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Impact of FERC Order 2222 on DER Participation Rules in US Electricity Markets

September 2022

Brent Eldridge
Abhishek Somani

U.S. DEPARTMENT OF ENERGY

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Abstract

Electricity markets in the bulk grid are beginning to implement market mechanisms that support the procurement of flexible capabilities from wide range of technologies, including distributed energy resources (DERs). The flexibility of these resources will help counterbalance supply uncertainties from large-scale integration of variable renewable generation. To encourage development of distributed and aggregated market participants, FERC Order 2222 was issued in September 2020 to require each Independent System Operator (ISO) in the US to implement rules that enable broader participation from aggregations of DERs in the bulk market. The following report first describes the generic design of ISO markets before introducing the new market participation rules that ISOs have proposed for compliance with Order 2222. The paper then describes how software performance issues may continue to affect the eligibility requirements and offer structures for DER aggregations participating in ISOs, noting that continued research on computational methods may help reduce burdens for DER integration. The prospects for transmission and distribution system coordination is second major issue discussed, which will require minor changes to existing processes in the short term. In the longer term, there is more opportunity for more wide-ranging reforms, such as the development of a Distribution System Operator (DSO) framework. Newly proposed market rules may affect how Transactive Energy Systems (TES) will help facilitate efficient formation of DER aggregations and operation of the individual DERs within an aggregation. Within the TES context, the challenge is to fully understand how resource eligibility and operational and planning coordination methods will affect the design and implementation of TES.

Summary

This report details some of the barriers to distributed energy resource (DER) integration in wholesale markets due to regulatory policy and the computational limitations of market clearing software. These issues have come into focus following the issuance of FERC Order 2222, which requires organized wholesale electricity markets in the US to propose and implement market participation models for aggregations of DERs. A primer on electricity market design is provided for background on the relevant market design issues. We identify five key aspects affecting DER integration in wholesale markets:

- Influence of FERC Order 745,
- Market participation eligibility requirements,
- Computational performance and accuracy of market clearing software,
- Telemetry and metering technologies, and
- Transmission and distribution coordination frameworks.

Each of these issues is summarized below.

Order 745 and market eligibility

Discussed in Section 3.0, Order 745 requires a specific form of remuneration to demand response resources based on their calculated baseline demand. Their deviation from baseline is paid at the Locational Marginal Price (LMP), but the opportunity cost of energy not consumed nevertheless distorts economic incentives for demand response. Order 745 requires ISOs to use a Net Benefits Test to help ameliorate these distortions. Order 2222 does not remove any of Order 745's requirements, so demand response that is included in a DER aggregation is also required to follow Order 745's requirements. Different ISOs have proposed different ways to satisfy these requirements, resulting in non-uniform market rules for heterogeneous aggregations of demand response with other DERs. Key research questions are as follows:

- How do FERC Order 745's requirements affect the investment decisions and offer strategies of heterogeneous DER aggregations?
- How should retail electricity tariffs be designed to foster efficient operation and investment in DERs? Are those requirements consistent with implementing a TES?
- How should TES be designed to prevent double-counting while facilitating efficient dual participation in retail and wholesale markets?
- What is the relative value of DERs in wholesale versus retail markets under existing retail and wholesale tariffs? How does this compare to socially optimal DER utilization?
- What relative value do DERs provide to the wholesale and retail markets under current tariffs and coordination schemes? How does this compare to their theoretically ideal utilization?

Market clearing software

Large scale integration of small DER aggregations will strain the computational performance of the software used for determining production schedules and market clearing. There are two main research areas stemming from this difficulty: first, computational enhancements to improve

the market software, and second, DER participation policies that can reduce computational difficulty without reducing market efficiency. CAISO, NYISO, MISO, and PJM have all proposed “self-commitment” participation for DER aggregations, meaning that DER aggregations in those markets cannot submit complex offers (e.g., start-up cost, minimum run time) that are available to conventional generators. Key research questions are as follows:

- What aspects of complex, multi-part offers are necessary for aggregators to accurately express the costs of possibly heterogeneous DER technologies (e.g., demand response, storage)?
- What optimization algorithms or routines might ISOs develop to improve the commitment and dispatch logic of large numbers of small DER aggregations?
- What is the effect of DER self-scheduling on the efficiency and stability of real-time markets?
- What alternatives to distribution factors would improve the accuracy and efficiency of multi-nodal DER aggregation dispatch?
- What rules are most suitable for defining acceptable multi-node aggregation zones? E.g., shift factor thresholds, historical congestion patterns, etc.
- How do changes in distribution system conditions (congestion, maintenance, topology changes) affect the accuracy of static distribution factors[1]?

Telemetry and Metering

Telemetry and metering are required to ensure operational awareness of dispatched DER aggregations and accurate billing. A variety of communication technologies are available, ranging from private Wide Area Network (WAN) to public internet service, which are available at different costs and have different levels of security. ISOs also have various data quality and frequency requirements for participation in the energy and ancillary services markets; for example, ISO-NE only requires 5-minute telemetry data for energy market participation whereas CAISO, NYISO, MISO, and SPP each require sub-10-second telemetry data. Differences among ISO telemetry and metering requirements could affect decisions to create DER aggregations in different markets. Key research questions are as follows:

- Given the relaxed telemetry requirements in some ISOs, is there a potential for oscillatory dispatch from DER aggregations? What price formation improvements would reduce this behavior?
- Is there a significant risk to grid cybersecurity due to the use of public internet to send and receive telemetry data?
- Does the installation and maintenance cost of telemetry and metering equipment pose a significant barrier to entry for DER aggregators?

T&D Coordination

Frameworks for coordination between the transmission and distribution systems are still in their infancy, and best practices are still developing. DER aggregators, distribution utilities, and ISOs could experience operational and planning difficulties due to overlapping, incohesive, or divergent objectives of the different systems. More operational experience should help inform

[1] Distribution factors define a fixed proportion of the aggregation’s dispatch coming from each node in a multi-node aggregation.

the relevant stakeholders of the key difficulties and their magnitude in terms of lower market efficiency and higher opportunity costs, but proactive research efforts may help identify these issues and possible solutions. For example, transactive energy systems (TES) have potential for smoothing coordination gaps by sending economic signals to individual DERs that can help guide efficient participation in one, the other, or both systems. How often and what is the likely impact of distribution utility overrides on DER dispatch? How might this be internalized in a DER aggregator's offer? Key research questions are as follows:

- What information can distribution utilities provide to DER aggregators to ensure that accepted offers do not violate distribution system constraints?
- How can ISOs simplify or expedite interconnection studies for small DER aggregations while still ensuring safe and reliable distribution and transmission system operations?
- What role should distribution utilities play in creating price signals to support efficient DER investment and integration?
- How can transactive energy systems improve and simplify the necessary coordination between distribution utilities, DER aggregators, ISOs, and regulators?

Order 2222 leaves specific T&D coordination schemes open to the consideration of ISOs, distribution utilities, DER aggregators, and relevant electric retail regulatory authorities. It is unlikely that near-term Order 2222 compliance proceedings will result in a complete overhaul of T&D coordination frameworks, but it will instead create steps along the road to a more cohesive framework.

Section 5.0 discusses the potential for longer term reforms to address T&D coordination, especially the potential for DSOs and TES. Key research questions are as follows:

- What institutional, regulatory, jurisdictional barriers might prevent the development of DSOs in the US? How are these barriers different for the implementation of a distribution-level TES?
- What are the market design considerations for a potential DSO? What is the most appropriate network model for distribution system operations? Would a TES approach these considerations differently?
- How would a DSO interact with customers/end users? How would a DSO interact with the transmission system operator? Would these interactions be coordinated more efficiently in a TES?
- What added value would a DSO approach provide to DER integration and improved distribution and transmission coordination? What are the economic benefits? What are the reliability benefits? How would these benefits compare with the implementation of other TES-based frameworks?

Regulatory Status

Each FERC-jurisdictional ISO has submitted its initial FERC Order 2222 compliance filing, which describes how each respective ISO proposes to change its tariff to comply with Order 2222's requirements. The compliance filing date represents only a first step towards the implementation of any newly proposed market participation rules for DER aggregations; relevant stakeholders are able to submit comments supporting or criticizing aspects of the proposals before FERC issues its acceptance or rejection of the proposed tariff amendments. Each proposal can be monitored through FERC's eLibrary[1] to see the current status of the proceedings. Docket numbers for each ISO's filing are provided in Table 5.1.

Table 5.1. FERC Order 2222 Regulatory Summary

ISO	Compliance Filing Date	Implementation Date	Major Updates	Docket Number(s)
CAISO	7/19/2021	11/1/2022	Reduces the minimum size of DER aggregations from 0.5 MW to 0.1 MW.	ER21-2455-000
NYISO	7/19/2021	Q4 2022	Changes existing DER aggregation model to allow individual DERs to participate as an aggregation.	ER21-2460-000
PJM	2/1/2022	Capacity: 7/1/2023 E&AS: 2/2/2026	Proposes a "no-commitment" DER aggregation participation model.	ER22-962-000
ISO-NE	2/2/2022	Capacity: 2/2024 E&AS: Q4 2026	Proposes new "Dispatchable DERA" and "Settlement-only DERA" participation models and widens requirements in other existing participation models.	ER22-983-000
MISO	4/18/2022	10/1/2029	Proposes a distributed energy aggregation resource (DEAR) participation model.	ER22-1640-000
SPP	4/28/2022	Q3 2025	Adds DER aggregation to the list of valid Resource types.	ER22-1697-000
ERCOT	N/A	Q2 2024	ERCOT's Passport Program includes updates to accommodate distributed generation resources in the Energy Management System and implements a 1 MW minimum capacity for those resources.[2]	N/A

[1] https://elibrary.ferc.gov/eLibrary/search
[2] Seely, Chad. "PUC Project No. 48540, Review of Real-Time Co-optimization in the ERCOT Market, Update on the Real-Time Co-Optimization Project." Memo to the Public Utility Commission of Texas. December 10, 2010.

Acknowledgments

We thank Hayden Reeve and Robert Pratt for comments on an earlier version of this paper.

Acronyms and Abbreviations

In addition to the acronyms and abbreviations below, specific ISO participation and resource models are described in Appendix A.

AC	Alternating current
AGC	Automatic Generation Control
ARR	Auction Revenue Right
CAISO	California Independent System Operator
CONE	Cost of New Entry
CPUC	California Public Utilities Commission
DER	Distributed Energy Resource
DLMP	Distribution Locational Marginal Price
DR	Demand Response
DSO	Distribution System Operator
DU	Distribution Utility
EDC	Electric Distribution Company
EPRI	Electric Power Systems Research Institute
ERCOT	Electric Reliability Corporation of Texas
ESIG	Energy Systems Integration Group
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Right
ICAP	Installed Capacity
ICCP	Inter-Control Center Communications Protocol
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
LBA	Local Balancing Authority
LMP	Location Marginal Price
LMR	Load Modifying Resource
LSE	Load Serving Entity
MISO	Midcontinent Independent System Operator
MOPR	Minimum Offer Price Rule
MVAR	Megavolt Ampere Reactive
MW	Megawatt
NYISO	New York Independent System Operator
PJM	PJM Interconnection LLC
PNNL	Pacific Northwest National Laboratory
RA	Resource Adequacy

RERRA	Relevant Electric Retail Regulatory Authority
RTO	Regional Transmission Organization
RUC	Reliability Unit Commitment
SCED	Security Constrained Economic Dispatch
SCUC	Security Constrained Unit Commitment
SIT	Stevens Institute of Technology
SPP	Southwest Power Pool
TO	Transmission Owner
TOU	Time-of-Use
WAN	Wide Area Network

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1.0 Introduction

On September 17, 2020, FERC issued Order 2222 with the purpose of widening the participation of distributed energy resources (DERs) in wholesale electricity markets.[1] DERs include numerous emerging technologies such as electric storage, distributed solar, demand response, energy efficiency, and electric vehicles and are typically located on the distribution system or behind a customer meter. Wholesale power markets have traditionally focused their operations and market design around the use of relatively few, large, centralized power plants to respond to changes in essentially inflexible demand at the other end of the transmission network. In contrast, DERs consist of many small resources that are often co-located with demand or may consist of controllable demand response resources.

The transition from large, centralized power plants to small, distributed resources will put new stresses on existing wholesale market designs and provide an impetus for market reforms that improve coordination between small-scale resources and the bulk grid. Wholesale market operators, called Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs),[2] allow different types of resources to participate in their markets through different participation models. These participation models include not only the ability to offer or bid price and quantity pairs, but also various precise operating characteristics and cost functions that can be modeled in the ISO's market clearing software. Although participation models are ideally technology-neutral, many DERs may not be able to participate due to limits on the minimum resource size, ability to aggregate multiple resources, and/or other technical requirements. The goal of FERC Order 2222 is therefore to reduce these barriers to entry of DER participation in ISOs by requiring that all market operators include some form of participation model that allows DER participation to the broadest extent that is technically feasible.[3]

Large scale integration of DERs in wholesale power markets raises various new research questions. Some of these questions broadly relate to software improvements, e.g., how to accurately model DER aggregations in market clearing software that was originally designed for conventional generators operating in the bulk grid. Relatedly, there is a need for new coordination schemes that will ensure that transmission and distribution system operations are managed efficiently and achieve the desired safety, reliability, and economic objectives of both systems. Lastly, DER integration will require the development of new standards for the communication, measurement, and verification of services provided by DERs.

1.1 Report Outline

The following report focuses on the impact of FERC Order 2222 on modeling and efficient coordination of newly integrated DERs by the ISOs that manage the bulk market. We broadly define two areas with significant impacts from Order 2222: first, the computational performance of ISO market clearing software, and second, the coordination mechanisms between the transmission and distribution systems. Today's ISO market clearing software was designed to

[1] FERC, "Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators," Docket No. RM18-9-000; Order No. 2222. September 17, 2021.
[2] While there are minor differences in the RTO and ISO terms defined in FERC Order 2000, the two terms ISO and RTO will be used interchangeably here.
[3] FERC, Order No. 2222. 2021. P 204.

optimize a fleet of conventional generators that has distinct characteristics compared to DER technologies, and as a result, innovative new software and algorithms are needed to harness the full potential of DERs and other emerging technologies.[1] Second, DERs are defined as being connected to the distribution system or subsystems. Distribution system operations have traditionally been under the purview of local distribution companies, retail electricity suppliers, and local and state regulators, but the growth of DER technologies has led to overlapping retail and wholesale market boundaries that will require careful coordination strategies among system operators, resource owners, energy consumers, and regulators.[2]

Each ISO has proposed slightly different terminology for DER aggregators (i.e., the market participant) and DER aggregations (i.e., the resource), shown below in **Error! Reference source not found.**. To avoid confusing or contradictory text, this report will refer simply to "DER aggregators" and "DER aggregations" rather than the ISO-specific acronyms.

Table 1.1. DER Aggregator and Aggregation Terminology

ISO	DER Aggregator	DER Aggregation
CAISO	Distributed Energy Resource Provider (DERP)	Distributed Energy Resource Aggregation (DERA)
ISO-NE	Distributed Energy Resource Aggregator (DER Aggregator)	Dispatchable Distributed Energy Resource Aggregation (DDERA) or Settlement-Only Distributed Energy Resource Aggregation (SODERA)
MISO	Distributed Energy Resource Aggregator (DERA)	Distributed Energy Aggregation Resource (DEAR)
NYISO	DER Coordination Entity (DCE)	DCE Aggregation (DCEA)
PJM	Distributed Energy Resource Aggregator (DER Aggregator)	Distributed Energy Resource Aggregation Resource (DER Aggregation Resource)
SPP	Distributed Energy Resource Aggregator (DERA)	Distributed Energy Resource Aggregation (DER Aggregation)
ERCOT	Resource Entity (RE)	Distributed Generation Resource (DGR), Distributed Energy Storage Resource (DESR), or Aggregated Generation on Resource (AGR)

[1] ARPA-E, "Grid Optimization (GO) Competition: Inspiration." Accessed 12/9/2012. Link: https://gocompetition.energy.gov/inspiration
[2] Dennis, Jeffery S., Suedeen G. Kelly, Robert R. Nordhaus, and Douglas W. Smith. "Federal/state jurisdictional split: implications for emerging electricity technologies." Energy Analysis and Environmental Impacts Division, Lawrence Berkeley National Laboratory. (2016). At 7-9.

