Reducing DER Variability and Uncertainty Impacts on the Bulk Power System

DER Data Collection, Storage, and Sharing with DER Aggregators
SPIDERWG White Paper

Statement of Purpose

Large penetrations of distributed energy resources (DER) are significantly increasing variability and uncertainty within Bulk Electric System (BES) planning and operations. This uncertainty is largely driven by lack of knowledge of the quantity, location, and characteristics of DERs, especially as related to their impacts on the bulk power system (BPS). The need to reduce uncertainty about DER impacts has been made more urgent by the introduction of Federal Energy Regulatory Commission (FERC) Order 2222. This order introduced the concept of the DER Aggregator,[1] which allows multiple DERs to participate in wholesale markets. The System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) recently published the *BPS Reliability Perspectives on the Introduction of the DER Aggregator*[2] white paper, which touches on the modeling, verification, study, and coordination of this new entity within the electric ecosystem. That paper assessed that the uncertainty and variability of DERs required further exploration. This paper documents the findings of such an exploration and identifies areas of improvement and technical considerations to account for reliability impacts associated with integrating DERs. This paper also identifies methods to improve data collection and data sharing between the applicable entities described below. The methods described in the paper are applicable not only to entities with deregulated market structures and DER Aggregators but also to vertically integrated utilities or any other entity that seeks to reduce uncertainty through collection and sharing of DER data.

Applicable Entities

DER Aggregators, Transmission Planners (TP), Distribution Planners, GIS Administrators, Regulators, and other entities that require knowledge of the size, location, and capabilities of DERs in aggregate for reliability-focused studies (e.g., Distribution Operators, Balancing Authorities (BA), Transmission Operators (TOP), and Reliability Coordinators (RC)) may find this paper useful to refine their internal practices and procedures.

SPIDERWG and the Operational Perspective

The SPIDERWG is composed of transmission and distribution entities but has historically been focused on planning. For this effort, since the SPIDERWG identified that operational time frame concerns may be more prevalent than planning, SPIDERWG members engaged with their TOPs, RCs, and distribution operators. Data for DERs, which is foundational for planning and modeling to support operational functions, remains a focus of this paper.

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[1] Some abbreviate this term as DERA, and individual market terms have various ways to describe this same entity. This paper uses DER Aggregator for the abbreviation of Distributed Energy Resource Aggregator to help differentiate between the entity that aggregates DERs (i.e., DER Aggregator) and the aggregation of DERs in modeling.

[2] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/SPIDERWG_White_Paper_-_BPS_Persepectives_on_DER_Aggregator_docx.pdf

Definitions and Clarifications

The SPIDERWG's definition of DER is a "Source of Electric Power located on the Electric system";[3] in many instances, the definition of "DER" varies depending on the context. This paper uses the SPIDERWG-preferred definition as the primary definition to focus on the reliability aspect of the conversation. The SPIDERWG definition includes only generation and storage devices on the distribution system and not flexible loads (i.e., demand response). Other definitions and clarifications for this paper are provided below:

FERC Definition of DER: "A distributed energy resource is any resource located on the distribution system, any subsystem thereof or behind a customer meter."[4] FERC states that these resources may include electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment.[5]

Distributed Energy Resource Aggregator: "An entity that aggregates one or more distributed energy resources for purposes of participation in the capacity, energy and ancillary service markets of the regional transmission operators and independent system operators."[6]

DER Geographic Location: The physical address or geospatial coordinates that define where the DER is located.

DER Electric Location: The DER location on the electric network. The minimum required information to locate a DER on the distribution and transmission network is the meter identification and transmission point of interconnection. These two points allow the distribution utility to utilize its system knowledge to establish additional parameters, such as the feeder, substation, or portion of its system, and the Independent System Operator/Regional Transmission Organization (ISO/RTO) to use its system knowledge to establish parameters such as sub-node, node, or market regions.

Different organizations have varying DER definitions according to their focus. With Order 2222, FERC aimed to give distribution-connected resources access to the market. The SPIDERWG's definition focuses more specifically on reliability. The varying definitions create confusion in the industry without the above-established context. Adding to the set of definitions, Project 2022-02 is scoped to define DER in the *NERC Glossary of Terms*[7] and has proposed a definition that slightly differs from the SPIDERWG definition, although the spirit of the definitions is the same.[8]

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[3] The SPIDERWG has posted a document for definitions available here:
https://www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document.pdf

[4] Part 35, Chapter I, Title 18, Code of Federal Regulations, § 35.28(b)(10).

[5] Federal Energy Regulatory Commission, Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, Order No. 2222, 85 FR 67094 (Oct. 1, 2020), 172 FERC ¶ 61,247 ("Order No. 2222"), P. 114.

[5] Ibid., P. 114.

[6] FERC Order No. 2222, (September 17, 2020) P 85

[7] Available here: https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf

[8] Primarily, the SPIDERWG definition used nested terms to simplify the length of the DER definition while the project's term does not use nested definitions.

U-DER and R-DER Designations

Modeling designations in SPIDERWG documents may have caused some confusion about what DER is under the control of a DER Aggregator, specifically whether utility-scale DERs (U-DERs), retail-scale DERs (R-DERs), or both are included in the aggregation under the control of a DER Aggregator. As the R-DER and U-DER distinctions are primarily used for modeling purposes, both may be collected under a single DER aggregation. Since the installations are smaller and typically non-utility owned, it is more difficult to gather location-specific information (both geographic and electric network location) for R-DER. This is not a concern for populating aggregate models of this equipment since the aggregation is not specific to one location, and other SPIDERWG reliability guidelines, white papers, and technical reports have provided methods to model aggregate DER.[9]

One further distinction relative to U-DERs is that it can be large enough to require a dedicated facility from the distribution utility. Therefore, it is likely to have gone through a much more rigorous interconnection review than an R-DER, and the utility will have more detailed information on the assets being installed.

Survey Process

To best analyze the uncertainty and variability of DER Aggregators, the SPIDERWG asked its members to complete a voluntary survey. The survey process and aggregate answers are provided in **Appendix A** and **Appendix B**, respectively. However, the limited number of responses (6 received from over 100 sent) prevented the SPIDERWG from generalizing the results.

Variability and Uncertainty of DER on Electric Systems

NERC's *2023 Long-Term Reliability Assessment*[10] projected rapid growth of DERs with behind-the-meter solar photovoltaic (PV) projected to reach 90 GW of capacity by 2033. Key to this type of DER is that its output can rapidly increase and decrease with weather patterns and the daylight cycle. The ramp stemming from large amounts of distribution-connected PV resources can strain other grid resources. Other forms of DER technology, including battery energy storage systems, may not be as predictable through engineering judgment and weather conditions as the current solar PV dominant technology type. This introduction of variability and uncertainty can be influenced further by end-use customer choices and preferences, resulting in potentially even further operating characteristic uncertainty. Although DER forecasting tools have made significant progress in predicting DER output, the accuracy of such tools is entirely dependent on knowledge of the total amount of DERs and their characteristics as well as their mapping to the correct substation and bus within the power system model.

System operators and planners need information on the quantity of DERs and where they are connected to reliably operate and plan the system. This paper explores variability and uncertainty reduction in this data and identifies methods of gaining this information. With high DER penetration leading to high uncertainty, key entities may be prevented from planning and modeling the system appropriately. The same variability and uncertainty may not impact an entity in lower penetrations as greatly as those with higher penetrations; however, a common, clear, and consistent method for TPs to gather data reduces the impacts

[9] SPIDERWG reliability guidelines are available here: https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx
[10] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf

of variability and uncertainty under both low and high penetrations. Over the past several years, NERC has published a variety of white papers that provide guidance on the data requirements and models for DERs necessary to reduce this variability and uncertainty. This paper further focuses the discussion to provide guidance on the types of DER data and the collection process in a manner that reduces uncertainty on this information critical for planning and modeling.

The SPIDERWG has found that the variability and uncertainty in system planning are reduced by data collection from distribution owners and DER Aggregators providing clear, reportable data fields to the TP and TOP. The Electric Power Research Institute (EPRI) has also undertaken work on DER Aggregator planning impacts, particularly in identifying key data exchanges needed in the long-term planning horizon.[11] This report confirms the findings from the SPIDERWG[12] and Security Integration and Technology Enablement Subcommittee (SITES) white papers[13] stating that the data reporting obligation for DER Aggregators facilitates an enforceable and reliability-focused reduction of risk to the planning of the future BPS. The data exchange process could be significantly enhanced with a single point of truth for DERs that allows data exchange based on the Common Information Model (CIM).

The DER Aggregator's Role

The DER Aggregator's role was defined in FERC Order 2222 and resulting clarifications by the Commission about the interactions of DER Aggregators, individual DERs, and ISO/RTOs. FERC stated that the DER Aggregator—not the individual DERs in the aggregation—is the single point of contact with the ISO/RTO, responsible for managing, dispatching, metering, and settling the individual DERs in its aggregation.[14] These statements in Order 2222 establish that the DER Aggregator is the entity that will interact with RTOs and ISOs and be responsible for the operation of the individual DERs within its control. The DER Aggregator will also be responsible for the collection of data on factors such as DER characteristics and location plus information on DER operation and measurement of DER participation.

FERC Order 2222 implementations across each jurisdictional area will define in more detail the interaction between the DER Aggregators, distribution system operators (DSO), TOs, and ISOs. Local implementations will also define the role of DER Aggregators in operating DERs, controlling setpoints, and adjusting inverter parameters. Each jurisdictional area may have multiple settings for inverter-based resources (IBR) across the geography of their system and may have multiple requirements for implementation of these operational parameters. It is anticipated that the DER Aggregator will be responsible for understanding these operational requirements and ensuring that individual DERs operate according to the guidance provided by the operational control authority.

Although the operational setpoint or day-to-day operational requirements may differ between utilities or ISOs/RTOs, the fundamental DER dataset required for all stakeholders to be able to appropriately plan,

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[11] Available here: DER Aggregation Participation in Electricity Markets: EPRI Collaborative Forum Final Report and FERC Order 2222 Roadmap
[12] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/SPIDERWG_White_Paper_-_BPS_Persepectives_on_DER_Aggregator_docx.pdf
[13] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_Cybersecurity_for%20DERs_and_DER_Aggregators.pdf
[14] FERC Order No. 2222 (September 17, 2020), P 266.

model, and operate the electric system effectively will be consistent for everyone. The DER Aggregator will play an important role in the accuracy and currency of the individual DERs that they control and represent to the marketplace.

DER Data Collection, Storage, and Sharing Survey

The SPIDERWG conducted a voluntary survey of its own members to attain greater clarity regarding the interactions with the DER Aggregator and ways to reduce variability and uncertainty. As the survey received only a limited number of responses, the results are not conclusive of all industry examples but demonstrate the beginnings of specific trends important to consider for transmission planning and operations.

Survey Results

Six SPIDERWG members, including four ISO/RTOs, responded to the survey. Most companies that participated share different transmission functions (e.g., TOP, Resource Planner (RP), BA, TP, RC) with one of them being a distribution operator and two being distribution providers (DP). In terms of peak gross load, four members have over 20,000 MW with these four members' DER installed capacity ranging between 1,000MW and 5,000 MW. Even though these entities' roles, DER installed capacity, and peak loads vary widely, the survey would have benefited from more responses. Therefore, the SPIDERWG decided that the survey's results may not be conclusive but provide a landscape of different practices for DER Aggregator data exchange.

The SPIDERWG interpreted the survey results as showing that introducing the DER Aggregator in the planning realm may *reduce* variability and uncertainty. The survey also yielded recommendations for maintaining situational awareness (a key reliability aspect) in the operations time frame. However, these survey results only apply to DERs that are collected by DER Aggregators for aggregation to the ISO/RTO markets. DERs that are not aggregated will not have the benefit of a DER Aggregator verifying or keeping DER information current. It is important for all DERs, not just those with DER Aggregator participation, to be known and accounted for in planning and modeling processes.

DERs can be made up of a variety of resources that may not currently be included in the interconnection process, most notably electric vehicles. Consequently, it should be expected that a significant number of DERs will remain "unknown," especially when utilities rely solely on DER Aggregators to provide DER information.

