DISTRIBUTED ENERGY RESOURCE PARTICIPATION IN WHOLESALE MARKETS: LESSONS FROM THE CALIFORNIA ISO

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Synopsis: The California Independent System Operator (CAISO) aims to "support" and "facilitate" wholesale market participation by aggregations of distributed energy resources (DERs)—solar panels, batteries, and other energy technologies installed in small quantities at scattered locations.[1] This reflect CAISO's recognition that "[t]he number and diversity of these resources are growing and represent an increasingly important part of the future grid."[2] However, CAISO has also recognized that system operators can only draw on DERs if they perform reliably, their operation is predictable and transparent, and their contributions are large enough to be economical both to their owners and the grid as a whole.[3] While the aggregation of multiple DERs can support each of these conditions, providing for such aggregation will require adjustments to existing wholesale market rules.

CAISO is not alone in recognizing the potential contributions to market performance of aggregated DERs, but it was the first wholesale market operator to begin exploring how to make the adjustments necessary to enable their participation. Similar programs for the aggregation of demand response have existed in markets operated by CAISO and other independent system operators and regional transmission organizations (ISO/RTOs) for several years. Those programs do not, however, allow energy exports to the bulk power grid. To address this limitation, CAISO adopted a new program, which allows DERs to provide energy and ancillary services to the grid.

At the time of writing, CAISO's program had attracted just four participants—DER providers or "DERPs"—none of which had yet begun operating in the energy or ancillary services markets. Meanwhile, the other ISO/RTOs and the Federal Energy Regulatory Commission (FERC or the Commission) that oversees them are following CAISO into the fray. The FERC is considering requiring all ISO/RTOs to adopt their own programs for DER aggregation, which may be modeled on the one currently used by CAISO.[4] Despite this, however, there has been

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1. *Order Accepting Proposed Tariff Revisions Subject to Condition*, 155 F.E.R.C. ¶ 61,229 at P 1–2 (June 2, 2016).

2. CAISO, ENERGY STORAGE & DISTRIBUTED ENERGY RESOURCES PHASE 3 ISSUE PAPER 3 (Sept. 29, 2017).

3. 155 F.E.R.C. ¶ 61,229 at PP 2–6.

4. Notice of Proposed Rulemaking, *Elec. Storage Participation in Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators*, 157 F.E.R.C. ¶ 61,121 (Nov. 17, 2016). FERC has convened a technical confer-

no comprehensive review of how the CAISO program is operating and why it has attracted so few participants. This article is intended to fill that gap.

This article examines CAISO's DER program after its first year of operation. It draws on written comments submitted to CAISO in the course of program development and on interviews the authors conducted with stakeholders—including active and potential DERPs, investor-owned utilities, and customer groups—to identify "barriers" to program participation. Irrespective of whether these barriers are appropriate—e.g., to ensure continued wholesale system reliability as DER penetration increases—they have clearly prevented the DER program fulfilling CAISO's stated goal. The barriers should, therefore, be considered by other ISO/RTOs in developing programs with similar goals. The authors identify six key lessons that other ISO/RTOs and regulatory authorities can learn from CAISO's experience.

ence to explore issues relating to DER aggregation. *See* Notice of Technical Conference, *Participation of Distributed Energy Resource Aggregations in Markets Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators*, (Feb. 15, 2018), https://perma.cc/ZGB2-BDFP.