2.0 Wholesale Electricity Market Design

General guidelines for wholesale electricity markets were developed by FERC Order 888, which established rules for open access and nondiscriminatory access to the high-voltage transmission grid.[1] The basic functions and requirements of RTOs and ISOs were subsequently established by FERC Order 2000.[2] In addition to operating the wholesale electricity markets, RTOs and ISOs also have a responsibility to maintain system reliability. Because the terms RTO and ISO are synonymous for practical purposes, the document will simply refer to ISOs although both types of organizations are implied. The following section provides background on the basic market design adopted by all ISOs. In addition to various broad summaries,[3,4] more comprehensive treatments of the topics discussed are referenced throughout the background section.

2.1 Energy Market

Energy is the key commodity traded in ISO markets. ISO markets also include various ancillary services that are necessary for maintaining system reliability, such as reserve capacity that can be quickly available after a generator or transmission line outage, frequency regulation, voltage support service, and "black start" capability to restore service after system outages. Some ISOs include capacity markets to help incentivize investment in an efficient level of generating resources that meet resource adequacy goals. ISOs also allow trading of some purely financial products so that participants can hedge against uncertainties. These financial services include virtual bidding and financial transmission rights (FTRs). The following paragraphs describe each of the above products in more detail.

2.1.1 Two-settlement system

All ISOs currently use a two-settlement system to price and schedule energy production. Two-settlement refers to the use of a day-ahead and a real-time market. The day-ahead market takes place the day before actual energy delivery. Generators submit offers to the ISO detailing their costs and production capabilities (e.g., minimum and maximum capacity). The ISO then determines a least cost production schedule for the next day's 24-hour period based on the submitted offer costs by solving an optimization problem called Security Constrained Unit Commitment (SCUC). The day-ahead market schedules generators that have notification and start-up lead times that are short enough to fit within the day ahead market's time horizon (e.g., <24 hours). Solutions from the SCUC software determine financially binding market positions for market participants as well as a production schedule that allows generators to plan their daily operations.

Generator costs that are input to SCUC are typically "price-based" (also called offer-based), meaning that the schedule is optimized according to a price curve that is offered by the

[1] FERC, "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities," Docket Nos. RM95-8-000- and RM94-7-001; Order No. 888. April 24, 1996.

[2] FERC, "Regional Transmission Organizations," Docket No. RM99-2-000; Order No. 2000. December 20, 1999.

[3] Cramton, Peter. "Electricity market design." *Oxford Review of Economic Policy* 33, no. 4 (2017).

[4] O'Neill, Richard P., Udi Helman, Paul M. Sotkiewicz, Michael H. Rothkopf, and William R. Stewart. "Regulatory evolution, market design and unit commitment." *The Next Generation of Electric Power Unit Commitment Models* (2002): 15-37.

generator. Offers can also be "cost-based," meaning that the cost inputs are computed by the ISO based on fuel price indices (e.g., cost-based offers may be used if a generator does not pass a market mitigation screen). Both price-based and cost-based offers may consist of multiple parts to reflect the unit's variable fuel costs, start-up cost, operating costs, and other operating characteristics.[1]

Day-ahead production schedules are typically calculated in 1-hour increments, and once the day-ahead market is cleared, the ISO sends a production schedule to each market participant and publishes the day-ahead prices. The prices and scheduled quantities are financially but not physically binding for each participant. For example, if a generator is unable to produce the quantity scheduled in the day-ahead market due to an unforeseen loss of capability, then it must purchase that quantity at the real-time price, which may entail a financial loss.

2.1.2 Non-convex market clearing

The day ahead market addresses a key market coordination difficulty found in electricity markets. Market-based coordination is primarily achieved by public and transparent pricing, and these prices are called "uniform" when all products at a specific time and location are bought or sold at the same price.[2] Markets also rely on "supporting" prices, meaning that the socially optimal production schedule is consistent with each market participant's individual profit maximizing schedule. Unfortunately, the production capabilities of conventional generators possess important non-convexities that almost always eliminate the possibility of finding a set of uniform prices that also support the optimal scheduled quantities.[3,4] Because of the presence of non-convexities, no uniform pricing scheme can adequately signal the efficient production and consumption quantities of participants in electricity markets. Some generators may be unprofitable given market prices even though they are part of the efficient schedule, and some may appear profitable even though they are not scheduled to produce in the market.

To help incentivize efficient participation, ISOs provide side-payments that guarantee revenue sufficiency, often called make-whole or uplift payments, which are lump-sum payments are paid to resources that offer economically into the market and follow the efficient schedule determined by the ISO.[5] These side-payments guarantee that centrally-scheduled resources will not incur financial losses for participating in the market. However, they can also distort market incentives because the payments are non-transparent and discriminatory.[6]

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[1] O'Neill, Richard P., Paul M. Sotkiewicz, Benjamin F. Hobbs, Michael H. Rothkopf, and William R. Stewart Jr. "Efficient market-clearing prices in markets with nonconvexities." *European journal of operational research* 164, no. 1 (2005): 269-285.

[2] The term "uniform" here does not preclude the use of prices (like LMPs) that vary by time and location.

[3] O'Neill, *et al*. (2005). Typical examples of non-convexities include (a) fixed costs to begin or to continue generating power that are independent of the amount of power produced, (b) minimum output levels that are positive if a generator is online, or zero otherwise, or (c) minimum up-/down-times that a generator must follow once it comes on-/off-line.

[4] Gribik, Paul R., William W. Hogan, and Susan L. Pope. "Market-clearing electricity prices and energy uplift." *Cambridge, MA* (2007): 1-46.

[5] Sauer, Will. "Staff Analysis of Uplift in RTO and ISO Markets," *Federal Energy Regulatory Commission* (2014).

[6] O'Neill, Richard P., Anya Castillo, Brent Eldridge, and Robin Broder Hytowitz. "Dual pricing algorithm in ISO markets." *IEEE Transactions on Power Systems* 32, no. 4 (2016): 3308-3310.

2.1.3 Self-scheduling and self-commitment

Some generators may prefer not to be scheduled by the ISO's centralized SCUC optimization, perhaps due to longer lead times (e.g., >24 hours) than can be efficiently modeled, fuel contract provisions, long-term contract obligations, or other various reasons.[1] To accommodate these resources, all ISOs allow generators to self-commit or self-schedule into the market. The two terms are related but not synonymous. Self-commitment occurs when the generator specifies its operating status to the market operator, but otherwise allows the market operator to economically dispatch the resource within its operating limits. For example, a self-committed unit may be forced to be online at a 50 MW minimum operating level, but it might also be available for economic dispatch up to a 100 MW maximum operating limit.

As a result of self-committing, the resource is not eligible to recoup any costs associated with its start-up decision and operating status, as those decisions were made by the resource owner rather than the ISO. Self-scheduling occurs when the resource owner specifies the precise MW value that the resource will produce. A self-scheduled resource is a pure price-taker in the market and also is not eligible for make-whole payments. Unless the resource is unable to accurately provide its costs in the ISO's offer format (e.g., due to long lead times, fuel contracts, etc.), self-commitment and self-scheduling cannot improve market efficiency and may reduce market efficiency in some cases.[2]

2.1.4 Real-time dispatch

The real-time market operates similarly to the day-ahead market except that it is both physically and financially binding. The scheduling problem is somewhat simplified compared to the day-ahead market because it typically only considers dispatch of generators that were already committed by the SCUC software in the day-ahead market (or in subsequent operator actions such as reliability unit commitment). Fast-start units, typically defined as generators that are able to start up within 10 minutes, are also typically considered for commitment during the real-time market. When commitment decisions are not considered, the ISO's market clearing software solves an analogous problem to SCUC called Security Constrained Economic Dispatch (SCED).

Each ISO has nonperformance penalties for resources that are unable to follow their dispatch signal. Each ISO has implemented 5-minute binding intervals for the real-time market, and many ISOs have adopted different look-ahead horizons for the real-time dispatch optimization, ranging from a single period model or multi-period models up to 2 hours look-ahead horizon. Because most resources in the real-time market were scheduled in the day-ahead market, they only receive payment for the difference in their actual production compared to the day-ahead schedule. The real-time market is also called an imbalance market since it settles differences from the day-ahead schedule.

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[1] Sioshansi, Ramteen, Shmuel Oren, and Richard O'Neill. "Three-part auctions versus self-commitment in day-ahead electricity markets." *Utilities Policy* 18, no. 4 (2010): 165-173.

[2] Sioshansi, *et al*. (2010). A related issue is whether self-scheduling is incentivized by bilateral contracts such as power purchase agreements (PPAs). For conventional generators, most PPAs are structured as a contract-for-differences such that that it doesn't matter if the seller physically provides the energy or purchases it on the spot market. Consequently, it is more profitable for such generators to submit economic offers rather than self-commit. Many renewable generators use a different type of agreement called a unit-contingent PPA. Unit-contingent PPAs pay for the physical output of a resource, which consequently incentivizes these resources to self-schedule.

2.1.5 Locational marginal pricing

Locational marginal prices (LMPs) are used to price energy in both the day-ahead and real-time markets. The principle behind LMPs is to set prices equal to the marginal value of energy at the time and location that it is needed. [1] These prices are calculated exactly by the shadow prices (i.e., dual variables) in the market operator's SCUC/SCED optimization software.[2] LMPs may differ among different locations in the transmission network due to congestion or physical line losses. Congestion occurs when transmission line constraints become binding, i.e., are utilized to their maximum capacity. Unlike many other commodities, electric power must flow through the transmission system according to the laws of physics. Therefore, when the transmission system is congested, system operators must dispatch more expensive units so that power flows do not exceed the limits of the constrained lines. LMPs will consequently reflect the higher cost of generation downstream from the binding constraint and lower costs upstream from the constraint.

2.2 Ancillary Services

Certain ancillary services are procured in the day-ahead and real-time markets.[3] These products include regulation, contingency reserves, and ramping reserves that set aside additional real power supply capacity, as well as other services to help ensure grid reliability.

Regulation is a service for fast-responding resources that can be used to keep the system in balance during the second-to-second fluctuations that occur between the real-time market intervals. Resources that participate in the regulation market must be able to respond quickly to the ISO's regulation signals for Automatic Generation Control (AGC). This requires expensive investment in AGC equipment, high quality telemetry, potential wear-and-tear costs, and reserving an amount of resource capacity dedicated to regulation. Due to these costs, generators can typically submit price-based offers to provide regulation service.

Other types of reserves allow the ISO to manage uncertainties over longer periods. Operating reserves[4] are required for reliability and are procured by the ISO in case the system experiences a generator contingency (i.e., unplanned outage) and must quickly restore power. Ramping reserves are a more recently developed product that have only been implemented in a few ISOs. Ramping reserves are not required for reliability purposes but help incentivize some resources to reserve some of their flexibility so that it is available to respond to uncertain output from renewable generators.

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[1] The term "marginal cost" is often used in place of "marginal value" but is not strictly accurate. LMPs can be set by any marginal resources or system constraints, including the cost of generation, benefit of consumption, cost of reserve shortfall, transmission capacity violation penalties, or any other terms that appear in the objective function of the market operator's dispatch optimization software.

[2] Scwheppe, F. C., M. C. Caraminis, R. O. Tabors, and R. E. Bohn. "Spot pricing of electricity." Kluwer Academic Press (1988).

[3] Helman, Udi, Benjamin F. Hobbs, and Richard P. O'Neill. "The design of US wholesale energy and ancillary service auction markets: Theory and practice." In *Competitive Electricity Markets*, pp. 179-243. Elsevier, 2008.

[4] Operating reserves are not defined uniformly across all ISOs in the US. See Helman, et al. (2008).

The prices for ancillary services are determined by co-optimizing ancillary services with energy in the SCUC and SCED scheduling problems.[1] Like LMPs, ancillary service prices are also set by the value of shadow prices (dual variables), specifically from the zonal requirement constraints for each ancillary service product. Co-optimization of reserves and ancillary services in SCUC and SCED ensures that dispatch instructions are efficient and consistent with the LMPs and reserve prices.[2] Unlike energy, ancillary service reserve products are often procured on a zonal basis. Other ancillary services, such as voltage support and black start capability, are procured outside of the day-ahead and real-time markets.

2.3 Financial Hedging

ISOs offer two basic products for financial hedging. The first is virtual bidding, which is used to hedge uncertainties between the day-ahead and real-time markets.[3] Virtual bidders submit a price and quantity curve to the ISO and are cleared just like any other resource in the day-ahead market. Because the virtual bid is not tied to a physical asset, the position must be offset in the real-time market. Virtual bidders may offer to buy or to sell. A virtual bid to buy in the day-ahead market means that the virtual bidder believes the real time price will be higher. For example, a virtual bidder might submit a bid to buy 1 MWh at $50 in the day-ahead market. If the day-ahead market clears at $45/MWh and the real-time market clears at $55/MWh, then the bidder would sell 1 MWh in the real-time market to earn a profit of $10.

Virtual bidding is possible because the quantity purchased (sold) in the day-ahead market must be exactly equal to the quantity sold (purchased) in the real time market, resulting in zero net energy produced or consumed. Although no energy is physically produced, the presence of virtual bidders in the day-ahead market is intended to aid price convergence, i.e., so that the clearing price of the day-ahead market will be the expected clearing price of the real-time market. There is also reasonable evidence that virtual bidding helps pre-position system resources and reduces the cost of system dispatch in expectation, given the range of uncertainties that might occur in real time.[4,5,6]

The other main hedging product available in ISOs is called a financial transmission right (FTR).[7] Whereas virtual bidding is a temporal hedge, across time, FTRs provide a geographic hedge against congestion in the transmission system. As mentioned earlier, the presence of

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[1] Ma, Xingwang, Yonghong Chen, and Jie Wan. "Midwest ISO co-optimization based real-time dispatch and pricing of energy and ancillary services." In *2009 IEEE Power & Energy Society General Meeting*, pp. 1-6. IEEE, 2009.

[2] When LMPs and reserve prices are calculated independently, they can create misaligned incentives for resources to convert their reserves into energy or energy into reserves, which results in electrical imbalance. Assuming no exercise of market power, co-optimization removes the incentives for inefficient substitution between products.

[3] Jha, Akshaya, and Frank A. Wolak. "Testing for market efficiency with transactions costs: An application to convergence bidding in wholesale electricity markets." In *Industrial Organization Seminar, Yale University*. 2013.

[4] Jha and Wolak. 2013.

[5] Kazempour, Jalal, and Benjamin F. Hobbs. "Value of flexible resources, virtual bidding, and self-scheduling in two-settlement electricity markets with wind generation—Part II: ISO models and application." *IEEE Transactions on Power Systems* 33, no. 1 (2017): 760-770.

[6] Li, Ruoyang, Alva J. Svoboda, and Shmuel S. Oren. "Efficiency impact of convergence bidding in the California electricity market." *Journal of Regulatory Economics* 48, no. 3 (2015): 245-284.

[7] Hogan, William. “Financial transmission right formulations.” JFK School of Government, Harvard Electricity Policy Group, Harvard University, http://www.ksg.harvard.edu/people/whogan, 2002.

transmission congestion creates price separation between various nodes in the transmission system. The price difference results in an overcollection of energy purchases from load compared to energy sales from generators called the congestion surplus. ISOs therefore run FTR auctions in which the market participants place bids for the right to collect some proportion of the congestion surplus. Each FTR position is defined between a source node and a sink node and typically entitles the FTR holder to the congestion surplus collected for those two nodes over a specific month.