Transmission planning to enable DER Aggregator market participation requires coordination[15] between the ISO/RTO, DER Aggregators, Transmission Owners/Utilities, Distribution Utilities, and Relevant Electric Retail Regulatory Authorities (RERRA). As the SPIDERWG survey results were not conclusive, the team looked to outside reports and frameworks to determine the coordination needed to reduce variability and uncertainty. One EPRI report[16] considers some long-term planning studies and key data exchange between DER Aggregators, DER owners, and the operations and planning staff, which includes the following:

[15] The SPIDERWG has published a paper describing the available coordination and communication strategies related to DERs. This is available here: [TandDCoordinationDocument_draft_White_Paper (nerc.com)]

[16] [DER Aggregation Participation in Electricity Markets: EPRI Collaborative Forum Final Report and FERC Order 2222 Roadmap]

1. **Ensuring Adequate Transmission Impact and Reliability Assessment Studies:** The upcoming participation of DER Aggregators in the wholesale market could necessitate assessing the potential impact of one or more DER aggregations on the transmission system.
2. **DER Modeling Methods in Long-Term Transmission Planning Studies:** In most cases, research has confirmed the adequacy of modeling methods such as the NERC *Reliability Guideline on Parameterization of the DER_A Model* to study bulk system voltage and frequency performance under high levels of DERs.[17] The industry continues to identify corner cases where more sophisticated modeling of individual DERs and DER Aggregations may be desired.
3. **Ensuring Adequate DER Capabilities, Performance, and Functional Settings:** The technical interconnection and interoperability requirements (TIIR) for DERs, including those that may choose to participate in the wholesale market through a DER Aggregator or a distribution system operator, are not subject to FERC jurisdiction. FERC recognized—and highlighted in Order 2222—the responsibilities of the RERRA to initiate and lead coordination between the stakeholders on each side of the transmission-distribution interface, including ISOs/RTOs, Distribution Utilities, and DER Aggregators.
4. **Key Data Needs, Exchanges, and Update Mechanisms:** Modeling of DER and DER Aggregators in transmission planning studies and technical reviews requires adequate and efficient collection of DER data and could become increasingly important as more DER Aggregators begin to participate in the wholesale market. Several key categories of data needs and exchanges discussed include management of DER functional settings, remote configurability, common file format for DER functional settings, and potential use of a DER settings database.

The above points from the EPRI report highlight the desire for a common, clear, and consistent method of exchanging both planning and operational datasets to identify important DER information that a DER Aggregator sends to the ISO/RTOs. Further, a common, clear, and consistent data exchange can be leveraged for utilities that require coordination between myriad DERs, even those not under a DER Aggregator. The benefits of reducing variability and uncertainty translate to more accurate studies and therefore clearer identification of potential reliability risk in the planning horizon. The SPIDERWG looked at the CIM as a method for reducing variability and uncertainty as a response to the key points from the EPRI report above.

Use of the Common Information Model for DER Data Exchange

Exchange of DER data among DER owners, DER Aggregators, and other entities, including distribution service providers (DSP), transmission service providers, and market operators, presents a unique challenge due to both the disparate nature of data and the fundamental differences in modeling practices by individual grid operators. The CIM is a semantic standard for consistent representation of power system data across the generation, transmission, distribution, market, and customer domains. It is an open-source information model that provides standardized definitions for common grid components and business procedures under an Apache 2.0 license (free to use and modify).

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[17] DER Modeling Guidelines for Transmission Planning Studies. 2019-2021 Summary. EPRI. Palo Alto, CA: September 2021. 3002019453. [Online] https://www.epri.com/research/products/000000003002019453.

As a semantic standard, the CIM provides the technical equivalent of an English dictionary of spelling and vocabulary for electric equipment. The CIM differs from more widely known communications standards (such as IEC 61850) in that it only specifies the agreed-upon names for various devices and their physical characteristics (e.g., that length of a wire should be written as “Conductor.length”). The semantic standard does not dictate how the data should be communicated but is critical for both parties to understand what is being sent and whether the data received has any meaning in the given context (e.g., the attribute of “length” makes no sense in describing market revenue paid to a DER). The CIM also maps to a set of corresponding International Electrotechnical Commission (IEC) standards that define usage of the information model and compliant data exchange mechanisms.

With the introduction of unbalanced distribution network modeling in version 17 of the Grid package of the CIM, it now stands as the only standard that offers a consistent method for representing power system equipment and utility business processes in both transmission and distribution. Detailed representations of grid-edge devices and further improvements to distribution network modeling will be released in version 18 of the CIM Grid package.

The CIM divides power system data into three domains. The first is the Asset model, which describes the characteristics of individual devices (such as nameplate data) and maps to the IEC 61968 series of standards. The second is the Grid model, which describes the role that a given asset (such as a breaker, switch, or power transformer) plays when connected to the electric system and maps to the IEC 61970 series of standards. The third is the Market model, which describes the behavior of assets (including aggregate behaviors of DERs through a DER Aggregator or virtual power plant) and maps to the IEC 62325 and IEC 62746 series of standards. Complete representation of DER consists of one or more ***asset*** records (derived from the Asset section of the CIM), one or more ***equipment*** records (derived from the Grid section of the CIM), and one or more ***resource*** records (derived from the Market section of the CIM).

Leveraging the CIM has two extremely powerful benefits, the first of which comes with adopting a standard and thereby creating a common understanding of the data being exchanged. The CIM is extremely well developed in this area not only because all data elements are defined in a single object model but also because the relationships among elements are established and documented. This means that information can be passed from one system to another by leveraging standard terminology, and the meaning of the data is understood equally on both ends. Data exchanges can be incorporated into larger databases because the relationships among elements are defined. This is not true of all standards, many of which merely define the exchanges without establishing a model vocabulary behind those exchanges.

Case Study: Enabling Interoperability with Europe’s Common Grid Model Exchange Standard (CGMES). The CGMES effort established in Europe is the CIM’s greatest success story. The European Network of Transmission System Operators (ENSTO-E) represents 40 electric transmission system operators (TSO) from 36 countries across Europe and led the development of a CIM standard for grid model data exchange. Not only were the standards developed and ratified by the IEC, but ENTSO-E also developed a conformity test process that currently lists 21 compliant products.[18] The CGMES process calls for each TSO to create so-called Individual Grid Models (IGM) of their systems both annually as a year-ahead projection as well as daily to capture short-term changes at different hours of each day. With a set of relevant IGMs in hand, each regional security coordinator (RSC) then assembles the models into a single common grid model (CGM). This CGM supports wide-area analysis processes and, when sent back to the individual TSOs, provides visibility into neighboring grids that would otherwise require highly manual processes.

The second benefit of using the CIM for DER data exchange is that the CIM is designed to reconcile the data with the representation of the electric power system. Not only can the CIM help to capture DER data in a standard way, but the data can also immediately be embedded into the models that are used for long-term planning, operational planning, and operations to manage the grid across time. While DER data is a relatively new addition to the CIM, mechanisms to update DERs follow the time-proven processes of any type of grid equipment, such as transmission lines, breakers, and transformers.

Case Study: Tracking Grid Changes with ERCOT's Network Model Management System (NMMS). As the electricity markets in Texas transitioned from zonal to nodal, the Texas market operator, ERCOT, realized the importance of an accurate grid model. Given its role as the operator, but not the owner, of the grid assets, ERCOT understood that the details needed to build a grid model must be collected from other entities, namely the Transmission Owners in Texas. As a result, the NMMS was implemented as the single point of entry and maintenance for the network model topology used by external ERCOT market participants. During the lifespan of the initial NMMS implementation, the system processed roughly 2 million grid model changes over the course of a decade. At the end of the period, less than half of the original data elements were untouched from the initial model from 2009.[19] However, the use of the CIM enabled a consistent workflow for handling these changes and maintenance of a single source of truth used for planning, operations, markets, asset management, and all other key business functions performed by ERCOT.

Use of the CIM facilitates mapping of DER data through use of a consistent set of data classes and attributes across all utility models by a consistent globally unique identifier that is invariant across all systems. Using the CIM, a single source-of-truth object can be created for each DER, along with one for the capabilities for every instance of its make and model, one for the unique data related to the asset that is installed and configured, one for the role that asset plays in the larger interconnected system of equipment, and one for its role in the market, often that of an aggregated resource. Exchange of such data can be facilitated by the creation of a shared CIM-based data exchange service that would eliminate the need to develop custom orchestration software to coordinate the data integration for every utility in a "one-off" manner. Using persistent identifiers, information can be shared regardless of the entity of origin using references that allow updates to be made across multiple systems maintained by multiple entities.

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[18] https://docstore.entsoe.eu/major-projects/common-information-model-cim/cim-for-grid-models-exchange/conformity-registry/Pages/default.aspx

[19] https://cimug.ucaiug.org/Meetings/eu2024/Arnhem%202024%20Presentations/CIM%20University/Track%202/CIMU%20T2%20S2a%20Moseley-ERCOT%20CIM.pdf

Figure 1 below shows some of the key entities involved in exchange of DER data, including the customer, the distribution grid operator, and the regional TP. Each of these entities will use a different software system with a different database and a different naming convention. Even within a single utility entity, the same piece of equipment will have slightly different names between different departments. Consider the simple example of mapping a set of DERs to the correct feeder breakers and individual transmission/sub-transmission substations. Information detailing the various physical assets and power system network models will be located across multiple databases from multiple software systems. Some of the required data includes the capacity from the interconnection agreement, metering point from the customer billing database, feeder connection point from the geographic information system (GIS), substation breaker from a system one-line diagram, and transmission bus from the bus-branch planning model (or node-breaker energy management system (EMS) model). Without a standard representation of power system components, a series of data tables would need to be created for each representation. Even if each application uses the same "human-readable" name for a particular piece of equipment, the exact naming string, description, and set of properties modeled will vary by application. A mapping table is then required between each set of data tables to reconcile differences in identification and attributes of each asset. Although utilities have been able to manage this in the past, the vast increase in data quantity associated with DERs will make manual data mapping impossible.

However, the use of the CIM with a consistent class name and a persistent identifier for each DER and each associated data type solves this naming problem. The identifier needs to be created only once and then stored in an object registry as part of a set of a master list of identifiers for data import and export. The identifier does not have to be human-readable and is generally not intended to be displayed to the end users of advanced power applications. Rather, it is a machine-readable identifier that can be referenced across all databases and data exchanges between multiple entities. To ensure global uniqueness across all systems, the identifier should be a universally unique identifier (UUID), a 128-bit integer that is serialized as a 32-character hexadecimal string. For the DER-to-substation mapping example, the DER would be assigned a unique identifier when first created during the interconnection approval process, with the identifier stored in the object registry. That identifier would then be referenced by all other systems, such as the GIS model, customer billing database, and planning model. The data mapping process then becomes a simple table join query that gathers all references to the master identifier across each enterprise system and combines them into an aggregate representation that can be shared with the TP and other external entities. Further information on the use cases and core data classes used for data exchange by the CIM is available in a series of primer documents.[20,21,22]

[20] Enabling Data Exchange and Data Integration with Common Information Model. 2022, PNNL-32679. Richland, WA. [Online] https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-32679.pdf

[21] A Power Application Developer's Guide to the Common Information Model, 2023, PNNL-3946, Richland, WA. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-34946.pdf

[22] Common Information Model Primer, Ninth Edition, 2023, EPRI, Palo Alto, CA. https://www.epri.com/research/programs/062333/results/3002026852

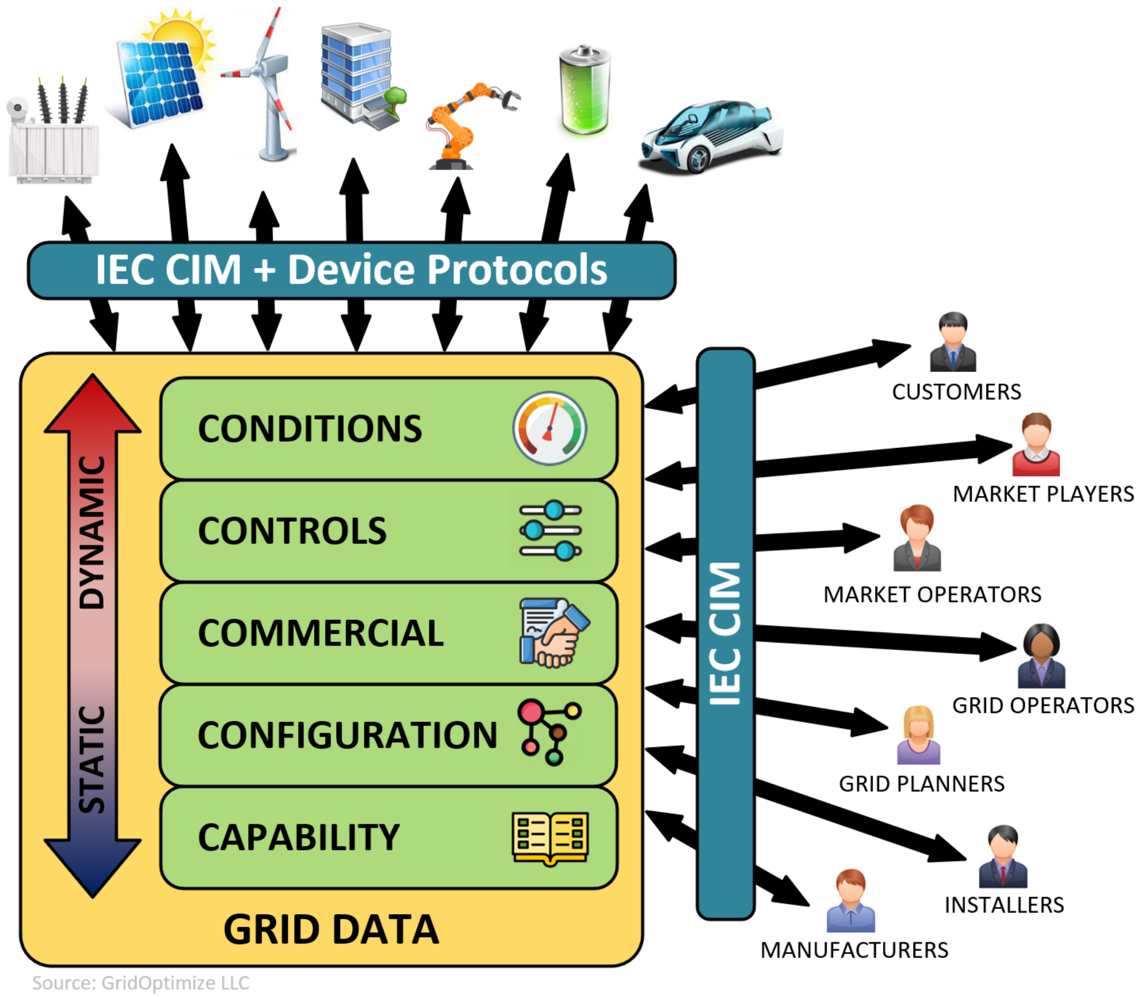


Figure 1: Visualization of Grid Data Types

Modeling DERs in CIM

The five distinct functions in the energy industry covered by DER data, as follows, will be defined in this section:

- Capability Data
- Configuration Data
- Commercial Data
- Controls Data
- Conditions Data

This data can be provided by multiple entities across the energy industry, including the manufacturer, owner, aggregator, and utility operator (see **Figure 1**). Typically, each of these stakeholders use their own set of custom data formats, which are difficult to share and interpret. Since the CIM is a high-level semantic model focused on enterprise-level data, it must be paired with lower-level, device-focused communications protocols (such as IEC 61850 or IEEE 2030.5) to enable real-time information gathering and ultimately device controls, as shown in **Figure 2**. This white paper focuses on the types of data needed to reduce variability and uncertainty in system planning, seen in the green semantic data layer of **Figure 2**.

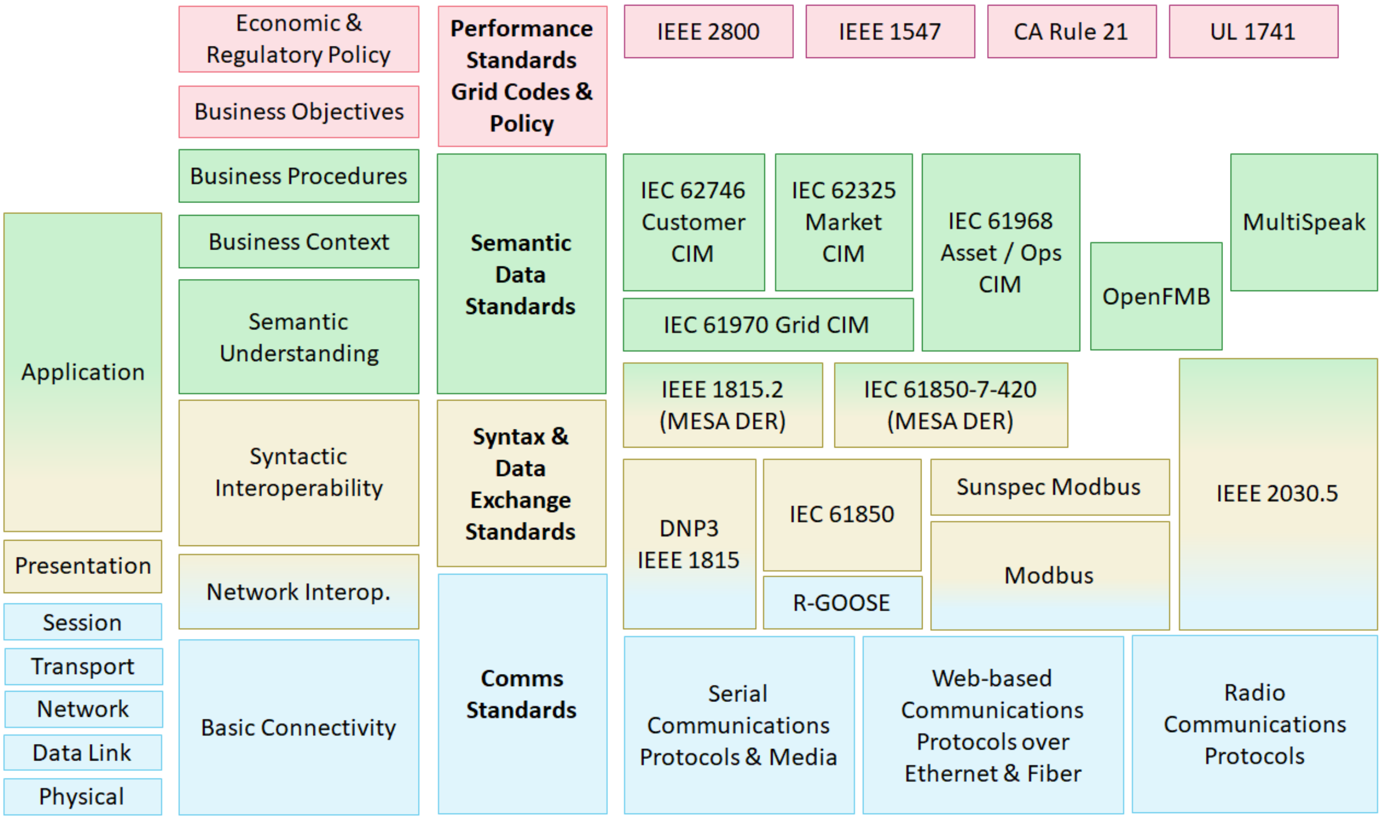


Figure 2: Standards Landscape for Exchange of DER Data

As DER penetration increases, all parties will need to be able to obtain data for decision-making and analysis. To this end, creation of a "single source of truth" for each DER is recommended to help eliminate confusion and incorrect DER models. Moreover, establishment of a master repository of DER data can make data management substantially less costly and challenging. The types of data to be included in such a repository are described below.

DER Capability Data

DER capability data describes the nameplate capabilities of the DER, which are generally identical for all instances of a particular make and model of battery, solar panel, or electric vehicle charger. In general, capability data is relatively static and is either provided by the manufacturer or determined by evaluation through testing labs. The data is tied to a particular make and model of DER and can be reused as each asset is produced along with its own unique data-like serial number or electronic address. The California Energy

Commission has the most complete set of capability data for DERs, available online.[23] Examples of DER capability data include the following:

- Make and model identifier
- Rated voltage
- Rated current
- Maximum apparent power output
- Maximum reactive power injection
- Reactive power absorption maximum
- Storage capacity (storage DERs only)
- Active power charge rate maximum (storage DERs only)
- List of IEEE 1547-2018 operational modes available

Detailed asset-based modeling with standardized data sheets for distribution equipment was added to the CIM such that common data could be defined unique to a particular make and model and simply referenced by each physical asset deployed on the grid. This approach for utility-owned grid equipment is being extended to cover DER datasheets and core modeling in version 18 of the CIM Grid package. The latest version of CIM packages (as well as the previous CIM17/CIM100 release) is available for download from the UCAiug CIM User Group website.[24]

Documenting datasheets to support DERs include two major subsets of data. The first set of data is the nameplate data and includes the rated voltage, maximum power capabilities, and full set of data elements inspired by the requirements published in IEEE 1547-2018.[25] The second set of data, also driven largely by requirements in IEEE 1547-2018, documents available operational modes and protection capabilities and is much more substantial. R-DER assets are expected to be primarily “off-the-shelf” equipment with datasheets consistent across any instance of that make and model. U-DER assets are expected to be “built-to-specification” equipment with datasheets unique to that installation. The modeling structures are identical regardless of the number of references to a DER datasheet (i.e., a single U-DER or thousands of R-DERs).

The process of collecting DER capability consists of two phases. First, the datasheet must be located. In the best case, the data can be found on the manufacturer’s website, embedded in datasheets, or in the user manuals. Second, the data must be converted from human-readable documents (such as PDFs and spreadsheets) to the proper data class fields in the CIM. This requires both knowledge of the CIM as well as training in electrical engineering to help ensure that data is properly converted. To avoid duplication of modeling efforts, it is possible to create a collaborative “single source of truth” data environment to provide

[23] https://www.energy.ca.gov/programs-and-topics/programs/solar-equipment-lists
[24] The CIM Users Group has released CIM version 18 in early 2024. The latest is available here: https://cimug.ucaiug.org/CIM%20Model%20Releases/Forms/AllItems.aspx
[25] https://standards.ieee.org/ieee/1547/5915/

this information. The “single source of truth” environment would enable access to DER capability data to users through a graphical user interface (GUI) and application programming interface (API) access.

DER Configuration Data

DER configuration data describes how a particular asset is connected to the grid and how it is configured during installation. Much of this information is known by the installer and the distribution utility, typically published in a one-line electrical diagram and in GIS representations. Importantly, this modeling allows the utility to incorporate information about the DER into long-term planning studies and short-term operations planning studies.

Examples of DER configuration data include the following:

- Asset identifier
- Owner
- Geospatial location
- Electrical equipment settings (e.g., ride-through, frequency droop gain, return-to-service)
- Energization date
- Grid point-of-interconnection (POI), which is any/all of the following:
  - CIM connectivity node identifier
  - Feeder identifier
  - Substation identifier
  - POI for transmission-distribution interface

Interconnection agreements and permitting information for R-DERs can be stored in a variety of non-standard methods, including a spreadsheet, a customer billing system, a dedicated DER database, or a GIS system in which each R-DER is associated with the street address (or geospatial coordinate location) of the customer premises. Meanwhile, the data relating to the DER connection to the grid is typically contained within a GIS database. Finally, power flow models used for interconnection studies and system planning are most frequently described by proprietary data formats to support specific vendor tools. None of the typical sources of data (DER database, GIS, or modeling tools) use a standard format, naming, or structure, making collection and sharing of data extremely difficult. Furthermore, the tools and data listed above are nearly exclusive to distribution utilities; a transmission entity would likely struggle to open and parse any of the model files and data.

The CIM provides a better approach. DER configuration data is instantiated in two areas of the CIM. The first is the asset data, which documents the particular instance of a certain type of DER (in a manner similar to how distribution utilities perform asset management to track hundreds of instances of certain makes/models of pole-top transformers). The asset data consists of the serial number of the particular asset, who owns it, and where it is located. If local codes require constraints on the capability data (e.g., a certain operational mode required to be set during installation), this information is also captured and tracked with the asset information.

The second area of the CIM is the grid representation perspective, known within the CIM as equipment data. This data represents the role of the asset in the electric grid used for power flow studies and operations. The most important data to be collected is the POI data, which describes where the DER is connected in the distribution feeder and in the bulk transmission system. Although the POI can be estimated using geospatial techniques, the preferred approach would be for the utility to provide a reference to a persistent grid location identifier (such as the bus number or CIM connectivity node). Mapping U-DER and R-DER to the correct bus within the power system network model is a major milestone in the data collection process toward reducing uncertainty regarding DER impacts. This mapping creates an accurate topological model of individual resources in support of the implementation of existing SPIDERWG recommended modeling practices.

As the specific name, number, or other identifier for the grid POI likely varies across entities, careful internal database maintenance of DER connection points to the TP's desired representation at the grid POI is necessary to mitigate duplication or erasure of data. Data entry entities are likely not aware of the TP's internal nomenclature on this point. Further, operational configuration can alter the DER connection point through reconfiguration of the distribution system, meaning that, for operational purposes, some of these points may not be the same under all operating conditions. These discrepancies between entities highlight the importance of a "single source of truth" system of record, which is discussed below.

DER Aggregation Commercial Data

Aggregation commercial data in this context represents how the DER participates in any number of market opportunities, from local distribution utility programs to third-party energy retailer/aggregator programs to wholesale market service opportunities. A key point in commercial agreements, at least from the utility perspective, is if the DER is directly participating or is participating as part of an aggregation where some or all of the device-level details may be ignored. Examples of DER aggregation commercial data include the following:

- Resource identifier
- Aggregation identifier(s)
- Service qualifications (e.g., energy, ramping)
- Service start and end dates

Collecting and mapping this data is even more complicated and offers one of the strongest use cases for adoption of the CIM. Myriad data validation needs to be performed at this level, including the following:

- Is a given DER participating in the DER Aggregator's provided service?
- Is the DER in an aggregation already?
- If not full capacity, how much of the capacity is part of the aggregation?

