MARKET PARTICIPATION MODEL DESIGN CONSIDERATIONS FOR DISTRIBUTED ENERGY RESOURCE AGGREGATIONS

An EPRI FO2222 Phase 1 Collaborative Report

July 2021

Abstract

In September 2020, the Federal Energy Regulatory Commission issued Order No. 2222: Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators. The order requires independent system operators (ISOs) and regional transmission operators/organizations to incorporate appropriate modifications to their market design and market clearing software to enable enhanced participation of distributed energy resource aggregations (DERAs) in energy, ancillary services, and capacity markets. Several research gaps are identified to meet the requirements in the order that are presently being collectively addressed by the Electric Power Research Institute Collaborative project in collaboration with key stakeholders. The order specifically directs the ISOs to modify their market rules and tariffs to establish DER aggregators as a market participant, allowing it to register DERAs under one or more participation models that accommodate their physical and operational characteristics appropriately. The DER aggregators have the option to use existing participation models, or the ISO can create new participation models that might better capture the characteristics of DERAs. This technical brief describes several key aspects of participation model design for DERAs as outlined in the order, including a discussion of the outstanding challenges and possible frameworks for addressing these gaps.

Introduction

The primary objective of the Market Operations and Design Workstream as part of the EPRI FERC Order 2222 Collaborative project is to support the FERC jurisdictional RTOs, ISOs, and other stakeholders on their needs to address the established requirements for participation models for DERAs. This includes conducting a comprehensive survey of the state-of-the-art participation model design options that may align with DERA characteristics, and those that are presently being discussed at the numerous stakeholder proceedings across the U.S. to address O2222 requirements. The main goal of the dialogues held through this workstream is to provide the different stakeholders with the opportunity to discuss the benefits and potential challenges of the numerous proposed participation model approaches. Additionally, this workstream will also aim to catalogue the additional research and development that may be required for implementing O2222 and beyond, specifically for systems with increased penetrations of DERAs, with consideration of reliably and efficiently utilizing these resources in the wholesale electricity markets.

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

[2] *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.

DER Aggregation Participation Model

As per Order 2222, FERC required each RTO/ISO to modify its market rules and tariffs to establish DER Aggregator as a market participant, allowing it to register DER aggregations (DERAs) under one or more participation models that accommodate their physical and operational characteristics appropriately. In this regard, FERC stated that it is up to the RTOs/ISOs on how they may need to adjust their existing participation models or create one or more new participation models for DERAs. RTOs/ISOs were also provided with the option to choose between a mixture of the two aforesaid approaches. The ISO proposed participation models may not entirely capture all the physical and operational characteristics of each DER type that constitutes the DERA given the associated complexities. 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

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This white paper was prepared by EPRI.

RTO/ISO to modify its tariff to allow single DERAs that comprise of different types of DER technologies, i.e., heterogeneous DERAs, to participate in its energy, ancillary services, and capacity markets (when applicable) and when technical capable of doing so.

While individual ISOs/RTOs had used the term participation model with slightly different meanings in the past, the term was first introduced by FERC in its Notice of Proposed Rulemaking (NOPR) on energy storage and DERA participation in wholesale markets.[3] It 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 841 included a slightly revised definition of "tariff revisions that consist of market rules that, recognizing the physical and operational characteristics of the resource, facilitates their participation in RTO/ISO markets."[4] 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." Generally, RTOs/ISOs may consider new participation models when new technologies have characteristics that would make them operate in its wholesale markets differently from other resources (e.g., electric storage resource models) or when it has been observed that characteristics could be incorporated to more efficiently operate existing resources (e.g., advanced combined cycle models).

Notably, while participation models reflect characteristics of specific supply technologies (including demand response) and are named after those technologies, they do not typically require that technology to use the participation model aligned with its technology or may even allow some technologies to use different technology-specific participation models.