Before entering the FTR market, FTRs are typically initially allocated as auction revenue rights (ARRs) based on the historical load and generation profiles of load serving entities (LSEs). The holder of an ARR can choose to convert their ARR into an FTR or to receive the purchase price of selling their ARR in the FTR market.[1] Ideally, FTRs allow LSEs to create a “perfect hedge” against congestion when serving load through a bilateral contract for generation at a separate network location, such that the FTR’s value offsets the price difference between the two locations.[2] However, some FTR markets are not fully effective at providing their intended benefits because many LSEs do not meaningfully participate in the FTR market and many FTR allocations are based on outdated generation and load portfolios.[3] FTR trading and virtual bidding also introduce opportunities for market manipulation, but these potential economic inefficiencies from exercise of market power can be limited by introducing mechanisms to appropriately allocate FTRs and through additional market surveillance by regulatory authorities and market monitors.[4,5]

Other financial hedging instruments are available outside of the ISO market. Power purchasing agreements (PPAs), for example, allow LSEs to hedge their supply purchases over much longer, 10- to 20-year periods. Such forward contracting not only allows market participants to better hedge risks; it has also been shown to significantly improve offer incentives in real time (spot) markets.[6,7] Production cost savings due to forward contracting have been estimated to be as large as 59%.[8] Although forward contract positions are not typically public, estimates showed that between 40-85% of energy was forward contracted in PJM and New England from 1999 to 2000. A wide range of other financial products tied to ISO price indices are also available to participants in ISO markets and are not limited by the same stakeholder processes and regulatory approvals required for products defined in ISO tariffs. However, they will not be reviewed here since because are not part of the ISO market design.

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[1] Opgrand, Jeff, Paul V. Preckel, Douglas J. Gotham, and Andrew L. Liu. "Price Formation in Auctions for Financial Transmission Rights." *The Energy Journal* 43, no. 3 (2022).
[2] London Economics International, LLC, “Review of PJM’s Auction Revenue Rights and Financial Transmission Rights.” December 2020. Accessed March 14, 2022. Link: https://www.pjm.com/-/media/committees-groups/task-forces/afmtf/postings/lei-review-of-pjm-arrs-and-ftrs-report.ashx.
[3] Opgrand, *et al*. (2022).
[4] Joskow, Paul L., and Jean Tirole. "Transmission rights and market power on electric power networks." *The Rand Journal of Economics* (2000): 450-487.
[5] Prete, Chiara Lo, Nongchao Guo, and Uday V. Shanbhag. "Virtual bidding and financial transmission rights: An equilibrium model for cross-product manipulation in electricity markets." *IEEE Transactions on Power Systems* 34, no. 2 (2018): 953-967.
[6] Hortaçsu, Ali, and Steven L. Puller. "Understanding strategic bidding in multi-unit auctions: a case study of the Texas electricity spot market." *The RAND Journal of Economics* 39, no. 1 (2008): 86-114.
[7] Bushnell, James B., Erin T. Mansur, and Celeste Saravia. "Vertical arrangements, market structure, and competition: An analysis of restructured US electricity markets." *American Economic Review* 98, no. 1 (2008): 237-66.
[8] Bushnell, Mansur, and Saravia (2008).

2.4 Capacity Market

Many ISOs run organized capacity markets to help incentivize efficient market entry and exit.[1] It is often desirable from a system planning perspective to have more generation capacity than might actually be utilized every year, i.e., additional capacity that reduces the probability of systemwide shortages.[2] Capacity markets provide an additional revenue stream to ensure that resources have incentives to invest in an economically-efficient level of capacity that meets revenue adequacy goals. Each capacity market is structured slightly differently, i.e., over different time horizons and different specific participation rules. Most resources that offer into the capacity market are generation resources, but resources such as demand response, energy efficiency programs, and now DER aggregations can also participate.

ISOs clear the capacity market by constructing a demand curve based on the forecasted system peak demand and desired reserve level. The demand curve is capped at the cost of new entry (CONE), typically based on the cost of a new combined cycle plant, to ensure that the clearing price is not higher than reasonable. Awards in the capacity market also typically come with must-offer requirements and pay-for-performance agreements to ensure that the resources are available for dispatch and commitment in the day-ahead and real time markets, especially on critical peak days. Some markets, such as PJM, also have a minimum offer price rule (MOPR) that is intended to limit price distortions due to state policies that subsidize investment in renewable capacity, although the long term viability of the MOPR is a topic of much debate.[3] Capacity markets have been traditionally designed around the physical attributes and financial arrangements for gas-fired power plants, so the continued integration of renewable technologies has raised important questions about flaws in capacity markets related to fuel neutrality and future improvements in their design.[4]

2.5 DER Integration Frameworks

The ISO market described was designed to around the scheduling needs of conventional generators connected to the high-voltage transmission grid. Because FERC Order 2222 extends this market design to allow participation of more DERs located on distribution grids, it raises various practical considerations to address overlapping and sometimes conflicting needs of the transmission and distribution systems. The rest of this section describes some of the broad frameworks that may be used to interface transmission and distribution operators with DERs, ranging from a pre-Order 2222 status quo framework and up to more advanced Distribution System Operator-based frameworks that go beyond Order 2222's requirements.

A recent Energy Systems Integration Group (ESIG) report illustrates the DER integration frameworks that industry experts currently expect to be utilized in coming years.[5] Shown in

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[1] Bushnell, James, Michaela Flagg, and Erin Mansur. "Capacity markets at a crossroads." *Energy Institute at Hass Working Paper* 278 (2017).

[2] Cramton, Peter, Axel Ockenfels, and Steven Stoft. "Capacity market fundamentals." *Economics of Energy & Environmental Policy* 2, no. 2 (2013): 27-46.

[3] *Utility Dive*. "PJM's 'focused' MOPR takes effect, boosting renewables and nuclear as FERC commissioners deadlock." Ethan Howland. Published September 30, 2021. Accessed March 14, 2022. Link: https://www.utilitydive.com/news/pjm-focused-mopr-takes-effect-ferc-capacity-market/607417/

[4] Mays, Jacob, David P. Morton, and Richard P. O'Neill. "Asymmetric risk and fuel neutrality in electricity capacity markets." *Nature Energy* 4, no. 11 (2019): 948-956.

[5] Distributed Energy Resources Task Force, "DER Integration into Wholesale Markets and Operations," Energy Systems Integration Group. January 2022. https://www.esig.energy/.

Figure 1, the report discusses the DER Aggregator Model, LSE Model, and Total DSO Model. Although Order 2222 is premised on the DER Aggregator Model, stakeholder comments in the Order 2222 proceeding emphasized that an ideal coordination framework is currently unknown and will need to be developed.[1]

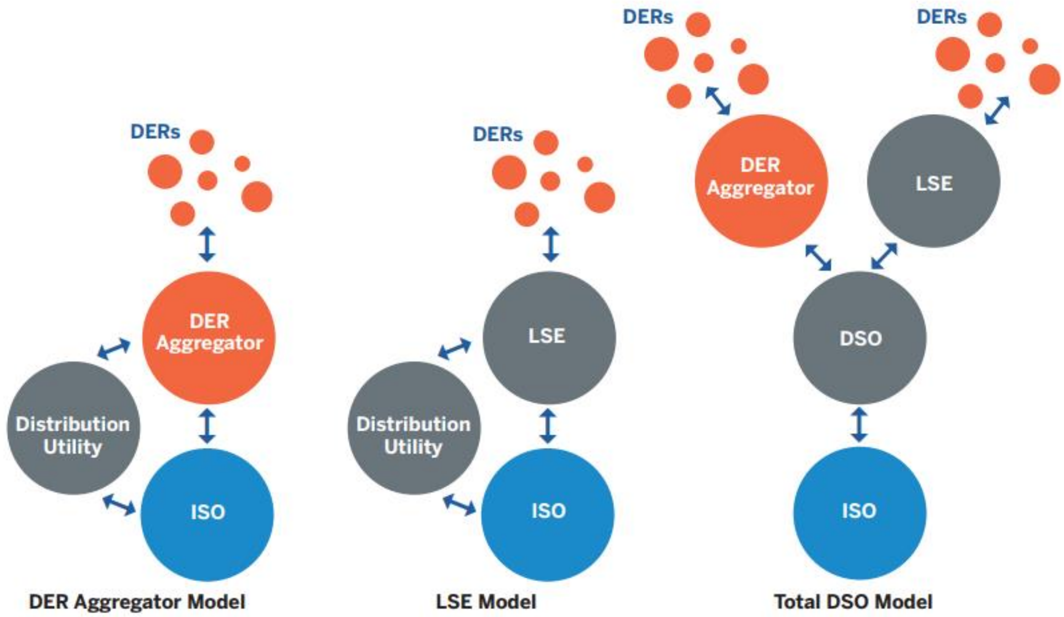

Figure 1. Three Structural Models for DER Participation in Wholesale Markets (source: ESIG)

In the DER Aggregator Model, the DER aggregator submits a single supply offer to the ISO for the DERs in its portfolio. The ISO then determines a dispatch schedule for the aggregation, and then the aggregator is tasked with scheduling its individual DERs to meet the total scheduled quantities. Because the DERs are being actively dispatched, the aggregator's DER dispatch schedule must be sent to the local distribution utility to ensure that distribution system constraints are satisfied. As will be discussed in Sections **Error! Reference source not found.** and 4.4, the DER aggregators could have difficulty in submitting accurate supply offers to the ISO due to potential scheduling conflicts with the distribution utility, or more broadly, due to their lack of awareness of distribution network conditions. For example, line switching, maintenance, storm damage, and voltage management may contribute to uncertain conditions that the DER aggregator is unable to accurately reflect in its offer to the ISO.[2]

In the LSE Model, DERs passively participate in the ISO market with the LSE acting as the intermediary.[3] Although this type of DER is not affected by FERC Order 2222, most DERs currently interact with ISO markets through the LSE model. Under this model, the DER's participation in the ISO market may depend on the specifics of retail electric tariffs that are available to the LSE's customers. Rather than participating as supply, DER participation is reflected through adjustments to the LSE's demand forecast. The LSE does not send a DER-level dispatch plan to the distribution utility for review, and consequently, there is less visibility

[1] FERC. "Order No. 2222." At P. 329.

[2] Merring, Bob, "DER Research Insights." MISO DER Task Force. March 2021. Slide 7.

[3] Distributed Energy Resources Task Force, "DER Integration into Wholesale Markets and Operations," Energy Systems Integration Group. January 2022. https://www.esig.energy/.

into the cost-efficiency of DER dispatch or possible effects on the reliability of the distribution system.

DER participation in the LSE model might be achieved through time-of-use (TOU) or real-time pricing tariffs, in which case the LSE would reflect the expected reduced energy usage in its demand bid to the ISO market. LSEs could also allow active DER participation by registering the DERs as a demand response resource or DER aggregation under the ISO tariff and submitting the aggregated bid curve of the resulting aggregation.[1] However, the LSE model usually does not optimize DER dispatch, and LSEs are typically inclined more towards status quo and high-capital cost projects due to the incentives of rate-of-return regulation. Existing retail tariffs have shown limited ability to incent efficient DER participation; a 2018 analysis concluded that the existing retail tariff designs are a significant barrier to efficient DER participation in California's wholesale energy market.[2] Static pricing, voluntary enrollment, competing retail and wholesale programs, and prohibitive technical and regulatory requirements all pose barriers to efficient DER participation in existing retail programs.[3]

The Total DSO Model would extend the distribution utility's current responsibility for maintaining safe and reliable distribution system conditions to also include facilitating a market clearing framework that interfaces between the distribution system and the bulk electric grid operated by the ISO.[4] Using a DSO to actively manage the distribution system could help ensure that aggregated DERs are able to satisfy local congestion and reliability issues while also maximizing the value that DERs provide to the transmission network.[5] Rather than contributing to uncertain distribution system conditions, line switching, maintenance, and voltage management can be scheduled and managed to maximize the value of DER dispatch and reduce operational uncertainty. Future prospects for DSOs are discussed again in Section 4.4.

A fourth alternative may be a centralized coordination scheme for the transmission and distribution systems. Such a centralized scheme would ensure that distribution connected DERs are accurately and efficiently dispatched directly by the ISO.[6] However, this option may have insurmountable information, computational, and jurisdictional barriers that prevent it from practical adoption. The ISO would need to be able to accurately monitor and control power flow throughout every connected distribution network. Data accuracy would be difficult to certify, and consequently the ISO dispatch instructions may jeopardize distribution system reliability and safety without significant monitoring from each local distribution utility. A realistic version of this option may nonetheless look similar to ESIG's DER Aggregator Model, albeit with a significant overhaul of the ISO dispatch software's modeling of its connected distribution systems. As will

[1] Widergren, S., Bhattarai, B., Pratt, R., Hanif, S., Singhal, A., Tbaileh, A., Bereta dos Reis, F., Reeve, H., 2021. DSO+T: Transactive Energy Coordination Framework. Pacific Northwest National Lab. (PNNL), Richland, WA (United States).

[2] Tansy, Tom; Ron Nelson, Kevin Moy, Suzanne Martinez. "Analysis Report of Wholesale Energy Market Participation by Distributed Energy Resources (DERs) in California." Report prepared by SunSpec Alliance for the California Energy Commission. December 2018.

[3] Haider, Rabab, David D'Achiardi, Venkatesh Venkataramanan, Anurag Srivastava, Anjan Bose, and Anuradha M. Annaswamy. "Reinventing the utility for distributed energy resources: A proposal for retail electricity markets." Advances in Applied Energy, 2021.

[4] Distributed Energy Resources Task Force, "DER Integration into Wholesale Markets and Operations," Energy Systems Integration Group. January 2022. https://www.esig.energy/.

[5] Bragin, Mikhail, Yury Dvorkin, and Atena Darvishi. "Toward coordinated transmission and distribution operations." 2018 IEEE Power & Energy Society General Meeting (PESGM). IEEE, 2018.

[6] Papavasiliou, Anthony, and Ilyes Mezghani. "Coordination schemes for the integration of transmission and distribution system operations." 2018 Power Systems Computation Conference (PSCC). IEEE, 2018.

be discussed in Section 4.2, the DER Aggregator Model may already pose a significant computational challenge for the largest ISOs, so the potential for a fully centralized DER-to-ISO system may be insurmountable.

3.0 Influence of FERC Order 745

Many DERs currently participate in retail net-energy-metering programs, but one of the key benefits of FERC Order 2222 is the access that aggregators of DERs will have to participate in the wholesale market. This opportunity may create complications from the potential dual participation in both markets and will require coordination among ISOs, distribution utilities, and local regulatory authorities. Opportunities for dual participation may look very different depending on the specific state and ISO.

Order 2222 explicitly forbids resources from receiving double payment for the same product supplied in two different markets, for example, a rooftop solar device receiving a net-energy-metering benefit as well as energy revenue from the wholesale market. DER aggregators therefore have economically significant decisions to make regarding how they will participate in either market. Retail markets may often offer more revenue to DERs than wholesale markets even though the wholesale market LMPs arguably provide the more efficient price signal. This creates misaligned incentives that may lead to market inefficiencies and poses barriers to wider DER integration.

3.1 Retail and Wholesale Incentives

Participation in the retail electricity market necessarily affects the wholesale market, just as the wholesale market also affects the retail market. Demand response programs provide a prime illustration of the complex interaction that occurs when retail load is curtailed to provide benefits in the wholesale market. Following the basic argument from Hogan,[1] incentives for efficient use of demand response can be obtained in a retail market where end-use customers are able to purchase their expected (“baseline”) consumption quantity in an energy forward market at a price F. Customers would subsequently be charged the wholesale price, λ, for deviations from their forward quantity.[2] If the customer provides demand response, they do so by selling a portion of their forward quantity back to the wholesale market. Since the forward quantity has already been purchased, the consumer’s incentive is wholly driven by the wholesale price λ; they will reduce their consumption if λ is higher than the marginal value of energy consumption or they will increase energy consumption if λ is lower than the marginal value. If the consumer provides demand response, then their net revenue from the original purchase and eventual sale of the foregone energy consumption is $\lambda - F$.

However, the above paradigm is not the status quo. FERC Order 745 requires demand response to be paid differently. Specifically, demand response is paid the LMP for each MWh of curtailment from a predetermined baseline consumption that does not need to be purchased in advance.[3] Because the demand response provider is not obligated to purchase the energy before selling the response into the wholesale market, their incentives for providing demand response are not simply a factor of λ but also involve the retail tariff rate, G, and the end user’s marginal value of energy consumption, V. Table 3.1 below shows how the incentives to dispatch

[1] Hogan, William. "Providing incentives for efficient demand response." Prepared for Electric Power Supply Association, Comments on PJM Demand Response Proposals, FERC Docket NEL09-68-000 (2009).

[2] This description is somewhat analogous to the day-ahead and real-time markets, though in this case the length of the forward period is not specified.

