and the 2017 updates were minor and impacted only a relatively small number of DR resources.

CAISO sub-LAPs were initially established to allow multi-node aggregations for DR resources. (CAISO's experience with participation across multiple transmission pricing nodes is currently limited to DR resources.) However, CAISO previously indicated that it does not recognize significant differences between multi-node DR aggregations and multi-node DERAs in terms of impact on transmission constraints. Some argue that a maximum size limitation could be imposed on these aggregations to further mitigate the impact of DER aggregations on transmission constraints. For this reason, CAISO adopted a maximum size requirement of 20 MW for DERAs that span multiple transmission nodes.

As of this writing, ISO-NE also proposes to allow aggregations on multiple transmission nodes and proposes a size restriction for these DERAs. (ISO-NE's proposal differs from CAISO's proposal by imposing a 5-MW size restriction for aggregated DERs on a single transmission node that is part of a multi-node DERA [13]. ISO-NE proposes to allow DER aggregations

across aggregation zones that are different based on the elected participation model. For the DR resource (DRR) and alternative technology regulation resource (ATRR) participation model options, individual DERs in an aggregation must be within the same DRR aggregation zone. In ISO-NE, DRR aggregation zones were defined as the geographically broadest area with minimal transmission constraints within the area, resulting in 20 DRR aggregation zones and more than 1,000 pricing nodes.) For other participation models that DERAs are eligible to use, DERs can aggregate within the intersection of a metering domain<sup>5</sup> and DRR aggregation zone. A common metering domain is necessary for these participation models because the models can settle both energy injections and withdrawals.

The primary approach to model resources on multiple transmission pricing nodes is to require the aggregator to submit distribution factors (DFs) that indicate the share of DERs on each transmission pricing node that is part of the aggregation. DFs can be a function of current or anticipated DER dispatch levels and can depend upon distribution system topology (e.g., switching status) as well. FERC requires DER aggregators to submit DFs as bidding parameters with their offer if their aggregation spans multiple transmission pricing nodes. Coordination between the aggregators, ISO/RTOs, distribution utilities, and transmission owners may be necessary to approximate DFs more accurately. However, some industry experts believe that requiring aggregators to follow the same DFs that they submitted to the market may be overly stringent and impact their business models by interfering with a minimum-cost solution that aggregators seek when disaggregating the dispatch instructions.

To address this issue, ISO-NE's market software models each DRR aggregation zone as a single pricing location. Therefore, each DERA is practically represented as a single-node aggregation and is not required to provide DFs per Order No. 2222. However, ISO-NE indicates that it may still need to know the share of DERs at each transmission node for dispatch and pricing purposes. ISO-NE proposes to extend to DERAs a procedure it has in place for DR aggregations, in which the ISO calculates DFs at each electric node based on historical load patterns.

One reason that ISO-NE does not require DERAs to provide DFs is that DERAs would not have access to publicly unavailable electric node information. CAISO, on the other hand, requires DER aggregators to submit DFs, along with other bidding parameters, with their real-time or day-ahead offer. The DER aggregator is paid at a weighted average LMP value, where weighting is based on the DFs. However, all DERs within the aggregation are paid the same price regardless of their location. In the 2016 DER provider (DERP) model, CAISO maintained that DERAs are required to follow the DFs. But CAISO does not propose to penalize DER

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<sup>5</sup> In ISO-NE, metering domains are “constructs under which Host Participant Meter Readers report supply and demand within their systems in every interval”.

aggregators if they provide the desired aggregate response, even if the response does not align with the submitted DFs. Therefore, the DERA response could practically deviate from the DFs without any consequences. This raises questions about whether DF-based pricing would be appropriate.

If DERs are located on both sides of a potentially binding transmission constraint, further complications could arise regarding system reliability and oscillation in prices and transmission flows. In fact, a recent MISO study shows that aggregation of resources on multiple transmission pricing nodes—known as commercial pricing nodes (CPnodes) in MISO—could cause price and flow oscillation issues. The study confirmed that even if DFs are updated in each real-time economic dispatch iteration based on the most recent state estimation results, price and flow oscillation could still exist because actual DER response may deviate from DFs if DER aggregators are not required to provide a response that follows the DFs. In a separate case study, PJM showed that DERAs on multiple transmission pricing nodes—may yield less accurate pricing and dispatch results, even if electrically close [27].

### Single Transmission Pricing Node Aggregation

Table 3-2 shows that most ISO/RTOs propose to require DERAs to aggregate behind a single transmission pricing node to address transmission constraint management difficulties and concerns about DERAs’ potential reliability impacts.

Table 3-2  
ISO/RTO proposals on locational requirements for DERAs

ISOs	Locational Requirements
CAISO	<p><b>Multiple Transmission Pricing Nodes</b></p> <ul style="list-style-type: none"> <li>• DERs to aggregate within a single sub-LAP (subset of pricing nodes with minimal price differentiation)</li> <li>• Same rule applies to DR</li> <li>• 23 sub-LAPs, compared with over 12,000 pricing nodes</li> <li>• Maximum DERA size limitation of 20 MW for DERAs across multiple transmission pricing nodes</li> </ul>

Table 3-2, continued  
 ISO/RTO proposals on locational requirements for DERAs

ISOs	Locational Requirements
ISO-NE	<p><b>Multiple Transmission Nodes / Single Pricing Node</b></p> <ul style="list-style-type: none"> <li>• All constituent DERs must be within a DRR aggregation zone (a subset of transmission nodes with minimal transmission constraints within the area)</li> <li>• Intersection of a DRR aggregation zone and a metering domain for other participation models</li> <li>• 20 DRR aggregation zones, compared with over 1,000 pricing nodes</li> </ul> <p>Maximum size of 5 MW for aggregated DERs located at a single transmission node that are part of a DERA</p>
NYISO, MISO, PJM, SPP	<p><b>Single Transmission Pricing Node</b></p>


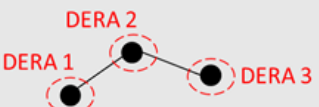
NYISO, MISO, PJM, and SPP have all indicated that single transmission pricing node aggregations will deliver better visibility and control for managing transmission congestion. A multiple transmission node aggregation could require costly changes to market engines to appropriately model geographically dispersed resources. And, providing sufficient situational awareness may require telemetry from each transmission node in the aggregation.

The ISO/RTOs that propose single transmission pricing node aggregations have slightly different perspectives on the potential geographic breadth of the aggregations. For example, NYISO has proposed a hybrid approach that aims to maximize the geographical scope of the aggregation, while minimizing impacts on bulk system constraints and maintaining market efficiency [28]. Based on the severity of historical transmission congestion and other system conditions, NYISO identified transmission locations across which DERs can aggregate that include one or more electrical nodes, and that are then converted into one pricing node. While PJM proposes a single transmission pricing node aggregation for wholesale energy service provision, it indicates that multiple transmission pricing node aggregation may be allowed for capacity service and ancillary service only aggregations. Initial discussions at SPP also suggest that broader aggregations could be allowed for ancillary-services-only resources. MISO proposes single transmission pricing node aggregations (at the elemental pricing node [EPnode]-level) for all wholesale services.

One challenge with single transmission node aggregations is the potential for reduced market participation. However, many in the industry argue that the minimum size requirement of 100 kW for DERAs is so small that

it eliminates any concerns about reduced market participation. Another concern is computational time difficulties, when a large number of small DERAs participate in the market, due to the inability to aggregate across several nodes. A recent MISO research study shows that the average computation times with single-node aggregations (EPnode-level), could be as large as twice that with multiple node aggregations (CPnode-level). The study also concludes that computational time could be further reduced using alternative ways to create aggregation zones based on their impact on transmission nodes (e.g., nodes with similar shift factors would be in the same aggregation zone). However, such approaches could introduce inaccuracies in the market solution. Table 3-3 compares the attributes of multi-node aggregation and single-node aggregation.

Table 3-3  
Multiple transmission node aggregation versus single transmission node aggregation

	Multi-Node Aggregation	Single-Node Aggregation
Locational Requirements		
Main Benefit	<ul style="list-style-type: none"> <li>• Greater market participation,</li> <li>• Lower chance of underperformance,</li> <li>• Improved services by the DERA.</li> </ul>	<ul style="list-style-type: none"> <li>• Better visibility and control to manage transmission congestion,</li> <li>• Reduced Telemetry Costs,</li> <li>• Minimize changes to the market engine.</li> </ul>
Challenges	<ul style="list-style-type: none"> <li>• Managing Transmission Constraints / Reliability Impact,</li> <li>• Pricing Issues,</li> <li>• Distribution Factor Update Issues.</li> </ul>	<ul style="list-style-type: none"> <li>• Potentially Lower market participation,</li> <li>• Computational Challenges.</li> </ul>
Relation to DERA size	<ul style="list-style-type: none"> <li>• Can impose maximum size limitations to mitigate the impact of DERA on constraints.</li> </ul>	<ul style="list-style-type: none"> <li>• No participation concerns because of small (100kW) min size requirement.</li> </ul>
Pricing	<ul style="list-style-type: none"> <li>• Paid at weighted average LMPs.</li> </ul>	<ul style="list-style-type: none"> <li>• Paid at nodal price (LMP).</li> </ul>

Distribution utilities will continue to provide safe, reliable electricity to residential, commercial, and industrial customers, but they must also support DER participation in wholesale markets through a DERA, without imposing undue barriers to individual DER owners or DER aggregators.

### Distribution System Reliability and Safety

Because Order No. 2222’s definition of DER pertains to resources interconnected to the distribution system, the role of distribution utilities is critical in ensuring that ISO/RTOs meet the order’s compliance requirements and that distribution system reliability is maintained. Distribution utilities will continue to provide safe, reliable electricity to residential, commercial, and industrial customers, but they 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 DERs that can be aggregated under Order No. 2222.


The first task for the Distribution Reliability and Safety Workstream was to fully explore the roles and functions of distribution utilities required in Order No. 2222. These cover three distinct timeframes: interconnection, DER aggregation review, and ongoing operational coordination [29]. The project team introduced several introductory frameworks for addressing these new and evolving functions, with the intent of leveraging existing and emerging technology, processes, data, and tools. The overarching goal of this task was to summarize the order's requirements for distribution utilities and the implications across the key areas impacted.

The second task for this workstream addressed the technical and procedural challenges that distribution utilities face in implementing Order No. 2222 [30]. Because distribution utilities have not traditionally played a major role in wholesale electricity markets, their existing processes may require substantial modifications or the creation of entirely new processes and tools. The accelerated timeline for developing or enhancing the supporting technology, processes, and tools means that utilities will likely rely on modified or evolved versions of existing analytics and tools. Through this task, the team determined that interconnection studies and operational tools are the highest priority for modifications. The team also determined that emerging tools, some of which are under development today, may also be needed to maximize DER availability and minimize disruptive curtailments.

The following subsections are organized by the key functional roles for distribution utilities under Order No. 2222: interconnection, aggregation review, and ongoing operational coordination. For each role, key stipulations from the order are presented along with the functional implications for distribution utilities. The subsections discuss the technical and procedural challenges associated with each role, and alignment with the current state of distribution planning and operational analytical capabilities. Each subsection also offers strategic considerations for successful near-term implementation and opportunities for capability progression.

### *Interconnection*

Under Order No. 2222, the interconnection of DERs to the distribution system for the purpose of participating in wholesale electricity markets as part of DER aggregations is not within FERC jurisdiction. In contrast, DERs that participate directly in wholesale markets remains in FERC jurisdiction. In addition, the order does not impose any standard reliability or safety criteria onto state and local interconnection procedures or agreements. Instead, distribution utilities, together with relevant electric retail regulatory authorities (RERRAs) bear the burden of determining what, if any, changes are required to interconnection



Challenge:  
Interconnection studies need to also evaluate the impact of DER providing coordinated services to the wholesale market.

procedures and agreements. The order makes clear that states and local authorities are permitted to both update existing interconnection procedures and require additional studies to capture the impacts associated with market participation through a DER aggregation.

One of the noted side effects of enabling market participation for DER aggregations is a possible uptick in DER interconnection requests. Among other impacts, FERC noted that this influx could be burdensome to ISO/RTOs, and that requiring ISO/RTOs to perform standard procedures would not reduce interconnection times or costs for small, behind-the-meter DER. While FERC opted to allow distribution utilities to manage interconnection, the Commission also stated that it would revisit the decision over jurisdiction if the distribution interconnection process was being abused or used as a barrier to market participation. As a result, distribution utilities may encounter increased scrutiny over the efficiency and efficacy of their interconnection practices and agreements, especially as they relate to market participation.

The vast majority of DER interconnection has traditionally been handled by distribution utilities, which have developed the requisite experience and systems for handling high volumes of applications. Even so, utilities frequently aim to update, improve, and streamline their processes. The combination of increasing both application volume and the number of DERs aggregating to offer bulk system services will present challenges in efficiently processing interconnection applications and maintaining distribution grid safety and reliability.

As shown in Figure 3-2, 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. While a tiered approach expedites certain applications, it also results in an array of different studies or screens applied in the interconnection process. Depending on a utility's current and legacy interconnection practices, DERs connected to the distribution system today may or may not have been studied to account for the impact of market participation.

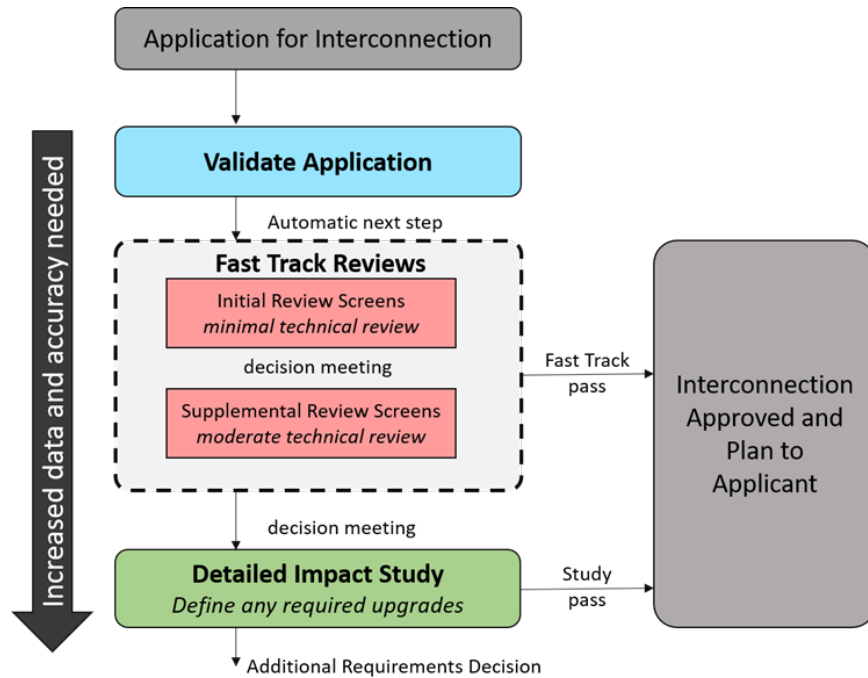


Figure 3-2  
High-level flow diagram of the utility interconnection review process modeled after the FERC Self-Generation Incentive Program

One of the primary challenges facing distribution utilities is capturing the impacts of DER aggregation market participation during the interconnection study process. Many DERs connected to the distribution system today are non-dispatchable and largely uncontrolled. This has led utilities to focus on impacts related to DER intermittency instead of the impacts of dispatching multiple resources in concert or to provide a service to the bulk system. Studying the coordinated dispatch of DERs to maximum technical capability aligns more closely with the expected behavior of DER aggregations participating in wholesale markets.

To overcome this gap, a practical first step is for distribution utilities to work with ISO/RTOs to document and standardize the performance requirements for various wholesale services.

Because DER aggregations can also provide various market products with different performance and technical requirements, there is some confusion about the behaviors and impacts that need to be studied during interconnection. To overcome this gap, a practical first step is for distribution utilities to work with ISO/RTOs to document and standardize the performance requirements for various wholesale services. Those performance requirements can then be mapped to existing or new technical studies about the safety and reliability of DER market participation. Clearly defined studies about various market services will ensure system reliability and help expedite the registration and review process.

The analytics used in DER planning and interconnection are continually evolving and adapting in response to driving factors and regulations like Order No. 2222. One current project focuses on the use of time-based

Under a flexible interconnection paradigm, larger plant sizes might be permissible at more locations through managed operation of the DER's active and reactive power.

hosting capacity analytics to understand how operating constraints change with time. This type of analysis can enable transition from a firm interconnection strategy towards a flexible interconnection strategy. The many options that are available for connecting new DERs to the grid are collectively known as flexible interconnection capacity solutions. [31]. Under a flexible interconnection paradigm, larger plant sizes might be permissible at more locations through managed operation of the DER's active and reactive power. These analytical enhancements squarely align with Order No. 2222's goals of minimizing barriers to DER participation in wholesale markets.

### *DERA Review*

Order No. 2222 requires distribution utilities to be responsible for reviewing the eligibility and technical feasibility of individual DERs participating in DER aggregations whenever an aggregation registers with a market. The order also requires that ISO/RTOs include a dispute resolution process to address and resolve any concerns that arise during the review process, which may also involve the RERRA. While distribution utilities cannot directly bar a DER's participation in an aggregation, the utility can require additional study, operational limits, or other mitigations to address safety and reliability concerns. One notable aspect of the DER aggregation review process is that DER interconnection occurs before DER aggregation formation or registration with the wholesale market.

Challenge: The eligibility review will require examination of the terms and conditions of the retail programs in which each DER is participating, which may require coordination with the RERRA.

The eligibility portion of the review is intended to determine whether individual DERs within an aggregation are participating in retail programs or tariffs that explicitly bar dual participation in wholesale markets through DER aggregations. This review requires examining the terms and conditions of the retail programs in which each DER participates, which may require coordination with the RERRA.