- What are the extents (voltage, geography, etc.) of the aggregation?
- Are there rules for which opportunities can be supplied coincidently?
- If multiple services of the aggregation are offered to different entities, for example T and D, which takes precedence?

The parties to coordinate or perform these validations are yet to be determined. However, according to the processes currently defined by the ISO/RTO FERC Order 2222 compliance filings, the DER Aggregator will be responsible for understanding the market rules and the submittal/enrollment of an aggregation with appropriate parameters. By building the DER representation in the layered fashion provided by the CIM, there exists an opportunity to capture the more fluid aggregation dataset separately and link it to the less dynamic (sometimes static) DER capabilities and configuration data. As the roles and capabilities of each DER changes over time, this linkage of datasets can be updated in the “single source of truth” system of record.

In addition to providing data classes for the assets and topology of the power system, the CIM also provides a baseline from which DER aggregations can be formed. Aggregations can be formed based on power system topology, market structures, or control hierarchy. As markets evolve, planners and operators need sufficient information to study reliability impacts, especially in the case where DER Aggregators span multiple market nodes, which can translate to multiple BES substations. TPs can use the information contained within the aggregation to validate their case assumptions to determine how the DER and DER Aggregators interact in their simulations. TOPs may be able to use this data to supply their real-time assessment or other operational time frame analysis.

DER Controls Data

While all the prior datasets are focused on exchanges among systems, DER controls data explains the interactions between systems and devices. Since the CIM is primarily a system-to-system protocol, this often means incorporating a device-specific protocol between the utility and the devices that need to be issued control, such as with IEC 61850-7-402 (which has native integration) or with IEEE 2030.5, CTA-2045, or OpenADR (where mappings are possible).

DER controls data can be grouped into two broad categories: energy scheduling and operational modes. Energy scheduling is an optimization of the device’s behavior to maximize profits and/or grid reliability. The results multi-function optimization could be a schedule of production or consumption levels[26] that are communicated to the device. Today, these function optimizations are most commonly delivered to devices via the internal communication channels provided by the device manufacturers, but it is anticipated that the industry will need general protocols to allow easier scheduling in the future.

The second category of controls covers those of operational mode, such as switching an inverter from constant power factor to Volt-VAR mode. Closely tied to operational mode are protection settings, such as the time constants for voltage and frequency ride through. These controls are primarily reliability-based,

[26] This translates to real power scheduling. In some cases, reactive power is also scheduled.

and utilities will need a standard way to deliver these settings (or signals to switch to settings groups) using a standards protocol.

DER Conditions Data

Another significant challenge is the collection of real-time measurements a for use by the distribution operators, and in aggregate, but the TOPs. At most substations shared between separate utilities, supervisory control and data acquisition (SCADA) data points for boundary equipment are obtained from dual-ported remote terminal units (RTU) and intelligent electronic devices (IED). The same set of measurements is sent across independent operational technology (OT) communications networks of the TOP and DSP. Only a minimal amount of data is exchanged through Inter-Control Center Communications Protocol (ICCP). Most control actions are coordinated by verbal communication between power system operators via telephone calls or scheduled in advance.

Most transmission utilities currently have no knowledge of total DER output from a set of feeders served by a given substation. Most EMSs only provide a display of the total real power and reactive power flow measured on each transformer winding. In regions with high penetrations of renewables where multiple distribution feeders push energy back into the transmission system, operators may only see a reversal in the power flow direction at the substation transformer with no further information on the amount of actual load and actual DER output.

Implementation of FERC Order 2222 will require significantly closer coordination and data exchange across the transmission-distribution (T-D) boundary. Like the network modeling problem, exchange of real-time data is also very difficult because existing data streams are highly siloed. Even if dual-metered advanced meter infrastructure (AMI) data is available (with separate metering of customer load and R-DER), this data is often not ingested and aggregated until the next business day. Use of data with such high latency would require recursive back-calculations and revision of market settlements for aggregate DERs to avoid double-counting of energy at the T-D interface. Furthermore, even if such data is available in real time, there are often no mechanisms except for ICCP by which the data can be aggregated and shared with transmission entities.

However, it is anticipated that low-latency DER data will become more readily available, either directly from the devices or through DER Aggregators using non-utility infrastructure. This potentially rich source of data introduces challenges in both the semantic realm (making sure translations are accurate between protocols) and the security realm (given that the primary communications mechanisms at the grid edge are not secured utility-managed infrastructure).

The CIM also provides the opportunity to transition to more efficient and automated reporting. Utilizing the allowable communications interfaces[27] for DERs, inverters could self-report to DSOs, TSOs, or ISO/RTOs when they disconnect or connect to the grid or when they enter into dead-band operation due to system

[27] Examples of these interfaces and allowable protocols can be found in Table 41 of IEEE 1547-2018. Additional proprietary protocols may also exist for communication to DERs.

voltage or frequency anomalies, significantly lowering the burden of grid operator reporting requirements while providing a robust dataset for post-event analysis.

Structurally, the CIM allows the power systems industry to deal effectively with the administrative functions of sharing DER and DER Aggregator data across all stakeholders. New tools and structures have been added to the CIM to support the operational and settlement aspects for DERs/DER Aggregators and are being demonstrated now. DERs and DER Aggregators present a new challenge to industry to effectively define a single point of truth for DERs and DER Aggregators (tens of millions over time) and share this information broadly across a wide range of stakeholders. An ad-hoc approach to DER and DER Aggregator data that cannot be collaboratively shared with all stakeholders will significantly undermine the industry's ability to utilize DERs and DER Aggregators for grid and market support. Utilizing the CIM as the foundation for this collaborative set of data will ensure the accuracy of the information for appropriate planning and modeling, dramatically reducing the IT costs over time and significantly reducing the time for the effective implementation of DERs and DER Aggregators into the grid and markets.

System of Record (Single Point of Truth)

With more than 3,000 utilities interacting with multiple ISOs/RTOs and market constructs, a DER can provide valuable services to both a utility retail program and a market product. To facilitate the effective implementation of FERC Order 2222 and make DERs broadly available to both utility retail programs and market products, a single point of truth or system of record can readily provide the capability and configuration data for the DER. Consistency of data input for aggregate DERs (through a DER Aggregator or other entity) is the key to ensure similar device-to-device treatment so that, when needed, the TP can pull the relevant information from the central repository and build a representative model of the aggregation. This improvement highlights the key nature of a single system of record for DER information and can readily reduce uncertainty between TPs and PCs.

Some entities that have implemented a system of record include the Australian Energy Market Operator,[28] EPRI,[29] the Vermont Electric Power Company,[30] and Collaborative Utility Solutions.[31] As these systems of record are typically not backwards-compatible to new or updated systems, element relationship definitions that were set on implementation may take a significant amount of time to update if they are not based on CIM data structures. Thus, TPs should ensure that the needed DER information can be made available through the single system of record, as having multiple systems to feed the data defeats the purpose of a common single system of record. In the ideal scenario, the system of record should do the following:

- Represent all the DER ***capability***, ***configuration***, ***commercial***, ***conditions***, and ***controls*** information through a robust set of parameters in the system of record
- Capture all the fields that a TP can translate into its software

[28] A report on CIM modeling is available at the Australian Renewable Energy Agency here: https://arena.gov.au/knowledge-bank/using-the-cim-for-electrical-network-model-exchange/
[29] Available here: https://www.epri.com/research/products/000000003002006001
[30] Initial architecture available here: https://www.vermontspc.com/sites/default/files/2024-01/VSPC_VXPlatformpresentation.pdf
[31] The library of resources for Collaborative Utility Solutions is available here: https://www.cusln.org/resources/Public%20Library

- Resolve TP-to-TP differences in modeling practices so that the data is communicable to neighboring TPs.

The breadth of industry stakeholders that require access to DER data (**Figure 3**) has expanded significantly when compared to the historical industry interactions with a single set of data. A single system of record ensures coordination across the necessary stakeholders. Collaboration among the necessary stakeholders that use this data reduces a DER Aggregator's variability and uncertainty impact. Entities seeking to implement a system of record should ideally ensure that the entities responsible for each function in the figure can leverage the system in order to reduce uncertainty and variability.

Figure 3: DER Data Uses

The potential for millions of DERs being connected to the grid provides unique opportunities for both the reliability and resiliency of the grid. Still, if there is no simple method to share DER data across the stakeholders in the energy value chain, it will be more difficult to effectively integrate, utilize, and ensure the reliability of the BPS with the growth of DER into the future.

The following barriers must be overcome when implementing CIM data to avoid disrupting utility practices:

- Stakeholders may need to be educated on the benefits of the CIM,[32] the update procedure, and the technical implementation of CIM profiles for DERs.
- Translation of CIM structure into proprietary software may require software vendors to update their code and release patches or versions to handle this syntax. For example, positive sequence load flow software already contains proprietary-to-proprietary file conversion support[33] (to communicate across other positive sequence load flow tools. Some software vendors may already have a CIM translation tool; however, those that do not may need code alterations to accept the way power flow and dynamic data is input to the program from CIM.
- As a subset of the translation barrier, planning practices may need updates to implement the CIM structure in procured proprietary software for use in transmission planning studies.
- Education on the methods to ensure a secure exchange of data among entities, which is separate from the CIM structure. For example, the CIM can be communicated across any file transfer protocol. Not all file transfer protocols are secure from malicious access. Entities may need education to establish good cyber posture and hygiene when implementing CIM (and other) data sharing mechanisms.
- Enhancements to standard-based data exchanges may be necessary. Currently, many of the NERC Reliability Standards require a mutually agreeable data format or provide an entity the full authority to require a specific data format. This may mean that entities could forbid data exchange in the CIM in lieu of proprietary protocols. Thus, a potential barrier to CIM implementation across the NERC footprint is a lack of incorporation by the entities into their standard practices that can be remedied by exposing such entities to the benefits of CIM per item 1 in this list.

[32] Such as materials using [insert items from footnote 21-23] for education.
[33] Such as the .raw file extension translation tools in positive sequence load flow software.

Appendix A: Detailed Survey Process with Questions

The SPIDERWG followed up its original modeling survey[34] with a set of questions that focused on the impacts of DER Aggregators and the responses to its original membership survey to track improvements. This survey was distributed to the SPIDERWG email distribution list, which has over 100 members, some of whom represent the same company. Six members, including four ISO/RTOs, responded. Most companies that participated in the survey share different transmission functions (e.g., TOP, RP, BA, TP, RC) with one of them being a distribution operator and two being DPs. In terms of peak gross load, four respondents have over 20,000 MW and these four stated having DER installed capacity in the range of 1,000–5,000 MW.

The following questions were asked in this survey:

1. What is your company function?
    a. If you are a Reliability Coordinator (RC), do you have specifications for DER data when performing your OPAs, RTAs, or real-time monitoring?
        i. How periodically is that information submitted? (e.g., seasonally, monthly, weekly, daily)
        ii. Do DER Aggregators provide any of this data?
    b. What are the specifications for DER data when performing your planning assessments?
        i. How periodically is that information submitted? (e.g., seasonally, yearly)
        ii. Do DER Aggregators provide any of this data?
    c. If you are a Reliability Coordinator, Transmission Operator, or Balancing Authority, are there differing rules for T-side connected generation resources versus DER and DER Aggregators (i.e., sources of power located on the distribution system)?
        i. Can you explain any difference in treatment of the two categories of generation resources?
2. What is the peak gross load of your area [MW]?
3. What is the minimum gross load of your area [MW]?
4. What is the total capacity of DERs connected to your system [MW]?
5. How are DERs being aggregated in your system?
6. Have you observed widespread tripping of DERs due to faults in operations? If yes, how many DERs tripped [MW and count, if available]
7. Do you receive any DER operational data (e.g., active power output of DER or DER status)
8. How do you model DERs in load flow studies? (buckets altered to be specific as net load hanging off transmission bus, modeled on low end of T-D XFMR)
9. Which positive sequence DER model do you use in your dynamic studies?