[3] FERC, “Demand Response Compensation in Organized Wholesale Energy Markets,” Docket No. RM10-17-000; Order No. 745. March 15, 2011. Link: https://www.ferc.gov/sites/default/files/2020-06/Order-745.pdf

demand response jointly depend on λ, the retail rate $G > 0$, and the marginal value $V > 0$. A demand response (DR) provider has incentive to inefficiently curtail load if the marginal value of energy consumption, V, is greater than λ but less than $\lambda + G$.

Table 3.1. Demand response incentives under FERC Order 745

Wholesale Price Signal	Wholesale and Retail Price Signal	DR Decision	Market Efficiency
$\lambda > V$	$\lambda + G > V$	Dispatch DR	Efficient
$\lambda > V$	$V > \lambda + G$	N/A	N/A
$V > \lambda$	$\lambda + G > V$	Dispatch DR	Inefficient
$V > \lambda$	$V > \lambda + G$	No DR	Efficient

Incentives for efficient dispatch of demand response can be restored by compensating demand response at the price $\lambda - G$, which would align the wholesale and retail incentives shown in Table 3.1. This would also restore the same incentives as the previously described framework that requires an energy forward purchase before demand response can be provided. There is a broad consensus among economists that the economically efficient price for demand response takes some form of the "LMP – G" scheme described above.[1] Although the price G was described above simply as the retail rate, its precise definition is a factor of the expected wholesale price and fixed network costs that make up the retail rate and has been subject to considerable debate in the context of efficient demand response compensation.[2,3] Paying demand response the LMP as required by FERC Order 745 therefore overcompensates these resources under current policies.

It can also be argued that load shifting, i.e., a demand response load reduction with a compensating load increase at a later time, also removes the incentive distortion described above. That is, if the total load quantity remains unchanged, then it can be argued that the consumer does not actually receive the benefit from not paying for some of its baseline consumption since the consumer eventually repurchases the curtailment quantity at the retail rate. On the other hand, "peak shaving" demand response, i.e., permanent load reductions, does not repurchase the curtailed quantity. The potential for economic distortions exists in part because these two types of demand response are treated interchangeably despite having different incentives.

To avoid market distortions caused by overcompensation, demand response resources are subject to the Net Benefits Test, which sets a price floor below which the ISO does not dispatch demand response. [4] The price threshold for the net benefits test is updated monthly and is calculated by determining the price at which the benefits to consumers become greater than the

[1] R. L. Borlick, J. Bowring, J. Bushnell, P. A. Centolella, H.-P. Chao, A. Faruqui, M. Giberson, D. Gonatas, S. Harvey, B. F. Hobbs, W. W. Hogan, J. P. Kalt, R. J. Michaels, S. S. Oren, D. B. Patton, C. Pirrong, S. L. Pope, L. E. Ruff, R. Schmalensee, R. J. Shanker, V. L. Smith, and R. D. Tabors. Brief of Robert L. Borlick, Joseph Bowring, James Bushnell, and 18 Other Leading Economists as Amici Curaie in Support of Petitioners, 2012. Link: http://www.scotusblog.com/wp-content/uploads/2015/09/2015-09-09-SCOTUS_EconomistsBriefDR.pdf

[2] Chao, Hung-po, and Mario DePillis. "Incentive effects of paying demand response in wholesale electricity markets." Journal of Regulatory Economics 43.3 (2013): 265-283.

[3] Borlick et al., (2012).

[4] FERC, Order No. 745. At P. 4.

payments to demand response providers.[1] By design, the test assesses consumer surplus rather than the total market surplus (the sum of consumer and producer surplus), so it is not capable of determining whether dispatching demand response will improve market efficiency.[2] Further, the net benefits test uses broadly aggregated metrics that may mis-identify beneficiaries due to, for example, lack of granularity and lack of information about forward contracts that may limit consumer exposure to LMPs.[3] The need for the Net Benefits Test arises because the LMP is inappropriately high compensation for demand response, and reliance on the net benefits test could likely be avoided by reforming demand response compensation methods.

The current structure of demand response programs also faces a difficulty due to the reliance on baseline data, which is unobservable and creates opportunities for manipulation.[4] The baseline issue is separate from efficient price formation with demand response, but it also poses a barrier to efficient integration of demand response and may present an opportunity to be revisited.

FERC justified Order 745's demand response requirements as a balance of policy judgements that need not strictly follow from textbook economic analysis.[5] Indeed, the market distortion may be limited given the relatively small amount of demand response that currently participates in the market, and the overcompensation may help spur development of new demand-side resources that may be needed in the longer term. Order 2222 makes no modifications to the Order 745's requirements, so potential issues surrounding dual retail and wholesale market participation may also be revisited once demand response occupies a larger share of both markets.

3.2 Joint Requirements of Orders 745 and 2222

Heterogeneous DER aggregations that include demand response must be able to satisfy requirements from both Order 745 and Order 2222. The combination of these two orders will affect how the net benefits test, metering requirements, and eligibility for dual wholesale and retail participation are implemented. As will be described below, this creates possible distortions to efficient market participation and additional compliance hurdles for aggregations that combine demand response with other types of DERs.

ISOs have taken different approaches to satisfying the net benefits test for DER aggregations that include demand response along with other types of DERs. CAISO requires that any aggregation that includes demand response must make their entire offer above the net benefits test threshold.[6] This requirement encourages demand response assets to participate under the ISO's dedicated demand response participation models and could therefore limit the economic

[1] Das, Chhandita, "Net Benefit Test Methodology – FERC Order 745," Market Information Working Group, New York ISO. December 2019. Link: https://www.nyiso.com/documents/20142/3832196/745_Methodology_MIWG_NYISO.pdf/
[2] Hogan. (2009).
[3] Ott, Andrew, "Statement of Andrew L. Ott," Panel discussion at the Commission's Technical Conference, Demand Compensation in Organized Wholesale Energy Markets. Federal Energy Regulatory Commission. Docket No. RM10-17-000. September 13, 2010.
[4] Hogan. (2009).
[5] FERC, Order No. 745. At P. 46.
[6] CAISO, "California Independent System Operator Corporation Response to Letter Requesting Additional Information," Docket No. ER21-2455-000. Filed 11/1/2021. At 6-8.

viability of heterogeneous aggregations that pool more diverse sets of resources. ERCOT is not required to implement the net benefits test and does not require separate metering of demand response. All other FERC-jurisdictional ISOs (NYISO, PJM, MISO, ISO-NE, and SPP) have proposed a different approach by requiring demand response to be measured separately from other resources in a DER aggregation.[1,2,3,4,5] Because separate data for demand response, the ISO can apply the net benefits test threshold to the portion of a DER aggregation that provides demand reduction service, and other DERs in the aggregation can be compensated below the net benefits test threshold.[6,7] There is a small potential that additional metering requirements to separate demand response from other aggregate DERs could lead to higher integration costs for DER aggregators. This potential seems small, however, since some amount of individual DER metering will anyway be required in order to calculate the DER aggregation's total output.

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[1] NYISO, "Compliance Filing and Request for Flexible Effective Date," Docket No. ER21-2460-000. Filed 7/19/2021. At 10.

[2] ISO-NE, "Motion for leave to answer and further answer of ISO New England, Inc." Docket No. ER22-983-000. Filed 7/25/2022. At 4-7.

[3] PJM, "Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C." Docket No. ER22-962-000. Filed 4/26/2022. At 21.

[4] MISO, "Order 2222 Compliance Filing," Docket No. ER22-1640. Filed 4/14/2022. At 39.

[5] SPP, "Compliance Filing of Southwest Power Pool, Inc." Docket No. ER22-1697-000. Filed 4/28/2022. At 24.

[6] ISO-NE, "Revisions to ISO New England Inc. Transmission, Markets and Services Tariff to Allow for the Participation of Distributed Energy Resource Aggregations in New England Markets," Docket No. ER22-983-000. Filed 2/2/2022. At 17.

[7] MISO, "Prepared Direct Testimony of Laura Rauch," Docket No. ER22-1640-000. Filed 4/14/2022. At 50.

4.0 Order 2222 Implementation

Having discussed relevant background to Order 2222 in the previous sections, the following discussion explores key issues that will affect the implementation of new participation models for DER aggregations. We first discuss rules for market eligibility in relation to Order 745 requirements and the prohibition on dual participation in retail and wholesale markets. The section next discusses how ISOs are planning to address needed improvements and modifications to the market clearing software, followed by telemetry and metering requirements. Lastly, we discuss coordination between the transmission and distribution systems. Key research questions are summarized at the end of each section.

4.1 Market Eligibility

While one of the motivating goals of Order 2222 is to open wholesale markets to DERs, it is not yet fully clear how widespread wholesale participation will be for DERs that already participate in retail markets through programs like net energy metering. The Order broadly prohibits resources from receiving compensation for providing the same service in both wholesale and retail markets, but specific instances of permitted or prohibited participation are typically left to be determined by non-ISO entities (e.g., host utilities and state or local regulatory authorities) during resource registration processes.

The obvious example of prohibited dual participation would be for DERs in net energy metering programs that would like to register in wholesale energy markets. For example, aggregated rooftop solar power may be worth more when sold at retail tariff rates. On the other hand, storage devices and flexible loads that are able to respond to real time price signals may be more valuable in the wholesale market, where they may be more profitable by providing regulation, reserves, or participating in price arbitrage. Aggregations that combine multiple types of DERs will need to consider how to maximize their revenue from retail and wholesale markets while being careful to avoid double counting.

CAISO has adopted a conservative stance towards potential double counting; while CAISO does not ban all participation from DERs participating in net energy metering programs, it requires that the net energy metering programs expressly allow wholesale market participation.[1] In practice, this requirement may be a de facto ban against wholesale participation from DERs in net energy metering programs. CAISO justifies this position, however, by asserting that retail tariff rates in California are significantly more lucrative than average CAISO prices that their dual participation restrictions will not pose a major influence on decisions of DER aggregators.[2] In later responses to protests in CAISO's Order 2222 docket, CAISO clarified that other various retail programs, such as for deferred distribution upgrades or standby microgrid service, are not comparable to any products offered by the ISO and would hypothetically be eligible for dual participation.[3]

Most of the other ISOs have adopted similar tariff language as CAISO in regard to prohibiting double counting of the service in the retail and wholesale market yet leaving specific permissible

[1] CAISO, "Tariff Amendment to Comply with Order 2222," Docket No. ER21-2455-000. Filed 7/19/2021. At 23.

[2] CAISO, "Tariff Amendment to Comply with Order 2222," Docket No. ER21-2455-000. Filed 7/19/2021. At 2-3.

[3] CAISO, "Answer to Comments," California Independent System Operator Corporation, Docket No. ER21-2455-000. Filed 9/3/2021. Page 12.

or prohibited instances open to a case-by-case analysis.[1,2,3,4] While this approach could create ambiguity in terms of what types of dual participation will be permitted, the purported benefit is that the lack of specificity will allow greater flexibility while retail tariffs for DERs begin to take shape. Like the other ISOs, PJM also did not commit to a strict permissible/prohibited dual participation policy, but the ISO did provide an example that DERs participating in net energy metering would be prohibited from providing capacity but would be able to provide ancillary services.[5] Most ISOs with capacity markets will likely have a similar prohibition because providing an ISO capacity product typically entails a must offer obligation in the ISO's energy market. Since a DER cannot provide retail net energy metering while also offering into the wholesale energy market, then it cannot participate in the ISO's capacity market even though the capacity product is not provided to the retail market.

The ability to diversify revenue streams may be one of the major advantages of participation in ISO markets, especially if additional retail-level revenue streams remain open to DER aggregators. That is, the combination of energy, ancillary services, capacity products may offer key advantages over the typically fixed tariff rates available through net energy metering. This may be a steep barrier, however, due to the typically higher rates available through retail net energy metering programs.[6]

Capacity market participation could offer unique benefits for DER owners. Whereas retail net energy metering will often be the most profitable decision for DERs like rooftop solar that produce energy throughout the year, capacity payments may be more sensible for demand response programs that are only expected to curtail load a few times per year. Of course, every ISO already allowed participation from demand response aggregations before Order 2222, so the question becomes whether aggregating demand response with a heterogeneous portfolio of storage and generation resources will be more economically valuable than separate participation of homogeneous aggregations of each resource type. This value proposition could be plausible, for example, for homogeneous DER aggregations that currently cannot participate in ISO markets or for heterogenous DER aggregations that otherwise would be unable to meet Order 2222's 100 kW participation threshold as separate homogeneous aggregations.

DERs are eligible for capacity market participation in the three ISOs with capacity markets (NYISO, ISO-NE, and PJM) [7,8,9] and in MISO's voluntary Planning Resource Auction.[10] DER aggregations are not eligible to provide Resource Adequacy capacity in CAISO.[11] Resources that provide capacity in MYISO, ISO-NE, PJM, or MISO are required to offer into the day ahead market and therefore cannot simultaneously participate in net energy metering. Further, the

[1] NYISO, "Compliance Filing…," Filed 7/19/2021. At 39-41.
[2] MISO, "Order 2222 Compliance Filing," Docket No. ER22-1640. Filed 4/14/2022. At 7-8.
[3] ISO-NE, "Revisions to…," Docket No. ER22-983-000. Filed 2/2/2022. At 29-30.
[4] SPP, "Compliance Filing of Southwest Power Pool, Inc." Docket No. ER22-1697-000. Filed 4/28/2022. At 10.
[5] PJM, "Order No. 2222 Compliance Filing of PJM Interconnection, L.L.C. Motion for Extended Comment Period," Docket No. ER22-962-000. Filed 2/1/2022. At 29.
[6] CAISO, "Tariff Amendment to Comply with Order 2222," Docket No. ER21-2455-000. Filed 7/19/2021. At 2-3.
[7] NYISO, "Compliance Filing…," Filed 7/19/2021. At 19-21.
[8] ISO-NE, "Revisions to…," Docket No. ER22-983-000. Filed 2/2/2022. At 20-24.
[9] PJM, "Order No. 2222…," Docket No. ER22-962-000. Filed 2/1/2022. At 34.
[10] MISO, "Order 2222…," Docket No. ER22-1640. Filed 4/14/2022 . At 12.
[11] CAISO, "Answer to Comments." Page 4.

must offer requirements typically apply to the entire planning year, so aggregators would not be able to change their retail or wholesale participation decisions on a day-to-day basis. Some markets, such as MISO, are exploring seasonal capacity constructs,[1] however, which may improve the ability of aggregators to change their participation decisions on a more timely basis.

Along similar lines as demand response compensation under FERC Order 745, the wider range of DER revenue streams opened by Order 2222 may raise similar issues for distorted incentives for wholesale and retail market participation. The availability of energy withdrawal service in DER aggregation participation models could be a useful corrective to the distorted incentives for traditional demand response. However, it isn't clear why a demand response resource would pursue wholesale market participation through energy withdrawal when the incentive distortion is in favor of more demand response.

New opportunities for misaligned incentives and double-counting may not always be clear cut. Some retail markets may include peak demand charges that are based on either a consumer's highest usage or their usage at the time of the system peak. If a DER aggregation reduces a customer's peak demand charge as a result of fulfilling its capacity obligation, then there is arguably a double payment for the same service in the wholesale and retail markets. The distinction may rely on detailed aspects of how the capacity credits and demand charges are defined, which may contribute regulatory uncertainty into a DERs potential revenue streams. To avoid this, suitable engineering-based methods may need to be established to quantify cross-subsidies between wholesale and retail markets and made available for the benefit of policy makers.

Reserves and regulation are not typically procured in retail markets, so there is less concern about wholesale and retail market interaction. Nonetheless, procurement of ISO-like products by distribution utilities could become more common in the future, as plans are already underway to develop more sophisticated distribution system management schemes such as DSOs.[2] Additional incentive and double payment issues may arise if future DSO market designs include procurement of reserve type products.

State policies like net energy metering may often determine whether DERs are more profitable in the retail or wholesale market. This is especially true for rooftop solar, which can receive much higher prices through the net energy metering programs than through wholesale markets. As mentioned in the beginning of this section, other resources like storage and flexible loads may be more profitable by providing regulation, reserves, or participating in price arbitrage in the wholesale market. To help improve efficient DER integration, detailed studies using well-established engineering methods should be performed to analyze DER investment and operation under various policies, especially to compare the effects of economically efficient wholesale and retail energy tariffs to existing policies.