Next Steps: Distribution utilities, ISOs/RTOs, and RERRAs must agree upon the compatibility of existing retail programs with the available wholesale services or products.

For distribution utilities, eligibility reviews impose a greater procedural challenge than a technical challenge. The most critical step to enable eligibility review is for distribution utilities, ISO/RTOs, and RERRAs to agree on the compatibility of existing retail programs with the available wholesale services or products. At a minimum, program compatibility agreements must be documented to maintain the transparency requirements required by Order 2222. Tools like the DER program compatibility matrix, shown in Table 3-4, can potentially shorten eligibility review by facilitating alignment between existing retail programs and the market products available to the aggregation [32].

Table 3-4  
 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

The second portion of the review is intended to capture safety or reliability impacts resulting from the expected behavior of the DERs participating in the DER aggregation. If these impacts were not previously studied, there may be a reasonable need to study or address them before market participation is allowed. FERC notes in Order No. 2222-A that a dispute resolution process is the appropriate venue for addressing concerns discovered in the review process.

For example, if a utility does not study the coordinated dispatch of DERs during interconnection, then additional studies may be needed to understand the risks associated with an aggregation participating in the bulk system market.

The technical review may uncover the need to perform additional studies of the DERs within an aggregation. For example, if a utility does not study the coordinated dispatch of DERs during interconnection, then additional studies may be needed to understand the risks associated with an aggregation participating in the bulk system market. However, if coordinated dispatch is typically studied during the interconnection process, then additional study might not be necessary.

Next Steps: Utilities can take the first step to review interconnection study practices in an effort to understand how well studies and screens during the interconnection process capture aggregated market participation.

For utilities, a first step toward creating effective processes for technical review and associated studies is to examine interconnection study practices to understand how well interconnection studies and screens capture aggregated market participation. Because of potential safety and reliability risks, the review may identify the need for additional studies that require significant engineering judgement and/or advanced simulation capability. Identifying issues during registration can result in improved processes for conducting studies that substantially enhance the efficiency of conducting the review.

### Ongoing Operational Coordination

Order No. 2022 includes the provision for distribution utilities to override ISO/RTO dispatch of a DER aggregation when needed to ensure the safety and reliability of the distribution system. For distribution utilities, the authority to override dispatch instructions is a welcome addition. However, several technological and procedural gaps regarding proper coordination and override capabilities must be addressed. The order does not define processes and protocols for coordination or communication, nor does it specify conditions that warrant a distribution utility's override. Instead, FERC allows ISO/RTOs to decide which standards, protocols, and reliability criteria will be used for override and coordination.

Another operational coordination issue is the order's requirement for DER aggregators to report changes in offered quantities or distribution factors that result from distribution outages or faults to the ISO/RTO. This follows traditional participation requirements for large generators, which must report outages and other output capability changes in real time. Although not explicitly required, the order implies that distribution utilities should create communication channels to inform DER aggregators of outages on the distribution system.

With firm interconnection as the archetype, utility curtailment and override of DERs is primarily limited to abnormal system configuration, and curtailment usually only applies to large DERs. Operators or switch writers typically identify the customers and DER owners who will be impacted by planned switching and provide those customers as much advanced notice of a planned interruption as is practical. If the firm interconnection paradigm persists and alternate system configuration remains a leading criterion for override and curtailment, the practices used today can be adapted to meet the order's requirements.

Challenge: A lack of available operational analytics for distribution operators may result in a strong reliance on planning criteria and rule-based approaches to DER management.

Operational tools that are currently available, such as distribution management systems, are not designed to assess aggregated DER dispatch for wholesale market services, nor are they ready to evaluate those impacts in real time. Like planning tools, distribution management systems are model-based and largely driven by representative load profiles instead of real-time measurements from the field. While utilities are pushing for advanced systems and tools that can evaluate real-time conditions against dispatch signals, this gap in capabilities means continued strong reliance on planning criteria and rule-based approaches to DER management until more advanced tools become commercially available.

Next Steps: Investigate the creation and communication of operating envelopes to assist in planning for and managing the dispatch of DER aggregations.

In the future, operational coordination among distribution utilities, DER aggregators, and ISO/RTOs can be simplified by providing capacity allocation projections, or operating envelopes, that aid planning and managing DER dispatch. An operating envelope is a time-varying region that defines the outer limits of power injection and absorption that the distribution feeder can accommodate. Managing DER to operate within the bounds of the envelope ensures distribution system safety and reliability. Operating envelopes can be defined coarsely at the feeder level or can be refined to location- or device-specific levels. In Figure 3-3, an example operational envelope for a customer with behind-the-meter DER shows the operating limits for the entire site.

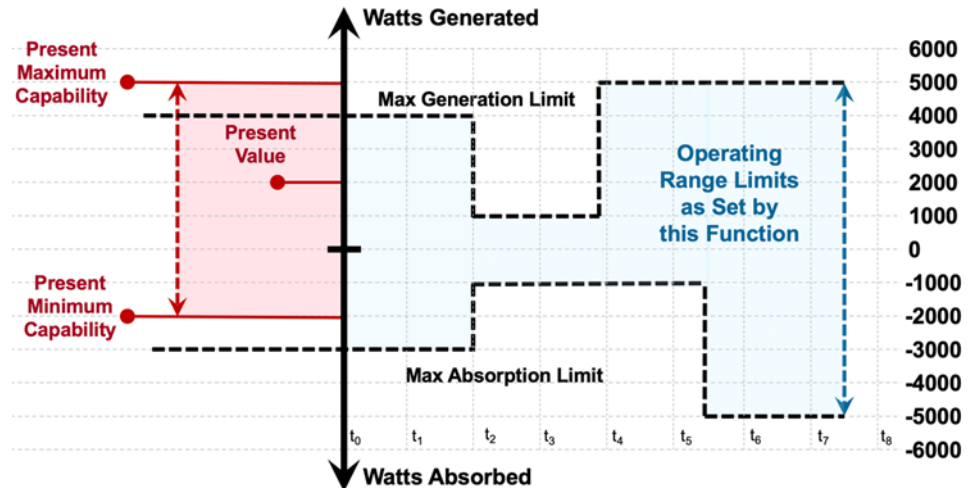


Figure 3-3  
 Example operational envelope showing time-varying limits for generation and absorption

A foreseeable implementation is to provide an operating envelope for individual aggregations, or for all DER within an aggregation that are connected to the same feeder. This framework gives the aggregator flexibility to manage individual resources and stay within the grid’s physical and operational limits. Furthermore, providing operating envelopes reduces the burden on the distribution utility to validate DER dispatch plans after aggregation-level awards are cleared in the day-ahead market. However, a less spatially refined envelope requires accounting for more uncertainty, and therefore results in more conservative DER limits. As a result, aggregators may request that distribution utilities assist in creating optimal dispatch schedules that maximize DER availability and minimize adverse grid impacts.

### Transmission Operations and Planning

Because these resources inject into the transmission system, provide transmission system grid services, and displace other technologies, transmission planners and operators must better prepare for efficient and reliable integration.

Large numbers of DERs participating in wholesale electricity markets can impact reliability of the transmission system. Because these resources inject into the transmission system, provide transmission system grid services, and displace other technologies, transmission planners and operators must better prepare for efficient and reliable integration. While Order No. 2222 does not contain many specific directives for changes in transmission operations and planning, many changes are implied and in some cases are already considered. This section focuses on bulk power system (BPS) operations and planning impacts that are not covered under wholesale electricity market operations, and discusses some of the key challenges and recommendations for transmission operations and for transmission planning.

## *Transmission Operations*

Transmission operators<sup>6</sup> play an important role in maintaining the operational reliability of the BPS while improving the outcomes of organized markets. DER growth influences operating decisions because DER market participation makes it easier to integrate DER to support the grid, and presents new challenges for facilitating market outcomes. The goal of the transmission operations and planning workstream is to use structured analysis to identify the main operating issues associated with high DER market participation [33]. The document reviews the main transmission operator functions in real-time operations and operations planning, identifies how DER market participation can influence BPS operations, and provides several options for TOs to integrate DER and mitigate possible adverse impacts.

The transmission operations and planning workstream has identified the core functional roles for transmission operators to maintain operational reliability (see Figures 3-4 and 3-5). The project team developed the transmission operator functional roles through review of NERC functional model and standards, previous EPRI analysis for transmission operators, and direct engagement with project advisors. While the research focused on the duties of transmission owners in their role as transmission operators, there are often overlapping or supporting consequences for ISO/RTOs in carrying out these roles.

The project team assessed the impact of DER market participation on each operational role based on the magnitude and frequency of occurrence criteria. To assess the future needs in the key functional roles for DER market participation, the functional analysis was divided across the following characteristics:

- The **current process summary** is a high-level articulation of the existing processes by transmission operator function.
- The **current interaction** contains summary indicators of existing interfaces between the transmission operator and the ISO/RTO, distribution utility, or DER aggregators by function.
- The **implications of DER market participation** is a summary of the expected impacts of DER market participation on the transmission operators; the magnitude of those impacts as DER participation increases; and how frequently the impacts are expected to occur. Implications are graded based on a four-point system ranging from minor effect/rare and localized occurrence to significant effect/continuous and broad occurrence.

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<sup>6</sup> In the United States, TOs may include ISO/RTOs and transmission owners, who each may have separate, but coordinated roles to operate the transmission and sub-transmission system.

- Mitigation options** include potential measures that transmission operators can take to mitigate negative impacts, possible challenges in adopting proposed changes, and examples of how mitigation measures are already implemented or piloted around the world. The team assessed options on a four-point scale ranging from simple to complex implementation.



Figure 3-4  
Transmission operation activities

Functional Role #2: Contingency Analysis

<b>Current Process Summary</b>	Contingencies are studied to determine post-fault system operational reliability, based on loss of transmission or generation assets identified in the contingency list. Some additional high-impact, low-probability events may be included, depending on local policies. These are studied using contingency analysis software tools in real time and in operational planning to assess post fault flows and inform the need for preventative actions and include a subset in the economic dispatch. These considerations apply both to transmission owners and RTO/ISOs.		
<b>Current Interactions</b>	<b>RTO/ISO</b> 	<b>Distribution Utility</b> 	<b>DER Aggregator</b> 
<b>Implications of DER Market Participation:</b>			
<b>Description</b>	<b>Magnitude</b>	<b>Frequency</b>	
DER or distribution protection settings may simultaneously trigger during a disturbance, giving rise to a loss of many DERs equivalent to a loss of a major generator/load. This may be included as a contingency event.	 Directly proportional to DER penetration.	 Rare occurrence.	
The locational effects of loss of DER is different from loss of a generator at a single bus.	 Depends on several factors like the regional market, protocols, grid-codes, and type of generation.	 Rare occurrence as the sudden loss of a full DER aggregation is less likely than for a conventional generator.	
DER ratios within the aggregation may vary pre- and post-contingency.	 Depends on several factors like the regional market, protocols, grid-codes, and type of generation.	 Continuous variability occurs in the minutes around the contingency. Additionally, legacy DER may change output because of fixed power factor or legacy ride through settings in areas close to the contingency.	
Outages on distribution networks influence post contingency conditions on the transmission level.	 Unlikely to have a widespread impact across a TO footprint, unless system is already severely compromised (e.g. storm).	 Rare occurrence as distribution outages will only affect DER aggregations in a material manner if the fault is with a primary transformer.	
DER will cause the lumped dynamic model of the distribution grid to change substantially for short circuit & transient stability analysis.	 Increasing situation due to the DERs penetration in some areas.	 Medium likelihood.	
<b>Mitigation Options:</b>			
<b>Description</b>	<b>How big a change in process is this mitigation?</b>	<b>Examples where this mitigation has been applied</b>	
Require DER aggregators or distribution utilities to provide net injections at each interface of the transmission's observability area.	 Requires DER Aggregation (DERA) to send multiple nodal estimates by SCADA, or static estimates to be dynamically determined.	Required for utility scale (MW+) in various locations. Distribution factors required in CAISO.	
Implement DER aggregation model in contingency analysis tools.	 Low readiness level of existing tools. Aggregation does not allow identification of the underlying type of generation.	None known to date.	

Figure 3-5  
Contingency analysis gap assessment

Recommendations

Table 3-5 summarizes DER market participation implications for each functional role and potential mitigation actions. Transmission operators may use these findings to support formulation of DER market participation plans. The structured analysis provides a holistic view of key functions that can be used as a template for system-specific self-

assessment. The document also provides information about high-level assessments of the difficulties associated with each role and provides examples where regions have implemented such measures.

In general, ISO/RTOs, distribution utilities, and DER aggregators will need to coordinate with transmission operators to address the challenges of DER market participation on operations functional roles. Key findings can be summarized as follows:

- Cross-entity data exchange is critical to sustaining situational awareness of the transmission system.
- Defining an observability region that extends beyond the network controlled by an individual entity and encompassing assets whose status has a material impact on the operation of a transmission operator's grid supports enhanced situational awareness. This may encompass neighboring transmission grids or parts of connected distribution grids as appropriate.
- Direct telemetry from distribution-connected, utility-scale DER and DER aggregation behavior at a nodal level substantially supports several transmission operator functions.
- Managing abnormal local or system operating conditions (including reconnecting microgrids) requires enhanced coordination and extensive data exchange during emergencies and restoration.
- To facilitate and leverage DERA during periods of grid maintenance, network topology data exchange and outage coordination activities must be enhanced between ISO/RTOs, transmission owners, and distribution utilities.
- DER will cause the lumped dynamic model of the distribution grid to change substantially for short circuit and transient stability analysis.

Table 3-5  
 Implications of DER market participation and mitigation options for transmission

Category	Functional Role	Implications	Mitigation Options
Real-Time Functional Analysis	Maintain Situational Awareness of the BPS	<ul style="list-style-type: none"> <li>DER growth will indirectly affect the solution of the state estimation solution by changing the net injection of active and reactive power at a given location in a short period of time.</li> <li>Active DER market participation influences the accuracy of the anticipated grid conditions that affect the outcome of the forecasted grid states.</li> </ul>	<ul style="list-style-type: none"> <li>Define observability regions for each TO that include part of the distribution grid and provide access to information</li> <li>Require prequalification processes to identify DER location, type, and capacity</li> <li>Use online forecasting tools to estimate indirect real-time DER injection and available flexibility</li> <li>Require DER aggregators or distribution utilities to provide net injections at each boundary interface of the TO's observability region directly to SCADA</li> <li>Extend direct telemetry from individual DER to the TO</li> </ul>
	Contingency Analysis	<ul style="list-style-type: none"> <li>DER or distribution protection settings may simultaneously trigger during a disturbance, causing loss of many DERs, which is equivalent to a loss of a major generator/load. This may be included as a contingency event.</li> <li>The locational effects of DER loss are different from loss of a generator at a single bus.</li> <li>DER ratios within the aggregation may vary pre- and post-contingency.</li> <li>Outages on distribution networks influence post-contingency conditions on the transmission level.</li> <li>DER will cause the lumped dynamic model of the distribution grid to change substantially for short circuit and transient stability analysis.</li> </ul>	<ul style="list-style-type: none"> <li>Require DER aggregators or distribution utilities to provide net injections at each interface of the transmission's observability area</li> <li>Implement a DER aggregation model in contingency analysis tools</li> <li>Exchange network models periodically between distribution utilities (DUs) and TOs for areas where distribution networks are meshed</li> <li>Develop dynamic and short circuit equivalent models in the operational time frame and exchange them with the TO</li> </ul>

Table 3-5, continued  
 Implications of DER market participation and mitigation options for transmission

Category	Functional Role	Implications	Mitigation Options
<p><b>Real-Time Functional Analysis</b></p>	<p><b>Restoration and Emergency Operations</b></p>	<ul style="list-style-type: none"> <li>• DER disconnects from the network in accordance with its configuration at the time of installation, based on a local issue, despite markets proceeding as normal.</li> <li>• DER may provide restoration or black start capability to local operators or TOs as part of restoration plans, temporarily overriding market participation during limited outages.</li> <li>• The market may not be suspended during a local emergency. Market, distribution and TO objectives may diverge, leading to longer restoration times.</li> <li>• In extreme events, DER may provide backup power to a customer in a microgrid; as the restoration process continues, these microgrids may be reconnected to the grid.</li> </ul>	<ul style="list-style-type: none"> <li>• Codify the DU and TO role in controlling DER when the market is suspended for restoration</li> <li>• Notify the TO if DER within a market aggregation is being used to provide backup power or resilience to critical distribution loads</li> <li>• TOs and DUs: Determine how DER will be integrated into restoration or emergency operation strategies, coordinate local restoration efforts, and coordinate DER interconnection requirements with market activity</li> <li>• Include DER aggregators in joint restoration training exercises</li> <li>• Return DER to production after service is restored and the grid is stabilized, with a predefined time delay and ramp rate; if that is not acceptable, DER communications may be used to disable permit service.</li> </ul>

Table 3-5, continued  
 Implications of DER market participation and mitigation options for transmission