[34] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_SPIDERWG_DER_Survey.pdf

   a. Do you use any non-positive sequence DER modeling for any transient dynamic study? (e.g., a generic EMT model for DER)

10. Which positive sequence load model do you use in your dynamic studies? (ZIP load, CLOD, cmpld, cmpld_der_a)
    a. Do you use any non-positive sequence load modeling for any transient dynamic study?
11. What offerings does the DER Aggregator have in your area?
    a. Is there an analogous entity for areas that are not ISO/RTOs that aggregate the response of generation-connected generation?
    b. How is the Demand Response program controlled in your area?
12. Does the DER Aggregator (or entity aggregating the DER in your area) have interconnection or participation requirements for participating DER? If yes, proceed to the following:
    a. Are those documented?
    b. Are those available to share for DPs?
    c. Are those available to share for transmission entities?
    d. How does Clause 10 of IEEE 1547-2018 play into account here?
    e. Are there additional technical requirements required for reliability from the ISO/RTO on participation? Are these publicly sharable? If so, please provide a link.
13. How and when do new DERs or existing DERs intended to increase the capacity signal to a DER Aggregator participate in that aggregation for your area?
    a. Does the DER Aggregator notify transmission entities of this new capacity for your area?
    b. Is this taken care of in the capacity review identified in FERC Order 2222, or is it a separate requirement of the ISO/RTO?
14. How do the distribution system operators and planners coordinate with the DER Aggregator for analysis of constraints on the distribution system?
    a. D-side constraints can have backup plans; how are those currently monitored?
    b. Are some of these schemes automated?
    c. What requires operator control and does that affect which T-D Interface a DER is pushing against?
15. If known, how does the DER Aggregator collect, store, and share the following:
    a. Planning data
    b. Operational data
    c. Short Circuit data
16. Does the DER Aggregator share resource type (PV, PV+BESS, Wind) information?

   a. Is this unit by unit, or lump sum?

17. Does the DER aggregator or entity supplying DER planning, operational, or short circuit data send notice to the transmission entity at the T-D Interface when DER device characteristics change?
    a. Is there a verification of capacity and control from that which is provided in the services to the information shared for planning?
    b. Is there a verification of capacity and control from that which is provided in the services to the information shared for operations?
    c. Is there a verification of capacity and control from that which is provided in the services to the information shared for protection relay coordination?
18. What set points or schedules does a DER Aggregator set on the DER it controls?
19. How is double counting or other duplication of generation accounted for?
    a. Is the DER Aggregator covering all of the T-D Interfaces?
20. What estimation techniques for DER Aggregator output are used to run a 15-minute ahead, 30-minute ahead, hour-ahead, and day-ahead analysis?
    a. Does the estimation spread across multiple load records?
    b. Does the estimation allow for creation of "new" generators in the model?
    c. Are predictions made on zones, substations, feeders? (select all that apply)
    d. How granular of a forecast is required?
    e. How does the forecast deal with uncertainty or error?
21. For your state estimator, how does the mismatch solution deal with negative records added to the load?
    a. Does an output negative load link with a DER generator dynamic model?
    b. How are mismatch loads dealt with in the OPA and RTA practices? Are they ignored, netted, or other?
22. Does your data quality checks or other operational assessment practices account for gross versus net loading at each T-D Interface?
    a. What metering supplies this gross versus net loading? (e.g., transformer-level, breaker-level, or DER device-level metering)
    b. Are these quality checks posted or otherwise available on request?
23. For information provided by the DER Aggregator, what telemetry granularity is the aggregator able to provide? (e.g., SCADA scans, Advanced Distribution Management System (ADMS), other time frame or framework)
    a. Do they disaggregate their load from active power producing generation resources?
    b. What metering is used or provided to telemeter the data for operational planning analysis?

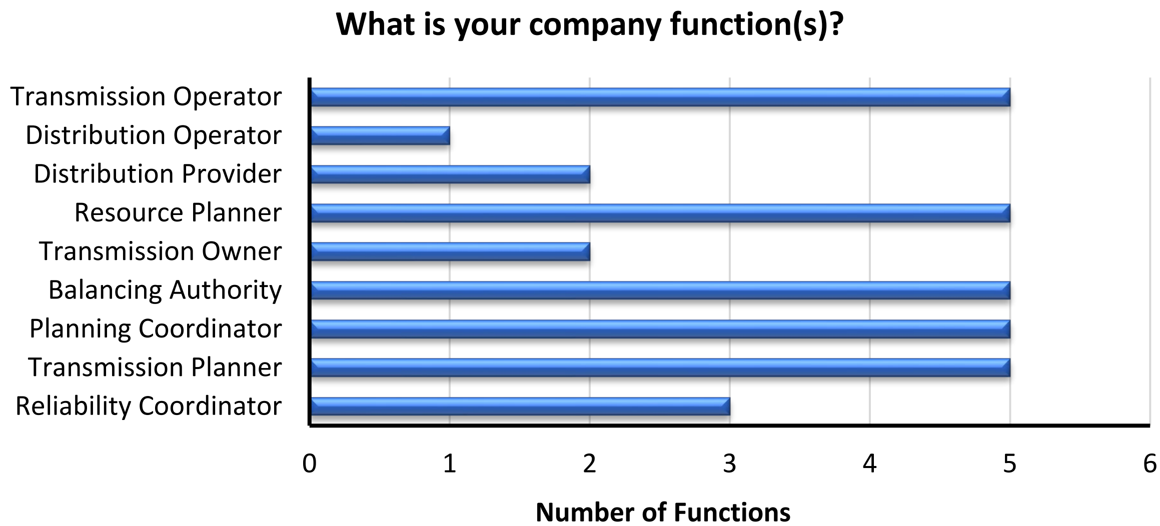
c. What metering is used or provided to telemeter the data for real-time analysis?

Appendix B: DER Aggregators Survey Responses

This appendix provides the aggregated responses from the survey as well as the key takeaways for each question asked. The values show the number of responses out of the total number of received surveys. The lack of survey participation should qualify the key takeaways as needing further investigation into other entity impacts.

Question 1

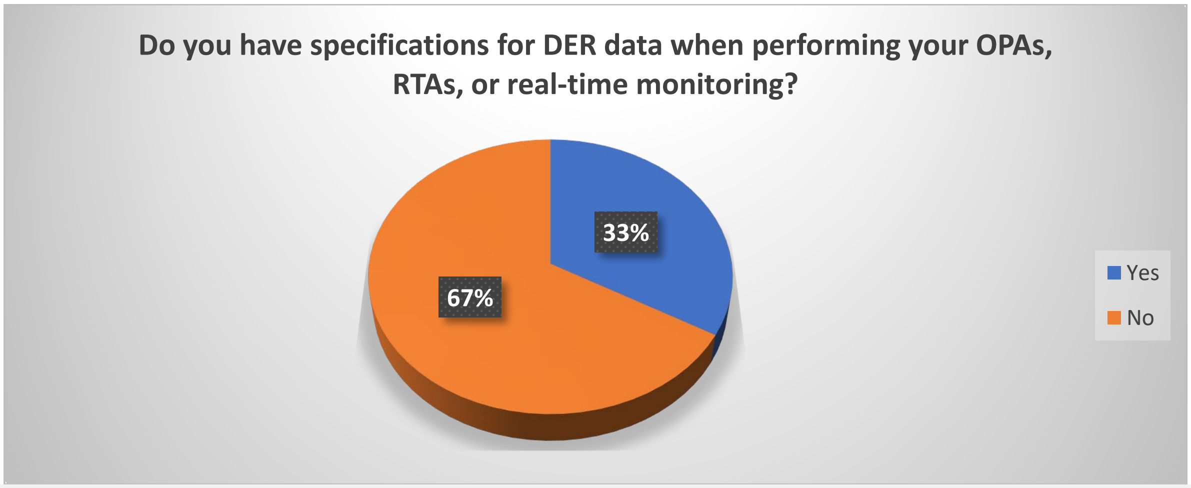
1. What is your company function(s)? (Select all that apply)



Key takeaway: Question 1
Most surveyed members represent multiple NERC entities simultaneously. Functional entities most represented among the surveyed members are TOs, RPs, BAs, PCs, and TPs.

Question 2

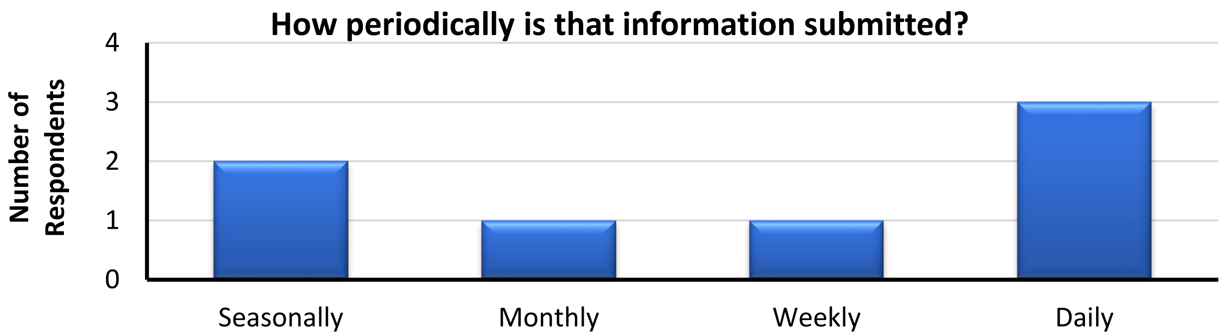
2. If you are a Reliability Coordinator (RC), do you have specifications for DER data when performing your Operating Planning Analysis (OPAs), Real-time assessment (RTAs), or real-time monitoring?



Key takeaway: Question 2
Only one surveyed member has specifications for DER data for OPAs, RTAs, or real-time monitoring.

Question 3

3. How periodically is that information submitted? (Select all that apply). Do DER Aggregators provide any of this data?



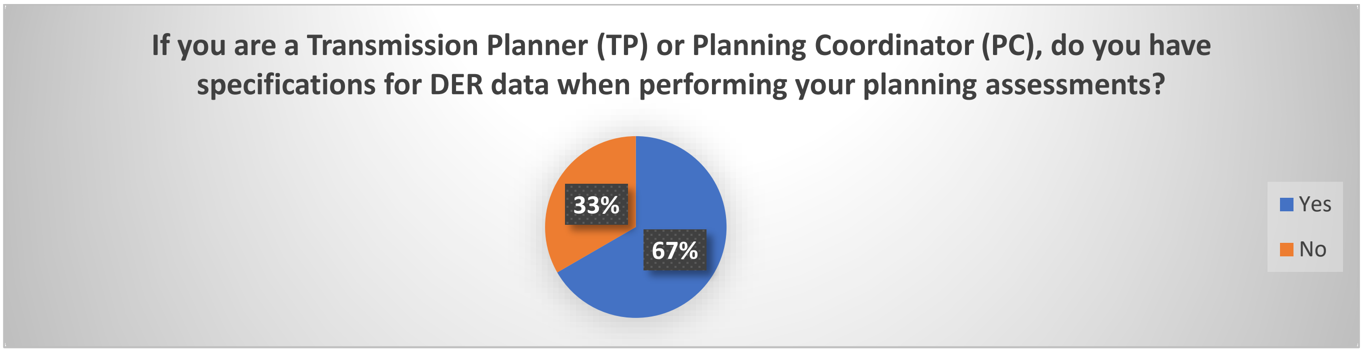
Key takeaway: Question 3
One entity emphasized that DER and DER aggregations registered for participation in the wholesale electric market provided data for a variety of assessments. Data is provided in a wide variety of time ranges with necessary modeling information (provided weekly), near-term reliability studies (hourly), and dispatch in real time (up to 2 seconds). Additionally, monthly updates are provided in terms of detailed distribution premises and devices that make aggregation. There is a need to identify how the OPA and RTA tools can capture a significantly growing set of data for the operational impact of DER Aggregators as these entities grow in their capacity and penetration.

According to another survey participant, data is provided via surveys submitted by the Transmission Owners in their company's footprint.

Most of the surveyed SPIDERWG members do not currently have DER Aggregators.

Question 4

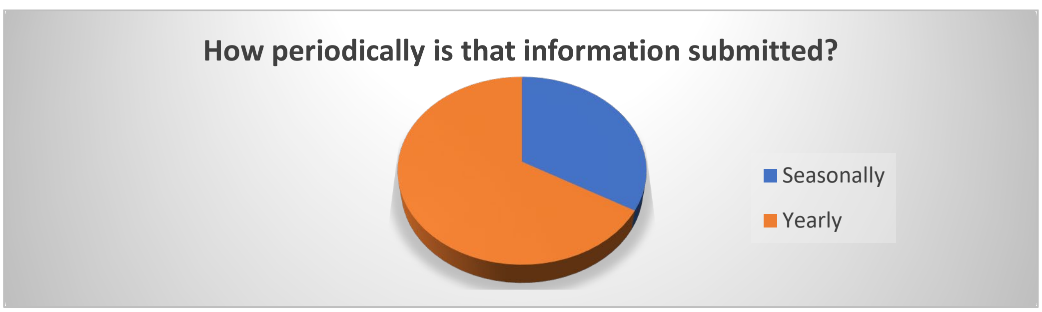
4. If you are a Transmission Planner (TP) or Planning Coordinator (PC), do you have specifications for DER data when performing your planning assessments?



Key takeaway: Question 4
The majority of survey participants (66%) stated that they have established specifications for DER data when performing planning assessments.