Using existing participation models as-is, i.e., without incorporating any new modifications, or with slight modifications, is potentially the quickest path to accommodate DERAs. Some adjustments to existing participation models might become necessary including, but not restricted to, the introduction of transmission distribution factors (DFs) for DERAs aggregating over multiple pricing nodes, modification of minimum resource size requirements, modification of commitment decisions (e.g., self-commitment or committed by the ISO), etc., to be compliant with Order 2222 requirements. Other reasons for modification may exist as well such as fairness with other participation models, unique features of the ISO, and computational tractability of scheduling algorithms, particularly with large numbers of small-sized resources. Additionally, if the physical and operational characteristics of the DERAs are such that their behavior is significantly different and unique when compared to existing participation model options, existing participation models may lead to inefficient operation of the DERA. Furthermore, if the reliability benefits of DERAs cannot be accommodated and valued appropriately through existing participation modeling options, there might be a need to introduce new participation models accordingly given these limitations. However, it should be noted that the introduction of new participation models is costly; therefore, a thorough analysis is required to ensure that the new participation model is necessary and has benefits that outweigh the costs of implementation.

It is natural to assume that an aggregation of DERs of the same technology type (i.e., a homogenous aggregation of DERs) is likely to fit into an existing participation model for stand-alone transmission-connected utility-scale resources, assuming an aggregation of technologies are similar to transmission-connected resources that already participate in the wholesale markets (e.g., utility-scale photovoltaic solar, wind, electric storage resources, dispatchable demand response resources, block demand response). However, certain changes may be needed to accommodate geographically dispersed resources (e.g., energy management system (EMS) location mapping, updating minimum resource size accommodations, provision of transmission distribution factors for DERs spanning multiple pricing nodes), while also satisfying the status quo participation model requirements associated with the specific resource type and meeting the general rules of aggregation, if any.

Modifying existing participation models and creating new participation models will require significant market clearing software development, and other costs such as stakeholder debate and design that might be greater than implementation costs. Existing participation models are typically well-understood through utilization and experience in the prior years. New participation models may have additional capabilities but must be fully explained,

[3] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, FERC,* Notice of Proposed Rulemaking, 81 FR 86522, 157 FERC 61,121, 2016.

[4] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, FERC*, Order No. 841, 83 FR 9580, 162 FERC 61,127, 2018.

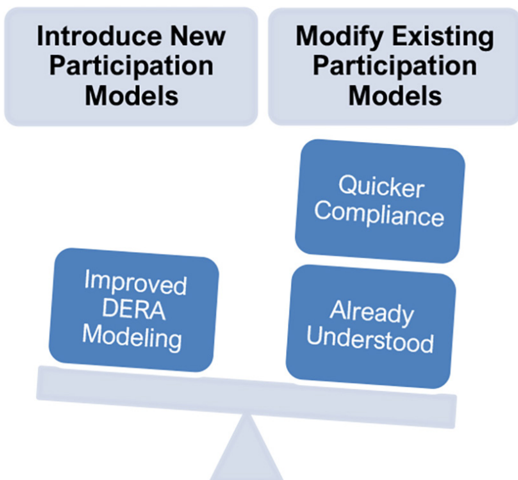

Figure 1: Introducing new participation model vs. modifying existing models.

introduced, and tested into several ISO systems (e.g., registration, settlement, market, EMS). Some ISOs believe that if specific market participants are already using an existing participation model, modifying it could have implications for the existing participants that could be risky to introduce, so it is crucial to ensure that the newly introduced modifications do not negatively impact existing participants that are already utilizing those models. Some stakeholders are of the opinion that new participation models are needed to comply with Order 2222 as the existing models cannot easily accommodate heterogenous aggregations of DERs, and/or those that are geographically dispersed. ISO-NE has preliminarily indicated that the operational capabilities of a heterogeneous aggregation cannot be adequately modeled using existing participation models. For example, its existing participation models do not allow for aggregation of injecting and withdrawing resources. ISO-NE has initially proposed two new participation models: Settlement-Only DERA (SODERA), a non-dispatchable model ineligible to provide ancillary services, and Demand Response DERA (DRDERA). DERAs can also use existing participation models. PJM has also suggested that the existing participation models either do not allow for aggregation (Generation model) or they do not allow for injection beyond the customer's meter (Demand Resource model). PJM intends to introduce new DERA participation models that allow DERs to inject power into the grid. PJM also states that their existing demand response (DR) participation models would be unchanged.