Category	Functional Role	Implications	Mitigation Options
<p><b>Real-Time Functional Analysis</b></p>	<p><b>Congestion Management on Sub-Transmission</b></p>	<ul style="list-style-type: none"> <li>• High DER market penetration may influence TO management of constraints on the sub-transmission network.</li> <li>• Changes to the configuration of the transmission and sub-transmission systems may affect pre-clearance limits on DER and on ISO/RTOs contingency analysis.</li> <li>• Redispatch actions may be needed at short notice for localized variability and uncertainty.</li> <li>• Incomplete sub-transmission automation and telemetry may reduce the set of switching/mitigation options available to manage congestion related to DER.</li> <li>• The makeup of the sub-transmission network may impact allocation of DER aggregation transmission distribution factors to ISO/RTO pricing nodes.</li> </ul>	<ul style="list-style-type: none"> <li>• ISO/RTOs: Manage congestion on sub-transmission in regions with substantial DER</li> <li>• DUs: Assume responsibility for sub-transmission network operation</li> <li>• Provide DER forecasts to TOs to develop congestion forecasts at an appropriate granularity (appropriate level)</li> <li>• TOs: Use DER and sub-transmission connected resources to manage congestion through ISO/RTO.</li> <li>• Optimize TO re-dispatch to manage sub-transmission constraints</li> <li>• Exchange operational grid data between TOs, DUs, and ISO/RTOs on the sub-transmission state</li> <li>• TOs: Specify and update interfaces and limits based on system conditions. These may affect DER aggregation distribution.</li> <li>• Implement regional sub-transmission redispatch markets</li> </ul>

Table 3-5, continued  
 Implications of DER market participation and mitigation options for transmission

Category	Functional Role	Implications	Mitigation Options
<b>Real-Time Functional Analysis</b>	<b>Management of System Voltages</b>	<ul style="list-style-type: none"> <li>• More active distribution networks and reduced numbers of generators on transmission networks may require dynamic voltage control to mitigate high voltage conditions.</li> <li>• DER production can increase system voltage at low load, causing deviation from allowable reactive and voltage limits.</li> <li>• Fixed power factor assumption for load may reduce effectiveness.</li> </ul>	<ul style="list-style-type: none"> <li>• Require DER aggregators to provide net injection information by transmission node in real time</li> <li>• Consider DER aggregators in the definition of voltage control areas</li> <li>• Integrate DER aggregations in support of transmission voltage control</li> <li>• Conduct dynamic reactive power forecasts based on DER market participation</li> <li>• Specify dynamic power quality T&amp;D interface limits before pre-qualification for day-ahead and real-time markets</li> </ul>
	<b>Asset Monitoring</b>	<ul style="list-style-type: none"> <li>• DER growth may substantially change the way assets (e.g., generators, shunts, or breakers) are used, so traditional maintenance practices may require revision to ensure sustained asset availability.</li> </ul>	<ul style="list-style-type: none"> <li>• Integrate forecasted DER market behavior in asset management assessment tools</li> </ul>

Table 3-5, continued  
 Implications of DER market participation and mitigation options for transmission

Category	Functional Role	Implications	Mitigation Options
Operational Planning Functional Analysis	Outage Coordination	<ul style="list-style-type: none"> <li>Increased variability and uncertainty of DER production alters traditionally safe periods for maintenance outages.</li> <li>A market process can be used to manage grid conditions during outage periods with coordinated DER.</li> <li>DER response to market signals can change system strength at locations in the network during outage periods, requiring compensation from other resources.</li> <li>Planned and unplanned distribution outages may constrain the ability of DER to support the bulk system.</li> </ul>	<ul style="list-style-type: none"> <li>Coordinate operation between TOs, DUs, ISO/RTOs and DERAs to give visibility on outage coordination including network topology, asset outages, and local constraints</li> <li>Notify TOs of DERA outages and productions , and included this information in forecasted conditions for system studies</li> </ul>
	Network Model Building and Exchange	<ul style="list-style-type: none"> <li>DER affects the net injections of both active and reactive power at primary substations in the generated network cases. This can be reflected indirectly as a change in the load or directly as generation at that node.</li> <li>Measures on the distribution network induced by DER, such as switching decisions, can impact voltage and injection location in the study.</li> <li>DER forecast error adds additional uncertainty to developed network models.</li> </ul>	<ul style="list-style-type: none"> <li>Exchange network topology daily at an hourly granularity between grid operators</li> </ul>

Table 3-5, continued  
 Implications of DER market participation and mitigation options for transmission

Category	Functional Role	Implications	Mitigation Options
<b>Operational Planning Functional Analysis</b>	<b>Contingency Definition</b>	<ul style="list-style-type: none"> <li>• If DER provides ancillary services such as operating reserves, the distributed nature of the response may require assessment of specific contingencies that were not previously studied.</li> <li>• If a DER becomes sufficiently large, the loss of that aggregation may constitute a contingency. This can originate due to protection, inverter controls, or loss of communication.</li> </ul>	<ul style="list-style-type: none"> <li>• TOs and ISO/RTOs: Assess whether the geographic spread of DERA can create conditions in which contingencies not previously included in contingency analysis should be studied in the operational setting</li> <li>• Introduce DERA capacity limits into the market registration process</li> </ul>

Figure 3-6 maps the key information or data exchanges that facilitate several potential options to mitigate and integrate DER into traditional transmission operations. In the future, ISO/RTO tariff development and transmission operator planning for DER integration may consider prioritizing the treatment of access to this information. Figure 3-6 also illustrates the information exchange needed for the different identified functional roles of transmission operations. Some information can be used for additional operational tasks. For example, operational planning engineers need to exchange information on net power injection to ensure a safe outage coordination and network. This information can also increase the situational awareness of the BPS and improve operational decision making to facilitate safe and reliable contingency analysis and system voltage management.

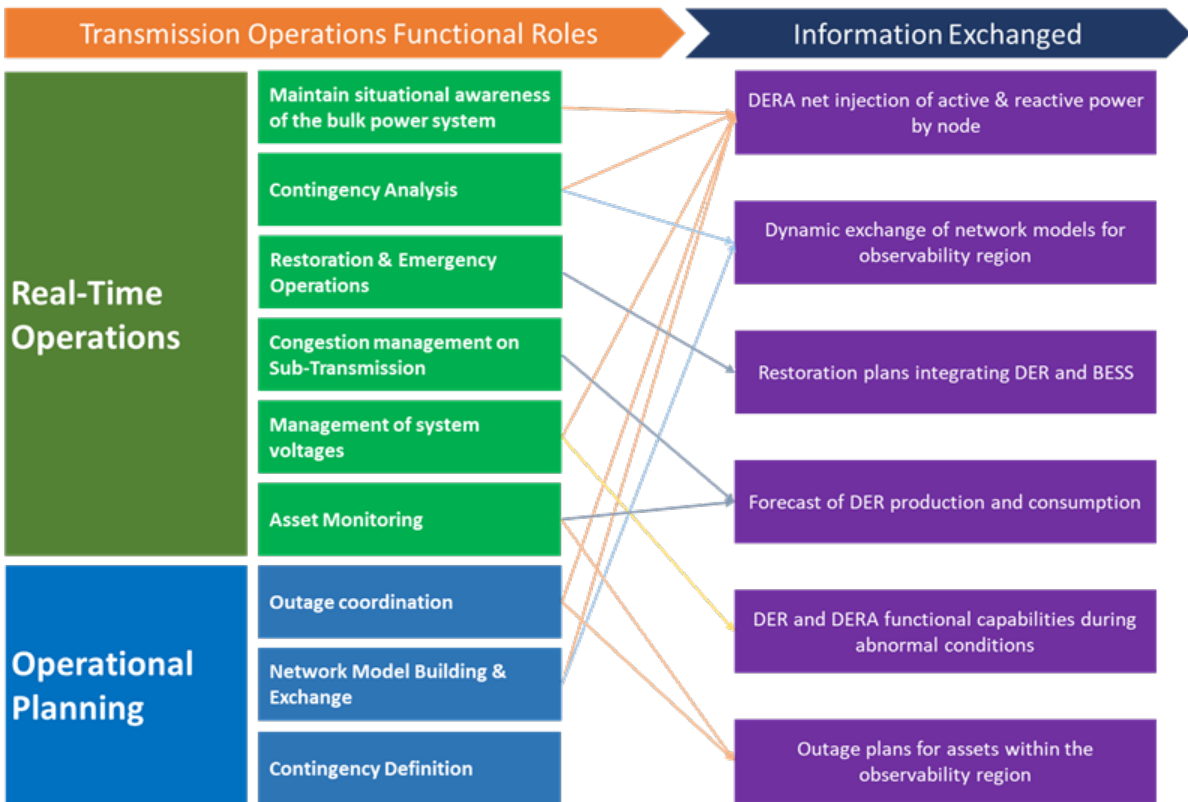


Figure 3-6 Summary of Information exchanged between functional roles in transmission operations as part of DER market impact

### Transmission Planning

FERC Order No. 2222 requires DER aggregators, RERRAs, and distribution utilities to provide information the ISO/RTOs need to perform DERA transmission impact studies. The order encourages FERC jurisdictional ISO/RTOs to establish coordination frameworks. It also notes that RERRAs could coordinate the development of interconnection

agreements and rules for individual DERs. In the transmission operations and planning workstream, the team reviewed several key aspects of DER transmission planning considerations [34]. This included a discussion of the pros and cons of each approach, the outstanding challenges, and possible frameworks for addressing these gaps.

Transmission planning to enable DERA market participation requires coordination between the ISO/RTOs, DER aggregators, transmission owners/utilities, distribution utilities, and RERRAs. Transmission planning conducted by the transmission planner can be performed by both transmission owners and ISO/RTOs. The primary *planning-related* objective of the transmission operation and planning workstream was to support the following:

- **FERC jurisdictional ISO/RTOs**, and as applicable transmission owners, in developing technical reviews based on screening criteria that may not require sophisticated modeling to assess the potential transmission impacts of DER aggregations; as well as their voluntary efforts to ensure adequate DER capabilities, performance, and functional settings
- **DER aggregators, RERRAs, and distribution utilities** in their expected identification of the information ISO/RTOs and transmission owners need to study the impact of DERAs on the transmission system
- **RERRAs** in their possible roles and responsibilities in coordinating the development of interconnection agreements and rules for non-jurisdictional (individual) DERs with BPS reliability perspectives in mind

As part of this effort, the workstream examined four areas:

- Ensuring adequate transmission impact and reliability assessment studies
- DER modeling methods in long-term transmission planning studies
- Ensuring adequate DER capabilities, performance, and functional settings
- Key data needs, exchanges, and update mechanisms

#### Ensuring Adequate Transmission Impact and Reliability Assessment

Participation of DER aggregators in the wholesale market could bring the need to assess the potential impact of one or more DER aggregations on the transmission system. Impact assessments from individual DERs are already part of many distribution utility interconnection processes (which are assumed to be under the jurisdiction of the RERRA). However, the impact of many coherently performing DERs within a DERA could differ from the impact of a single DER or a set of many diversely performing

DERs in a high-penetration region. Methods for modeling DER aggregations in long-term transmission planning reliability studies have existed for several years and are increasingly used by transmission planners [35]. Ongoing research currently investigates the opportunities and limitations of applying those methods to impact studies during the DERA registration process.

New ideas are emerging for technical reviews that do not require sophisticated modeling, but instead use simple screening criteria to identify potentially undue DERA transmission impacts.

As the industry continues to develop methods and practices for DERA transmission impact assessments, the scope of these reviews and the time required for the reviews should be reasonable and not create unjust barriers for DERA wholesale market participation. New ideas are emerging for technical reviews that do not require sophisticated modeling, but instead use simple screening criteria to identify potentially undue DERA transmission impacts. These screening criteria could complement existing DER impact studies conducted in the distribution interconnection process.

### DER Modeling Methods in Long-Term Transmission Planning Studies

EPRI has spearheaded research into DER modeling methods in long-term transmission planning. This includes model specification, parameterization/configuration, validation, and implementation of a DER\_A model for steady-state and dynamic performance analysis over the past decade. Findings contributed to the NERC *Reliability Guideline on Parameterization of the DER\_A Model* [35]. The method enables transmission planners to explore BPS reliability impacts and contributions from emerging technologies such as rooftop solar PV plus battery storage systems, which are likely resources for wholesale market participation via aggregation.

In most cases, research has confirmed the adequacy of these modeling methods for studying BPS voltage and frequency performance under high levels of DERs [36]. The industry continues to identify corner cases where more sophisticated modeling of individual DERs and DERAs may be desired [37]. Similarly, detailed electromagnetic transient (EMT) modeling in regions such as ISO-NE has shown that the generic DER\_A model can be used to adequately represent aggregations of inverter-based generation and storage connected to the distribution feeders of a transmission or sub-transmission substation in many cases [38]. These studies highlight the importance of adequate DER\_A model configuration [39].

Transmission impact assessments for individual DERs are already part of many distribution utility interconnection processes. However, the following potential gaps may exist:

- Assessment of individual DER impacts on the BPS may be limited to large-scale DERs.
- Many distribution utilities do not yet require individual DERs to perform reliably from a BPS perspective.
- The impact of many coherently performing DERs within a DERA could differ from the impact of a single DER or a set of many diversely performing DERs in a high penetration region.

FERC Order No. 2222 recommends keeping the scope and effort for a DERA transmission impact assessment reasonably limited. The order recommends avoiding duplicate transmission impact assessments of a utility-scale DER that is participating in a DERA and that might have already been carried out during the RERRA interconnection process. Limiting impact assessment to aggregation-related studies reduces barriers to DERA wholesale market participation. ISO/RTOs are primarily developing BPS impact assessments for DERAs that avoid lengthy and complex impact studies. Many ISO/RTOs are establishing technical reviews during the DERA registration process that use screening criteria to complement the DER transmission impact studies.

#### Ensuring Adequate DER Capabilities, Performance, and Functional Settings

The technical interconnection and interoperability requirements (TIIRs) for DERs, including those that participate in the wholesale market through a DER aggregator or a distribution system operator, are not subject to FERC jurisdiction. In Order No. 2222, FERC recognized and highlighted the responsibilities of the RERRA to initiate and lead coordination between the stakeholders on each side of the transmission and distribution (T&D) interface, including ISO/RTOs, distribution utilities, and DER aggregators.

Updating TIIRs for DERs remains an important step for reliably integrating these DERs into transmission planning and operations, whether or not they participate in the wholesale market. The specification, configuration, and management of functional settings of non-jurisdictional DERs that connect to the distribution system for the purpose of participating in wholesale markets through DER aggregators may impact BPS reliability, and as a result requires coordination across many stakeholders. However, the relationships, interfaces, and processes between these stakeholders are often poorly established or do not yet exist. FERC did not specify procedures for this or for other coordination needs but encourages each ISO/RTO to develop a coordination framework that addresses the needs of its region.

DERs (especially inverter-based DERs) provide a high degree of configurability to determine their response to, and performance during, grid events. IEEE 1547-2018 standardizes 99 functional parameters that

are only a subset of the settings modern inverter controls provide to the owner/installer. Examples include functional settings for voltage regulation, enabling/disabling regulation modes, frequency response, and trip settings. The latter two can determine the degree to which the ride-through capabilities for voltage, frequency, and frequency drop capability, as specified by the IEEE 1547-2018 abnormal performance categories, is utilized.

IEEE 1547-2018 allows the settings to be altered from default values, as needed and where justified, but only within the ranges of allowable setting that are explicitly specified in the standard. Considering the needs of a specific region, a regional or even distribution-utility-specific group of settings may be specified. These utility-required profiles (URPs) could consider and differentiate between DERs of different technology, size, etc., although they do not have to. As a result, different layers of DER functional settings may evolve (see Figure 3-7).

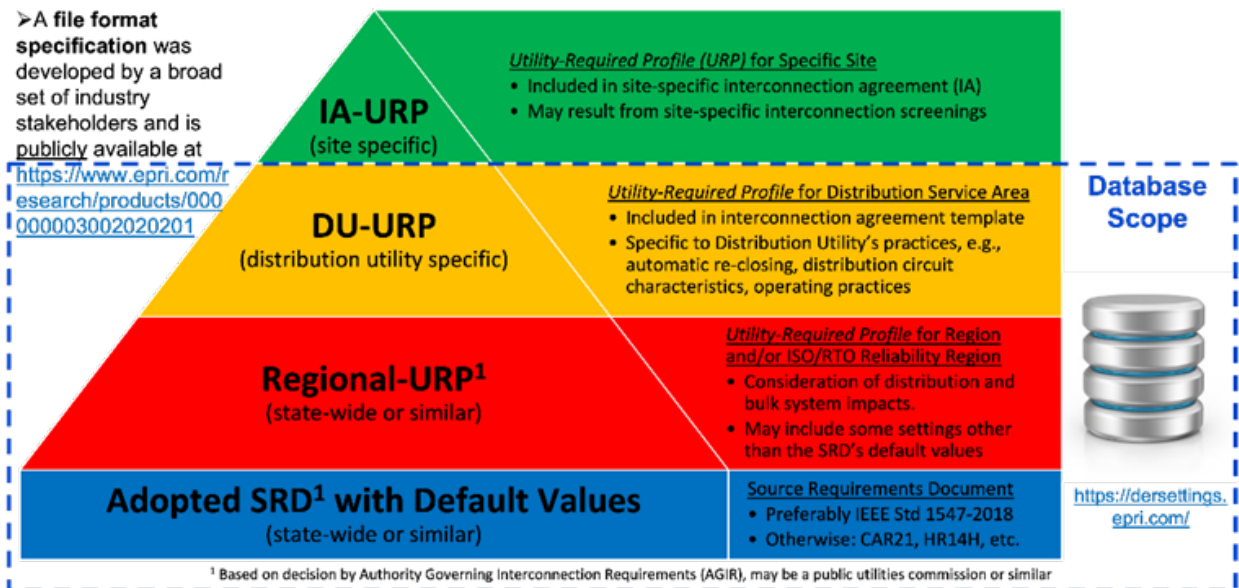


Figure 3-7  
Layers of DER interconnection requirements and settings

### Key Data Needs, Exchange, and Update Mechanisms

DER and DERA modeling in transmission planning studies and technical reviews requires adequate and efficient collection of DER data and could become increasingly important as more DERAs participate in the wholesale market. The *NERC Reliability Guideline on DER Data Collection for Modeling in Transmission Planning Studies*, proposes processes for data collection and exchange between responsible entities, as well as provides example data specifications needed for BPS reliability [40]. Following are several key categories of data needs and exchanges discussed in this workstream:

- **Management of DER functional settings.** Managing the increasing diversity of DER functional settings illustrated in Figure 3-7 may become a challenge because of their expected variety and volume. Even after distribution utilities and the ISO/RTO as the responsible reliability coordinator jointly specify regional DER functional settings, the reliable configuration of these DER settings in the field may not be easy.
- **Remote configurability.** An important advantage of DERs that participate in a wholesale market through a DER aggregator is that they will have to be integrated into some kind of DER management system (DERMS). When connected to a communications network, the appropriate DER communications interface provides access to at least each of the 99 functional parameters that IEEE 1547-2018 requires. Additional parameters may be available depending on the DER make and model [41]. The DERMS offers a DER aggregator remote configuration, reconfiguration, and management of functional settings for the individual DERs within a DERA participating in a wholesale market.
- **Common file format.** A common file format is a prerequisite for the reliable and automated configuration of DERs using “DER settings files.” EPRI developed the *Common File Format for Distributed Energy Resources Settings Exchange and Storage* in collaboration with a broad set of industry stakeholders [42].
- **DER settings database.** The EPRI-developed *DER Performance Capability and Functional Settings Database* can be used to store information about the assignment of certain classes of DERs to the normal and abnormal performance categories specified in IEEE 1547-2018, along with DER settings information [43].