Question 5

5. How periodically is that information submitted? Do DER Aggregators provide any of this data?



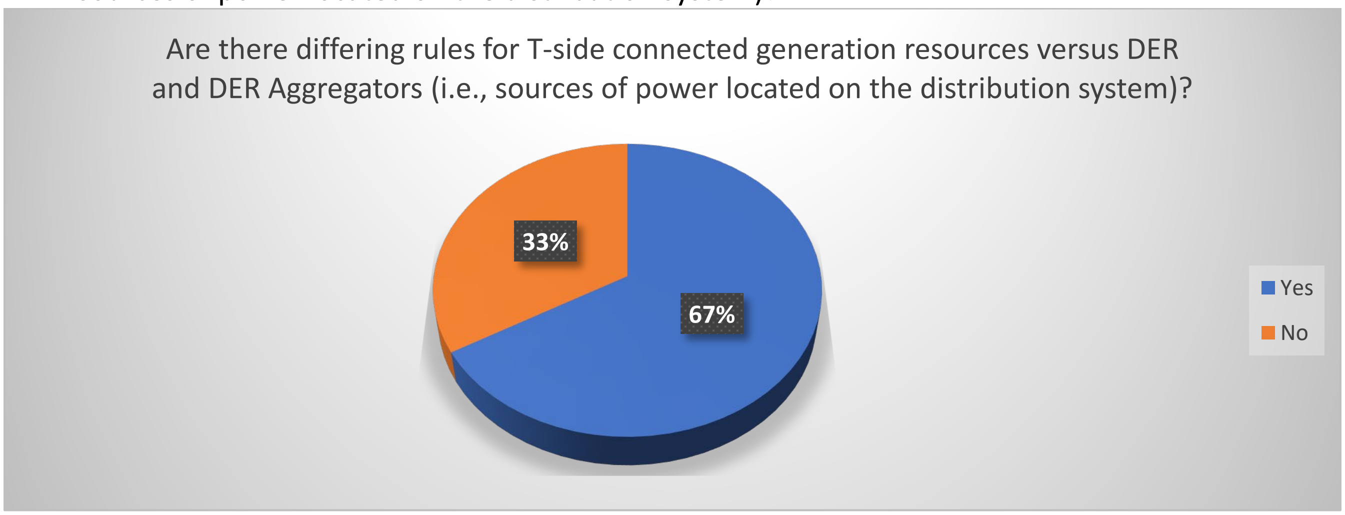
Key takeaway: Question 5
67% of surveyed entities stated that they do not have DER Aggregators connected to their system. However, their DER generation is based on forecast data that includes future and currently connected DER.

One entity claimed that DERs greater than 1 MW are required to register and provide data and are included in annual base-case development. Responses show that this data can be provided (or forecasted) seasonally or yearly.

According to another survey participant, data is provided via monthly surveys submitted by the Transmission Owners in their company’s footprint.

Question 6

6. If you are a Reliability Coordinator, Transmission Operator, or Balancing Authority, are there differing rules for T-side connected generation resources versus DER and DER Aggregators (i.e., sources of power located on the distribution system)?



Can you explain any difference in treatment of the two categories of generation resources?

The SPIDERWG received the following open-ended responses to this question:

- DER has different requirements for ride-through. Reactive power capability and voltage control are generally specified by the distribution provider.
- Transmission: Have to hold voltage schedule. Require ride-through of transmission connected generation. Evaluate need for AGC capability.
- Distribution: must hold unity power factor. Ride-through not required on distribution connected DER.

Key takeaway: Question 6

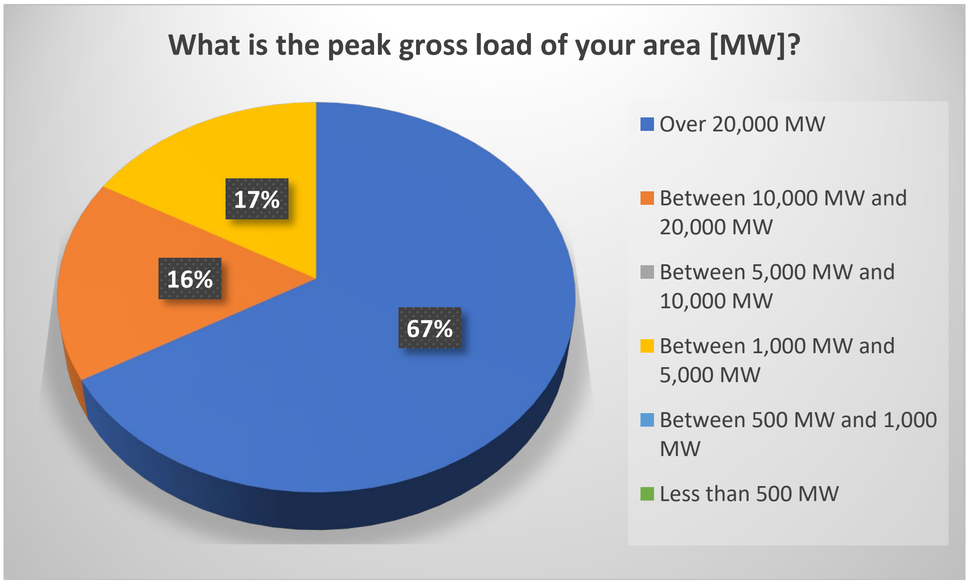
Two-thirds of surveyed SPIDERWG members showed that they have established specifications for DER data when performing planning assessments. As expected, members stated that there are different specifications for ride-through, voltage regulation, and other capabilities for resources connected to the transmission vs. distribution side and that DPs are responsible for specifying DER capabilities and performance.

Some survey participants shared that DERs enter the state interconnection process, whereas transmission-connected resources enter through ISO-NE's queue and the FERC interconnection process.

The SPIDERWG has published the Reliability Guideline Bulk Power System Reliability Perspectives on the Adoption of IEEE 1547-2018 to help RCs and BAs coordinate and specify DER functions that are key to ensure BPS reliability.

Question 7

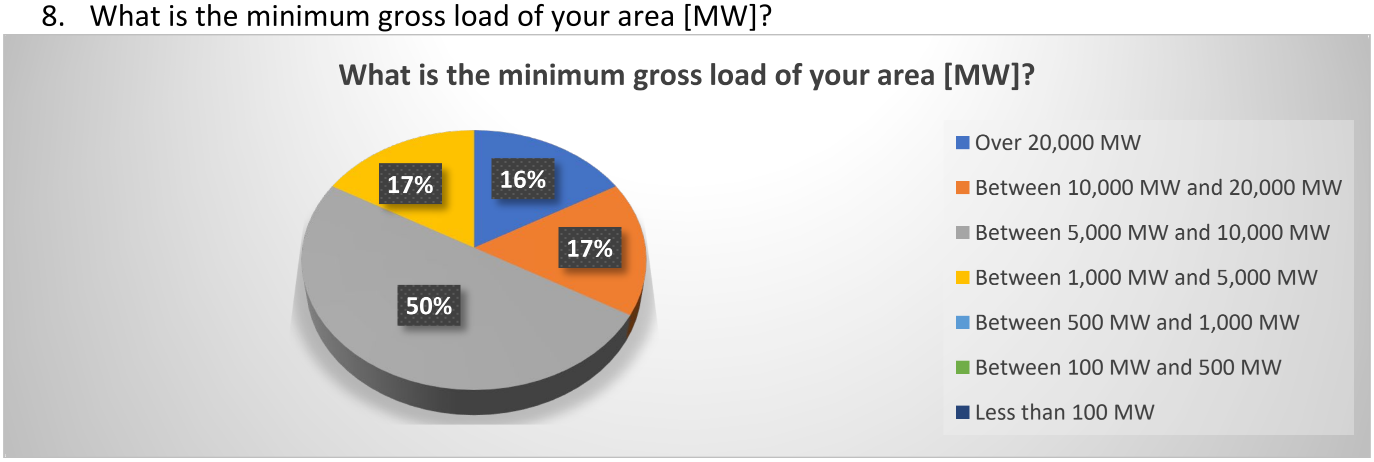
7. What is the peak gross load of your area [MW]?



Key takeaway: Question 7
The majority of surveyed members (75%) have over 20,000 MW peak gross load. The remaining two entities stated they have 1,000 MW–5,000 MW and 5,000–10,000 MW, respectively, of peak gross load.

Question 8

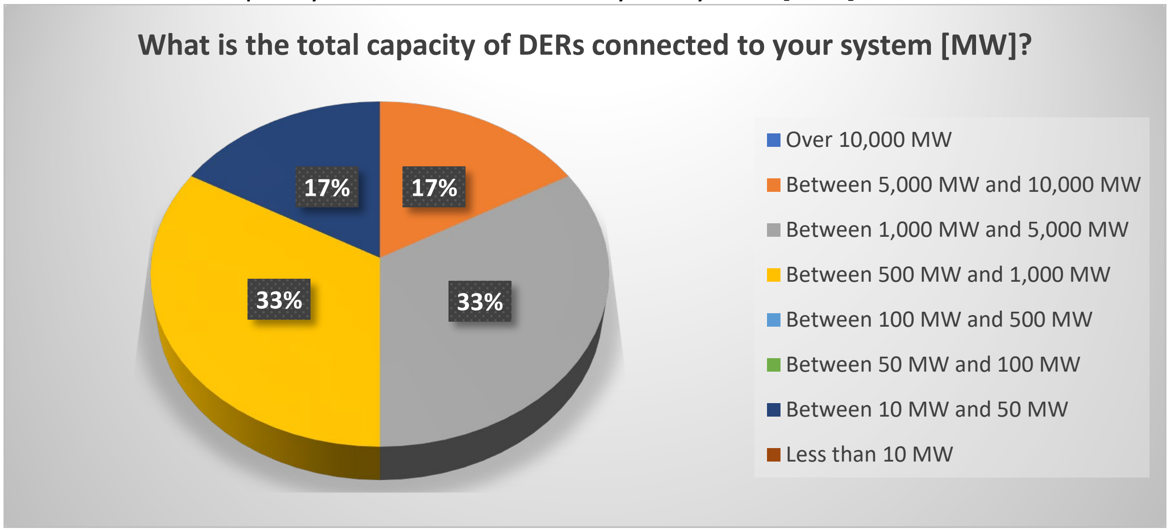
8. What is the minimum gross load of your area [MW]?



Key takeaway: Question 8
Minimum gross load among members ranges between 1,000 and over 20,000 MW

Question 9

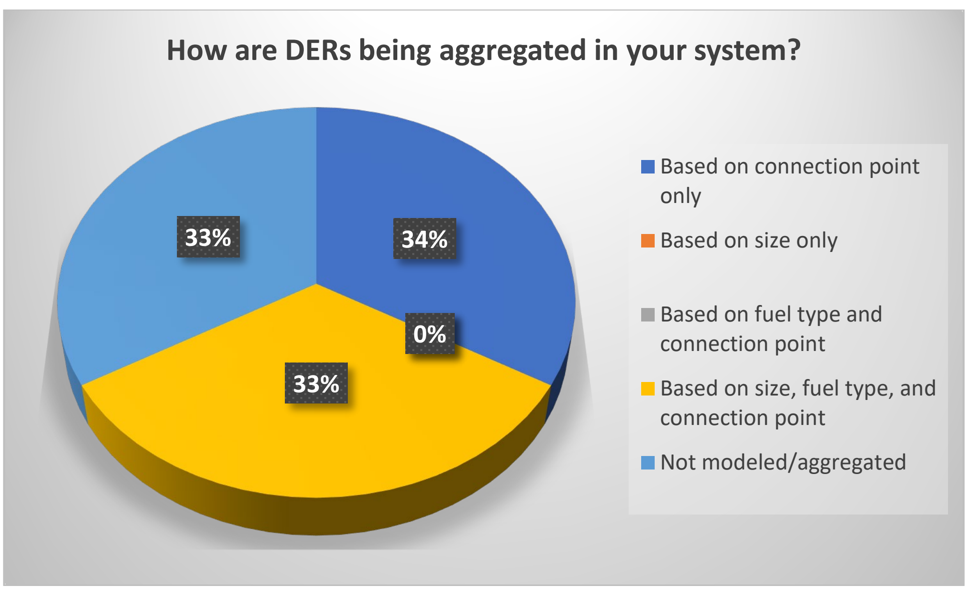
9. What is the total capacity of DERs connected to your system [MW]?



Key takeaway: Question 9
83% of members have significant DER capacity connected to their system that ranges between 500 and 5,000 MW. One entity has lower penetration ranging from between 10 and 50 MW.