There exist numerous challenges with introducing participation models for heterogenous DERAs that warrants further research and development. For instance, the majority of the ISOs are presently discussing settlement issues that are related to DERAs that comprise of demand response and other technologies. There are also operational and market challenges that are related to DERAs that comprise electric storage resources given concerns around state-of-charge consideration and management, particularly with increasing penetrations of such emerging technologies. Heterogenous participation models might require the DER Aggregator to self-schedule, which may potentially result in market inefficiencies. The discussion in the subsequent sub-section relates to the challenges associated with such heterogenous DERAs that include demand response resources, electric storage resources and variable energy resources specifically as examples while also suggesting a few potential solutions for consideration.

Heterogeneous DERAs including Demand Response Resources

FERC stated in Order 2222 that demand response (DR) aggregations are subject to the opt-out requirements of Order No. 719. In Order 2222-A, FERC clarified that only homogeneous demand response aggregations are subject to such requirements.[5] However, Order 2222-B reversed this particular finding of Order 2222-A, stating that a Relevant Electric Retail Regulatory Authority (RERRA) may still disallow the wholesale market participation of demand response resources within any DERA.

As for the settlement of demand response resources in a DERA, FERC asserted that Order No. 745 would still apply to demand response resources participating in heterogeneous aggregations. FERC issued Order 745[6] in March 2011 to standardize the compensation of demand response resources participating in wholesale energy markets administered by ISOs and RTOs. Order No. 745 states that when a demand response 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 a net benefits test, the resource must be compensated for its demand reduction in the energy market at

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

the locational marginal price (LMP). In particular, Order No. 745 established requirements for a net benefits test, required the review and modification (if necessary) of measurement and verification procedures including baseline estimates, and required a method for allocating the costs of demand response payments among the Loads that benefit from Load Reductions performed by demand response resources.

Order No. 745 required ISOs/RTOs to develop an approach for determining the net benefits threshold price (NBTP), which is "the point along the supply stack beyond which the overall benefit from the reduced LMP resulting from dispatching demand response resources exceeds the cost of dispatching and paying LMP to those resources." NBTP is calculated each month by the ISOs/RTOs for the next month using data from the same month in the prior year. The DR gets paid at LMP only if the LMP is greater than the NBTP for the current month. Alternatively, some ISOs calculate an offer floor based on the net benefits test, and the market software automatically rejects a demand reduction bid for a demand response resource if it is less than the offer floor.

RTOs need to ensure compliance with Order 745 when developing new rules for Order 2222. NYISO has a FERC-approved DER Aggregation participation model which is compliant with Order 745. In their DER Aggregation model, NYISO treats demand reduction as supply when calculating the total aggregation response. However, the demand reduction part gets compensated only if the Real-Time LMP for the corresponding interval meets or exceeds the monthly NBTP. ISO-NE has recently proposed to introduce a new participation model for heterogenous aggregations including demand response, called Demand Response DERA (DRDERA), to meet the compensation requirements of Order No. 745.

Some believe that Order 745 creates a double counting issue by requiring compensation for demand reductions, which are already benefited from avoided energy payment. However, FERC clarified in Order 2222-B that participation of demand response resources in a DERA does not constitute double counting, so long as the requirements of Order 745, including the net benefits test, are satisfied.