## Recommendations

After discussion with the workstream members throughout the project, the transmission operations and planning workstream determined the following transmission planning recommendations.

### *Conduct Simplified Screening Tests during DERA Transmission Technical Review*

Many coherently performing DERs within a DERA may pose different impacts than a single DER or a set of many diversely performing DERs in a high penetration region. At the same time, ISO/RTOs may limit the scope of a DERA transmission impact assessment to aggregation-related studies. As a result, technical review based on screening criteria would effectively complement the DER transmission impact studies that are already conducted [44]. Screening criteria could include, but may not be limited to:

- DERA members' IEEE 1547-2018 conformity
- DERA members' functional settings
- A requirement that DERA members are not located within congested BPS regions
- DERA and/or power system metrics, indicating potential significance of DERA impact on BPS performance [45,46]

Figure 3-8 illustrates a technical review process of DERA transmission impacts that does not require sophisticated dynamic studies and modeling in most cases. For most DERAs that seek to participate in the wholesale market, automating the screening could expedite the DERA impact assessment from several months to only a few weeks or days while upholding high BPS reliability standards.

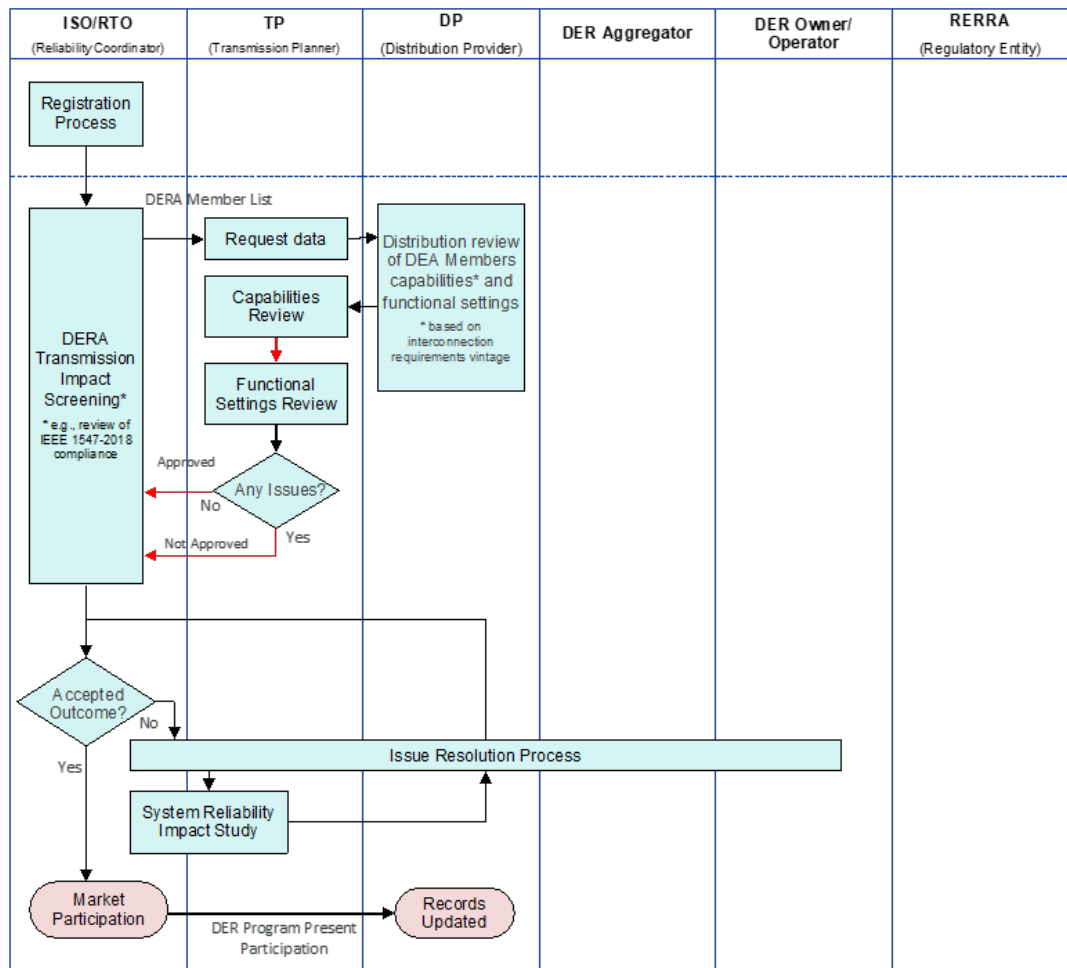


Figure 3-8  
DERA technical review process using screening criteria

Technical reviews and screening processes could play an important role when existing or new DERs seek to join a DERA, but RERRAs have not yet adopted technical interconnection requirements that support BPS reliability. Figure 3-9 illustrates outcomes of DERA technical reviews using screening criteria, depending on the time of DER interconnection.

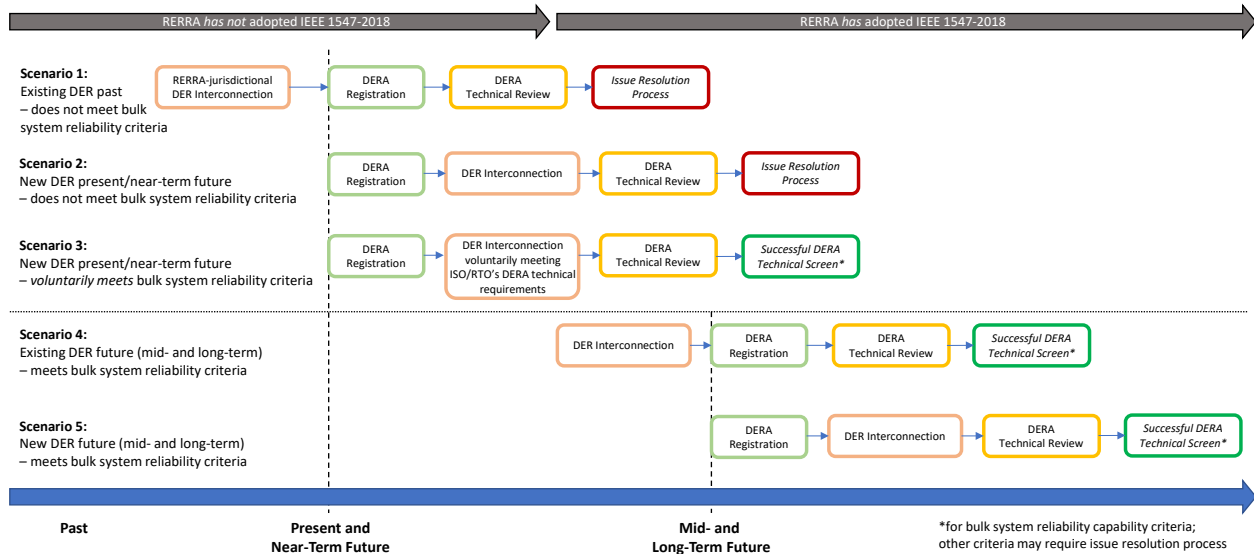


Figure 3-9  
Outcomes of DERA technical reviews using screening criteria, depending on the time of DER interconnection

### Utilize Advanced DER and DERA Modeling Improvements and Appropriate Parameterization

ISO/RTOs and transmission planners could integrate the *Aggregated Distributed Energy Resources (DER\_A) Model* into stability planning cases to study transmission reliability impacts and contributions from DERAs that better represent their behavior [47]. The NERC *Reliability Guideline on Parameterization of the DER\_A Model* as well as EPRI's latest *DER Modeling Guidelines for Transmission Planning Studies* provide valuable information on configuring the parameters for the DER\_A model for various study objectives [35,36].

The workstream presented two possible methods to represent DERA in power flow cases [34]. The first method uses a new version of the composite load model that either includes, or can connect to, the DER\_A model [48]. The second method uses EPRI's Aggregate DER Model Integration (ADMI) Tool. This Python script automatically replaces negative load at the transmission bus with an equivalent distribution feeder, connects load and DER\_A models at the equivalent distribution bus, and adequately configures branch elements so that the power flow solution resembles that of the case with negative load [49].

Even though most research and studies show the adequacy of the existing models and modeling methods for studying DERA transmission impacts using an adequately configured DER\_A model, the following modeling improvements could be further explored:

- **Use of more sophisticated DERA models** than the positive-sequence DER\_A model (e.g., the DER Cluster Study for which ISO-NE used plant-specific EMT models) [38]
- **More granular regionalization of the DERA models**, (e.g., instead of representing both legacy DERs and newer DERs that have IEEE 1547-2018-like performance capabilities and settings in a single instance of the DER\_A model at each substation, two or more groups of coherently performing DERs can each be represented by their own DER\_A model instance)
- **More or modified study cases** (e.g., conventional resource dispatches and transmission element switching statuses that lead to relatively high and low short-circuit strength in the DERA area; or cases in which the distribution utility has overridden DERA dispatch for distribution reliability)

#### *Adoption of IEEE 1547a-2020*

Based on recent findings, ISO/RTOs could initiate stakeholder processes that ensure advanced DER can become available in the marketplace in the 2022/2023 timeframe<sup>7</sup> and interconnect with proper configuration of the settings that are known to impact the BPS (see Figure 3-10) [39]. Standards such as IEEE 1547-2018, as amended by IEEE 1547a-2020, could be used as a broadly accepted industry reference and for good utility practice.

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<sup>7</sup> Inverter-based DER that are IEEE Std 1547<sup>TM</sup>-2018 capable and UL 1741 SB certified are becoming available later than expected. Latest information is made available at <https://sagroups.ieee.org/scc21/standards/1547rev/>.

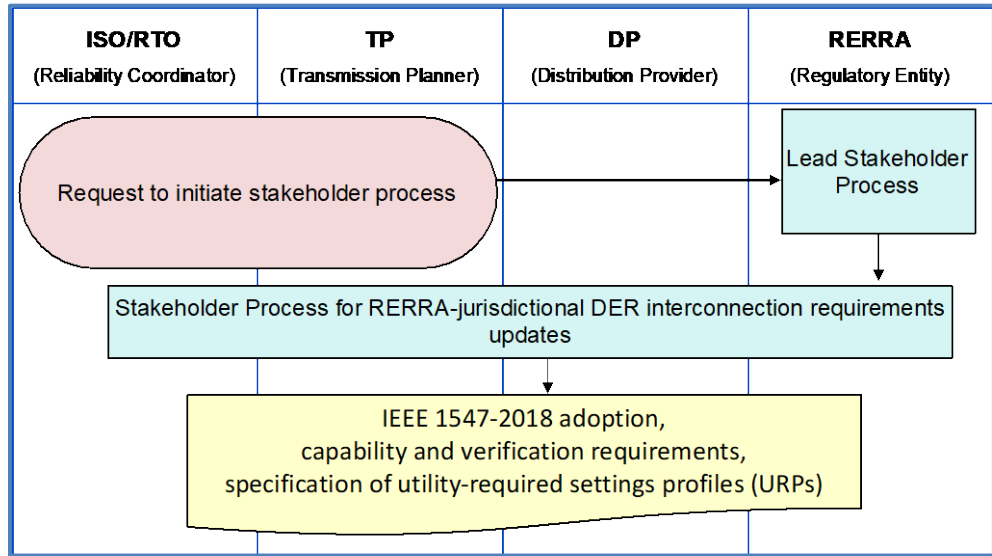


Figure 3-10  
Stakeholders coordination on DER technical interconnection requirements

### Coordination of DER Functional Settings through Stakeholder Collaboration Groups

IEEE 1547-2018 allows for flexible alteration of DER settings from default values, as needed and where justified, but only within the ranges of allowable setting that are explicitly specified in the standard. Thus, a stakeholder process could use the default values specified in the standard as a starting point and ask the responsible ISO/RTO, transmission planners, and distribution utilities to review whether these settings are appropriate. If any of these stakeholders proposes alternate settings that gain consensus among all stakeholders, a regional- or distribution utility-specific group of settings can be specified.

ISO/RTOs could voluntarily initiate collaborations at state and regional levels to engage all necessary stakeholders in the objective of leading the state regulatory entities and distribution utilities to successfully select appropriate regional settings (“regional URPs”). These settings should consider the region’s needs and fall within IEEE 1547-2018-specified ranges of allowable settings. Guiding principles for successful coordination frameworks could incorporate development of a joint vision; mutual respect with deep listening and understanding of individual stakeholder’s concerns’ a collaborative learning atmosphere; and ultimately the automation of (aggregated) data exchange to the extent reasonably possible. The timely establishment of these coordination frameworks could become a critical success factor for DERA wholesale market participation.

## Use of Common File Format for Management of DER Functional Settings

EPRI created a common file format to support the exchange and storage of DER settings information between parties and to enable consistent human and machine/software interpretation. The format provides a practical way to configure and verify functional settings within a DER and to share that information with others (see Figure 3-11). It also enables development of software and parsers that can automatically read the contents of the file. For these reasons, the common file format could play an important role in an ISO/RTO coordination framework.

Figure 3-11 illustrates possible use cases for EPRI's DER Settings database. DER equipment manufacturers, installers, and utility interconnection engineers can use the DER settings files that are uploaded to EPRI's DER Settings Database in the common file format to configure and validate functional settings applied in field DERs. As a result, this or a similar database could play an important role in an ISO/RTO coordination framework.

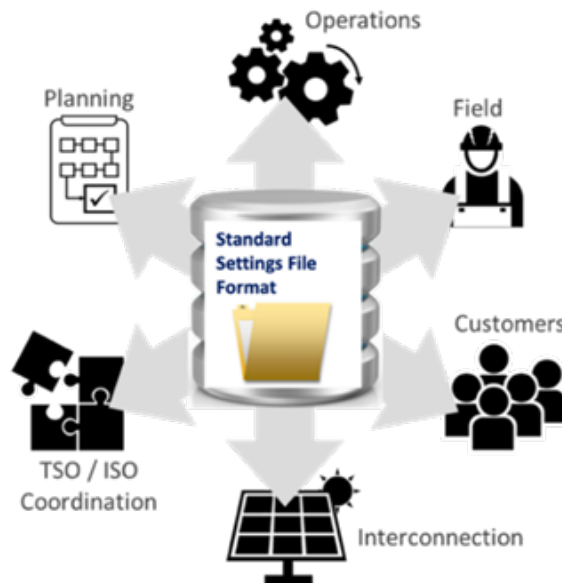


Figure 3-11  
DER performance and settings database with possible use cases for DER settings files that use a common file format

### Transmission, Distribution, and Aggregator Coordination

FERC Order No. 2222 requires ISO/RTOs to establish coordination rules across ISOs, DER aggregators, distribution utilities, and RERRAs that enable DER participation in the wholesale market while maintaining T&D

FERC Order No. 2222 requires ISO/RTOs to establish coordination rules across ISOs, DER aggregators, distribution utilities, and RERRAs that enable DER participation in the wholesale market while maintaining T&D grid

grid reliability. Lack of these coordination methods presents several obstacles to the successful implementation of Order No. 2222, including the following:

- Without a comprehensive coordination framework, DERs may never be allowed to interconnect over current network capacity, which limits access to wholesale markets. Without market access, DER owners see lost opportunity or decreased value for their DERs capable of providing grid services.
- As potential for additional DER interconnection is reduced, customers may lack incentives to deploy DERs.
- Network augmentations may increase and become uneconomic, resulting in costly infrastructure upgrades.
- Distribution and transmission assets may remain underutilized, with limited interconnected DER capacity.
- Allowing DER to interconnect above current network capacity limits without establishing transmission system operator-distribution system operator (TSO-DSO) coordination frameworks could result in an unreliable system, constraint violations, and equipment wear and tear.
- Due to lack of information sharing, unresolvable double-accounting issues may result when DER is used to serve both the distribution and the transmission system.