Question 10

10. How are DERs being aggregated in your system?



Key takeaway: Question 10

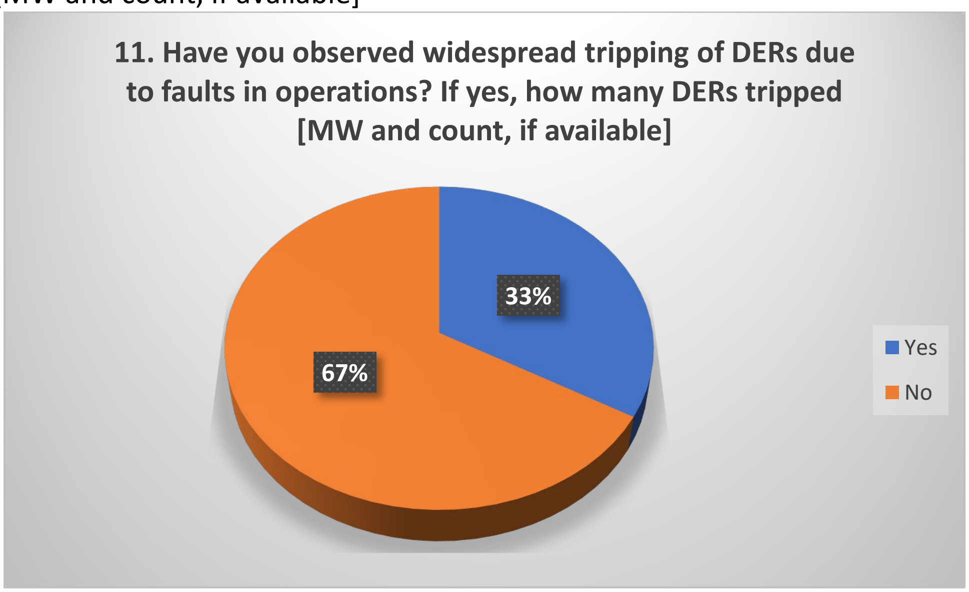
One-third of surveyed members stated that DER aggregations are performed based on size, fuel type, and connection points, while one entity mentioned that they are not being modeled/aggregated.

One entity mentioned that aggregation of DERs is performed according to their connection point and that devices or premises that make a DER Aggregator must individually have less than 1 MW of controllable capability. They are required to be within a single DSP and load zone but not behind the same connection point. Participation is not mandatory for DER over 1 MW, but, if they do participate, they must be registered separately.

The two surveyed companies with DER Aggregators in their footprint aggregate DERs based on point of connection.

Question 11

11. Have you observed widespread tripping of DERs due to faults in operations? If yes, how many DERs tripped [MW and count, if available]



Key takeaway: Question 11

Two entities observed DER tripping due to faults in operation without stating how many had tripped. DER capacities for each entity range between 1,000 and 5,000 MW and 5,000 and 10,000 MW, respectively.

Question 12

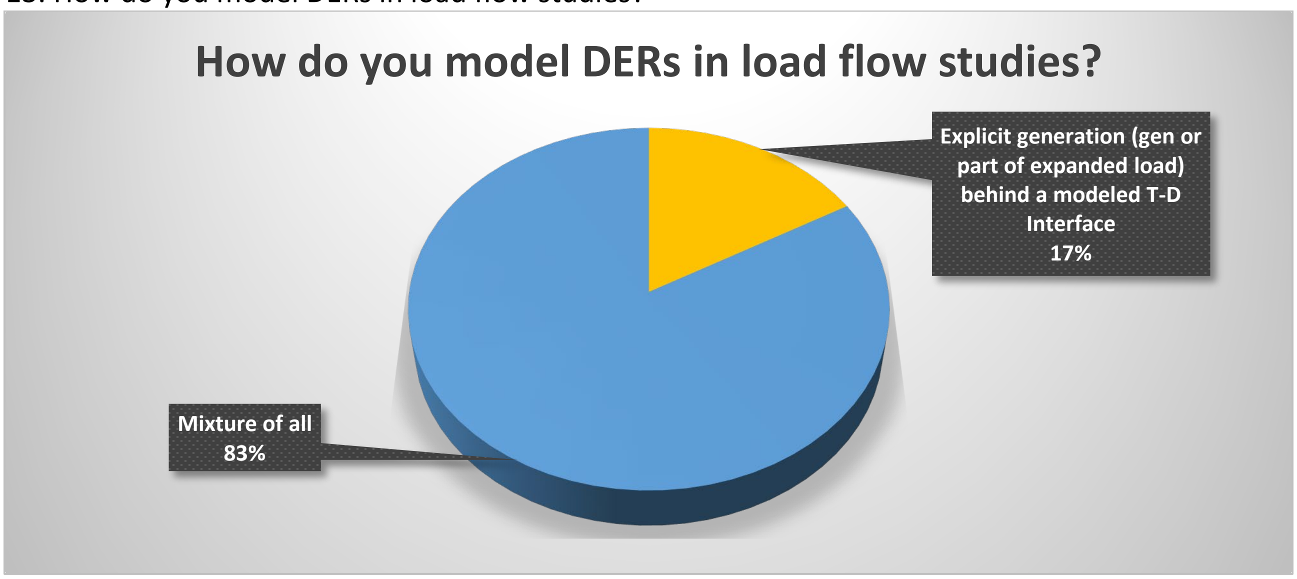
12. Do you receive any DER operational data? (e.g., active power output of DER or DER status)

Key takeaway: Question 12 (open-ended)
Most of the surveyed entities do not receive operational data from DERs. One entity requires data from DERs registered to the wholesale market, including power output, status, ramp rates, and operational limits. State of charge is also provided for some storage sites.

Two other entities shared that if the DERs participate in the market as a modeled generator, then they do provide operational data.

Question 13

13. How do you model DERs in load flow studies?



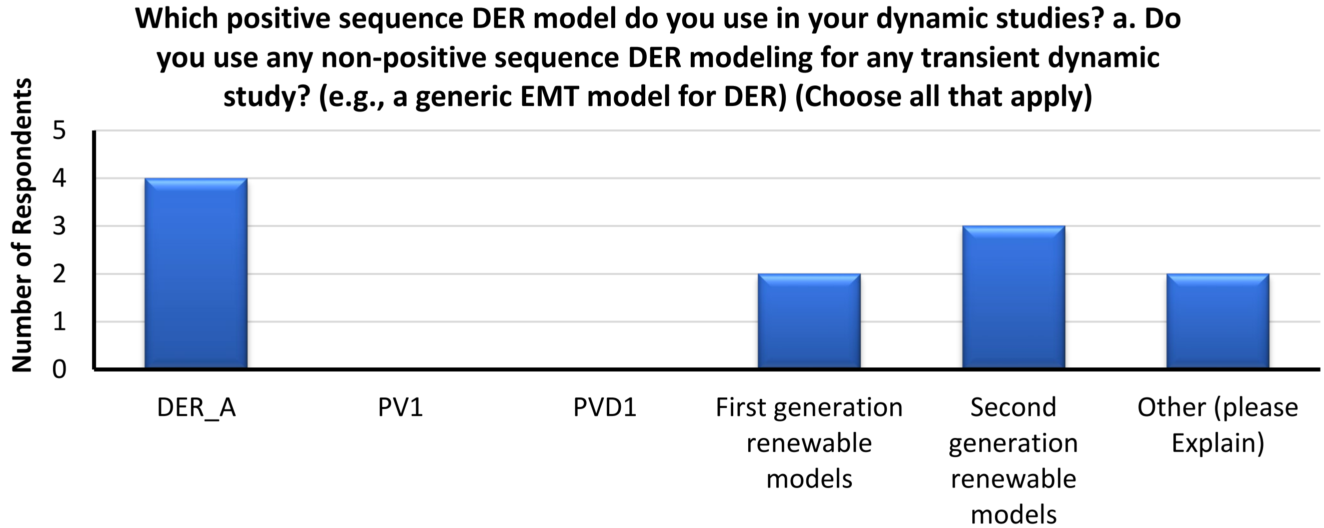
Key takeaway: Question 13
83% (5) of surveyed members model DERs with a mixture of the following: *a) negative load off the transmission bus b) negative load off an explicitly modeled T-D Interface c) explicit generation (gen or part of expanded load) hanging off the transmission bus d) explicit generation (gen or part of expanded load) behind a modeled T-D Interface.*

One of the entities stated that it models DER Aggregators like a controllable load resource and that they are seen as negative load. DERs over 1 MW are represented as generators mapped to a transmission bus and unregistered behind-the-meter units are netted with load.

One entity with the smallest amount of DER connected (10–50 MW) uses an explicit generator behind a modeled T-D Interface as a DER model.

Question 14

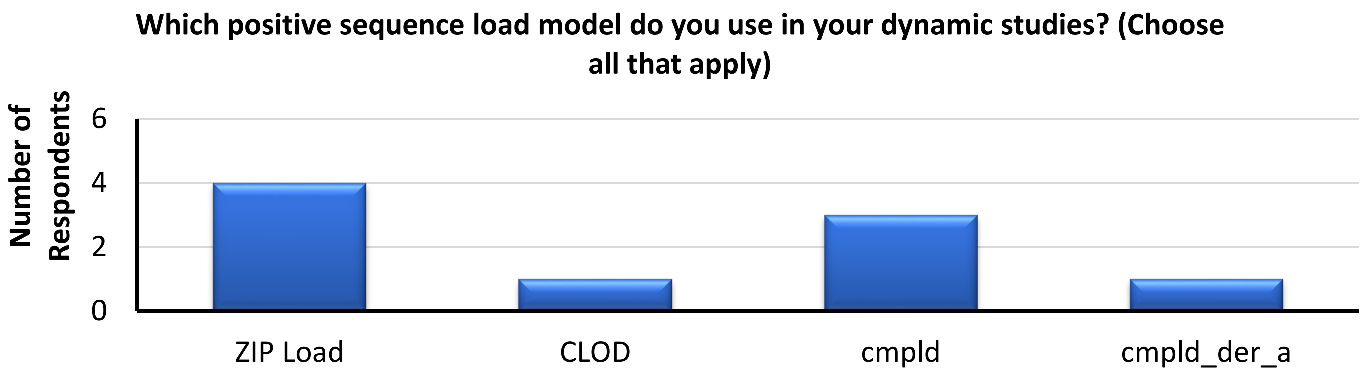
14. Which positive sequence DER model do you use in your dynamic studies? a. Do you use any non-positive sequence DER modeling for any transient dynamic study? (e.g., a generic EMT model for DER) (Choose all that apply)



Key takeaway: Question 14
Most of the surveyed participants use DER_A to perform dynamic studies. One entity separates inverter-based projects into two categories: projects less than 5 MW are modeled with DER_A and projects greater than 5 MW are modeled with second-generation renewable models. Synchronous generation is generally netted with the load, and no models are used unless they are greater than 5 MW, at which point they are modeled with explicit generator, exciter, and governor models.

Question 15

15. Which positive sequence load model do you use in your dynamic studies? (Choose all that apply)



Key takeaway: Question 15
The survey shows that different positive sequence models are used. ZIP load and cmpld models are used by the entity having DER aggregators.

Question 16

16. What offerings does the DER Aggregator have in your area? a. Is there an analogous entity for areas that are not ISO/RTOs that aggregate the response of distribution-connected generation? b. How is the Demand Response program controlled in your area?

Key takeaway: Question 16 (open-ended)

One entity allows DER aggregations to participate in its wholesale electric market. In general, the entity that represents a registered aggregator should also represent the load. Under the pilot for DER aggregations, they will be controlled through base point instruction produced using security-constrained economic dispatch.

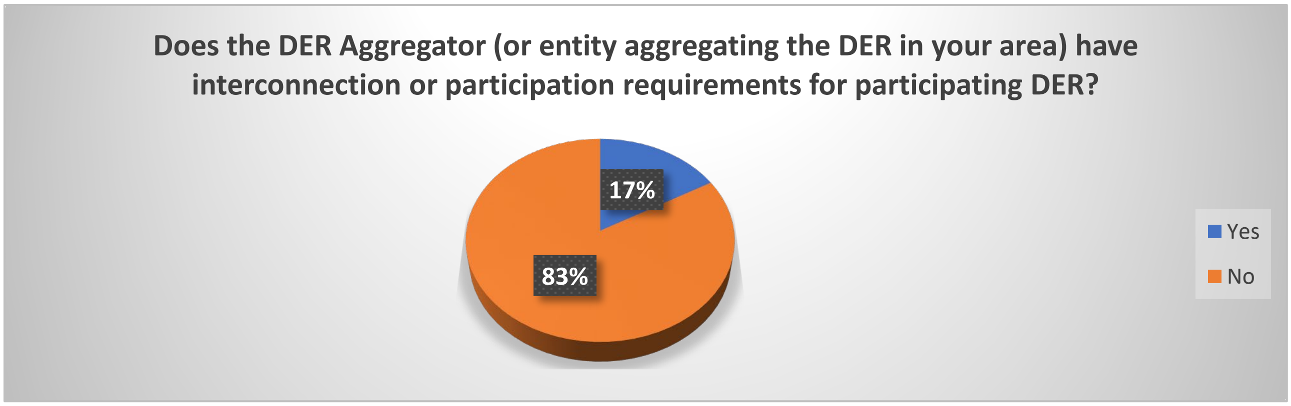
Another surveyed member responded that there is only one aggregator in their footprint, and the aggregator is simply a price taker in the respondent's market. The aggregator provides no services. For demand response, registration is performed under specific operating procedures.