Order 745 also required each RTO/ISO to allocate the costs associated with demand response compensation proportionally

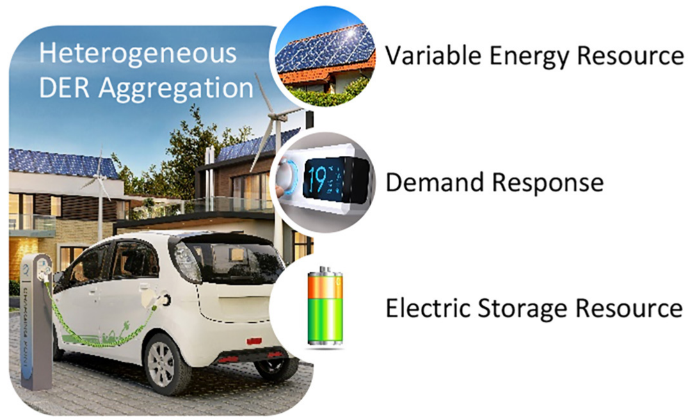

Figure 2: Challenging components in a heterogeneous DERA.

to customers who benefited from the demand response dispatch. If there is no transmission congestion, all customers are benefited and will need to pay for the demand reductions. In the case of transmission congestion, more complexities arise in identifying the set of customers who benefited from demand reductions. Further complications are caused when demand response is aggregated with non-demand response resources.

Another concern with respect to heterogeneous aggregations including demand response is the complications in calculating baselines. NYISO does not allow an Aggregator of an Electric Storage Resource (ESR) with highly variable host load to offer demand reductions because of concerns regarding inaccuracy of the Economic Customer Baseline Load Calculation (ECBL) approaches. NYISO further explains that such facility may instead qualify to participate as a stand-alone resource using the ESR participation model or in an aggregation given that separate metering facilities are installed for the load segment.

Other questions in this category are listed below:

1. What type of metering will be required to enable the calculation of demand reductions?
2. How will the ISOs avoid double counting for the other DERs per Order 2222?
3. What is the advantage of demand response aggregating with non-demand response DERs?
4. What are the benefits or likelihood of demand response resources aggregating through DER Aggregators as opposed to existing demand response aggregators?

[6] *Demand Response Compensation in Organized Wholesale Energy Markets*, FERC, Order No. 745, issued March 15, 2011. https://www.ferc.gov/sites/default/files/2020-06/Order-745.pdf.

5. DERs make the loads less predictable and more volatile. Would the baselining methodologies still be accurate considering variable loads and controllable DERs in the aggregations? Would there be any gaming opportunities?

Heterogeneous DERAs including Electric Storage Resources

FERC required that ISOs/RTOs allow for heterogeneous aggregations of DERs, but it did not establish explicit requirements for heterogenous DER aggregations that consist of electric storage resources (ESRs). Additionally, as per the Order's requirements, each ISO is also required to allow DER Aggregators to register its aggregated DERs under one or more participation models in the ISO's tariff that accommodate the DERAs physical and operational characteristics. While O2222 requires each ISO to incorporate bidding parameters into participation models that account for the physical and operational characteristics of DER aggregations, it does not explicitly say which parameters to include or whether DERAs that include certain technologies require different parameters from others. In the case of DERAs that include ESRs within the aggregation, there are operational and market design challenges related to one such parameter, the state-of-charge (SOC).

Some ISOs have stated that SOC information is crucial to ensure feasible and efficient operation of the grid. Moreover, providing SOC information through bidding parameters and telemetry may potentially assist the DER Aggregator in maintaining feasible SOC levels and as such, feasible energy, or ancillary service schedules. As per the DER Provider (DERP) provisions, CAISO intends to consider SOC at an aggregate level, but does not intend to collect or monitor the SOC information for the sub-resources that constitute the DERA. Analogously, ERCOT also intends to collect the SOC information from DERAs. The preliminary thought process at some of the ISOs is that heterogenous DERAs that consist of ESRs may potentially use existing ESR participation models, such as SPP's market storage resource (MSR), which in most regions has been approved by FERC as part of FERC Order 841. Accordingly, since resources using the ESR participation model are required to submit SOC information, the requirement will also apply to DERAs that use the ESR model in lieu of the ISO's overarching goal to be technology agnostic. In such instances, SOC information is being proposed to be obtained from the aggregation and not necessarily the individual DERs that constitute the aggregation. The collected information, which may not be necessarily physical, is envisioned to be used in the market models to ensure feasibility of the dispatch schedules. At most of the ISOs that are planning on considering SOC, there are still outstanding questions on better understanding how SOC is considered or represented by the Aggregator, specifically for heterogenous DERAs. Some ISOs have also indicated that there are concerns associated with how the ISO can substantiate that the provided information is correct or not and correspondingly design performance or compliance metrics given that the provided information is not physical for an aggregation. Regardless, FERC has assigned the aggregator the responsibility to ensure the performance of the DERA failing which the aggregator will be subjected to penalties.