Since 2018, EPRI has facilitated the TSO/DSO Coordination Working Group to address some of these key coordination challenges (see Figure 3-12). The group assembles multiple T&D stakeholders on a range of different topics to address solutions to DER coordination challenges. After FERC Order No. 2222 was issued and as part of the EPRI FO2222 Collaborative forum project, the TSO/DSO Coordination Working Group focused attention on some of the order's key coordination requirements. The project provided a guideline on different users and activities across many of the order's directives [50]. Group discussions were public and open for anyone to join. The goals of the working group include:

- To provide utilities with a complete framework for coordination regarding DER services, including process and data flow options
- To address fundamental needs for ISO/RTOs, DSOs, and DER aggregator coordination through a menu of well-defined technical functions
- To inform functional requirements of planning and operational control systems, including energy management systems, market management systems distribution management systems, DERMS, customer information systems, and supervisory control and data acquisition (SCADA) systems

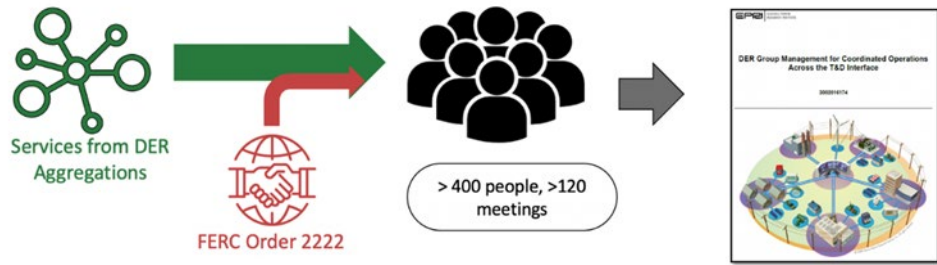


Figure 3-12  
 EPRI's TSO-DSO Coordination Working Group focuses on several key coordination challenges of FERC Order No. 2222

### Coordination Frameworks

The workstream developed a comprehensive list of coordination methods designed to address the needs for coordination about organized groups and DER aggregations between ISO/RTOs, TOs, transmission owners, distribution utilities, DER aggregators, RERRAs, customers, and other stakeholders. Figure 3-13 shows the roles and needs of the primary actors identified by the FERC order for coordination. The workstream focused on defining how each actor will interact and provide information to others to enable reliable and safe grid operation when DERs provide wholesale market services.

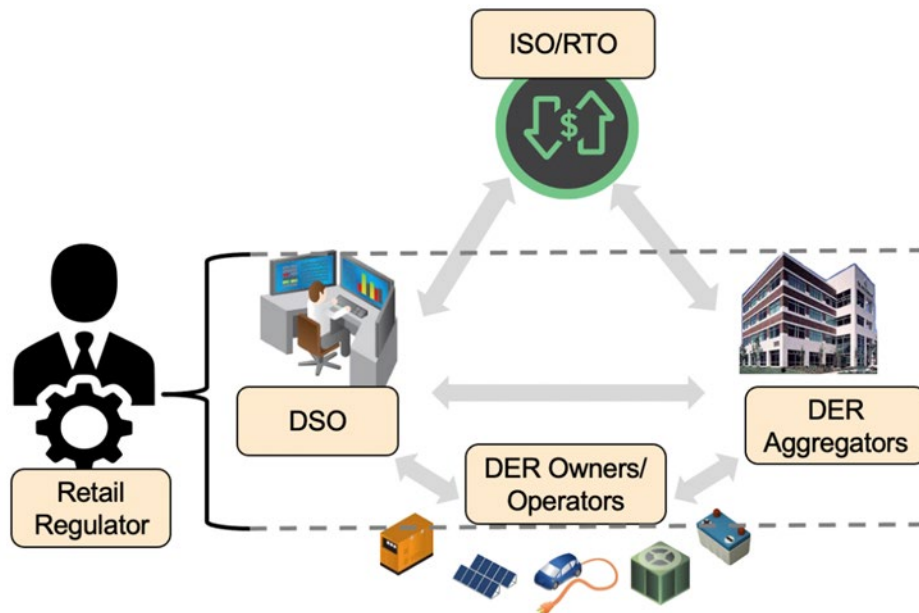


Figure 3-13  
 Reference actors and interfaces for TSO/DSO coordination

Each coordination requirement entails some form of exchange of information between entities identified in Figure 3-13. Entities in an exchange may perform a function or a sequence of functions to determine which information must be provided to other entities. Table 3-6 summarizes those interactions and provides example.

Table 3-6  
List of coordination interactions mapped to reference actors across different timeframes

Interaction	ISO/RTO	DERA	DU	RERRA
<b>Pre-Event /Registration</b>				
Registration	←			
DERA physical and operational characteristics	←			
Opportunities and restrictions for multiple service/program participation	←			√
List of DERs seeking to participate in wholesale markets and ISO/RTO market registration notification	←			
Mapping DERA response to pricing nodes	←			
List of DERs in an aggregation	←			
Attestation of compliance to DU procedures and regulations	←		√	√
Distribution utility review criteria	←			
List of DERs in an aggregation for distribution utility review	→			
Distribution utility review results	←			
<b>Operational Coordination</b>				
Notification of offer changes due to distribution constraints	←			
Distribution utility override of DERA award through ongoing operational coordination	←			
Dispatches for distribution utility awareness	→			
Distribution constraint notification	←			

Table 3-8, continued  
 List of coordination interactions mapped to reference actors across different timeframes

Interaction	ISO/RTO	DERA	DU	RERRA
<b>Post-Event / Settlement</b>				
Aggregate settlement data for the aggregations	←			
Individual DER data during audits	←			√

In each coordination framework, the roles of stakeholders may vary based on the regulatory, technical, and process decisions made in each jurisdiction.

The documented coordination functions of ISO/RTO, DSO, and DER aggregators can be applied to different coordination architectures that have been proposed and considered. For example, the total DSO, total ISO, and hybrid frameworks are proposed as different communication paths and responsibilities across the ISO/RTO and DSO [51]. Each may vary based on which entity has responsibility for aggregating at a given level, and how the communication flows across parties. In each coordination framework, the roles of stakeholders may vary based on the regulatory, technical, and process decisions made in each jurisdiction. Possible architectures include the following:

- The DER aggregator produces energy offers reflecting all DERs’ ability and costs to supply energy or services.
- Offers are made directly to the distribution system operator (DSO). In this case, the DSO then aggregates across its system or at each transmission node to then offer to the ISO/RTO.
- The DSO manages only the grid constraint violations created by DERs.
- The DSO may operate a local distribution market.

While Order No. 2222 did not require ISO/RTOs to develop a specific coordination framework, it does encourage it. However, some argue that most of the other coordination requirements essentially demand a coordination framework, even if it is not explicitly requested. The concept is evolving and may be a key area of research in the future.

To meet the order’s coordination requirements, utilities must establish some form of DER management capability. This could range from intelligent, autonomous grid-edge controllers to more sophisticated centralized DERMS systems.

Because the order enables third-party DER aggregators to participate in organized BPS markets, utilities must establish rules for aggregators to manage DERs and coordinate in real-time when DERs are operated. Several gaps exist today. Methods are needed to improve the

effectiveness, efficiency, and reliability of the utility-aggregator relationship by clarifying responsibilities, building robust interfaces, and developing a future-proof implementation strategy.

There is also a need to understand the benefits and limitations of different TSO-DSO coordination frameworks. In each jurisdiction, selecting and establishing a coordination framework will be a key decision for all TSO-DSO coordination stakeholders. Each involved entity must understand the benefits and limitations of each framework. The resulting performance of each DER coordination framework should be assessed across a set of key performance indicators, including economic and reliability benefits for the distribution system, BPS, DER owner/aggregator, end consumers, etc.


The TSO/DSO Coordination Working Group will continue to meet after this project to extend the discussions. These areas will be a key part of those discussions. The group will work with ISO/RTOs and distribution utilities to determine whether chosen paths are effective. The group will also identify advancements that enhance processes at high DER penetrations across various frameworks and jurisdictions (including those not subject to Order No. 2222 jurisdiction).

### Information, Communication, and Cyber Security

The Information, Communication, and Cyber Security (ICCS) Workstream reviewed and provided high-level recommendations for metering, data, telemetry, interoperability, and cyber security requirements, as listed in Order No. 2222. The primary audience for the study is ISO/RTOs, TOs, electric utilities or DSOs, DERA, and third-party DER aggregators focused on these aspects. In addition, the study recommendations could be relevant for state and federal regulators and DER customers (owners and operators of DERs). In particular, the workstream provided assessments on metering, telemetry, and data information sharing, as well as system interoperability and cyber security [52,53].

The requirements and recommendations are relevant to Sections IV.F, Information and Data Requirements, and IV.G, Metering and Telemetry Requirements from Order No. 2222. The order recommends that ISO/RTOs establish the market rules for information and data requirements to aggregate DER. The rules pertaining to data require that:

- Each DERA must provide “a list of the distributed energy resources” used in the aggregation, with information related to each individual DER, and its resource capacity, location, and operating limits.
- DERAs must maintain aggregate settlement data for the DER.
- DERAs must maintain data of each resource in the DER aggregation for a duration, as required by the ISO/RTOs for the purpose of auditing.



The ICCS workstream focuses on Metering, Telemetry, Data, Interoperability, and Cyber Security.

In support, FERC has determined that ISO/RTOs revise their tariff so that DERAs must provide the following:

- Physical and operational characteristics of its aggregation
- A list of the individual resources in its aggregation
- Any necessary information that must be submitted for the individual DERs
- Aggregate settlement data for DER aggregation
- Performance data for individual DERs in DER aggregation for auditing purposes

FERC required the ISO/RTOs to establish rules for metering and telemetry for DERAs, install and have capabilities, and if applicable, to establish rules for DERs as well. The order did not provide the actual requirements for these aspects, so the ISO/RTOs retain flexibility to institute rules that are applicable to their region. FERC did suggest that the ISO/RTOs balance the needs for maintaining reliability and fair settlement practices, fairness of treatment with other technologies, and reduced undue burden on small resources.

To support the industry, the ICCS Workstream focused on the following five areas. The first three core areas have direct relevancy to Order No. 2222: metering, telemetry, and data. The remaining two core areas are cut across the first three core areas: systems interoperability and cyber security. Figure 3-14 shows the methodology that the study analysis used.

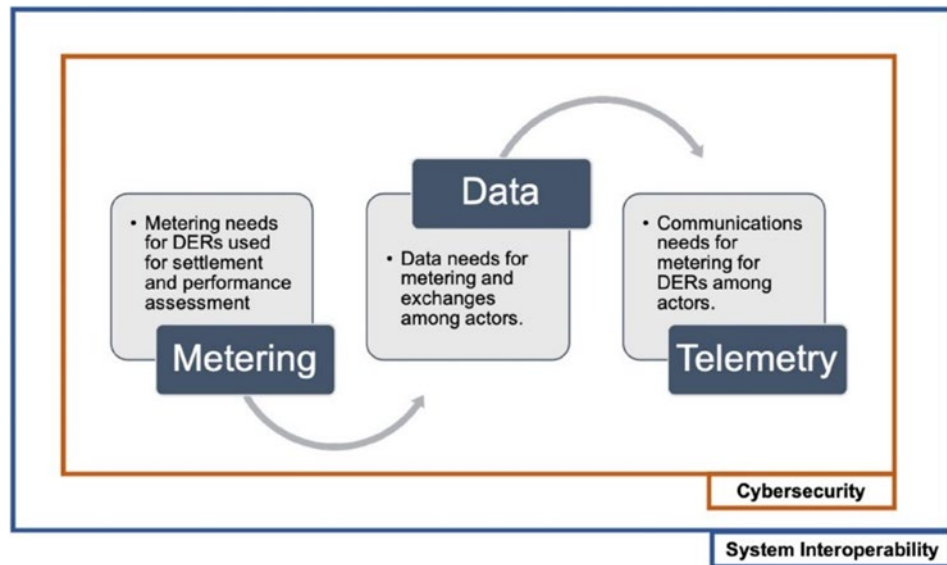


Figure 3-14  
Five concepts within the ICCS workstream

The definitions of these five core areas are:

- **Metering** is the measurement of energy, either consumed or produced, used for settlements.
- **Telemetry** is the ISO/RTO process(es) for direct measurement and communication of requisite physical, operational, and performance characteristics of a DER.
- **Data** is the data and information related to DERs, actors, settlements, and performance monitoring of individual DERs.
- **Interoperability** is the ability of the DER systems to exchange requisite data and information among the relevant smart grid domains and actors, markets, and networks.
- **Cyber security** includes maintaining the integrity, confidentiality, and availability of requisite data and DER systems.

The workstream focused on generic recommendations. This is because each ISO/RTO has different market rules and varied measurement and verification methods used for settlements. As a result, explicit recommendations for information and data requirements are impractical.

### *Metering*


Metering devices measure the energy that passes through a point on the grid. Customer retail meters are placed at the connection point to a residence or commercial facility, with other types used at other points on the grid, such as interties between control areas and at generating stations. This guide and Order No. 2222 focus on meters that are used to measure residential and commercial end use. With the advent of DER, these meters can measure energy produced in addition to the energy consumed. Meter data assume the form of energy values at periodic intervals or blocks, most commonly in 15-minute intervals, though five-minute, 30-minute, and hourly data blocks are also used.

The meter then sends these data blocks back to the utility at regular intervals—typically every 4 to 24 hours—where they can be used for performance assessment and settlement.

Utilities typically use customer meter data for monthly billing. Meters are distinguished from other measurement devices because they are certified to a standard that can be used for financial settlement—otherwise known as revenue quality meters. The meter data blocks enable time-of-use or real-time pricing, at least down to the granularity of the block interval.

### Key Considerations and Gaps

Order No. 2222 does not explicitly define specific metering requirements. However, the order does determine that:

 Metering requirements may be different for different types of DER.


- Meter data for aggregations must be available for settlements.
- Individual DER performance data must be maintained for audit purposes.
- Requirements should rely on existing metering infrastructure to the extent possible.
- Metering requirements may be different for different types of DER.
- Metering hardware and software requirements for DERAs need not necessarily be the same as for other resources.
- Meter data requirements for settlements should be consistent with other resources.
- Most behind-the-meter DERs are not required to be separately metered, which is also known as sub-metering.
- Metering requirements may differ based on the wholesale service the DERA provides.

While there are no explicit limits on metering requirements for either the aggregation or individual DER, any market rules that deviate from these guidelines should clearly define the reasons behind the additional requirements, including why they are “just and reasonable.”

Collaboration models include the sharing of meter data from the DER owner to the DER aggregator. Many will also include further sharing to a third-party such as the ISO/RTO for auditing or other measurement and verification. This is challenging because utilities are the custodians of the meter data, while customers are the owners of the data. The North American Energy Standards Board (NAESB) Energy Services Provider Interface (ESPI) standardizes the business practices necessary for customers to provide sharing rights to the utility and the exchange data contents and format. Two examples of implementations are The Green Button Connect My Data [54] and Smart Meter Texas [55]. The process requires the customer to opt-in to allowing the utility to share data with third parties; adoption rates have been very low in areas that have implemented the process.

### Key Recommendations and Next Steps

Any DER solution that uses the current performance of an advanced metering infrastructure must understand how that performance may change with increased use of DERs. ISO/RTOs must review extant metering infrastructure and standardized data and information access in determining the market rules for DER participation. Aggregators and ISO/RTOs should utilize standard meter data exchange mechanisms, while recognizing the importance of customer buy-in to the third-party meter data sharing rules. In many cases, simple point-of-interconnection metering may not be sufficient to validate behind-the-meter DER behavior. Separately-metered DER devices that utilize revenue quality



The NAESB Energy Services Provider Interface (ESPI) standardizes the business practices necessary for customers to share their meter data.

meters and advanced metering infrastructure are not yet common. Lower cost options can be used for DER device energy usage validation, such as inverter-provided measurements transported via cloud-based services. Market operator definition of rules could enable increased participation, especially from high numbers of smaller devices, by considering alternate approaches for energy usage measurement.

### *Telemetry*

In Order No. 2222, telemetry includes the ISO/RTO process and equipment for direct, real-time measurement and communication of requisite DER physical, operational, and performance characteristics. The telemetry requirements aid situational awareness and performance validation of DERAs and devices that provide services with response requirements (e.g., regulation service). In the order, FERC established that the DER aggregator is the entity responsible for managing the telemetry between the aggregation and ISO/RTO.

### Key Considerations and Gaps

Grid reliability needs to be ensured, without placing undue burden on device owners. This includes two sets of requirements:

- DER aggregators can use telemetry equipment to monitor individual DERs in real-time, so they can deliver performance compensations to the respective DER owners and validate aggregated telemetry, if necessary.
- DER aggregators can share the aggregated real-time telemetry with ISO/RTOs, as defined by the market rules, for real-time grid operations and for performance settlements.

Like metering, Order No. 2222 allows ISO/RTOs to decide whether to propose specific telemetry requirements for individual DERs in addition to that required from the aggregation. In addition, the DER aggregator may need to deploy communication systems to securely receive wholesale market dispatch signals or instructions from a market operator. While the telemetry requirements for DERAs should be analogous to other resources (as the order describes), alternative options for device-level telemetry could also be considered. In cases in which the devices are connected to a single point (e.g., a microgrid or campus), then the aggregation's telemetry provides electrically accurate information for situational awareness and performance. For geographically diverse aggregations, this is not possible, at least, not with traditional telemetry gateways and telecommunications. In these cases, the real impact of devices on the operation of the grid needs to be carefully considered, as well as options for validating performance after the fact.

Telemetry and the cost of telemetry will play a critical role for DER participation in ISO/RTO markets.

The workstream also identified that telemetry and the cost of telemetry will play a critical role for DER participation in ISO/RTO markets. Previous research has proposed leveraging an existing telemetry infrastructure used for retail DR markets to provide ancillary services that reduce telemetry costs. Future research with high penetration of DERs and DERA business models must review innovative approaches and field test them to reduce telemetry costs. A small subset of technology vendors and potential DERAs have expressed similar cost and technical challenges for telemetry.

### Key Recommendations and Next Steps

ISO/RTOs must have clear guidelines that align with planning and operational needs, consider cost to DERAs, and align with rules for similar services.