The following research questions will help address uncertain eligibility of DERs for various forms of market participation:

[1] MISO, "Resource Availability and Need (RAN) – Resource Accreditation," RASC-2019-2. Link: https://www.misoenergy.org/stakeholder-engagement/MISO-Dashboard/resource-availability-and-need-ran-seasonal-resource-adequacy/

[2] Consolidated Edison, "Distributed System Implementation Plan." June 30, 2020. Link: https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/distributed-system-implementation-plan.pdf

- How do the requirements of FERC Order 745 (e.g., demand response payment at LMP and the net benefits test) affect the investment decisions and offer strategies of DER aggregations that are made possible by FERC Order 2222?
- Given federal requirements for resource compensation in wholesale markets, how should retail electricity tariffs be designed to foster efficient operation and investment in DERs? Are those requirements consistent with implementing a TES?
- What methods should be used to identify prohibited double-counting in wholesale and retail electricity markets? How should TES be designed to prevent double-counting while facilitating efficient dual participation in retail and wholesale markets?
- What is the relative value of DERs in wholesale versus retail markets under existing retail and wholesale tariffs? How does this compare to socially optimal DER utilization?
- What relative value do DERs provide to the wholesale and retail markets under current tariffs and coordination schemes? How does this compare to their theoretically ideal utilization?

4.2 Market Clearing Software

4.2.1 Solution speed

Large scale integration of DERs poses an additional computational hurdle to the production scheduling and market clearing software used by ISOs. Day-ahead security constrained unit commitment (SCUC) software solves a mixed-integer optimization problem, which has attracted a significant amount of research and development funding due to its mathematical difficulty and economic significance.[1,2] The problem's difficulty comes from the requirement that most power generating resources must be discretely constrained on or off. For example, many power plants: 1) are not capable of producing power below a minimum threshold level unless they are completely off, 2) require a minimum up-time or down-time after a start-up or shut-down, and/or 3) incur fixed costs upon start-up or shut-down. ISO market clearing software is based on finding optimal solutions to the SCUC problem.

It is not clear if multi-part offers for fixed start-up and operating costs are needed in DER aggregation participation models or, relatedly, how DER aggregations should be represented in SCUC.[3] The day ahead SCUC problem is a difficult optimization problem, and due to the tight time constraints that ISOs must operate their markets, it is often only possible to solve the day ahead SCUC problem within a small tolerance (e.g., < 0.1%) of optimality.[4] Because of this tolerance, the SCUC software may completely neglect optimizing the production schedules of

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[1] ARPA-E, "Grid Optimization (GO) Competition: Inspiration." Accessed 12/9/2012. Link: https://gocompetition.energy.gov/inspiration

[2] Carlson, Brian, Yonghong Chen, Mingguo Hong, Roy Jones, Kevin Larson, Xingwang Ma, Peter Nieuwesteeg et al. "MISO unlocks billions in savings through the application of operations research for energy and ancillary services markets." *Interfaces* 42.1 (2012): 58-73.

[3] "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. At pages 4-2.

[4] Chen, Yonghong, *Aaron Casto, Fengyu Wang, Qianfan Wang, Xing Wang, and Jie Wan*. "Improving large scale day-ahead security constrained unit commitment performance." *IEEE Transactions on Power Systems* 31.6 (2016): 4732-4743.

DER aggregations that have a smaller economic value than the size of the optimality gap.[1] These inefficiencies can be ameliorated by lowering the optimality tolerance or by performing post-solution analysis, but such solutions may risk overshooting deadlines for posting market information and potential settlement disputes if some inefficiencies are missed.[2] MISO staff has performed analysis that concluded that optimizing the commitment of DER aggregations has little value, as many are already committed to meet needs in the retail market (see Section 0) and would anyway be able to approximate their commitment costs, if any, as a variable cost in their dispatch offer.[3] Hence, there may be a large computational cost and little value to adding binary variables for DER aggregations into ISO unit commitment software, although further research is necessary to confirm this presumption.

In accord with MISO's assumptions mentioned above, the overwhelming majority of literature on DER scheduling assumes convex offer curves made of simple price-quantity pairs.[4] Future studies could investigate what conditions might lead DERs to submit fixed costs in their offers, for example, if there are particular DER resource types or contractual arrangements with significantly different cost structure than typical DER aggregations. Aggregators could offer contracts that limit the total number of times that each end-use customer's devices will be called to provide grid services, in which case the aggregator would have an opportunity cost associated with initiating its service. To the extent that such resources or contractual arrangements exist, simulation studies to assess the economic impacts of DER aggregation self-scheduling may also be needed.

Many DER aggregations could choose to forego centralized dispatch altogether by always self-scheduling their output. ISO-NE and ERCOT have both proposed specific "settlement-only" resource models to accommodate this type of participation.[5],[6] This type of participation adds no practical computational burden to SCUC software. Given the generally small and convex attributes of DER aggregations, this participation model could possibly result in similarly efficient production schedules compared to centrally-dispatched participation if the resources are able to correctly anticipate and respond to efficient pricing signals. Further research may be able to better quantify possible trade-offs between economic and computational efficiency that may result from increased participation in settlement-only DER aggregation models.

Adding large numbers of small variables to the SCUC model is known to create software performance issues. For example, software performance can be affected even when bids do not include a non-convex commitment cost function, which has been observed with large numbers of virtual transactions in the MISO day-ahead SCUC software.[7] NYISO has proposed the creation of DER "Super Aggregations" to help reduce the number of continuous variables in the market software, where each Super Aggregation consists of any DER aggregations that are

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[1] Merring, Bob (2021). Slide 4.
[2] Merring, Bob (2021). Slide 11.
[3] Merring, Bob (2021). Slide 12.
[4] Nosratabadi, Seyyed Mostafa, Rahmat-Allah Hooshmand, and Eskandar Gholipour. "A comprehensive review on microgrid and virtual power plant concepts employed for distributed energy resources scheduling in power systems." Renewable and Sustainable Energy Reviews 67 (2017): 341-363.
[5] Yoshimura, Henry, Hanhan Hammer, Doug Smith, and Matt Gdula, "Order No. 2222: Participations of Distributed Energy Resource Aggregations in Wholesale Markets. Revised market design approach to comply with Order No. 2222," NEPOOL Markets Committee Webex. July 8, 2021. At 14-27
[6] ERCOT, "Distributed Generation (DG) in ERCOT," Link: https://www.ercot.com/files/docs/2021/11/02/DG_and_DR_in_ERCOT_2021.pdf
[7] Chen, Yonghong, *et al*. (2016).

unable to provide ancillary services and are located at the same transmission bus.[1] However, it is not clear how often the Super Aggregation construct might be used in NYISO or how effective it is in reducing computational burdens. Future research into additional model variable reduction approaches may be necessary to reduce the computational burden of large numbers of DER aggregations.

Many ISOs have taken different approaches to handling the unit commitment of small DER aggregations. MISO and PJM generally face the most difficult computational bottlenecks and have proposed requiring that DERs be self-committed or self-scheduled. In other ISOs, the handling of DER aggregations in unit commitment is mixed, with CAISO and NYISO proposing self-commitment-based participation models and ISO-NE, SPP, ERCOT proposing technology-neutral participation models that allow the submission of commitment-related costs. Each ISO's approach is summarized in Table 4.1.

Table 4.1.DER Aggregation Representation in Unit Commitment

ISO	ISO Commitment	ISO Dispatch	Economic Offer	Description
CAISO	No	Yes	Offer-based	DER aggregations are eligible for economic dispatch in day-ahead and real-time markets but cannot submit commitment costs.[2]
ISO-NE	Yes	Yes	Offer-based	ISO-NE's existing DRR model and proposed DRDERA model both allow resources to submit minimum deviation time and minimum time between deviations for the ISO's commitment and dispatch software. Commitment-related offers are also allowed under the ISO's GEN, CSF, and BSF participation options. DER aggregations using the SODERA model may submit offers in the day-ahead markets but must be self-scheduled in the real time market.[3]
MISO	No	Yes	Offer-based	All DER aggregations in MISO must be self-committed or self-scheduled. Commitment status options are identical to MISO's ESR model, including inject, withdraw, and continuous options to designate an online status.[4]
NYISO	No	Yes	Offer-based	DER aggregations are eligible for economic dispatch in day-ahead and real-time markets but cannot submit commitment costs.[5]
PJM	No	Yes	Cost-based	DER aggregations in PJM must be self-committed or self-scheduled. DER aggregations that offer a dispatchable range with non-zero cost must have an approved Fuel Cost Policy filed with PJM.[6]
SPP	Yes	Yes	Offer-based	DER aggregations may register as any Resource type of which it can meet the technical and operational

[1] NYISO, "Distributed Energy Resources Roadmap for New York's Wholesale Electricity Markets." January, 2016. Link : https://www.nyiso.com/distributed-energy-resources-der-
[2] CAISO, "Tariff Amendment…," July 19, 2021. §30.5.2.6.
[3] ISO-NE, "Revisions to…" At 12-18.
[4] MISO, "Order No. 2222…" At 52-63.
[5] NYISO, "Compliance Filing…" At 16-17.
[6] PJM, "Order No. 2222…" Filed 2/1/2022. At 35-36.

ISO	ISO Commitment	ISO Dispatch	Economic Offer	Description
				requirements. Because DER aggregations are not limited to a specific participation model, they are eligible to use the same offer parameters as other resources.[1]
ERCOT*	Yes	Yes	Offer-based	DGRs and DESRs are modeled according to ERCOT's Generation Resource model, which allows resources to submit three-part offers.[2,3]
* ERCOT is not required to satisfy FERC Order 2222 requirements.				

Regulatory requirements may limit the ability of self-scheduling based approaches in alleviating the computational burdens impose by small resources. Recall that the distinction between self-scheduling and self-commitment is that the former allows the resource to submit the precise quantity it will produce, while self-commitment only specifies the operating status of the resource. As a result, self-scheduled resources are insensitive to price and would be unable to guarantee that their dispatch is consistent with the net benefits test required by FERC Order 745. Likewise, any DERs that are aggregated with demand response may become de facto subject to the net benefits test price floor since all resources within a single aggregation must submit a single offer.

Heterogeneous DER aggregations may be able to avoid some of the restrictions placed by Order 745 by metering demand response separately from other types of DERs. For example, ISO-NE is proposing to compensate energy injection or withdrawal from DRDERAs at the LMP, even if the DRDERA is not dispatched by the ISO.[4] Because the different DER types can be metered separately, settling the dispatch of non-demand response DERs at the LMP arguably does not implicate Order 745. However, it creates a potential that DER aggregations may offer above the net benefits test threshold (because they include demand response) and subsequently dispatch their non-demand response assets in the real time market at a price below the net benefits test threshold. Assuming the non-demand response assets are dispatched optimally, the net benefits test may pose an obstacle to efficient price formation in the day ahead market and may create expensive imbalances in the real time market.

SPP's compliance framework allows most DER aggregations to register under the standard generator resource participation model, which will be expanded to comply with FERC Order 2222. Aggregations would therefore have the option to submit the full range of offer parameters including start-up and fixed operating costs. Aggregations that include storage could also participate as Market Storage Resources (MSRs) that would also enable charging status to be committed by the ISO. Homogeneous Aggregations also have the option to register as Dispatchable Demand Response (DDR), Block Demand Response (BDR), Multi-configuration Combined-cycle Resource (MCR), or Dispatchable Variable Energy Resource (DVER).[5]

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[1] SPP, "Compliance Filing …" At 11.

[2] ERCOT, "Clarify Requirements for Distribution Generation Resources (DGRs) and Distribution Energy Storage resources (DESRs)," Nodal Protocols Revision Request (NPRR) 1016, TAC Report. July 19, 2020.

[3] ERCOT. "ERCOT Concept Paper on Distributed Energy Resources in the ERCOT Region," Distributed Resource Energy & Ancillaries Market (DREAM) Task Force. August 19, 2015. At 43.

[4] ISO-NE, "Revisions to…" At 17.

[5] SPP, "DERA Registration Flow, Tariff and Market Model," Order 2222 Task Force Meeting Materials. June 30, 2021. Link: https://spp.org/spp-documents-filings/?id=253998

The following research questions may help guide the range of options that ISOs for how DER aggregations are represented in unit commitment and dispatch:

- What aspects of complex, multi-part offers are necessary for aggregators to accurately express the costs of possibly heterogeneous DER technologies (e.g., demand response, storage)?
- What optimization algorithms or routines might ISOs develop to improve the commitment and dispatch logic of large numbers of small DER aggregations?
- What is the impact of centralized commitment and self-commitment on DER profitability and market efficiency?

4.2.2 Oscillatory dispatch and pricing

FERC Order 2222 requires ISOs to establish locational requirements for DER aggregations that are "as geographically broad as technically feasible."[1] Allowing DER aggregations across multiple transmission nodes may lower barriers to entry and improve market operations in a few ways. For example, wider geographic aggregation would allow more resources in a single aggregation and may reduce uncertainty by pooling a more diverse set of resources.

However, the consideration of what is technically feasible will differ between different ISOs, and in most cases will have more to do with avoiding undesirable operating conditions. The dispatch quantities of multi-nodal DER aggregations are modeled using distribution factors, a set of nonnegative numbers that sum to one and specify what proportion of the aggregation is located at each transmission node.[2] As recognized in Order 2222, static distribution factors may be inherently incapable of modeling how multi-nodal DER aggregations contribute to power flow in the transmission system.[3] Aggregations of solar or other forecast-dependent resources may have significant difficulty in formulating distribution factors to a high degree of accuracy.[4]

These issues have been extensively studied in the MISO system.[5] In principle, distribution factors could be continually updated to ensure accuracy with the physical output of the devices in the aggregation, but it is not clear that this solution will always work as intended. In fact, studies have shown that continual distribution factor updates can result in power flow and pricing oscillations where the current market software may alternate between uneconomic and infeasible solutions.[6] The deviation creates an energy imbalance that must be compensated by other resources, and subsequently compensating the energy imbalance results in new market prices that might incentivize another deviation in the actual DER dispatch quantities. If this process is left unchecked, it can contribute to additional production costs due to unnecessary dispatch oscillations and result in price fluctuations that do not adequately signal efficient market behavior.[7]

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[1] FERC, "Order No. 2222…" P. 204.
[2] FERC, "Order No. 2222…" P.208.
[3] FERC, "Order No. 2222…" P. 211-224.
[4] EPRI (2021). At 4-3.
[5] Lei Wu, Yikui Liu, Yafei Yang, and Yonghong Chen, "Future Resource Studies in the MISO System," September 6, 2020.
[6] Kunyu Zuo, Yikui Liu, Jiarong Xia, Yafei Yang, Lei Wu, Yonghong Chen, "Impact of Distributed Energy Resource Integration on Real-time Energy Market Oscillation," IEEE PES General Meeting, 2021.
[7] Liu, Yikui, and Lei Wu. "Integrating Distributed Energy Resources into the Independent System Operators' Energy Market: a Review." Current Sustainable/Renewable Energy Reports (2021): 1-9.

Distribution factors also lack the ability to reflect changes due to distribution system operations and uncertain DER response. According to MISO's discussions with distribution system operators and DER aggregators, many distribution system operations (e.g., line switching, maintenance, storm damage, and voltage management) can create a substantial amount of uncertainty in achievable DER response. Similarly, they concluded that individual DER response is also uncertain and requires aggregators to over-commit and rotate resource commitments. Hence, the aggregated output at any single location may change dynamically, and there is currently no framework to dynamically adjust distribution factors to compensate for these uncertainties.[1]

Economic signals may currently be inadequate to disincentivize deviations and inaccuracies in the dispatch quantities of DER aggregations. All ISOs include some form of uninstructed deviation penalty that penalizes resources that do not follow ISO dispatch signals, but these penalty provisions include specific thresholds so that small deviations are not penalized. For example, SPP's threshold is its "Operating Tolerance" and is set at 5% of the resource's maximum emergency capacity, down to a minimum of 5 MW or a maximum of 20 MW.[2] Since many ISOs may set minimum thresholds that are larger than the size of typical DER aggregations, it is possible that DER aggregations would effectively not be required to follow ISO dispatch instructions. Therefore, a key research priority should consider whether or how ISO price signals can ensure accurate and stable dispatch from DER aggregations.