Alternatively, some ISOs have stated that monitoring and considering SOC for heterogenous DERAs that consist of ESRs would require a separate undertaking and is potentially improbable to propose or design as part of the Order 2222 compliance filings given the imminent deadline to comply with the Order. These ISOs have stated that there are challenges associated with determining how SOC is impacted when ESRs aggregate with other DER technologies, and whether there is even a need to monitor and consider SOC accordingly in the near-term. If the ISOs were to introduce the SOC offer parameter, there are questions around who manages the SOC of such heterogenous DER aggregations with most ISOs leaning toward self-management of SOC by the aggregator. If the SOC of such self-managed heterogenous aggregations is not considered adequately through appropriate offers, there are existing questions around the potential impacts on system reliability and economic efficiency, particularly with increasing penetrations of such emerging resources.

MISO is presently considering a fully flexible DERA Resource that is ESR capability based (note: MISO's ESR model is a future planned resource type that is not yet implemented) as a potential participation model option for heterogenous DERAs that includes ESRs or DERAs that would like to both withdraw and inject. In this regard, the planned participation model is proposed to be potentially eligible to provide all market products. It is dispatchable, but does not include commitment decisions (i.e., if opted, the DER aggregator will need to self-commit under this option). However, SOC will not be provided as an offer parameter and will be reserved for ESRs (or homogenous DER aggregations of ESRs) only. Unlike FERC Order 841, Order 2222 did not require ISOs to consider and monitor the SOC of DERAs that include ESRs, so this is likely to be one potential modeling option or pathway that most

ISOs may adopt in the near-future for such DER configurations given the complexities associated with market operating procedures that include SOC management. This suggested participation option may also change in the future as the ISOs gain additional experience with standalone ESR participation models that were introduced to comply with FERC Order 841. The DERA under this specific MISO option will still be allowed to inject, withdraw, or do both, hence the term fully flexible. Should heterogenous DER aggregations need SOC consideration, MISO has preliminarily advised that such aggregations participate using the ESR participation model.

Figure 3: Challenges in three types of heterogeneous DERA.

Heterogeneous DERAs including Variable Energy Resources

In Order 2222, FERC did not establish explicit requirements for heterogenous DERAs that include Variable Energy Resources (VERs). For such DERAs, there are research questions around: who provides forecasts for the aggregated VER components, i.e., the ISO or the aggregator or an independent provider, the ability of the suggested participation model to allow for an automatic and dynamic update of the aggregated VER component's forecasted maximum injection capability or upper economic limit in real-time based on the short-term forecasts, the ability of the heterogenous DERA to then also qualify for ancillary services provision (it should be noted that most ISOs presently do not allow solar and wind to provide reserves).

Further complexities arise when VERs aggregate with ESRs. One such difficulty is related to the ability and the potential need for the ISO to allow subsequent updating of bids or offers in real-time (potentially intra-hour) given the forecast deviations from the aggregated VER component (or SOC limitations). There are also concerns regarding mitigation of such dynamic offers on an intra-hour basis given the computational complexity associated with some of the mitigation processes. Other complexities include whether the aggregator should provide telemetry of the SOC 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 and the software's ability to accommodate dynamic ramp rates (if needed). The latter set of discussions are analogous to discussions that are presently taking place across the continent in relation to hybrid resources and might require additional market design and stakeholder discussion. Meanwhile, the ISOs/RTOs may propose participation models that defer the responsibility to address these complexities to DER aggregator.