For demand response, the standby generators and interruptible programs are controlled through the TCC (not by an aggregator).

Most surveyed entities mentioned that they do not have DER Aggregators or demand-response programs in their areas.

Question 17

17. Does the DER Aggregator (or entity aggregating the DER in your area) have interconnection or participation requirements for participating DER? If yes:
    a. Is there a verification of capacity and control from that which is provided in the services to the information shared for planning?
    b. Is there a verification of capacity and control from that which is provided in the services to the information shared for operations?
    c. Is there a verification of capacity and control from that which is provided in the services to the information shared for protection relay coordination?



Key takeaway: Question 17 (open-ended)

All participants responded that the DER Aggregator does not have participation requirements for participating DERs.

The entity with DER Aggregators claimed that the DSP has the interconnection requirements, not the DER aggregator. Specific rules for the DER aggregation pilot initiative are publicly available.

Another entity with DER Aggregators mentioned that rules for DER interconnection are required to meet UL certification 1741-SB and be compliant with IEEE 1547-2018, whereas transmission resources need to meet the requirements of the entity's planning and operating procedures. Also, DERs enter the state interconnection process, whereas transmission-connected resources enter through ISO-NE's queue and the FERC interconnection process. For DERs connected through an RTU to the ISO for modeled gens, 1547-2018 interoperability requirements do not apply.

Question 18

18. How and when does new DER, or existing DER wishing to increase its capacity, communicate to a DER Aggregator they wish to alter their equipment? a. Does the DER Aggregator notify transmission entities of this new capacity for your area? b. Is this taken care of in the capacity review identified in FERC Order 2222, or is this capacity review a separate requirement of the ISO/RTO?

Key takeaway: Question 18 (open-ended)

One entity shared changes to the aggregation, including monthly communications to detail changes to the premises/devices that make up the aggregation. These updates are provided to and require approval by the entity and the DSP before becoming effective. Transmission service providers are informed of changes in capacity but do not need to approve changes to the aggregation. Changes in capacity are a separate requirement from the O2222 review.

Most of the surveyed entities do not have DER aggregators or they do not act in that capacity.

Question 19

19. How do the distribution system operators and planners coordinate with the DER Aggregator for analysis of constraints on the distribution system? a. D side constraints can have backup plans; how are those currently monitored? b. Are some of these schemes automated? c. What requires operator control and does that affect which T-D Interface a DER is pushing against?

Key takeaway: Question 19 (open-ended)
One entity shared that, prior to allowing a premise or device to become part of an aggregation, the DSPs review the list of all proposed premises and devices and can either approve or reject each individual line item. This is the DSPs' first opportunity to head off potential concerns. Once the aggregators is in operation, the DSPs have the right to change how the aggregation is being managed should they see issues that they cannot otherwise easily manage. As this entity is managing the work in a pilot project, more formal procedures are under development to be developed. However, the entity stated they have no visibility of DSP procedures that may be in place to monitor and control reliability issues. To the degree an aggregator is limited by instructions from the DSP, the aggregator is required to reflect those limitations in the data provided (for example, as a reduction in available capacity reflected in real-time telemetry).

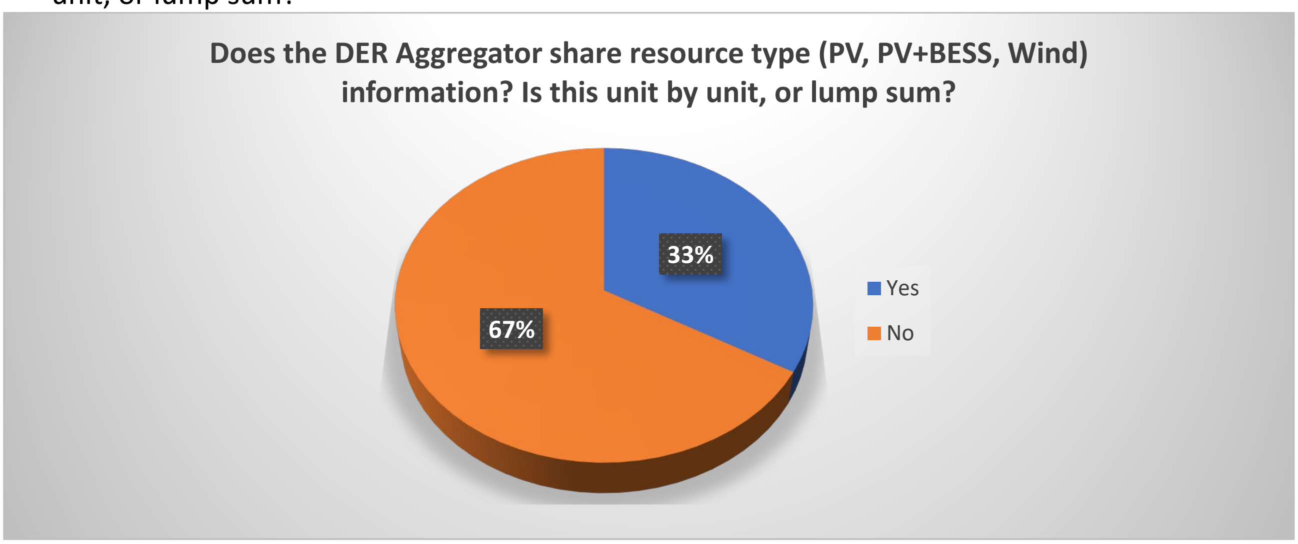
Question 20

20. If known, how does the DER Aggregator collect, store, and share (Planning Data, Operational Data, and Short Circuit Data)?

Key takeaway: Question 20 (open-ended)
From the survey responses, experiences from the one entity with DER Aggregators show that this task is left to the aggregators to organize. No rules are set on how to collect and store information. Only requirements on what information needs to be provided for studies and models have been specified.

Question 21

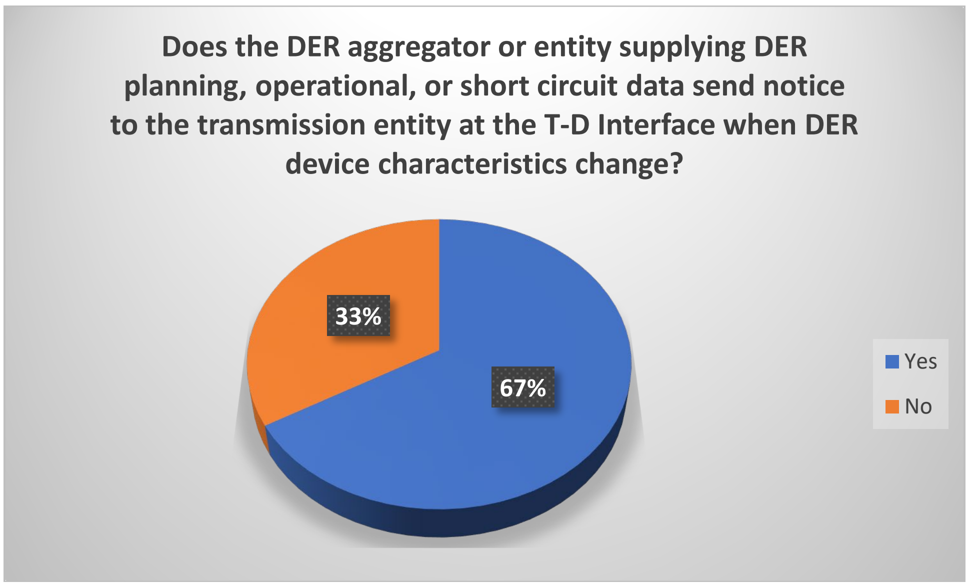
21. Does the DER Aggregator share resource type (PV, PV+BESS, Wind) information? Is this unit by unit, or lump sum?



Key takeaway: Question 21 (open-ended)
Entities with DER aggregators shared that real-time telemetry and near-term operational data (hours and days) are provided for the aggregation. Registration-type information is provided for each individual premise or device with this information updated monthly, following entity and DSP review.

Question 22

22. Does the DER aggregator or entity supplying DER planning, operational, or short circuit data send notice to the transmission entity at the T-D Interface when DER device characteristics change?
    a. Is there a verification of capacity and control from that which is provided in the services to the information shared for planning?
    b. Is there a verification of capacity and control from that which is provided in the services to the information shared for operations?
    c. Is there a verification of capacity and control from that which is provided in the services to the information shared for protection relay coordination?



Key takeaway: Question 22 (open-ended)
Only one entity responded that a DER aggregator or similar entity supplied DER planning, operational, or short-circuit data and sent notice to the transmission entity at the T-D Interface when DER device characteristics change. As shared in the previous question, entities with DER aggregators shared that real-time telemetry and near-term operational data (hours and days) are provided for the aggregation. Registration-type information is provided for each individual premise or device with this information updated monthly, following entity and DSP review. There is also a process to validate the real-time telemetry and operations performance of the aggregations.

The second entity with DER aggregators responded that if the capacity changes, then it is notified. Otherwise, it is not necessarily notified.

Most of surveyed member do not have aggregators within their area.

Question 23

23. How is double counting or other duplication of generation accounted for in DER Aggregators? Does this cover all T-D Interfaces? Explain.

Key takeaway: Question 23 (open-ended)
One entity responded: As part of the process for approving participation of an individual premise or device, validation is done to ensure that they are not also participating in another wholesale market program.

Another company records all DERs currently installed and planned and actively monitors for possible double-counting issues.

Question 24

24. How is double counting or other duplication of generation accounted for in resource plans? Does the DER Aggregator supply this information? Does the DER Aggregator cover all T-D Interfaces for these resource plans? Explain.

Key takeaway: Question 24 (open-ended)
One member responded that as part of the process for approving participation of an individual premise or device, validation is done to ensure that they are not also participating in another program, addressing duplication on the front end. Another entity responded that DER is typically handled in its load forecast as a load offset and not counted as generation.

Question 25

25. What estimation techniques for DER Aggregator output are used to run a 15-minute ahead, 30-minute ahead, hour-ahead, and day-ahead analysis?

a. Does the estimation spread across multiple load records?

b. Does the estimation allow for creation of "new" generators in the model?

c. Are predictions made on zones, substations, feeders? (please indicate all that apply)

d. How granular of a forecast is required?

e. How does the forecast deal with uncertainty or error?

Key takeaway: Question 25 (open-ended)
One entity with DER Aggregators stated that aggregators are required to provide hourly operational information. Maximum power consumption and low power consumption values for the aggregators for future hours are monitored.

Most of surveyed member do not have aggregators within their region.

Question 26

26. For your state estimator, how does the mismatch solution deal with negative records added to the load?

    a. Does an output negative load link with a DER generator dynamic model?

    b. How are mismatch loads dealt with in the OPA and RTA practices? Are they ignored, netted, or other?

Key takeaway: Question 26 (open-ended)
One surveyed member responded that a fake generator model is added to the state estimator to represent the DER behind the station. The size of this model is commensurate with the expected capacity and expected output of the DERs.

Question 27

27. Do your data quality checks or other operational assessment practices account for gross vs. net loading at each T-D Interface?

    a. What metering supplies this gross versus net loading? (e.g., transformer-level, breaker-level, or DER device-level metering)

    b. Are these quality checks posted or otherwise available on request?

Key takeaway: Question 27 (open-ended)
Entities with DER aggregators have gross 15-minute meter data available for validation in the first phase of the pilot project. Other approaches are likely be considered in future phases. Rules specific to the DER aggregation pilot are publicly available.

Most of the surveyed members do not have aggregators within their region.

Question 28

28. For information provided by the DER Aggregator, what telemetry granularity are they able to provide? (e.g., SCADA scans, Advanced Distribution Management System (ADMS), other time frame or framework)
    a. Do they disaggregate their load from active power producing generation resources?
    b. What metering is used or provided to telemeter the data for operational planning analysis. What metering is used or provided to telemeter the data for real-time analysis.

Key takeaway: Question 28 (open-ended)
For DER aggregators, one entity requires providing telemetry with granularity as low as 2 seconds, in alignment with requirements for other resource types. This includes the following:

a. Providing both options where either a device can be part of the aggregation or the whole premise can be part of the aggregation.
b. Operational planning analysis based on resource plan data provided for the aggregation. In general, these processes do not depend on meter data or telemetry.
c. 15-minute meter data is the data available for validation.

Most surveyed members do not have aggregators within their area.