ACRONYMS

CAISO	California Independent System Operator
CPUC	California Public Utility Commission
DER	Distributed energy resource
DERP	Distributed energy resource provider
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
kW	Kilowatt
kWh	Kilowatt hour
LRA	Local regulatory authority
LMP	Locational marginal price
MST	Market Administration and Control Area Services Tariff
MW	Megawatt
MWh	Megawatt hour
NEM	Net energy metering
NYISO	New York Independent System Operator
PDR	Proxy demand response
PJM	PJM Interconnection
PV	Photovoltaic
RDR	Reliability demand response
RTO	Regional Transmission Organization
SCID	Scheduling coordinator identification number
UDC	Utility distribution company
WDAT	Wholesale Distribution Access Tariff

I. INTRODUCTION

Across much of the U.S., the electricity system is undergoing a fundamental transformation, albeit at different rates in different jurisdictions.[5] Two shifts are driving this transformation. The first relates to the fuel used for generation. Coal and nuclear-fired generation resources are under pressure, primarily because they are increasingly uneconomical relative to natural gas and renewables, but also because growing volumes of renewables make inflexibility in generation resources a liability.[6] The second shift relates to the scale and location of generation resources and is this article's main point of focus.

5. LISA SCHWARTZ ET AL., ELEC. END USES, ENERGY EFFICIENCY, & DISTRIBUTED ENERGY RES. BASELINE 188–89 (Jan. 2017).

6. DEP'T OF ENERGY, STAFF REPORT TO THE SECRETARY ON ELEC. MKTS. & RELIABILITY 15–19 (Aug. 2017).

Whereas electricity was historically generated at centralized facilities and transported long distances to customers, today, smaller distributed energy resources (DERs) located on or near customers' premises account for a sizeable and growing share of electricity supply.[7] These resources, which include small-scale solar, wind, and storage systems, can offer a number of advantages over conventional generating facilities. DERs located close to energy consumers can, for example, enhance reliability by increasing the diversity of generation and avoiding the losses that attend long-distance transmission.[8] Their use also presents challenges, however, particularly because their operation can interact with both the bulk power system, which is managed by wholesale market operators subject to federal regulation, and the distribution grid, which is managed by utilities subject to state regulation.[9] It is difficult to generalize about the balance of benefits and costs arising from DER installations, and the parties to whom they accrue, because these values depend on the circumstances of a given location and regulatory jurisdiction.[10]

To date, DERs have principally been located behind-the-meter and used to meet onsite needs, and so have played a limited role in wholesale electricity markets. Current wholesale market rules, which were written with conventional generators in mind, impose participation requirements that DERs often cannot meet, such as minimum size thresholds.[11] Recognizing this, and seeking to realize the potential benefits of DER participation, several market operators have recently proposed rule changes that would allow DERs to participate on an aggregated basis.[12] The California Independent System Operator (CAISO) led the way, establishing a program in June 2016 through which DER aggregations may participate in its wholesale energy and ancillary services markets.[13] Notably, while CAISO's is the first DER aggregation program, programs for the aggregation of demand

7. Jason Abiecunas, Rick Azer & Tim Imlah, *Technology: Distributed Generation Still Part of the Plan as Technology Adoption Matures*, BLACK & VEATCH 2017 STRATEGIC DIRECTIONS: ELEC. INDUS. REPORT 37 (2017) ("Distributed energy resources continue to drive change within the electric industry. . . . This movement is requiring utilities to transform traditional centralized networks into flexible, distributed and integrated power networks that are starting to evolve from demonstration mode to more solid, longer-term investments that play an important part in developing new business models").

8. DNV GL & NYISO, A REVIEW OF DISTRIBUTED ENERGY RES. 18–22 (Sept. 2014).

9. *Id.* at 11-12, 26.

10. *See* Susan F. Tierney, *The Value of "DER" to "D": The Role of Distributed Energy Res.*, SUPPORTING LOCAL ELEC. DISTRIBUTION SYS. RELIABILITY 31-36 (Mar. 2016) (noting implications of distinct state policies and physical aspects of distribution grids in Southern California Edison and Consolidated Edison's respective service territories).

11. DNV GL & NYISO, *supra* note 9, at 115.

12. DER aggregation should not be confused with Community Choice Aggregation. The latter is a means by which municipalities can specify parameters for electricity services procurement on behalf of their residents. Those parameters often include a high volume—or exclusive use of—renewable generation to serve the community's load. *See* N.Y. STATE ENERGY RESEARCH & DEV. ADMIN.: CMTY. CHOICE AGGREGATION, https://www.nyserda.ny.gov/All-Programs/Programs/Clean-Energy-Communities/Clean-Energy-Communities-Program-High-Impact-Action-Toolkits/Community-Choice-Aggregation (last visited Sept. 30, 2017).