The use of distribution factors can be avoided by only allowing DER aggregations between nodes with similar impacts on the transmission system. MISO investigated the use of this aggregation scheme under various similarity thresholds, e.g., a maximum shift factor[3] difference of 0.01. The aggregation scheme is particularly useful for reducing the number of resources modeled in the SCUC software, and consequently large reductions in solution time. However, the study results also showed that these similarity thresholds could still result in unacceptably large power flow deviations exceeding 40 MW, 70 MW, and 100 MW, respectively, for shift factor similarity thresholds of 0.01, 0.02, and 0.03.[4] The possibility of large approximation errors was a major factor in MISO's decision to restrict DER aggregations to a single node.[5]

In contrast to MISO's studies, CAISO allows DERs to aggregate within any one of its 23 sub load aggregation point (sub-LAP) zones, shown in **Error! Reference source not found.**. CAISO's sub-LAP zones are designed by grouping nodes together that have similar sensitivities to power flows on typically congested transmission paths, and these zones are also used for demand response aggregations.[6] In 2016, CAISO was the first ISO to implement a DER aggregation model and has integrated over 2,200 MW of distributed resources in its wholesale markets without facing major operational issues.[7] ISO-NE has similarly proposed to allow DER

[1] Merring, Bob (2021). Slide 7.

[2] SPP, "Open Access Transmission Tariff," Sixth Revised Volume No. 1, Attachment AE. At §6.4.1.2.

[3] Shift factors express the proportion of power that will flow across a specified transmission line per unit of power injected at a particular electrical bus. Here, a maximum shift factor difference of 0.01 would mean that power injections at any of the aggregated busses have the same effect on all transmission lines up to a tolerance of 1%.

[4] Wu, *et al*., 2020.

[5] MISO, "Order 2222 Market Model Review, Requirements for Aggregation," IR070, April 12, 2021. Slide 7.

[6] CAISO, "Tariff Amendment…" July 19, 2021. At 17.

[7] CAISO, "Tariff Amendment…" July 19, 2021. At 1-2.

aggregations across multiple nodes in the same DRR Aggregation Zone.[1] Hence, concerns about dispatch inaccuracies could be more of a theoretical concern than a practical one, or the weight of the concern may be heavily dependent on regional topology and DER penetration levels. The current and proposed locational DER aggregation requirements for each of the seven ISOs in the US are provided in Table 4.2.

Figure 2. Sub-LAP Zones in CAISO

Table 4.2. ISO Locational Requirements for DER Aggregations

ISO	Zonal/Nodal	Description
CAISO	Zonal	Multi-node aggregations are allowed within any one of CAISO's 23 sub-LAP zones.[2] The same sub-LAP aggregation policy applies to demand response and DER aggregations.
ISO-NE	Zonal	DER aggregations may register under various resource types. Generator Assets (GEN), Continuous Storage Facilities (CSF), Binary Storage Facilities (BSF), Settlement Only Distributed Energy Resource Aggregations (SODERAs), or Demand Response Distributed Energy Resource Aggregation (DRDERAs) can be aggregated if they are in the same DRR Aggregation Zone and metering domain. Alternative Technology Regulation Resources

[1] ISO-NE, "Revisions to…" At 25-27.
[2] CAISO, "Tariff Amendment…" July 19, 2021. At 17.

ISO	Zonal/Nodal	Description
		(ATRRs) and Demand Response Resources (DRRs) can be aggregated within the same DRR Aggregation Zone but do not need to be in the same metering domain. Groups of DERs that can inject ≥ 5 MW at a single transmission node are not eligible to be included in multi-node aggregations.[1]
MISO	Nodal	DEARs can only aggregate within a single node. Multi-node DER aggregations that are 1 MW or more can instead register as DRR-I type resources.[2]
NYISO	Nodal	DERs in an aggregation must be located at the same transmission node.[3]
PJM	Nodal	In the energy market, DERs may be located at separate nodes if they map to the same pricing node.[4] DER aggregations can be aggregated by zonal/sub-zonal LDA for participation in the capacity market and by EDC/TO zone level to determine performance payments for ancillary services.[5]
SPP	Nodal	DER aggregations must be located at the same physical and electrically equivalent injection point in the transmission system.[6]
ERCOT*	Nodal	Distributed Generation Resources (DGRs) and Distributed Energy Storage Resources (DESRs) must be connected to a single bus in the Network Operations Model.[7]

* ERCOT is not required to satisfy FERC Order 2222 requirements.

There is a substantial need for research into the efficient and reliable operation of multi-node DER aggregations. An EPRI review of FERC Order 2222 underlines the need to develop proven engineering methods for determining and validating multi-node aggregation schemes and to evaluate the potential impact of multi-node aggregation policies on incentives to form DER aggregations.[8] Models of the high-voltage transmission system simplify and blur the distinctions between electrical locations in distribution networks. Although distribution networks are often idealized as radial networks that connect to a single transmission node, some distribution networks have meshed structure and/or may connect to multiple transmission substations. PJM's proposed DER aggregation model recognizes this complication and hence models the distribution of an aggregation's output across multiple transmission nodes (provided that all DERs in the aggregation primarily map to the same pricing node[9]), even though multi-nodal aggregations are not allowed.[10] NYISO has likewise identified the need to coordinate with distribution utilities to define sensible mappings between locations in the distribution and transmission system, in effect prohibiting DER aggregations across distribution nodes that may

[1] ISO-NE, "Revisions to…" At 24-27.
[2] MISO, "FERC Order 2222 Filing Framework," Iteration 2, IR070. August 2, 2021. Slides 42 and 42.
[3] NYISO, "Compliance Filing…" July 19, 2021. Pages 25-27.
[4] PJM, "Order 2222 Design Full Proposal," DIRS. November 2021. Slides 29-45. We keep the nodal requirement designation here due to the single pricing node requirement.
[5] PJM, "Order 2222…" November 2021. Slides 64-68.
[6] SPP, "Compliance Filing…" Page 17.
[7] ERCOT, "ERCOT Nodal Protocols, Section 3: Management Activities for the ERCOT System," December 1, 2021. At 3.8.6(3).
[8] EPRI (2021). At pages 4-2,3.
[9] Pricing nodes refer to the locations where LMPs are calculated. Some pricing nodes may include multiple nodes from a more detailed network model.
[10] PJM, "Order 2222…" November 2021. Slides 29-45.

violate thermal constraints or utility boundaries.[1] The potential for more coordination between ISOs and distribution utilities is discussed further in Section 4.4.

The following research questions would help to address possible shortcomings of multi-nodal DER aggregations in ISO market dispatch:

- What alternatives to distribution factors would improve the accuracy and efficiency of multi-nodal DER aggregation dispatch?
- What rules are most suitable for defining acceptable multi-node aggregation zones? E.g., shift factor thresholds, historical congestion patterns, etc.
- How do changes in distribution system conditions (congestion, maintenance, topology changes) affect the accuracy of static distribution factors?

4.3 Telemetry and Metering

FERC Order 2222 requires participating DERs to set up various telemetry and metering devices to ensure accurate market participation. Telemetry provides market operators with an accurate picture of how each system resource is dispatched in real time and is typically updated at a frequency of every few seconds. Metering data is used to determine the billable quantities that will be charged or credited to each market participant and is collected for each settlement interval, typically every five minutes.

While metering and telemetry allows measurement and verification that is necessary for market participation, there are various options for the specific technologies that ISO might require from DER aggregators. Based on ISO-NE's filings, there are currently three metering technology solutions available to prevent double-counting: calculate a demand response baseline at the retail delivery point, installing parallel metering equipment so that the DER is electrically separated from the host facility, or device sub-metering that subtracts the DER dispatch from the meter reading at the retail delivery point.[2] Using the baseline deviation option at the retail delivery point will often be the least costly option because it uses the customer's existing meter. The downside is that the DER must use whatever metering equipment is currently installed, typically in 5-minute or longer increments, which could preclude participation in regulation or other ancillary services. Some metering and telemetry requirements may be expensive, especially in comparison to the small size of many DERs. A 2019 study from EPRI found that network connectivity, telemetry scan rate, and encryption requirements each contributed significantly to the cost of telemetry.[3] Encryption requirements will not be examined here, but further details can be found in the referenced EPRI reports.

Individual DER metering data requirements may sometimes create ambiguity about the level of data granularity that is actually required. For example, MISO proposes to require metering for each individual "DER Group" within a DER aggregation to ensure accurate settlements in compliance with FERC Order 745.[4] DER Groups allow aggregated metering among

[1] Ferrari, Michael, "Transmission Node Identification for DER Participation in Wholesale Markets." Market Issues Working Group. August 29, 2018. Link: https://www.nyiso.com/icapwg
[2] ISO-NE, "Motion for leave…" Filed 7/25/2022. At 7.
[3] EPRI, "*Low-Cost Telemetry for Mass Market Demand Response: Market Study and Alternatives for Lower Telemetry Costs*." EPRI, Palo Alto, CA: 2019. 3002015273. Table 2-1.
[4] MISO, "FERC Order 2222 Filing Framework," Iteration 3, IR070. August 30, 2021. Slide 63.

heterogeneous DERs, such as a group of thermostats or water heaters.[1] This requirement also allows the DER's electric distribution company (EDC) and load serving entity (LSE) to perform validation and ensure that no double counting occurred between retail and wholesale services.[2]

Nearly all ISOs either support or require Inter-Control Center Communications Protocol (ICCP, also called IEC 60870-6) over a private Wide Area Network (WAN) to send and receive encrypted telemetry data. These communications technologies have broad industry acceptance and provide a reliable and secure data pipeline between ISO control centers and generators. However, requirements for a WAN connection can be costly and time consuming for market participants with relatively small portfolios, such as DER aggregators,[3] and EPRI has previously noted that ICCP standard may not be well-suited for communication with the distribution and consumer domains.[4] Distributed Network Protocol (DNP3) is the main alternative to ICCP due to its simplicity, reliability, and efficient use of bandwidth.[5] DNP3 can also reduce the cost to establish a telemetry link because it can also be sent through a public internet service,[6] so long as connection availability and redundancy requirements are met.[7] CAISO relies exclusively on DNP3 for telemetry data. NYISO, PJM, and ISO-NE support both ICCP and DNP3. MISO, SPP, and ERCOT rely exclusively on ICCP. Table 4.3 below further summarizes the telemetry requirements for DER aggregations in each ISO. Details of the network infrastructure used by some ISOs is protected information and therefore not publicly available.

Table 4.3. Telemetry Requirements for DER Aggregations

ISO	Subcomponent Meter Data	Subcomponent Telemetry	Aggregation Telemetry	Private WAN connection	Public internet connection	Telemetry Scan Rate
CAISO	Not required	Not required	≥10MW or providing AS	Yes	Yes	4 seconds
NYISO	Yes, for energy injection, withdrawal, and demand response[8]	Yes, for energy injection, withdrawal, and demand response[9]	All resources	Yes	Yes	6 seconds
PJM	Yes, for demand response	Not required	≥10MW or providing AS	Yes	Yes	1 minute, or 2/10 second if providing regulation

[1] MISO, "FERC Order 2222 Filing Framework," Iteration 3, IR070. August 30, 2021. Slides 59-63.
[2] MISO, "FERC Order 2222 Filing Framework," Iteration 2, IR070. August 2, 2021. Slide 65.
[3] NYISO, "Enabling Technologies for Distributed Energy Resources: An evaluation of alternative communication technologies." Report by the New York Independent System Operator. December 2019. Link: https://www.nyiso.com/documents/20142/1391862/Enabling-Technologies-for-DER-Study-Report.pdf [Accessed: 8/18/2022]
[4] EPRI, "*The Communication Networks Guidebook for Intelligent Transmission System*," ERPI, Palo Alto, CA: 2009. 1017848. Page 2-74.
[5] EPRI, "*The Communication Networks Guidebook…*" Page 2-67.
[6] NYISO, "Enabling Technologies…" December 2019.
[7] EPRI, "*Low-Cost Telemetry…*" Table 2-1.
[8] NYISO, "Compliance Filing…" Filed 7/19/2021. At 10.
[9] NYISO, "Compliance Filing…" Filed 7/19/2021. At 10.

ISO	Subcomponent Meter Data	Subcomponent Telemetry	Aggregation Telemetry	Private WAN connection	Public internet connection	Telemetry Scan Rate
ISO-NE	Yes, for demand response[1]	Yes, for demand response[2]	All resources except SODERA	(Not public)	(Not public)	4 seconds (regulation), 1 minute (10-min spin or non-spin), 5 minutes (30-min non-spin or energy)
MISO	Yes, but each Resource Group (i.e., type of DER) can be aggregated	Not required	All resources	Yes	No, but available to other resources	2 seconds (regulation), 10 seconds (10-min spin or non-spin), 4 seconds (energy)
SPP	Yes, for demand response resources	Yes, for demand response resources	All resources	(Not public)	(Not public)	10 seconds (DDR and BDR), 4 seconds (all other resources)
ERCOT	Not required	Not required	All resources	Yes	No	2 seconds

Table 4.3 shows the differences in ISO telemetry requirements. On the most relaxed end, CAISO and PJM do not require any telemetry for certain resources under 10 MW if they do not provide ancillary services (AS). ISO-NE also permits a no-telemetry option for resources participating under the SODERA model, which also is not eligible to provide ancillary services.

Scan rates also differ between ISOs. The most relaxed scan rates are 5 minutes to provide energy and 30-minute reserves or 1 minute to provide 10-minute spinning or non-spinning reserves in ISO-NE. PJM also allows a 1 minute scan rate for aggregated resources that do not provide regulation. All other ISOs require telemetry scan rates between 2 to 10 seconds.

Research Questions:

- Given the relaxed telemetry requirements in some ISOs, is there a potential for oscillatory dispatch from DER aggregations? What price formation improvements would reduce this behavior?
- Is there a significant risk to grid cybersecurity due to the use of public internet to send and receive telemetry data?
- Does the installation and maintenance cost of telemetry and metering equipment pose a significant barrier to entry for DER aggregators?

[1] ISO-NE, “Revisions to…” At 31-35.
[2] ISO-NE, “Revisions to…” At 31-35.

4.4 Transmission and Distribution Coordination

DER integration requires coordination between the DER aggregator and distribution utility, between the DER aggregator and ISO, and processes to allow distribution utilities to override ISO dispatch instructions if necessary. Order 2222 allows flexibility in how communication and data coordination procedures are established at each ISO.[1] Because Order 2222 does not prohibit dual participation in retail and wholesale markets, the ISOs, distribution utilities, and regulatory authorities will similarly need to monitor DER market activities to ensure that impermissible double-counting does not occur.[2]

ISO-NE's compliance filing provides an example framework and likewise allows flexibility in how distribution utilities implement these requirements due to differences in the utility's capabilities or the local regulatory requirements.[3] Although specific protocols are not specified, distribution utilities will need to communicate any known distribution system limitations to the DER aggregator so that these limitations can be reflected in the aggregator's offer to the ISO. After the ISO clears either the day-ahead and real-time market, the DER aggregation's dispatch instructions will be sent to both the DER aggregator and distribution utility. The aggregator will then provide an asset-level dispatch schedule to the distribution utility for review. The distribution utility will then notify the aggregator of any necessary modifications to the asset-level dispatch schedule, and the DER aggregator will accordingly notify the ISO of any changes to its aggregate output or its distribution factors.

ISOs typically do not monitor or manage distribution system assets and therefore have limited visibility regarding whether DERs pose safety and reliability risks to distribution systems or whether congestion or other issues in the distribution network will limit the ability of DERs to provide the services scheduled by the ISO. MISO has found that line switching, maintenance, storm damage, and voltage management happen regularly in the distribution system and contribute to dynamic and uncertain conditions.[4] DER dispatch could also result in bi-directional power flows, and this change in operating conditions compared to design assumptions can increase the chances of having over/under voltage issues or congestion in the distribution system.[5,6] Hence, dispatch overrides by distribution utilities might not be a totally uncommon risk for DER aggregators, and the aggregators will need to determine how to quantify this risk in their offers to the ISO.