Bidding, Dispatch, and Commitment Parameters

FERC required each RTO/ISO to revise its tariff to: (1) require DERAs that span multiple pricing nodes to provide the RTO/ISO with the allocation from each pricing node, i.e., transmission distribution factors, at initial registration and any time they change, and (2) incorporate bidding parameters into participation models to account for physical and operational characteristics of aggregated DERs. In complying with the latter requirement, each RTO/ISO must either include the needed bidding characteristics as part of its new participation model or adjust bidding parameters of existing participation models.

Each RTO/ISO may revise tariff to manage locational attributes of DERAs in different ways reflecting unique network topology or characteristics of the RTO/ISO but must provide information on how to update distribution factors and other parameters.

The bidding parameters that a DER aggregation may need to provide depends upon the elected participation model. However, bidding parameters that are typically common across participation models for traditional technologies such as economic bids/offers (i.e., price-quantity pairs), ramp rates, maximum and minimum operating limits are potentially needed regardless of the opted participation model.

Transmission distribution factors (DF) will be needed as a bidding parameter if multi-node aggregation is allowed to reflect the anticipated portion of the DERA at each node. In this regard, CAISO requires DERAs across multiple pricing nodes to submit DFs and update them through bidding parameters. Most ISOs are of the opinion that bidding parameters for a DERA should be updated at the same frequency as for other resources given that their overarching goal is to be technology-agnostic. There is existing debate on whether DFs may or may not be accurately calculated as there are too many unknown factors that may potentially impact the accuracy of the DFs such as distribution system topology, the dynamic nature of DERs' dispatch within an aggregation, forecast errors related to variable energy resources, impact of a constituent DER leaving and joining another DERA, etc. While some believe that distribution factors need frequent updates, others state that static distribution factors might be sufficient. Numerous stakeholders are of the opinion that without accurate distribution factors, market dispatch of DERAs may challenge system reliability, efficiency, and accurate nodal pricing. There is also some debate around whether DERAs should be levied with imbalance charges if its aggregate response is aligned with an ISO issued dispatch instruction, but its nodal response differs from the submitted DFs. In this regard, it should be noted that as per CAISO's FERC approved participation model design, DERAs will not be levied with imbalance charges in such instances.

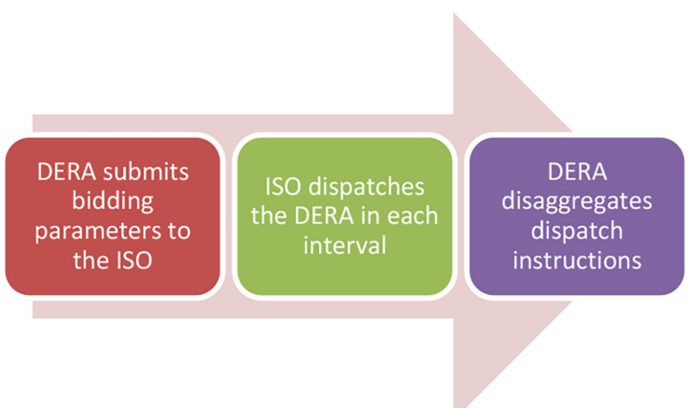

Figure 4: DERA operational participation process.