The project team recommends that ISO/RTOs consider clear and separate guidelines for telemetry data and DER management signals within their market rules, while considering the technical and cost implications of DERAs. The guidelines for telemetry requirements of data must align with the market rules required for safe, reliable, and resilient operation of the electric grid. The data type and granularity specified for the telemetry must be clearly identified to support specific ISO/RTO uses, such as real-time visibility and M&V requirements for settlements. It is also important to compare telemetry data requirements against the market rules that are used for similar services (e.g., energy provision versus frequency regulation), and where applicable, review the possibility of leveraging the DU's metered data and infrastructure (e.g., smart meters) used for billing and retail DR market participation.

### *Data and Information*

The ISO/RTO defines data requirements to describe the members of an aggregation, settlement data, and individual DER performance data.

Order No. 2222 defines high-level, DER-specific requirements for aggregators to provide information to the relevant ISO/RTO, including the DER members of an aggregation and DER aggregation settlement data. In addition, the order requires aggregators to maintain performance data for each DER in an aggregation for audit purposes. The order does not define detailed requirements for these information exchanges. The ISO/RTO defines specific data requirements to describe the members of an aggregation, settlement data, and individual DER performance data.

This section identifies typical information exchanges and data contents that exist or can be expected to exist under changes brought about by the order. As the order states, each ISO/RTO defines its own requirements for these exchanges and for data retention by the aggregators (i.e., for audit purposes). An example collaboration model is used to demonstrate information exchanges, applicable standards, and gaps (see Figure 3-15).

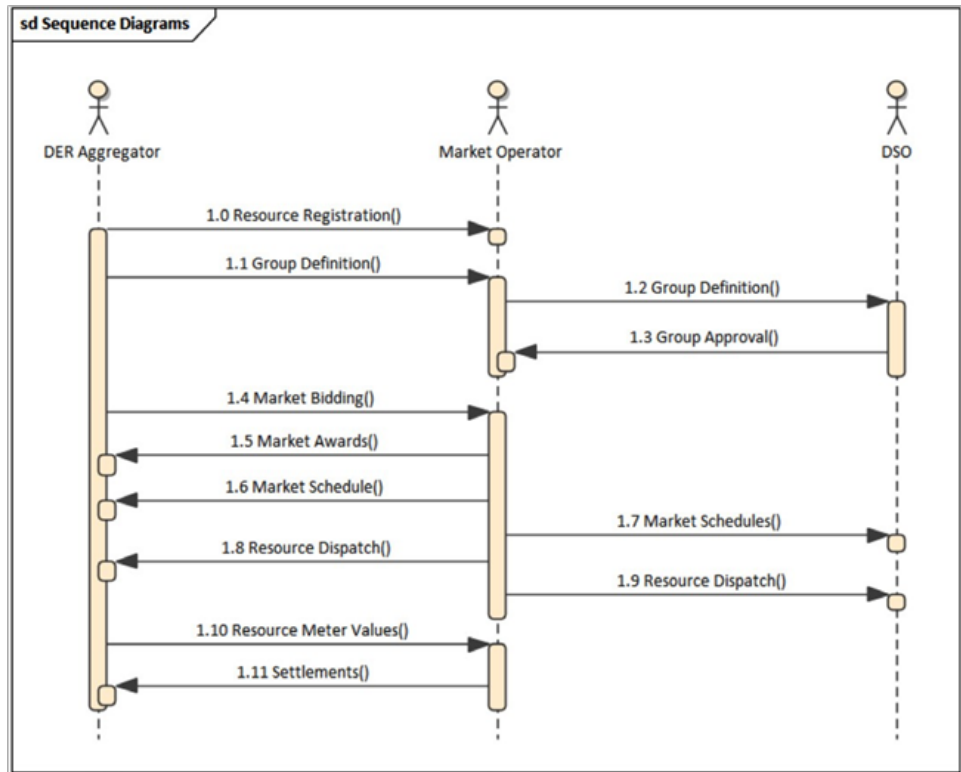


Figure 3-15  
Example collaboration model

There are other frameworks discussed in the coordination workstream of this project. This one is used for illustration purposes and is not meant to imply a preference. Regardless of the model used, the information exchanges (see Table 3-7) and applicable standards (see Table 3-8) are similar.

Table 3-7  
DER market participation exchanges

Source	Target	Message	Contents
DER aggregator	Market operator	Resource registration	<ul style="list-style-type: none"> <li>• Resource location</li> <li>• Device locations and types</li> <li>• Markets and services</li> <li>• Capacity for each service</li> <li>• Distribution factors (for multimode)</li> <li>• Ramp rates</li> </ul>
DER aggregator	Market operator	DER group definition	<ul style="list-style-type: none"> <li>• Device locations and types</li> <li>• Resource markets and services</li> </ul>

Table 3-7, continued  
DER market participation exchanges

Source	Target	Message	Contents
Market operator	DU	DER group definition	<ul style="list-style-type: none"> <li>• Device locations and types</li> <li>• Resource markets and services</li> </ul>
DER aggregator	Market operator	Bidding	<ul style="list-style-type: none"> <li>• Price curves for each service</li> <li>• Biddable parameters (DF, ramp rate, etc.)</li> </ul>
Market operator	DER aggregator	Market awards	<ul style="list-style-type: none"> <li>• Awards for each service; quantity and price</li> </ul>
Market operator	DER aggregator	Resource schedule	<ul style="list-style-type: none"> <li>• Expected operating points</li> </ul>
Market operator	DU	Resource schedule	<ul style="list-style-type: none"> <li>• Expected operating points</li> </ul>
Market operator	DER aggregator	Market dispatch	<ul style="list-style-type: none"> <li>• Operating points for the resource</li> </ul>
DER aggregator	Market operator	Telemetry	<ul style="list-style-type: none"> <li>• Operating point for resource</li> <li>• Operating point for devices</li> </ul>
DER aggregator	Market operator	Energy	<ul style="list-style-type: none"> <li>• Interval metered energy</li> </ul>
Market operator	DU	Energy	<ul style="list-style-type: none"> <li>• Interval metered energy</li> </ul>
Market operator	DER aggregator		<ul style="list-style-type: none"> <li>• Price/quantity pairs</li> <li>• Energy accounting</li> <li>• Performance penalties</li> </ul>

Table 3-8 shows existing data exchanges standards that can be used to meet these participation exchanges.

Table 3-8  
Market message exchange standards

Message	Example Standards
Resource registration	IEC 62325-452
Group definition	IEC 61968-5
Market bidding	IEC 62325-452
Market awards	IEC 62325-452
Market schedule	IEC 62325-452
Resource dispatch	DNP3/IEC 61850
Resource interval meter data	(NAESB) REQ 21—ESPI

## Key Considerations and Gaps

Additional research is required to determine an approach that could reduce this barrier to entry, for aggregators without unnecessarily burdening the ISO/RTOs.

In standardizing the common market interactions (consistent with other resource types) there are competing forces. From the ISO/RTO perspective, it is most efficient to re-use the existing data formats and exchange mechanisms, with additional contents as necessary. However, there has been little standardization across the North American ISO/RTOs in this space. Aggregators that seek to participate in multiple markets are faced with the significant costs of building data interfaces that are unique to each market. Aggregators and service providers would prefer to see standardization across the industry. A similar situation exists with settlements data which is even more challenging due to the lack of an identifiable or de facto standard in the industry. Additional research is required to determine an approach that could reduce this barrier to entry, for aggregators without unnecessarily burdening the ISO/RTOs.

A key implication of Order No. 2222 is the likely exchange of third-party data. For example, a distribution utility will be informed about, and possibly asked to approve, the DERs in an aggregation. They will also be provided with scheduling information to use for distribution operations and as part of settlements calculations. In these cases, another entity owns the data, but the custodial responsibilities to securely manage and protect the data are critical to minimizing financial and reputational risk. Further discussion is included in the cyber security section.

## Key Recommendations

Order No. 2222 indicates that each ISO/RTO must define requirements for performance data that the aggregator must retain for each DER in its aggregation, for auditing purposes. Because this is a relatively new process, coordination of exchange mechanisms across market operators would provide consistency. Submitting these mechanisms to a standards development organization is also recommended.

### *Interoperability*

Systems interoperability in the context of Order No. 2222 is about the ability of systems among the relevant domains, actors, markets, and networks to exchange requisite data and information.

## Key Considerations and Gaps

The key challenge for interoperability within Order No. 2222 is the potential complexity of the broader architecture. The order will provide a framework for a diverse set of makes and types of DERs to be simultaneously leveraged for market purposes. In parallel, distribution utilities may leverage these same resources for distribution system focused services.

Interoperability is a concept that can be applied to metering, telemetry, and data/information requirements to streamline integration and reduce costs.

FERC O2222 creates a complex coordination equation between DERAs, distribution utilities, ISO/RTOs, and DERs, each with its own communication interface, data requirements, and protocols.

The level of coordination required to ensure that T&D systems are operated in a safe, reliable, resilient, and economical manner requires coordination between ISO/RTOs, distribution utilities, DERAs, and DERs. This creates a complex coordination equation (see Figure 3-16), in which each stakeholder type has its own communication interface, data requirements, and protocols.

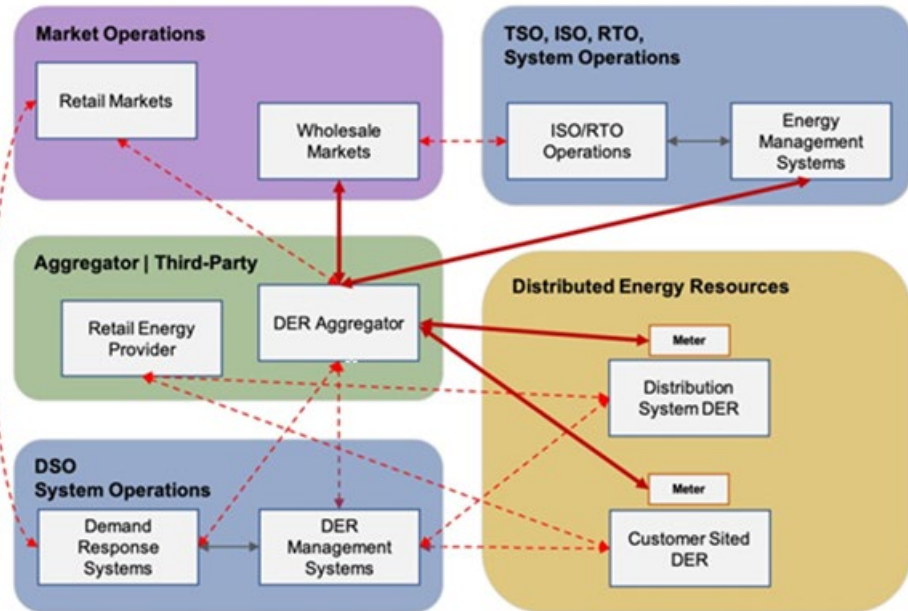


Figure 3-16  
DSO system interoperability

This also creates an interoperability challenge, because some of these interfaces are not standardized *en masse* today. Standards exist, but they do not fully address both semantics (the information layer or meaning of data) and syntax (the communication layer or technical structure of the message) of data exchanges (see Figure 3-17). Both are important for interoperability. Further complicating the solution is that adoption is fairly low, and standardization is custom to each ISO/RTO. This leads to a low-interoperability environment in which integration costs tend to be high because each integration takes additional time and effort in both the short term and the long term. This can also create a situation in which utilities and customers experience “vendor lock-in” because costs to change technologies become prohibitive. Neither of these situations is ideal for facilitating broader participation in markets and achieving utility clean energy goals.

When interoperability is low, integration costs tend to be high. The key is standardization.

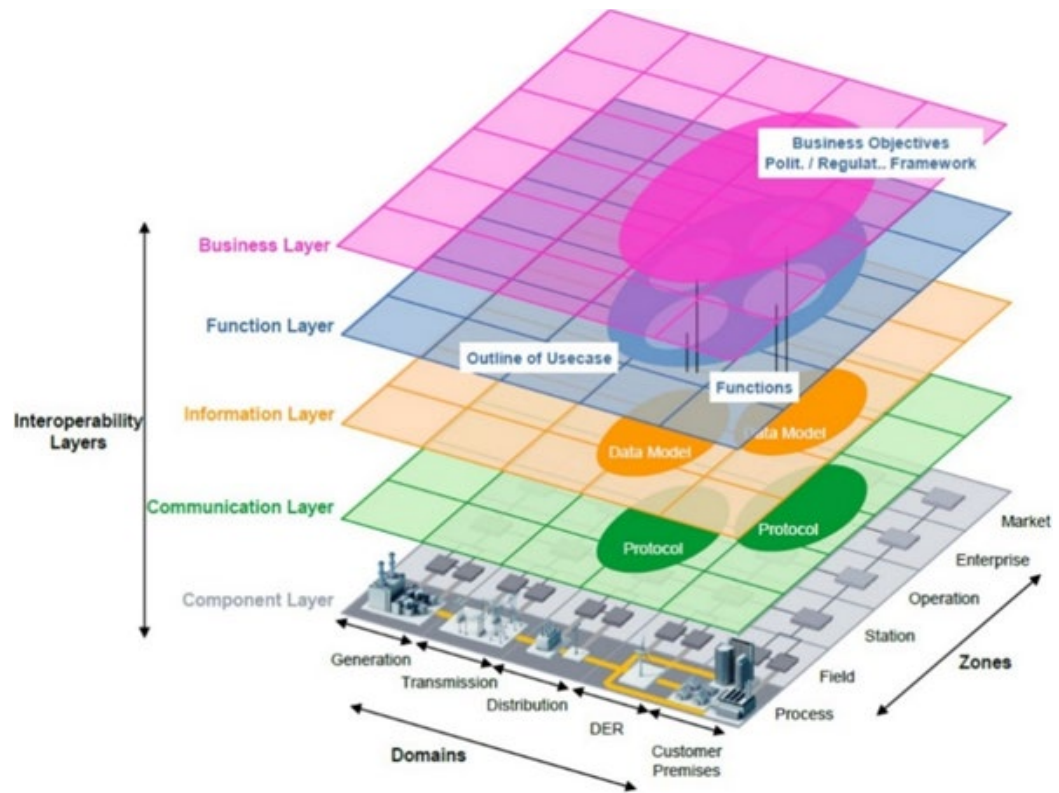


Figure 3-17  
The Smart Grid Architecture Model (SGAM)

### Key Recommendations and Next Steps

To address these interoperability issues, EPRI recommends the use of standards, including both standardized information models and standardized communication protocols.

The communication and information requirements for market communication interfaces differ between system operators. Meeting these requirements can be expensive and may be prohibitive for smaller scale aggregators. Standardization could reduce costs. This would require coordination between system operators to inform development of a standard set of harmonized requirements. To address this, EPRI recommends that ISO/RTOs consider some level of standardization to make the markets more accessible to DERAs of all sizes.

In addition to ISO/RTO interfaces, EPRI also recommends standardization between distribution utilities, DERAs, and DERs.

EPRI maintains a list of communication protocols and tracks their maturity through its Protocol Reference Guidebook [56,57]. It provides a guide to the relevant stakeholders engaged in the DER programs with in-depth analysis and deployment options for protocols and standards across the component, communications, and information layers of the Smart

EPRI maintains a running list of DER information and protocol standards through the Information and Communication Technologies program.

Grid Architecture Model (see Figure 3-17). A summary of the protocol landscape is shown in Figure 3-18 on top of EPRI's Federated Architecture for DER model [58].

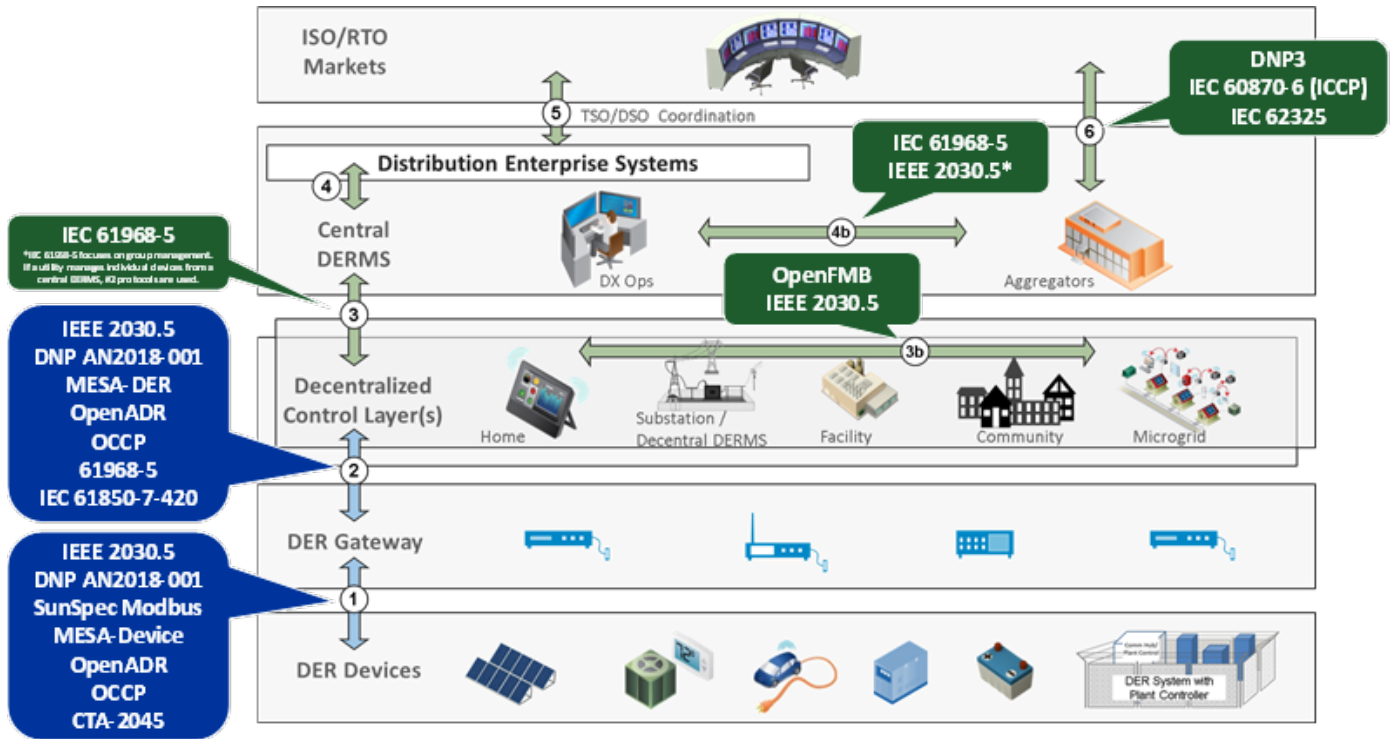


Figure 3-18  
DER information and protocol standards

This work is ongoing in two key areas.