13. CAISO operates wholesale markets for energy, capacity, and ancillary services in most of California and a small part of Nevada. *See* 155 F.E.R.C. ¶ 61,229.

response services have existed since the early 2000s in CAISO and other wholesale markets.[14]

CAISO's DER aggregation program was, by all accounts, intended to facilitate DER participation in wholesale energy and ancillary services markets.[15] However, after one year of operation, the program has attracted just four DER aggregators[16] None of those aggregators had, at the time of writing, yet begun providing services in CAISO's energy or ancillary services markets. This article suggests why that is the case. The article is, to the authors' knowledge, the first comprehensive assessment of the CAISO program. It provides valuable insight into the program's apparent failure to achieve its goals, something which is urgently needed, as the Federal Energy Regulatory Commission (FERC) is considering requiring other independent system operators and regional transmission organizations (ISO/RTOs) to establish DER aggregation programs, which may be modeled on that used by CAISO.[17]

To develop those insights, the authors reviewed written comments submitted to CAISO about the program and interviewed a number of stakeholders, including the four DER program participants; other DER owners and aggregators that had participated in CAISO proceedings related to the DER program; and the three investor-owned utilities in California (where they are referred to as utility distribution companies (UDCs)), on whose systems DERs have been deployed. Representatives of CAISO did not respond to our interview requests.

The interviewees expressed remarkably consistent views on CAISO's DER program, and almost all identified the same barriers to program participation—though they disagreed on the value of maintaining, eliminating, or finding ways around them. Those barriers fit neatly into three categories: regulatory barriers from the design of the program; economic barriers from features of the wholesale market and its current participants; and technical barriers from limitations in available technologies. All three types of barriers are significant, but determining whether those in the regulatory category in particular can be lowered without compromising system stability and reliability should be a priority for CAISO, since they appear to drive at least some of the economic barriers. Many of the barriers take the form of "chicken-and-egg" problems that are closely interrelated and thus need to be addressed simultaneously.

Although CAISO's circumstances are in some ways unique, its experience may offer lessons for other wholesale market operators looking to develop DER aggregation programs. We identify six lessons that should guide program development in all markets.

This article proceeds as follows: Part II provides an introduction to DERs and their current uses. Part III then discusses how and why DERs should be integrated

14. Letter from CAISO to FERC Sec'y Magalie R. Salas at 2–3 (Oct. 21, 2002) (noting that aggregators participated in CAISO DR programs launched in 2000 and 2001).

15. *Id.* at 2.

16. CAISO, INFORMATIONAL REPORT OF THE CAL. INDEP. SYS. OPERATOR CORP. (Nov. 30, 2016).

17. *See generally* 157 F.E.R.C. ¶ 61,121. FERC has convened a technical conference to explore issues relating to DER aggregation. *See* Notice of Technical Conference, *Participation of Distributed Energy Resource Aggregations in Markets Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators,* (Feb. 15, 2018), https://perma.cc/ZGB2-BDFP.

into wholesale markets. CAISO's program for DER integration is discussed in Part IV, with a detailed examination of the program's limitations in part IV (D). Based on that examination, Part V identifies lessons for DER program design. Part VI concludes.