Over longer horizons, coordination between aggregators, distribution utilities, and ISOs may also allow more efficient and cost-effective planning and interconnection procedures. However, Order 2222 does not exercise jurisdiction over DER interconnections at the distribution level, so there is no requirement for ISOs to develop interconnection procedures for aggregated DERs.[7]

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[1] Heidarifar, M., N. Singhal, E. Ela, E. Lannoye, L. Kristov, "Distributed Energy Resource Aggregation Participation in Organized Markets: Federal Energy Regulatory Commission Order 2222 Summary, Current State-of-the-Art, and Further Research Needs," Technical Update, No. 3002020586, February 2021.

[2] FERC, "Order No. 2222…" At P. 159-164.

[3] ISO-NE, "Revisions to…" At 37.

[4] Merring, Bob (2021). Slide 7.

[5] Karagiannopoulos, Stavros, et al. "Active distribution grids providing voltage support: The Swiss case." IEEE Transactions on Smart Grid 12.1 (2020): 268-278.

[6] Hadush, Samson Yemane, and Leonardo Meeus. "DSO-TSO cooperation issues and solutions for distribution grid congestion management." Energy Policy 120 (2018): 610-621.

[7] FERC. "Order No. 2222." At P. 96-97.

For example, PJM's proposed 5 MW maximum size limit on the individual DERs in an aggregation is intended to align with other PJM requirements that allow small resources to bypass or fast-track through the interconnection process.[1] MISO's Order 2222 implementation plan similarly proposes an interconnection process ("DERA Technical Review") that is separate from MISOs regular generator interconnection process and is only required if the distribution-level interconnection review identifies a potential reliability impact to the transmission system.[2] While some aspects of DER interconnection policies may differ between ISOs , much of the relevant interconnection policy may be decided by distribution companies and state and/or local regulatory agencies. The design and implementation of well-functioning transactive energy systems in distribution systems may help to streamline and standardize this aspect of DER integration.

Additional research could pursue the following questions regarding improved transmission and distribution coordination:

- How often and what is the likely impact of distribution utility overrides on DER dispatch? How might this be internalized in a DER aggregator's offer?
- What information can distribution utilities provide to DER aggregators to ensure that accepted offers do not violate distribution system constraints?
- How can ISOs simplify or expedite interconnection studies for small DER aggregations while still ensuring safe and reliable distribution and transmission system operations?
- What role should distribution utilities play in creating price signals to support efficient DER investment and integration?
- How can transactive energy systems improve and simplify the necessary coordination between distribution utilities, DER aggregators, ISOs, and regulators?

[1] PJM, "Order No. 2222…" Filed 2/1/2022. At 43-45.
[2] MISO, "Order No. 2222…" At 14-23.

5.0 Longer Term Reforms

As discussed in Order 2222, DER integration will require new and revised coordination frameworks between the ISO, DER aggregators, distribution utilities, and the relevant electric retail regulatory authorities (typically, state and/or local public utilities commissions).[1] ISOs are responsible for maintaining reliability of the high-voltage transmission system, which is also the point of interconnection for the generators that have traditionally participated in ISO markets. Because DER aggregations are typically connected at the distribution level, additional oversight is needed to ensure the safe and reliable operation of the physical equipment that forms the distribution network. In addition to physical assets, oversight is also needed to ensure that DER aggregators do not engage in market manipulation by receiving compensation from both retail and wholesale markets for the same service.

The following discussion of transmission and distribution coordination is organized into short-term and long-term issues. First, there are various aspects of operational and planning coordination that are required by FERC Order 2222. These coordination issues will affect DER integration in the near term. The discussion then turns to more forward-looking issues around the frameworks used to control distribution system operations, such as the prospect for a DSO-based framework, and potential reforms to better align wholesale and retail market incentives. FERC Order 2222 does not require adoption of any of these longer-term considerations, but they may be necessary to ensure continued efficient integration of DERs.

DSOs are still in their nascent stage of development, and there are many operational and jurisdictional issues to work out before they can become more widely adopted. Many DSO proposals are directly analogous to the ISO market design and propose the use of distribution locational marginal prices (DLMP) with a centralized SCED-based pricing and dispatch model.[2,3] The analysis that results in a DLMP-based distribution system markets follows from directly extending the ISO's centralized optimization design into the distribution level, and it implicitly assumes a shared objective and shared power flow constraints between the ISO and the lower level DSO. Short of creating a DSO, adopting a coordination scheme based on TES may enable efficient pricing and dispatch of distribution-level resources without requiring a specific structural model for DER participation.

There may be significant challenges to designing price-based schemes to coordinate activities that jointly affect transmission and distribution systems. The interests and concerns of transmission and distribution system operators do not necessarily align in a way that neatly fits into a shared optimization objective. A DSO may be much more concerned with maintaining reactive power and voltage support, which are not typically modeled in ISO dispatch algorithms and therefore may lack an adequate coordination mechanism.[4] A significant amount of literature on coordinating transmission and distribution operations attempts to resolve this incompatibility

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[1] FERC, "Order No. 2222…" At P. 272-331.

[2] Caramanis, Michael, Elli Ntakou, William W. Hogan, Aranya Chakrabortty, and Jens Schoene. "Co-optimization of power and reserves in dynamic T&D power markets with nondispatchable renewable generation and distributed energy resources." *Proceedings of the IEEE* 104, no. 4 (2016).

[3] Bai, Linquan, Jianhui Wang, Chengshan Wang, Chen Chen, and Fangxing Li. "Distribution locational marginal pricing (DLMP) for congestion management and voltage support." IEEE Transactions on Power Systems 33, no. 4 (2017).

[4] Liu, Yikui, and Lei Wu. (2021).

by applying the AC power flow constraints to both networks.[1] Yet this still underestimates the coordination issue since there lacks a widely accepted framework for managing distribution system operations. For example, unbalanced three-phase AC power flow, voltage control, and network reconfiguration may be essential components of a future DSO's software toolbox but are not part of standard SCUC and SCED software used by ISOs.[2] Aside from modeling issues, the DSO's ownership of physical assets in the distribution system may also present a conflict of interest that poses a barrier to efficient DER dispatch.[3] For example, a DSO may choose to operate its system more conservatively than necessary to avoid reliability or safety concerns. DERs could therefore become unreasonably constrained from allowing their full capability to be available to the transmission system. Before price-based frameworks for coordination between the distribution and transmission systems can be implemented, they will need to demonstrate compatibility with existing distribution network safety and reliability standards to earn the trust of distribution system operators.

There is considerable opportunity to explore new market designs to help facilitate DERs and broader consumer participation in electricity markets. The potential development of DSOs and TES will raise many important research questions:

- What institutional, regulatory, jurisdictional barriers might prevent the development of DSOs in the US? How are these barriers different for the implementation of a distribution-level TES?
- What are the market design considerations for a potential DSO? What is the most appropriate network model for distribution system operations? Would a TES approach these considerations differently?
- How would a DSO interact with customers/end users? How would a DSO interact with the transmission system operator? Would these interactions be coordinated more efficiently in a TES?
- What added value would a DSO approach provide to DER integration and improved distribution and transmission coordination? What are the economic benefits? What are the reliability benefits? How would these benefits compare with the implementation of other TES-based frameworks?

[1] Givisiez, Arthur Gonçalves, Kyriacos Petrou, and Luis F. Ochoa. "A review on TSO-DSO coordination models and solution techniques." *Electric Power Systems Research* 189 (2020).
[2] Network reconfiguration, also called line switching or topology optimization, is becoming more common in ISO commitment and dispatch software. However, network reconfiguration at the distribution level tends to be done to manage voltage levels and balance three-phase systems, while at switching at the transmission level tends to be more for economic purposes.
[3] Liu, Yikui, and Lei Wu. (2021).

6.0 Conclusion

Over the past few decades, wholesale electricity market design has evolved towards improving the efficiency of production schedules for conventional generators connected to the transmission system. Order 2222 represents a step in the evolution of market design towards smaller, distributed, and distribution-connected devices, but there are significant market design questions that remain to be addressed. Distorted incentives due to existing retail tariff structures, technical limitations of existing optimization software, and limited coordination schemes between the transmission and distribution-level operators are likely to be major hurdles for near-term DER integration into wholesale markets.

Much of the potential for distorted economic incentives comes not from Order 2222, but from Order 745. By requiring demand response to be paid at the wholesale LMP, Order 745 over-incentivizes demand response; curtailed load receives a double benefit from, first, not having to pay for the energy not consumed and, second, from the wholesale LMP. Some of the distortion is removed when demand response is procured from load shifting resources, but ISO demand response programs do not always distinguish load shifting from other resources that do not increase their consumption to compensate for load curtailments. Offer mitigation measures such as the Net Benefits Test also reduce some, but not all, of the economic distortion, yet also increases the complexity involved in market participation. This complexity extends to Order 2222 compliance plans because the proposed participation models must accommodate Order 745's requirements within potentially heterogeneous aggregations of demand response and other types of DERs.

A potential influx of DERs to the wholesale market could also stress the computational burden of SCUC software used by ISOs to determine generation production schedules and market clearing prices. SCUC is a computationally challenging non-convex, mixed integer and linear programming problem that requires significant research support. If the ISO's SCUC models cannot be solved within the timeframes required by market clearing processes, then the ISO may be left with sub-optimal production schedules. Market clearing prices can be similarly affected since they will be based on an inefficient resource utilization. Research efforts can be directed to avoid this outcome by investigating higher fidelity SCUC formulations, DER aggregation and offer calculation methodologies, and efficient wholesale price formation.

Many details of transmission and distribution coordination remain to be resolved. Wholesale markets serve wide geographic areas that may often have many distinct regulatory authorities and various distribution companies that adopt different procedures and technologies. Order 2222 does not impose a specific scheme for transmission and distribution coordination; certainly, there is currently no widely agreed upon framework for this. Now that Order 2222 has opened new doors to DER integration, there is opportunity for T&D coordination research to identify new problems and inefficiencies based on actual practice as well as to further study possible implementation of more advanced T&D coordination frameworks. DSO framework has motivated many recent research articles and seems to promise significantly improved integration of grid-edge resources like DERs, yet there is still a large gap between the DSO model and typical distribution utility practices.

Appendix A – ISO Participation Models for DER Aggregations

A.1 CAISO

FERC's requirements issued in Order 2222 were based in part on CAISO's existing DER participation models. Tariff revisions for the DER participation model were filed in March 2016 and subsequently approved by FERC in June 2016. CAISO's DER participation models underwent minor changes as proposed in their Order 2222 compliance filing submitted to FERC on July 19, 2021.[1] Once CAISO implements the minor tariff modifications for Order 2222 compliance, DER aggregations will be eligible to participate, at minimum, under one of the seven participation models described in **Error! Reference source not found.** below.

For compliance with Order 2222, CAISO allows aggregated resources to register as heterogeneous or homogeneous DER aggregations (DERAs), or as Proxy Demand Response (PDR) or Reliability Demand Response Resource (RDRRs). A DERA is designated as heterogeneous if it includes at least one demand response resource (called a "Distributed Curtailment Resource" when included in a DERA) and at least one resource that is capable of injecting energy. Heterogenous DERAs are subject to the net benefits test and all other demand response requirements. A DERA is designated as homogeneous if it does not include any demand response. DERAs are eligible to provide energy, spinning reserves, and non-spinning reserves in both the day-ahead and real-time markets. They are not eligible to provide regulation. The California Public Utilities Commission (CPUS) currently does not allow DERAs to qualify for Resource Adequacy (RA), although the CPUC has recently held workshops to possibly extending RA Capacity eligibility to DERAs.[2] Telemetry is only required if the DERA provides ancillary services or is larger than 10 MW and must provide a signal every 4 seconds.

Resources with over 0.1 MW of capacity may also register as PDR or RDRR. Only demand response is eligible to participate under these participation models. Like DERA, PDR and RDRR are not eligible to provide regulation; however, these resources are eligible to provide Resource Adequacy (RA) capacity. PDR and RDRR are eligible to provide spinning and non-spinning reserve, but they must meet at least 0.5 MW of curtailment capability and be sustainable for 30 minutes. PDR is eligible to submit economic bids in the day ahead and real time markets. RDRR may submit economic offers in the day-ahead market but can only participate in the real time market if the system is in or near an emergency condition. Telemetry is only required if the PDR or RDRR provides ancillary services or is larger than 10 MW and must provide a signal every 4 seconds.

CAISO also allows resource aggregations under a Non-Generating Resource (NGR) participation model by registering as Dispatchable Demand Response (DDR), Limited Energy Storage Resource (LESR), or a Generic NGR. These resources do not meet Order 2222's requirements because they must have at least 0.5 MW of capacity to participate. DDR and LESR may provide energy, spinning reserve, non-spinning reserve, and regulation up and down. Generic NGR may only provide regulation un and down in the day-ahead and real-time markets. DDR, LESR, and Generic NGR are all eligible to provide RA Capacity.

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[1] CAISO, "Tariff Amendment to Comply with Order No. 2222," California Independent System Operator Corporation, Docket No. ER21-2455-000. July 19, 2021.

[2] CAISO, "Answer to Comments," California Independent System Operator Corporation, Docket No. ER21-244-000. Page 4.

Table 6.1. DER Aggregation Criteria, CAISO

	Minimum Size (Energy)	Minimum Size (Spin/Non-Spin)	Minimum Size (Regulation)	Maximum DER Size	Maximum Total Size	RA Capacity Eligibility
Heterogeneous DERA	0.1 MW	0.1 MW	Ineligible	1 MW	20 MW*	Ineligible
Homogeneous DERA	0.1 MW	0.1 MW	Ineligible	1 MW	20 MW*	Ineligible
PDR	0.1 MW	0.5 MW†	Ineligible	None	None	Yes
RDRR	0.1 MW	0.5 MW†	Ineligible	None	None	Yes
LSR	0.1 MW	0.5 MW†	Ineligible	None	None	Yes
DDR	0.5 MW‡	0.5 MW‡	0.5 MW§	None	None	Yes
LESR	0.5 MW‡	0.5 MW‡	0.5 MW§	None	None	Yes
Generic NGR	Ineligible	Ineligible	0.5 MW§	None	None	Yes

* Applies only if aggregated across multiple nodes
† Capacity must be sustainable for 30 minutes
‡ Capacity must be sustainable for 60 minutes
§ Capacity must be sustainable for 15 minutes

A.2 NYSIO

In addition to CAISO, FERC Order 2222 also relied on NYISO's existing DER participation model. NYISO originally submitted its DER participation model in June 2019, and it was accepted by FERC in January 2020. NYISO's DER participation models subsequently underwent minor changes as proposed in their Order 2222 compliance filing submitted to FERC on July 19, 2021.

NYISO simplified and collapsed some of its demand response models into a single DER Coordination Entity Aggregation (a.k.a. "Aggregation") participation model. The main changes required by FERC Order 2222 were a definitional change to allow the Aggregation to consist of a single resource and the small utility opt-out provision.

The Aggregation participation model allows economic dispatch in the day ahead and real time markets. Resources must have at least 0.1 MW capacity to provide energy, and they must have at least 1 MW capacity to provide operating reserves and regulation. NYISO implemented the 0.1 MW minimum capacity requirement prior to Order 2222. In addition, DERs in an Aggregation must not be capable of injecting more than 20 MW.[1] All resources must be located at the same transmission node.

Additionally, DERs may participate under NYISO's economic and reliability-based demand response programs. The reliability-based programs currently have significantly more participation and consist of the Emergency Demand Response Program (EDRP) and Special Case Resources (SCR). Both EDRP and SCR must consist of interruptible load or behind-the-meter resources.

[1] NYISO, "Compliance Filing…," Filed 7/19/2021.

Participation in EDRP requires at least 0.1 MW of load curtailment. When called, EDRP resources receive the maximum of $500/MWh or the LMP. The program is not eligible for NYISO's capacity market.

Resources have a significant incentive to participate as SCR rather than EDRP since SCRs are eligible to provide capacity. In addition to receiving capacity (ICAP) payments, SCRs also receive the LBMIP when called. Almost all SCRs submit at the SCR price ceiling of $500/MWh.

The economic-based programs are small and could be phased out in the future. NYISO's Day-Ahead Demand Response Program (DADRP) schedules interruptible load or behind-the-meter resources in the day-ahead market only. The program requires at least 1 MW of load curtailment, which can be aggregated within the same load zone and LSE. Because the resources must be demand response, they are required to offer above the monthly net benefits test threshold. However, no DADRP offers have been submitted since 2010.