Most ISOs state that commitment parameters might not be needed for DERAs. Bulk system commitment may not be necessary or beneficial since DERs are located on the distribution system and typically serve end-use or distribution needs and because there is not a single resource to turn "on". Introduction of commitment decisions in this regard might result in potential conflicts if individual DERs within the aggregation are also providing other services outside the ISO's markets, e.g., distribution services, since the ISOs only model and optimize the bulk power system. Additionally, market operators have questions around how to determine the startup time for a DERA where a subset of constituting DERs are online and others not. Another important concern regarding the commitment of small DERAs is the potential to pose a significant computational burden on market clearing software that would challenge daily market clearing timelines. It may be appropriate to allow DER aggregations to indicate their availability and to offer appropriate incremental energy bid costs to cover any startup or no-load related cost. Considering these challenges, it may be beneficial to require small DERAs to self-commit rather than be economically committed. In this regard, CAISO and NYISO have proposed using dispatch-only models for DERAs. Furthermore, some ISOs have also considered requiring wholesale offers for dual-participating DERAs who have simultaneous retail or distribution service obligations by self-scheduling with the ISO the resultant energy schedules. However, there is still existing debate around whether commitment decisions may be required for a DERA including demand response resources. Presently, some ISOs/RTOs such as SPP and ISO-NE include commitment decisions for their DR participation model to appropriately represent unique physical characteristics related to DR which may respond to ISO requests in discrete blocks; accordingly, there may be a need to include commitment decisions for heterogenous DERA participation models that include DR. As an example, typical registration parameters for demand response resources in SPP include startup cost (which requires the introduction of commitment decisions), cost for demand reduction, cost of ancillary services, etc.

There is also some preliminary discussion around additional distribution system information that may be needed as part of a potential bidding parameter, that are unique to DERAs. One example is information on distribution system losses. While marginal transmission losses are accounted for in energy prices and

are inherently utilized in potentially dispatching more expensive resources that due to lower losses may be dispatched before cheaper resources with higher transmission losses, distribution losses cannot be accommodated directly with network models. It is unclear whether and how distribution losses can be incorporated through bidding or otherwise, or whether it is simply factored into the DERA energy cost offers. Finally, some bidding parameters may need to change on a dynamic basis depending upon the constituent DERs in the DERA, such as ramp rates.

DER and DERA Size Requirements

FERC required each RTO/ISO 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 require a minimum or maximum DER size requirement, nor a maximum DERA size requirement.

Most ISOs believe that if an individual DER is greater than a certain MW size, it should participate as a stand-alone resource or be its own aggregation. Some think that the maximum resource requirement is also driven by market manipulation and physical withholding concerns. For instance, resources should not be allowed to avoid the interconnection queue by locating on the distribution system. PJM states that if the metering and telemetry requirements for an individual DER within a DERA differ from traditional transmission connected resources, a maximum size requirement might be required to ensure the RTO has the best visibility possible to resources that have a greater chance to impact the transmission constraints. Presently, CAISO has imposed a 1 MW maximum size requirement and NYISO a 20 MW maximum size requirement for individual DERs within an aggregation. ISO-NE has suggested that large DERs that are greater than 5 MW should be its own dispatchable DERA. There are still open questions around what an appropriate maximum size value is, if elected to be included.

As for the maximum size requirement for the DERA, most believe that such a requirement is needed for DERAs that span multiple transmission pricing nodes to restrict their impact on intra-zonal network constraints. For instance, CAISO has a 20 MW size restriction for DERAs if aggregating over multiple pricing nodes.

Conclusions

FERC Order 2222 required each ISO/RTO to either modify existing participation models or establish new participation models to facilitate the participation of DERAs in wholesale electricity markets. This technical brief summarizes several outstanding challenges and proposes potential solutions associated with each of the suggested modeling paths to enhance DERA participation in ISO/RTO markets. Furthermore, additional research challenges to better address several key market design aspects, e.g., pricing and settlement, participation model, state-of-charge management, ancillary services, for specific configurations of heterogeneous DERAs e.g., heterogeneous DERAs including DR resources, heterogeneous DERAs including ESRs, heterogeneous DERAs including VERs, are also recognized and reviewed in great detail. Other market design aspects such as bidding parameters, dispatch and commitment decisions, and minimum size requirements are also included. The recognized research gaps and possible frameworks for addressing the gaps are a result of numerous dialogues with key stakeholders in the Market Operations and Market Design workstream of the EPRI FERC Order 2222 Collaborative project.

Note

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Market Operations and Market Design

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3002020587 July 2021

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