**EPRI is conducting a gap analysis of today's standards** against the data exchange requirements associated with the different actors and interactions within a FERC Order No. 2222 use case. This will clarify which protocols are up to the challenge, and for those that are not, the gaps that need to be filled to prepare them. The update to associated information standards and protocols is likely to lag behind development of the business-layer requirements (e.g., market participation requirements and distribution utility program requirements). This is intentional and allows the standards to update and refine their information models to reflect the actual data exchanges required.

**More work is also needed to develop a scalable communication architecture.** Although the ISO/RTO-DERA interface is a primary focus in the FERC O2222 process, communication methods among other actors (e.g., distribution utilities, DERAs, and DERs) also need to be considered to ensure that local and distribution system impacts are understood and managed. EPRI has developed concepts such as the Federated

Additional research is needed to develop a scalable architecture to meet the needs of FERC O2222 and to update relevant information and protocol standards to support the architecture.

Architecture for DER Integration and continues to refine this work considering the evolving Order NO. 2222 requirements [58].

### *Cyber Security*

In Order No. 2222, cyber security refers to the protection of systems and data from cyber threats. Security protections must include the following properties:

- **Integrity.** Data and systems cannot be tampered with, corrupted, or otherwise altered by an unauthorized party.
- **Confidentiality.** Data can only be read by authorized parties.
- **Availability.** Systems must remain accessible and available for use.

### Key Considerations and Gaps

All three security properties must be applied to data used in metering, telemetry, settlements, and DER system and performance information. To meet interoperability objectives, critical system assets for grid and market operations must be designed to meet the security property of availability.

Order No. 2222 presents a major paradigm shift in which expanded use of public networks and third-party systems is required to fulfill expected interoperability functions. It also requires the pervasive use and exchange of data. This results in expanded attack surfaces on the grid, in energy markets, and on customer privacy. These risks must be addressed through clear definitions of cyber security responsibilities across a multi-party grid. Currently, there is no framework or specific regulatory standard that clearly defines cyber security responsibilities among grid participants in the context of Order No. 2222, resulting in cyber security trust challenges within interfacing party interactions.

### Key Recommendations and Next Steps

Order No. 2222 does not specify requirements for cyber security and data privacy. Rather, the order recommends that ISO/RTOs coordinate with distribution utilities and relevant electric retail regulatory authorities to establish protocols for sharing metering and telemetry data. This workstream concluded that development of these protocols should adopt a risk-informed engineering approach, where technology and procedural security controls are commensurate with financial, privacy, safety, and grid reliability impacts resulting from likely cyber-attack vectors.

EPRI has identified the following research recommendations to support development of needed security controls, procedures, and an overall trust and security responsibility framework in support of Order No. 2222.

Interfacing grid entities must establish their own security protocols, as FERC O2222 does not specify requirements. Establishing mutual consensus on technologies, procedures, and security language within contractual agreements between grid parties is expected to be a major challenge.

A chain-of-trust framework will be required to inform the proper security protocols to be coordinated across a multi-party grid.

### *Confidentiality of Data*

- Guidelines and methodologies to conduct privacy impact assessments for DERAs need to be developed. These assessments should consider the financial and privacy impacts resulting from adversarial exfiltration of:
  - Resource registration information
  - Bidding and cost information
  - Individual DER system information
  - Individual DER system performance data
  - Customer energy use and production data
  - Personal identifiable information
- A privacy-by-design data architecture and governance model is needed that establishes expected data protection roles, responsibilities, and processes for ensuring confidentiality of customer and market data

### *Integrity of Data and DER Systems*

- Cyber security criteria for DER systems and communication protocols used for interoperability and data exchanges are needed. These criteria should consider:
  - Requirements to use National Institute of Standards and Technology (NIST)-approved cryptographic suites and protocols to protect against data manipulation in motion and at rest
  - Testing standards for DER systems and communication protocols to ensure adequacy of security control implementations

### *Availability of Data and DER Systems*

- Risk assessment methodologies are needed to evaluate a grid entity's role in the electric sector and the associated security control and redundancy measures that these roles must adopt and maintain. These measures should be informed through evaluation of potential impact to financial, safety, reliability, and privacy losses resulting from cyber events against the entity's systems and data.
- Trust frameworks are needed to help specify which requirements should be included within business-to-business contracts for interfacing parties. These requirements should specify availability and service levels for negotiated grid and data sharing services.

### *Customer Technologies and Retail Interactions*

The Customer Technologies and Retail Interactions Workstream focused on interactions between wholesale markets and retail programs [59]. Substantial DER penetration and rapid growth in program participation

Substantial DER penetration and rapid growth in program participation have compelled scrutiny over the possibility of dual program participation—a situation in which one DER can simultaneously participate in multiple programs.

have compelled scrutiny over the possibility of dual program participation—a situation in which one DER can simultaneously participate in multiple programs. Both wholesale and retail programs in the electric power industry employ DERs to provide valuable services across the electricity value chain. Figure 3-19 illustrates types of opportunities for DER use in wholesale markets and BPS services, distribution system services, and/or retail/customer programs.

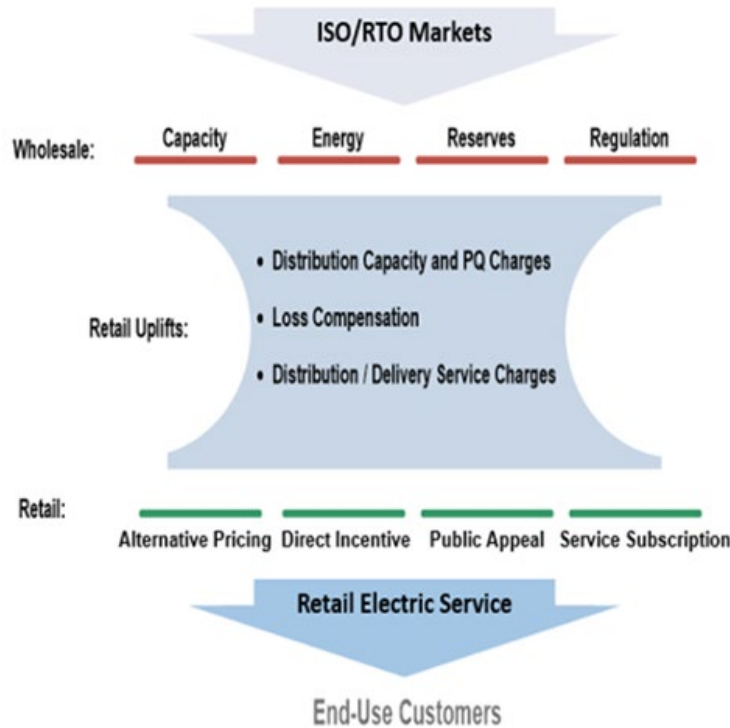


Figure 3-19  
Opportunities for DERs across the electricity value chain

### Dual Participation

FERC Order No. 2222 directed ISO/RTOs to allow for dual participation, while also directing them to prevent double payment. The latter involves compensating a resource more than once for providing the same service (e.g., retail bill savings and wholesale payments for the same kWh). The purpose is to avoid double payment for a DER's contribution when it provides essentially the same service through both a wholesale and a retail program in which it participates simultaneously. The order also directed ISO/RTOs to prevent double payment from multiple wholesale services, such as a DER participating in both a DER and DR aggregation, or in two separate DER aggregations providing the same service.

Diverse perspectives on dual program participation exist across the electric power industry, as evident in comments submitted to FERC on this topic under Order No. 222 proceedings. Perspectives on dual

program participation combinations that are acceptable can differ by stakeholder type and region and are also influenced by existing DER and DR programs in place. The challenge of clarifying perspectives on dual participation and double counting requires considering diverse perspectives, while respecting regional differences in market structures, metering methods, and existing DER/DR programs.

### Dual Participation Perspectives

The workstream team compiled feedback through collaborative webcast exchange, individual and group interviews, as well as online polling that EPRI conducted during mid-2021<sup>8</sup>. Common perspectives were identified by stakeholder type. For example, as a group, ISO/RTOs clarified that dual participation refers to:

- Simultaneous registration in both wholesale and retail programs is possible
- An overlapping timeframe for a resource to be reserved or committed under both retail and wholesale programs is possible

Regarding the meaning of dual “participation,” load serving entities (LSEs) generally shared the opinion of distribution utilities. They unanimously agreed that dual participation refers to allowing simultaneous registration in both wholesale and retail programs. There were differences in opinion as to whether they would allow resources to be reserved or committed for an overlapping timeframe under both a retail and wholesale program. They also differed as to whether dispatch for more than one service would be possible at any given time.

Generally, third-party aggregators stress the economic importance of allowing DERs to participate in multiple services, and welcome an environment in which different market participants could provide different services to an ISO/RTO with the same resource. They recommend that any restrictions on dual program participation be narrowly tailored, and generally view ISO/RTOs as well-positioned to place checks to prevent double counting, so long as the utility is agreeable.

### Double Counting from Sub-Metering

Figure 3-20 shows different configurations of sub-metering. The blue arrows in the figure are used to explain how sub-metering contributes to double counting. Three primary metering methods for DER are shown on the left side of the figure: separately metering DER, net metering DER, and sub-metering DER. Variations of metering involving multiple DER are shown to the right of the figure.

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<sup>8</sup> These are not official specific views by any company or individual, but instead are aggregate perspectives based on input as interpreted by the EPRI team.

The blue arrows indicate the types of measurements supported under each metering alternative. For example, separately-metered DER supports measurements of DER export and consumption to/from the grid, whereas net metered DER measures net production and consumption at the customer meter.

Unlike net metering, sub-metered DER directly measures an individual behind-the-meter DER asset's contribution, in terms of production and consumption. Moreover, the customer facility-level meter includes the behind-the-meter DER's contribution, potentially leading to double counting the DER's contribution.

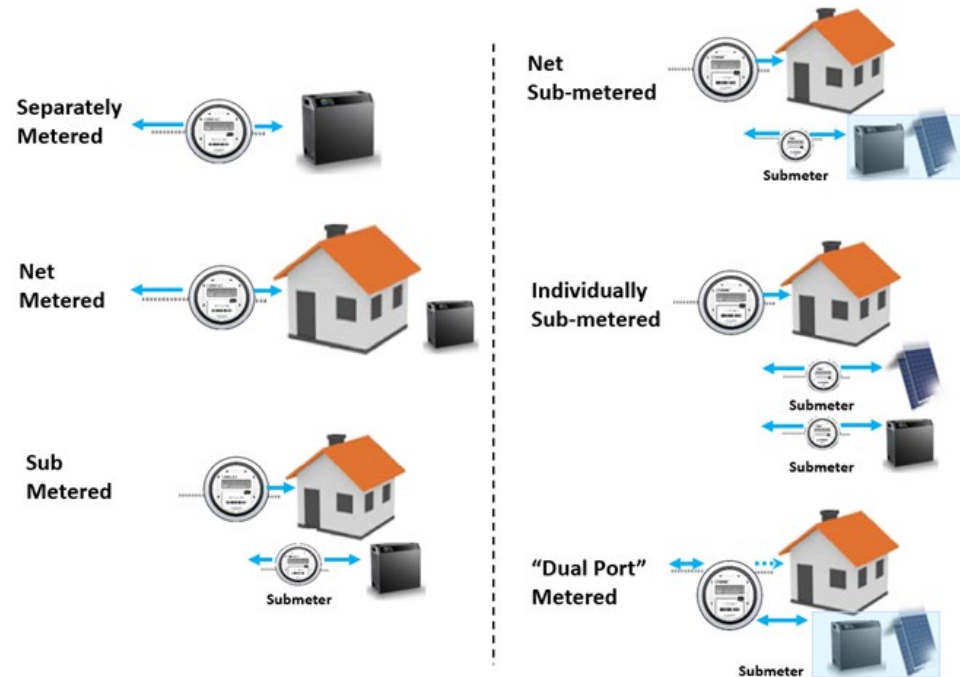


Figure 3-20  
Associated measurements of metering alternatives for DER

Similarly, each variation of sub-metering shown in Figure 3-20, includes the contribution of several sub-metered DER assets in the overall measurement at the facility-level meter. The two blue arrows pointing to the right in each of the sub-metered cases is indicative of the overlap between measured facility-level consumption and measured DER consumption. Each of these three illustrated variations of sub-metering show two solid blue arrows to the right of the customer meter, which is indicative of the potential for double counting the contribution of behind-the-meter DER.

In contrast, dual port metering (the last case illustrated in Figure 3-20) measures facility-level net import (i.e., net electricity delivered to facility from the grid) as well as DER net consumption, so that there is no overlap in measured DER contribution. From these measurements, customer load can be calculated net of the contribution of DER.

## Key Recommendations and Next Steps

### *Reconstitute to Avoid Double Counting Sub-Metered DER*

Sub-metering may involve a single DER asset or multiple behind-the-meter DER assets, which may be netted together or individually sub-metered. Sub-metering DER counts the contribution of DER twice; once through the facility-level meter, and again through the submeter. Therefore, reconstituting the load is needed to back out the contribution of DER from the facility-level meter.

### *Adopt Dual-Port or Multi-Port Metering*

As an alternative to sub-metering, net metering, or separately metering DER, utilities may adopt advanced metering capabilities that automatically avoid double counting the contribution of DER. In particular, dual-port metering (for one DER) or multi-port metering (for multiple DERs) can provide measurements that identify grid-supplied versus DER-supplied power for a calculable quantity of customer facility load (without DER consumption included). This avoids double counting the contribution of behind-the-meter DER. Utilities considering advanced metering rollouts in the face of higher DER penetration may determine that the timing is opportune to deploy dual-port metering capability.

### *Align Retail Billing Structures with Cost Drivers*

For LSEs, a behind-the-meter DER also impacts the revenue the load aggregator collects in its provision of electric service. DR generally reduces electricity consumption at a targeted period of time and/or shifts the load across a longer period of time. In the former case of load reduction without shifting (energy-neutral case), revenue loss is a concern.

Lost revenue can translate to ratepayers with DER/DR assets not paying their "fair share" of allocated costs, especially fixed costs and costs for consumption not commensurate with energy production. This is a particular concern for distribution services that are generally recovered on a volumetric basis of total measured energy over the entire billing interval, especially among mass market customers. For customers with DER such as energy storage or PV that are billed via net energy metering, the potential loss in revenue recovery can be substantial and not sustainable. DER employed to prioritize customer-specific service needs (e.g., customer demand charge management, and microgrid applications

wherein the grid provides backup power) may also be problematic for utility cost recovery. To achieve a more sustainable rate structure, clarity is needed on wholesale cost drivers so that retail billing can be better aligned with the cost drivers.

### *Consider Unbundling Demand Charges for DER Customers*

Retail rate restructuring is key for sustainably accommodating DER participation. Cost-reflective rates would consider measured demand (kW) as a billing determinant on mass market customer bills. This is a gradual process that requires educating mass market customers on how power demand (measured in kW) differs from energy (measured in kWh), and how demand is a major contributor to underlying system costs to serve customer demand reliably. Additionally, retail bills can consider unbundling with further granularity, such as including billing determinant(s) that recognize reliability costs (e.g., ancillary service costs, transmission costs, uplift charges, and generation capacity). Increasing the transparency of wholesale costs incurred can help avoid some double counting when DERs provide multiple services, such as capacity and ancillary services.

This will help the electric power industry transition retail rate structures, which currently recognize energy as the primary billing determinant that customers can impact, to structures that also recognize the importance of peak demand and non-energy costs. This is an important step toward accommodating dual program participation of DER and avoiding misaligned outcomes.

### *Enable Impactful Customers by Advancing Retail Programs*

Power demand can be a major cost driver in the provision of electric service reliability. Retail programs aligned with capacity as a cost driver can include provisions to help customers automate their preferences for demand (e.g., demand limiting appliances and breakers for lower priority uses). Through thoughtful program design, the electric power industry can collectively advance programs to enable impactful customers that are economically incentivized to adjust load and help capture avoided costs.

### *Future Work*

Collaborative advancement of retail programs is key to achieve and sustain definitive steps of progress. Recommended future work also includes:

- Clarifying stakeholder perspectives while respecting regional differences
- Distinguishing market contexts


Examining the particular market contexts under which programs exist can help explain where divergent stakeholder perspectives are found. Market contexts, cost recovery, and unbundling methods collectively drive business implications for DER. Therefore, recommended future work includes framing the unique market contexts that provide the background and environment for DER participation. A side-by-side comparison of market requirements can reveal similarities and reconcile differences in perspectives amid the backdrop of existing DR programs and participation rules, including compensation rules for DR dictated under FERC Order No. 745. In addition, each state, jurisdiction, and utility often has different retail billing practices regarding the definition of volumetric. By evaluating which practices enable ISO/RTOs and DER aggregators to best understand allowable practices to avoid double payment, these practices can be borrowed or advanced further to remove further burdens to wholesale market participation.