The second economic-based demand response program is the Demand Side Ancillary Service Program (DSASP). DSASP resources also must consist of interruptible load or behind-the-meter resources, and they may only provide reserves, regulation, and frequency response. Like DADRP, DSASP requires at least 1 MW of load curtailment that can be aggregated within the same load zone and LSE, and resources are required to offer above the monthly net benefits test threshold. The program currently consists of two resources that proved 75 MW of operating reserves.

A.3 PJM

PJM's DER participation models are currently undergoing development through stakeholder discussions in anticipation of their Order 2222 compliance filing deadline of February 1, 2022. The following description of PJM's new DER participation model is based on a straw proposal from August 16, 2021.

To comply with Order 2222, PJM has is proposing a new DER Aggregation (DERA) participation model that did not exist prior to Order 2222. DERAs are eligible to provide energy, synchronous reserves, regulation, and capacity. As required by Order 2222, there is a 0.1 MW minimum capacity requirement to participate as a DERA. There is no maximum DERA size, and there are no minimum or maximum limits for individual DERs in a DERA.

PJM's straw proposal states that DERA will be modeled in the day ahead and real time optimization software without binary (i.e., on/off status) variables. Two options are being considered for this no-commitment model. Option 1 is that DERAs would self-schedule in the day ahead and real time markets, and since they are self-scheduled, the resources would be ineligible to receive make-whole payments. Option 2 would also allow DERAs to self-schedule in the day ahead and real time markets, or they could alternatively submit cost-based (i.e., mitigated) offers that would be eligible for lost opportunity cost and make-whole payments.

PJM's approach to allow DERAs to provide ancillary services is not yet clear. Broadly, there will be some mechanism to allow DERAs to provide both synchronous reserves[1] and regulation.

[1] It may be problematic if PJM allows DERAs to provide synchronous reserves but not asynchronous reserves because the possibility that the total supply of synchronous reserves is less than the supply of asynchronous reserves could raise the price of the lower quality reserve product above the price of the higher quality reserve product.

In general, DERA resources must be located at the same transmission node to be dispatched in the day ahead and real time markets. As of PJM's August 16 straw proposal, there is some leeway in the single-node requirement. PJM's network software defines elemental nodes (Enodes) for physical modeling and pricing nodes (Pnodes) for market settlement purposes. DERAs may aggregate DERs at multiple Enodes so long as each DER maps primarily to the same Pnode.

However, the capacity and ancillary service markets also allow different locational requirement. PJM allows DERAs to be aggregated by zone and sub-zonal LDA for participation in the capacity market, and they may be aggregated by reserve zone to determine performance payments for ancillary services.

A.4 ISO-NE

ISO-NE's DER participation models are currently undergoing development through stakeholder discussions in anticipation of their Order 2222 compliance filing deadline of February 2, 2022.

DER aggregations in ISO-NE may participate as any one of seven alternative participation models, as shown in **Error! Reference source not found.**. The Demand Response DER Aggregation (DRDERA) and Settlement Only DER Aggregation (SODERA) participation models were proposed in ISO-NE's Order 2222 compliance plan. Because a DER aggregation may choose to participate under various participation models, the ISO-NE uses the term Dispatchable DER Aggregation (DDERA) to refer to aggregations that use the GEN, CSF, BSF, ATRR, DRR, or DRDERA models (i.e., any DER aggregation except for SODERA).

Table 6.2. DER Aggregation Criteria, ISO-NE

	Minimum Size (Energy)	Minimum Size (Spin/Non-Spin)	Minimum Size (Regulation)	Maximum DER Size	Maximum Total Size	FCM Capacity Eligibility
GEN	0.1 MW	0.1 MW	0.1 MW	5 MW	None*	Yes
CSF	0.1 MW	0.1 MW	0.1 MW	5 MW	None*	Yes
BSF	0.1 MW	0.1 MW	0.1 MW	5 MW	None*	Yes
ATRR	Ineligible	Ineligible	0.1 MW	5 MW	None*	Ineligible†
DRR	0.1 MW	0.1 MW	Ineligible	5 MW	None*	Yes
DRDERA	0.1 MW	0.1 MW	0.1 MW	5 MW	None*	Yes
SODERA	0.1 MW	Ineligible	Ineligible	5 MW	5 MW	Yes

* Multi-node aggregations may not be greater than 5 MW at any single node.
† ATRR can provide capacity by registering as other participation models that provide energy.

ISO-NE has proposed tariff changes for DRDERAs to submit the following day-ahead bidding parameters in the day-ahead market:

- Price and baseline deviation quantity pairs that may vary for each hour of the day.
- All prices submitted by the DRDERA must be above the Demand Reduction Threshold Price (i.e., net benefits test), or will otherwise be set equal to the threshold price.
- Baseline deviation quantities cannot include avoided peak transmission or distribution losses.
- Start-up time.

- Notification time.
- Minimum deviation time no greater than 24 hours.
- Minimum time between deviations.
- Maximum deviation amount that is no greater than the sum of the maximum capabilities of the constituent DERs.
- Changes to the maximum and minimum deviation from what is included in the DRDERA's offer data, based on physical operating characteristics and/or resource availability.

Unlike Generator Assets, DRDERAs cannot submit start-up and no-load costs. DRDERAs are not eligible to self-schedule.

SODERAs may also submit offers to ISO-NE's day-ahead market. SODERA offers only apply to the day-ahead market, and like DRDERAs, consist of price and quantity pairs that may vary for each hour of the day.

Locational requirements of each participation model are described below. DER aggregationss that can inject 5 MW or more at a single transmission mode are prohibited from inclusion in multi-node aggregations. DER aggregations that are larger than 5 MW are therefore single-node and are settled at the nodal LMP. Multi-node DER aggregations are settled at the DRR Aggregation Zone Node Price.

Table 6.3. DER Locational Requirements, ISO-NE

Participation Model	Locational Requirement
Generator Asset	Single DRR Aggregation Zone and a single host utility metering domain
ATRR	Single DRR Aggregation Zone
CSF	Single DRR Aggregation Zone and a single host utility metering domain
BSF	Single DRR Aggregation Zone and a single host utility metering domain
DRR	Single DRR Aggregation Zone
SODERA	Single DRR Aggregation Zone and a single host utility metering domain
DRDERA	Single DRR Aggregation Zone and a single host utility metering domain

DER aggregations participate in ISO-NE's Forward Capacity Market (FCM) by registering as a Distributed Energy Capacity Resource (DECR). A DECR can be formed by aggregating multiple DDERAs or multiple SODERAs within the same DRR Aggregation Zone. DDERAs and SODERAs cannot be aggregated into the same DECR due to differences in energy market participation.

A.5 MISO

MISO's DER participation models are currently undergoing development through stakeholder discussions in anticipation of their Order 2222 compliance filing deadline of April 18, 2022. The following sections described the proposed DER policies as of YYYY.

As currently proposed, MISO is considering a new resource type called a Distributed Energy Aggregation Resource (DEAR) that is based on Energy Storage Resource (ESR) participation model, which is under development, and the existing Dispatchable Intermittent Resource (DIR) model.[1] ESR and DIR minimum participation levels will be proposed to be set at 0.1 MW. To help MISO's market optimization software accommodate large numbers of small resources, all DEARs under 1 MW will be required to self-commit.

MISO also considered lowering the participation minimum to 0.1 MW for the DRR I, DRR II, and GEN participation models, but these alternatives were rated lower in terms of solution complexity and implementation costs. MISO's ESR and DIR participation models do not require large DER assets to participate in the MISO market individually.[2] However, MISO's approach allows Electric Distribution Companies (EDCs), states, Transmission Owners (TOs), or MISO interconnection studies to identify system impacts based on DER or DEAR size.

MISO's ESR participation model is under development, but stakeholder materials provide the expected outline of ESR attributes and requirements.[3] The participation model is expected to allow a minimum participation threshold of 0.1 MW and to allow power injection as well as withdrawal. Three operating statuses are allowed for charging, discharging, and continuous operation, and the resource is required to self-commit which operating status it will be in. Because ESRs are required to self-commit, they are not eligible to receive make-whole payments. The ISO is still able to dispatch the continuous portion of the resource's operating range. ESRs are expected to provide a wide array of market products, including energy, capacity, regulation, spinning and non-spinning reserves, ramp capability, and short-term reserve.[4]

The DIR participation model was available in MISO's market prior to Order 2222 and is expected to be modified to comply with the Order's requirements. DIRs can participate in MISO's energy and capacity markets and are committed and dispatched by the ISO. Because DIRs are intended for intermittent resources, they are not eligible to provide any reserve products (i.e., regulation, spinning and non-spinning reserves, ramp capability, and short-term reserve).

DER aggregations could presumably also participate under the DRR-I and DRR-II participation models. However, both DRR-I and DRR-II currently requires a 1 MW minimum resource size and therefore cannot be used to satisfy compliance with Order 2222. Nevertheless, DER aggregators that do satisfy the DRR-I and DRR-II requirements may find benefits to participating under these models.[5] For example, participation as DRR-I could allow multi-node DER aggregations and commitment by MISO's scheduling software. However, DRR-I resources are not eligible to provide regulation, non-spinning reserves, or ramp capability, and they must be block dispatched (i.e., on/off). Resources that participate as DRR-II are eligible to provide energy, capacity, regulation, spinning and non-spinning reserves, ramp capability and spinning reserves. Additionally, DRR-II can be both committed and dispatched by the ISO, but must be located at a single node.

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[1] DER Task Force, "Order 2222 Evaluation Framework," Integrated Roadmap Issue IR070, March 8, 2021. Slide 11. Link: https://cdn.misoenergy.org/20210308%20DERTF%20Item%2005%20Evaluation%20Framework%20Stage%20Review528122.pdf

[2] MISO, "FERC Order 2222 Filing Framework," Iteration 1, IR070. June 7, 2021. Slide 41.

[3] DER Task Force, March 8, 2021. Slide 13.

[4] DER Task Force, March 8, 2021. Slide 12.

[5] DER Task Force, March 8, 2021. Slide 12.

Multi-node aggregations are also allowed for Load Modifying Resources (LMRs), in addition to DRR-I. MISO also has an existing participation model for Aggregators of Retail Customers (ARCs).

MISO plans to allow DEARs to participate in the capacity market if it meets the 0.1 MW minimum participation threshold. Rather than propose a new planning resource type for aggregated DERs, the capacity credit of individual DER within the aggregation is accredited based on MISO's existing resource types. For new resources, the DEAR can provide MISO with the resource's capacity amount, and historical availability data is used once a resource has sufficient historical operating data.[1]

Only single node aggregations are allowed in MISO's DEAR model. The ISO found that single node aggregations would provide the highest level of grid reliability and resiliency, lowest implementation costs, and had the lowest dispatch solution complexity. MISO's uses the term Elemental Pricing (EP) Node to describe the lowest level component included in the Commercial Model. Each EP Node correspond to elements in MISO's network model. EP Nodes are level below Commercial Pricing (CP) Nodes, which are used to calculate LMPs.

Other alternatives considered by MISO included allowing multi-node aggregations for on/off resources, multi-node aggregations for dispatchable resources based on historical mappings, and multi-node aggregations for on/off resources in the same LBA. However, these solutions were not chosen. MISO's decision to limit aggregations to a single EP Node was motivated by the need to accurately model and price resources in the real-time market.[2] Multi-node DER aggregations can alternatively register as LMR or DRR-I type resources.[3]

MISO's stakeholder materials shared ratings of "Best," "Better", "Good", or "Red Flag" for each alternative based on: 1) grid reliability and resiliency, 2) market efficiency, 3) solution complexity, and 4) implementation costs. The single EP Node approach received a "Best" score in each of these categories except for market efficiency, for which it was rated "Good." Supporting these conclusions, MISO collaborated in a research project with the Stevens Institute of Technology (SIT) in 2019-2020 that modeled the pricing and flow oscillations that could occur if aggregated DER dispatch is not modeled precisely. Their results showed that allowing multi-node aggregations within a 3% shift factor tolerance could cause over 100 MW in transmission flow error.[4]

Because MISO is planning on adopting a single EP Node DEAR model, there is currently no need to require DEARs to submit distribution factors. Several aggregators and distribution companies advised MISO that accurate distribution factors would be difficult to provide due to the dynamic nature of DEAR response and due to frequent changes in distribution topology.[5]

The following DEAR information will be included in MISO's commercial model to represent the DEAR[6]:

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[1] MISO, "Order 2222 Resource Adequacy Review," Issue IR070, Resource Adequacy Subcommittee, July 7, 2021. Slides 3-5.
[2] MISO, "Order 2222 Update," Market Subcommittee, IR070. September 2, 2021. Slide 5.
[3] MISO, "Order 2222 Update" September 2, 2021. Slide 5.
[4] MISO, "Order 2222 Market Model Review, Requirements for Aggregation," IR070, April 12, 2021. Slide 7.
[5] MISO, "Order 2222 Market Model Review…" April 12, 2021. Slide 14.
[6] MISO, "FERC Order 2222 Filing Framework," Iteration 1, IR070. June 7, 2021. Slide 45.

Table 6.4. DER Model Data Description, MISO

Information	Description
Unit EPNode	Representation in the Operations Models
CPNode Name	Commercial pricing node
Minimum Output	(MW)
Maximum Output	(MW)
Maximum Nameplate	Installed capacity (MW)
Default Ramp Rate	(MW)
Energy	Ability to offer energy (yes/no)
Regulation	Ability to offer regulation reserves (yes/no)
Spinning	Ability to offer spinning reserves (yes/no)
Supplemental	Ability to offer on-line supplemental reserves (yes/no)
Unit Type	DERa
Fuel Type	DERa

The DEAR will be required to provide the following real-time data[1]:

Table 6.5. DER Real Time Data, MISO

Information	Description
Aggregate Control Mode	Current control mode of the DEAR
Resource Aggregate Output (MW)	The MW output of the DEAR
Resource Aggregate Output (Mvar)	The MVAR output of the DEAR
Resource Breaker Status	DEAR representative breaker status to indicate availability of the DEAR
Echo Resource Setpoint Measurement	Echo the DEAR's received setpoint. Allows MISO to verify that the setpoint was recieved

A.6 SPP

SPP's Order 2222 compliance filing proposes to create a DER Aggregator (DERA) as a new type of market participant that will be able to register DER Aggregations.[2] SPP intends most DER Aggregations to participate using the standard GEN resource model, but it is not restricted from registering as any resource type if it meets the technical and operational requirements of the resource type. For example, a DER Aggregation with energy storage can register as a Market Storage Resource (MSR) to facilitate offers for charging and discharging attributes, or it could register as a Multi-configuration Combined-cycle Resource (MCR), in rare cases, if the DER Aggregation should submit configuration-based offers based on the technical and operational characteristics of its underlying resources. Other valid resource types in SPP include Dispatchable Demand Response (DDR), Block Demand Response (BDR), and Dispatchable Variable Energy Resource (DVER). The filing reduces the minimum offer level to

[1] MISO, "FERC Order 2222 Filing Framework," Iteration 1, IR070. June 7, 2021. Slide 46.
[2] SPP, "Compliance Filing of Southwest Power Pool, Inc.," Order No. 2222, Docket No. ER22-1697-000. Page 6-8.

0.1 MW for all resource types and states that there is no maximum size of the aggregation and no maximum or minimum size of the DERs in the aggregation.[1]

DER Aggregations in SPP's Energy and Operating Reserve Markets must be aggregated at a single transmission node, and as a result are not required to submit distribution factors.[2]

Table 6.6. DER Aggregation Criteria, SPP

	Minimum Size (Energy)	Minimum Size (Spin/Non-Spin)	Minimum Size (Regulation)	Maximum DER Size	Maximum Total Size	RA Capacity Eligibility
GEN	0.1 MW	0.1 MW	0.1 MW	None	None	Yes
MSR	0.1 MW	0.1 MW	0.1 MW	None	None	Yes
DDR	0.1 MW	0.1 MW	0.1 MW	None	None	Yes
BDR	0.1 MW	0.1 MW	0.1 MW	None	None	Yes
MCR	0.1 MW	0.1 MW	0.1 MW	None	None	Yes
DVER	0.1 MW	0.1 MW	0.1 MW	None	None	Yes

[1] SPP, "Compliance Filing…" Page 15-16.
[2] SPP, "Compliance Filing…" Page 17.

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