II. BACKGROUND: DISTRIBUTED ENERGY RESOURCES

A. What are Distributed Energy Resources?

A DER is any resource that is connected to the electricity distribution grid rather than the bulk power system, or is located "behind-the-meter" on an end-use customer's premises.[18] DERs include:

- *distributed generation*: small electricity generating units that are owned and/or operated by a UDC;
- *behind-the-meter generation*: generating units located on the customer's side of the meter;
- *electric storage*: batteries and other devices capable of receiving electricity, storing it, and later discharging it back to the grid; and
- *demand-side management*: practices and activities that have the effect of reducing demand for electricity (load). These include demand response, whereby customers reduce their electricity usage during peak periods in response to price increases or incentive payments, whether by foregoing that usage altogether or by shifting it to off-peak periods.[19]

B. Current Uses of Distributed Energy Resources

Customers with DERs capable of generating electricity onsite—e.g., solar photovoltaic (PV) systems—can use those resources as an alternative to grid power. Currently, this combination of onsite generation and load reduction by DER owners characterizes most DER use. Onsite generation has grown significantly in recent years, with over 1.1 million U.S. homes now equipped with solar

18. *Id.* at 1 n.2 (defining a DER "as a source or sink of power that is located on the distribution system, any subsystem thereof, or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, thermal storage, and electric vehicles and their supply equipment").

19. N. AM. ELEC. RELIABILITY CORP., DISTRIBUTED ENERGY RES.: CONNECTION, MODELING & RELIABILITY CONSIDERATIONS 1 (2016) (providing that "DG" refers to "[a]ny non-BES [i.e., Bulk Electric System] . . . generating unit or multiple generating units at a single location owned and or operated by the distribution utility"). *See also id.* (providing that "BTMG" refers to a "generating unit or multiple generating units at a single location (regardless of ownership), of any nameplate size, on the customer's side of the retail meter that serve all or part of the customer's retail Load with electric energy"); 157 F.E.R.C. ¶ 61,121, *supra* note 5, at 1 n.1 (providing that an electric storage resource [is] "a resource capable of receiving electric energy from the grid and storing it for later injection of electricity back to the grid"); Final Rule, *Demand Response Compensation in Organized Wholesale Energy Mkts.*, 134 F.E.R.C. ¶ 61,187, at 2 n.2 (Mar. 15, 2011) (providing that "[d]emand response means a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentivize payments designed to induce lower consumption of electric energy"). *See also* FERC v. Elec. Power Supplier Ass'n, 136 S.Ct. 760 (2016) (upholding FERC's authority under the Federal Power Act to adopt Order 745 and determining that the process of adoption had been legally sound).

PV systems, and a new system installed every 2.5 minutes.[20] Depending on its location and prevailing weather conditions, the average residential solar system, which has five kilowatts (kW) of capacity, can generate up to 8,190 kilowatt hours (kWh) of electricity annually.[21] Most states allow customers to sell excess electricity to their UDC in return for a bill credit that offsets the cost of purchased electricity (a practice known as "net energy metering" or NEM).[22] State NEM policies are thought to have contributed to the rapid growth in distributed solar in recent years—so successfully that in many states the volume of distributed solar resources is approaching or has exceeded caps set by the legislation or regulation authorizing compensation via NEM.[23]

State and federal policies have also driven increased use of demand-side management, including both energy efficiency investments and demand response resources. In 2015, approximately 9.1 million customers participated in demand response programs, resulting in cumulative electricity savings of over 1.2 million megawatt hours (MWh).[24] This has significant benefits, providing a flexible and low-cost means of balancing electricity supply with load. Traditionally, achieving this all-important balance has required meeting increases in load with additional generation. However, because load reaches its highest point or "peaks" for only a few days or hours each year, this approach has resulted in inefficient investment in expensive "peaker" generating capacity that sits idle nearly all the time.[25] Where demand response resources are available, grid operators can draw on them instead, thereby reducing or shifting electricity load to bring it into line with existing supply and thus delaying or avoiding investment in new generation.

20. Barry Fischer & Jammie Mountz, *These 3 Maps Show the Absurd Growth Potential of Rooftop Solar in America*, SOLARCITY BLOG (Dec. 9, 2016), http://blog.solarcity.com/rooftop-solar-potential-maps.

21. SOLAR ENERGY INDUS. ASS'N: SOLAR PHOTOVOLTAIC TECH., https://www.seia.org/research-resources/solar-photovoltaic-technology (last visited Apr. 19, 2017).