### DERA Use Case Information

During the project, a few stakeholders identified a key cross-cutting challenge that they face. When participating in multiple large stakeholder groups, participants sometimes struggle to communicate in similar contexts about a generic DERA and potential challenges. DERs assume many different forms, and due to FERC's rule of heterogeneity, DERAs assume even more forms. As ISO/RTOs, distribution utilities, DER aggregators, RERRAs, and other stakeholders work to solve problems, they need to examine common and unique DERA possibilities, assess their use case, and identify hurdles. This enables determination of mitigation strategies that can improve the ability to integrate a large set of existing and future DERs to participate in wholesale markets in the future.

With this motivation, the team developed the DERA Market Participation Use Case Survey Tool as part of this project [60]. This was an unplanned activity with significant anticipated value based on project participant feedback. EPRI was uniquely positioned to develop this tool due to the project, its strong relationships with ISO/RTOs and distribution utilities, as well as close contacts with regulatory staff, aggregator companies, and other industry contacts. This third-party independent moderation is best suited to ensuring that information is unbiased. EPRI conducted separate calls across various stakeholder groups, including ISO/RTOs, distribution utilities, and third-party aggregators to gather relevant information. The idea is to construct an evolving information source that increases in value with future contributions.

The tool is an advanced, dynamic survey form. The concept is to enable multiple stakeholders and experts in the industry to proceed through a DERA use case to determine whether various activities present additional important considerations, challenges that require further mitigation, or barriers that may prevent the DERA from full participation. After users



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incorporate information into the survey, they can submit it to EPRI. EPRI will compile the information and share it with stakeholders and previous contributors to determine whether solutions or changes may be needed. Solutions can include new tools, data exchanges, coordination needs, market design and tariff changes, and regulatory changes.

The primary activities include adding a DERA use case and entering survey information on any potential challenges or barriers associated with the DERA use case activities. The following characteristics make up the DERA use case (see Figure 3-21):

- DER interconnection locations
- Number of points of interconnection
- Number of distribution circuits across which the aggregation is distributed
- Number of transmission pricing nodes across the aggregation
- Whether the aggregation is generally injecting or withdrawing, and with reference to what
- The wholesale market product or service in which it participates
- Whether it provides services to the distribution utility
- Whether it provides customer services
- The type of retail program, if any, in which it participates
- The DER technologies that make up the aggregation

Directory of DERA Use Cases	DERA Use Case Name	Summary description =>	Transmission pricing Nodes	Injecting or withdrawing?	Wholesale Services to ISO/RTO	Services to Distribution Utility	Services to customer(s)	Retail program/tariff structure	DER technologies	DER technologies	DER technologies	DER technologies	DER technologies	DER technologies	DER technologies
	DER_Ax_a_DERA	FOM; single generator; wholesale only	Single	Injecting onto distribution grid	Energy	None N/A	None N/A	None N/A	Generator						
	Injecting_Metered_NWA_DERA_1	FOM; no retail load; potentially a distribution utility facility-wholesale + distribution system services	Single	Injecting onto distribution grid	Capacity	N/A for distribution congestion management	None N/A	None N/A	Community PV	Energy storage					
	True_DRA_DERA_1	Demand response aggregation that participates as a DER Aggregation	Multiple	Only Load Modifying Technologies	Energy	None N/A	None N/A	None N/A	Load Modifying Technology	Generator					
	Qualifying_DRA_DERA_1	Demand response aggregation which may meet FERC Order 745 requirements, but includes injecting technologies	Multiple	Injecting technologies but net withdrawals at meter	Energy	None N/A	None N/A	None N/A	Generator	Energy storage	Load Modifying Technology				
	AE11_E	Fleet of electric buses across one or more school districts	Single	Only Load Modifying Technologies	Energy	Distribution Capacity	None N/A	None N/A	Electric School Buses	Residential smart thermostat					
	AE22_E	Residential smart loads	Single	Only Load Modifying Technologies	Energy	None N/A	TOU bill management	Time of Use Energy + Demand Charge [seasonal]	Residential water Heater	Residential battery					
	AE33	Residential solar, storage, and EV charging	Single	some net injections some net withdrawals at meter	Energy	Distribution Capacity	TOU bill management	None N/A	Rooftop residential PV	Generic Electric Vehicle no V2G					
	AE44	FOM distribution-connected community solar and storage	Single	Injecting onto distribution grid	Energy	Distribution Capacity	None N/A	None N/A	Community PV	Energy storage					
	PJM_1_1	FOM; Solar; wholesale only	Single	Injecting onto distribution grid	Capacity	None N/A	None N/A	Other	Variable renewable resource						
	PJM_3	BTM ESR co-located with load	Single	some net injections some net withdrawals at meter	Capacity	None N/A	None N/A	Other	Energy storage						
	PJM_4	BTM ESR+DR co-located with load	Single	some net injections some net withdrawals at meter	Capacity	None N/A	None N/A	Other	Energy storage	Load Modifying Technology					
	PJM_5	BTM ESR+DR co-located with load	Single	some net injections some net withdrawals at meter	Capacity	None N/A	None N/A	Time of Use Energy (seasonal coordination)	Rooftop residential PV	Demand resource					
	MISO_Aspen	Heterogeneous DR (Water heaters, building lighting control, BTM Gen co-located with building load)	Single	Withdrawing	Energy	None N/A	None N/A	None N/A	Residential water Heater	Generator	Commercial building with lighting control				
	MISO_Birch	Heterogeneous DER (Water heaters, Air Conditioner, Storage, Diesel Generator, Rooftop Solar)	Single	Both	Energy	None N/A	None N/A	None N/A	Residential water Heater	Commercial building heating and cooling	Energy storage	Diesel Generator	Rooftop residential PV		
	MISO_Chestnut	Injection + ESR (Rooftop PV Systems, Energy storage)	Single	Both	Energy	None N/A	None N/A	None N/A	Rooftop residential PV	Community PV					

Figure 3-21  
Example DERA use cases

To ensure the latter aspects are dynamic or to correctly define a newly considered use case, users may also enter additional wholesale market services or products, distribution services, customer services, and retail programs to an already comprehensive list of each. New DER technologies can be added as well.

The user then reviews 47 activities, including interconnection, registration, equipment installation, market participation and market clearing, real-time operations, and settlements (see Figure 3-22). The user can fill in any of these activities, start from an existing set of information for the use case, or start from scratch.

	A	B	C	D	E	F
1	<b>Matrix for examining multi-use DERA use cases under FER Order 2222</b>					
2	<b>Populate Use Case</b>	<b>Save Data</b>	<b>Share Data</b>	<b>Use Case and Activity Challenge Analysis</b>		
3	<b>Activity</b>	<b>Actor</b>	<b>FERC Order 2222 provisions applicable to all use cases</b>	<b>Provisions, procedures and issues specific to all use cases</b>	<b>DER_As_a_DERA</b>	
4						
15	Install any DER specific metering infrastructure	DER owner/user	DERs are not responsible for providing required metering data to the ISO, but in some circumstances may require specific meters be installed and shares access of the data with the aggregator. The RTO may propose specific metering requirements for individual DERs.	Revenue quality metering for every DER may be too high cost given small resources.		
16	Updating static list of DERs that make up the DERA	DER Aggregator	The DERA must update list of DERs in each aggregation as well as any associated information and data.	Should be comparable to procedure for other aggregated resource types such as DR. Any modification will trigger the distribution utility review process described above.		
<b>Ongoing market and operational activities</b>						
17	Submit offer to participate in capacity market or contribute to resource adequacy	DER Aggregator		Apply rules for determining capacity value or qualifying capacity (QC), as well as deliverability status or Net QC (NQC).	N/A	
18	ISO capacity auction or resource adequacy showing, determine contribution of DERA if eligible	ISO / RTO	DERA should be eligible if technically capable of providing service			
19	DERA outage & derate procedures	DER Aggregator	Aggregator is responsible to notify ISO of any reduction in available capacity including if capacity available is impacted by distribution system			
20	Pre-Day-ahead Market (DAM) activities	DER Aggregator				
21	Pre-DAM activities	ISO / RTO				
22	Pre-DAM activities	Distribution Utility				
23	DERA offers into ISO day-ahead market	DER Aggregator		Offer parameters depend on the elected participation model; DER Aggregator needs to account for distribution system outages and other circumstances that might impact its response		
24	ISO Day-ahead market clearing, DA scheduling and	ISO / RTO	DERA should be eligible if technically capable of providing service	ISO provides DA schedules & AS awards to DERA. Question: Does the DERA receive a commitment		


Figure 3-22  
Walking through the use case activity survey entries

EPRI plans to use the DERA Market Participant Use Case Survey Tool in various efforts and across multiple research initiatives.


EPRI plans to use the DERA Market Participant Use Case Survey Tool in various efforts and across multiple research initiatives. The success of the tool will depend on the number of users that provide entries. The information should be useful for all types of stakeholders and researchers.



## Section 4: Conclusions and Next Steps



Organizations that have not coordinated with others in the past may need to create new communications processes, and organizations with little knowledge of electricity industry subsectors may be motivated to quickly begin learning.



While Order No. 2222 is substantial, it is not the end point for DER integration within electricity markets.

FERC Order No. 2222 will impact electricity policy in the last several years. It paves the way for new market participation opportunities for electricity customers, owners of small resources, innovative technologies, and organizations that create aggregation software and business models to support the growing need for affordable, reliable electric power.

However, the order did not prescribe how ISO/RTOs and other market participants should address the directives, which require coordination and communication across many key organizations and roles. As a result, organizations that have not coordinated with others in the past may need to create new communications processes, and organizations with little knowledge of electricity industry subsectors may be motivated to quickly begin learning.

Efforts to bring stakeholders together to address the order's requirements include discussion forums like EPRI's FO2222 Collaborative Forum, which enables ISO/RTOs and other parties to begin collaboration and allows similar organizations across geographic boundaries to participate in discussions that include representatives from more than one region or that address multiple topics. While Order No. 2222 is substantial, it is not the end point for DER integration within electricity markets. As a result, the industry overall will benefit from ongoing group meetings, collaborations, and forums.

The FO2222 Collaborative Forum assembled experts from distribution and transmission utilities, ISO/RTOs, and empowered RERRAs, third-party aggregators, and other key stakeholders to share learnings, educate and inform, and collectively begin to address key challenges. Six workstreams identified specific gaps associated with meeting the order's directives and began developing a roadmap. As discussed in the preceding sections of this report, the workstreams developed several collective actions out of each of their respective discussions. This gap analysis, roadmapping, and collective activity will be critical to enabling the participation of aggregated DERs in wholesale electricity markets in which the DERs can cost-effectively provide wholesale market services

and provide services for other domains that will result in fair equitable treatment and maintain the reliability and safety of both the bulk transmission system and the distribution system.

## Recommendations

In addition to detailed workstream-specific recommendations, the forum generated many recommendations and that span across all workstreams. These are discussed below.

One of the most important (if obvious) findings is the need to continue with coordination and collaboration.

**Coordination, Education and Collaboration.** One of the most important (if obvious) findings is the need to continue with coordination and collaboration. While meeting the directives of Order 2222 was primarily under the responsibility of ISO/RTOs, many rules that the ISO/RTOs established as part of their designs and compliance filings may need to be carried out by other entities such as distribution utilities, DER aggregators, or RERRAs. Including all parties throughout the process will ensure that those who must implement new tools or methods to account for new designs are aware and generally a part of established approvals processes before FERC finalizes these decisions. In addition, because each region may be in different places in terms of regulatory status and DER penetration levels, sharing ideas across regional boundaries is essential. Although ISO/RTOs and distribution utilities are focused on their own jurisdictions, many are analyzing the needed changes together and many approaches may work well across different regions. Finally, the EPRI forum found that education, particularly across specific seams, is essential. The forum focused on educating transmission-focused experts on distribution systems and educating distribution system experts on wholesale electricity markets and transmission operations. Extending education to retail experts and wholesale experts should be a future focus to ensure that dual-participation allowance rules do not inflict double-counting violations, which are increasingly complex as wholesale markets and retail rates continue to evolve. This education across the seams, and the collaboration and coordination across stakeholders, should continue into the future to ensure a fair process that includes the expertise and responsibilities of every stakeholder to support effective decision making.

Throughout the many discussions, an often-observed terminology-related challenge was amplified.

**Terminology Consistency Enhancements.** This collaborative project was a large effort bringing technical distribution and transmission experts together to discuss challenges and opportunities for improvement. Throughout the many discussions, an often-observed terminology-related challenge was amplified. Different ISO/RTOs and different utilities across the world use different terminology to refer to the same items and/or the same terminology to refer to different items. Inconsistent terminology is complex issue across transmission and distribution spaces. Terms like “behind the meter” or “injecting onto the grid” are commonly used in either transmission or distribution circles, but they can mean different things depending on the meter (e.g., a wholesale load or an individual residential customer) and/or grid. Even distributed energy resources,

while are explicitly defined in Order No. 2222, can mean different things in different regions and in areas that are outside FERC jurisdiction. Because the collaborative discussions yielded many examples of inconsistent terminology, the project team identified the following actions to improve consistency and clarity:

- In a working group, forum, or other collective group of individuals, include and address terms and definitions from the start. In case of disagreement, identify the terms that have the most consensus and stick to those terms and definitions. And, keep a glossary (such as the NERC Spider WG glossary [61]) handy.
- Explicitly add meaningful adjectives to terms, including terms where individuals may believe that they are assumed. As a simple example, “behind the meter” can mean “behind the customer retail meter” or “behind the wholesale load meter.”
- Use terms that are obvious and intuitive and eliminate ambiguity. Participants may not always have a glossary nearby and may be new to the conversation; this can allow for clear communication as effectively as possible.

### **Start Granular, then Work Up to Collective Mitigation**

**Strategies.** Large initiatives with substantial industry players often want to make substantial impacts on the industry. With these expectations, it can be difficult to make progress on smaller actionable steps and changes to methods and tools that address important smaller-scale challenges. This project found that understanding broad challenges and mitigation strategies for general DER aggregations is difficult. DERAs assume many shapes, sizes, and forms, and FERC Order No. 2222 provided direction on activities across almost every time frame from registration to market interface, operations, and settlements. By drilling down to understand all the characteristics of a specific DERA and focusing on one activity at a time, experts in different areas will be able to better identify challenges and determine whether there may be potential solutions to address them. To help stakeholders identify specific DERA characteristics, EPRI developed DERA Use Case Survey Tool, which empowers users to describe the challenges in detail to support identifying effective solutions.

**Prepare Now for Future Evolution.** While starting with specific use cases and activities (as described above) will help stakeholders understand today’s challenges, solutions should be developed with sufficient flexibility to support changes in the future. New DER technologies, business models, and market models will be created and continue to evolve. While it is impossible to predict all future changes when developing DERA integration tools and methods, the industry should attempt to anticipate future changes and determine whether a solution is too narrow to extend beyond the current case. As the industry evolves, flexibility will be crucial.

By drilling down to understand all the characteristics of a specific DERA and focusing on one activity at a time, experts in different areas will be able to better identify challenges and determine whether there may be potential solutions to address them.

Solutions should be developed with sufficient flexibility to support changes in the future.

When possible, harmonization can provide tremendous benefits, including less education time for entities that deal across multiple regions.

**Harmonization is Beneficial When it can be Applied.** Every ISO/RTO and utility has different rules and procedures. However, when possible, harmonization can provide tremendous benefits, including less education time for entities that deal across multiple regions. In some cases, harmonization may reduce costs; for example, for DERs or DER aggregators, participation compliance will lead to different implementations. This can occur naturally through collaborative forums and sharing best practices across entities of different regions.

## Next Steps

Several recommendations led to further actions within each of the workstream discussions. Follow-on studies in each of the areas can be conducted by individual organizations or jointly across organizations. A few examples include the following:

- Investigate the benefits of different heterogeneous aggregation participation models by performing technoeconomic studies with different models. Explore the parameters that, if used, may help determine their cost-effectiveness, feasibility, economic efficiency, and reliability benefits.
- Investigate whether multi-node aggregations are necessary (i.e., whether single-node aggregations be sufficient for participation numbers), and if so, evaluate how multi-node aggregations may be feasible.
- Determine whether existing software can handle large numbers of small DERAs for both commitment and dispatch-only, where limitations may arise, and what software or hardware solutions may allow for feasible run times.
- Distribution utilities can work with their relevant ISO/RTO to document and standardize the performance requirements for various wholesale services that DER aggregations provide. Utilities can then use those requirements to study the safety and reliability of DER market participation, and ultimately improve the interconnection study process.
- Determine the need and functionality and develop tools that allow distribution utilities to efficiently address registration for large numbers of DERs participating in aggregation to access the wholesale market.
- Investigate advanced systems and tools that can evaluate real-time conditions against dispatch signals to maximize DER availability throughout the year, while maintaining system safety, reliability, and power quality. The anticipated tools will make it possible to study how often DERA override due to distribution constraints may occur during planning processes.

- Study the operational implications of large numbers of DERs participating in both wholesale markets and distribution system services to understand the necessary steps to reduce reliability impacts on both systems, and understand whether transmission system solutions may reduce impacts on the distribution system, and vice versa.
- Explore different coordination frameworks and document these frameworks so that all actors can use them when appropriate.
- Demonstrate the effectiveness and fairness of alternative metering and energy usage monitoring as well as telemetry with pilot programs and other demonstrations.
- Develop a set of guidelines and methodologies to conduct privacy-impact assessments for DERAs. These assessments should consider both the financial and privacy impacts of sharing related information.
- Continue education across retail rate designers and wholesale market operators to understand which services may be embedded in rates or retail programs.
- Develop lists of agreed-upon program compatibility between retail and wholesale services that are eligible for simultaneous participation and those that are restricted. Develop similar lists of double counting scenarios and share these lists across states and ISO/RTOs for improved regional understanding.



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