22. As of April 2017, thirty-nine states and the District of Columbia had laws requiring utilities to offer NEM to customers. In a further two states, utilities voluntarily offered NEM. DATABASE OF STATE INCENTIVES FOR RENEWABLE ENERGY: NET METERING, http://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2017/04/DSIRE_Net_Metering_April2017.pdf (last visited Feb. 1, 2018).

23. ROBERT MARGOLIS ET AL., U.S. DEP'T OF ENERGY SUNSHOT: Q4 2016/Q1 2017 SOLAR INDUS. UPDATE (Apr. 2017) (tracking growth of solar installations and adjustments to state NEM program caps).

24. ENERGY INFO. ADMIN., ELECTRIC POWER SALES, REVENUE, AND ENERGY EFFICIENCY FORM EIA-861 DETAILED DATA FILES: DEMAND RESPONSE, https://www.eia.gov/electricity/data/eia861 (Nov. 21, 2016).

25. *See generally id.*

III. INTEGRATING DISTRIBUTED ENERGY RESOURCES INTO WHOLESALE ELECTRICITY MARKETS

A. Introduction to Wholesale Electricity Markets

Electricity was historically provided by vertically integrated utilities, which owned generating facilities, as well as transmission and distribution infrastructure.[26] Those utilities provided bundled services that included the sale of electricity as well as its transmission and distribution.[27] Beginning in 1996, however, utilities were required to unbundle wholesale electricity transmission from wholesale sales and act as something closer to common carriers of transmission services.[28] Many utilities placed their transmission facilities under the management of an ISO/RTO.[29]

There are currently seven ISO/RTOs in the U.S., each of which is a non-profit or profit-neutral corporation, with responsibility for managing the bulk power system in one or more states (see Figure 1).[30] Each ISO/RTO operates several markets, including:

- two wholesale electricity or "energy" markets, namely:
  - a day-ahead market, in which participants commit to buy or sell electricity at various times over the next twenty-four hours, based on forecast load; and
  - a real-time market, in which participants buy and sell electricity to balance differences between the day ahead commitments and actual load and generation; and
- various ancillary services markets, which are used to procure operating reserves, energy imbalance, and other services that ensure system reliability.[31]

26. Justin Gundlach & Romany Webb, *Carbon Pricing in New York ISO Markets: Federal and State Issues*, 35 PACE ENVTL. L. REV. 5 (Feb. 2017), http://columbiaclimatelaw.com/files/2017/02/Gundlach-Webb-2017-02-Carbon-Pricing-in-NYISO-Markets.pdf.

27. *Id.* at 3.

28. Order No. 888, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities*, 75 F.E.R.C. ¶ 61,080 (Apr. 24, 1996); Order No. 889, *Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct*, 75 F.E.R.C. ¶ 61,078 (Apr. 24, 1996); Order No. 2000, *Regional Transmission Organizations*, 89 F.E.R.C. 61,285 (Dec. 20, 1999). For a discussion of the orders, *see* Justin Gundlach & Romany Webb, *Carbon Pricing in New York ISO Markets: Federal and State Issues*, 35 PACE ENVTL. L. REV. 5-6 (forthcoming), http://columbiaclimatelaw.com/files/2017/02/Gundlach-Webb-2017-02-Carbon-Pricing-in-NYISO-Markets.pdf.

29. Gundlach & Webb, *supra* note 27, at 6.

30. *Id.* at 7.

31. FERC: SECURITY CONSTRAINED ECONOMIC DISPATCH: DEFINITION, PRACTICES, ISSUES, AND RECOMMENDATIONS 5-6 (2006); PJM: LEARNING CENTER: ANCILLARY SERVICES MARKET, https://learn.pjm.com/three-priorities/buying-and-selling-energy/ancillary-services-market.aspx (last visited June 3, 2017).

The ISO/RTO markets are, with one exception, regulated by the Federal Energy Regulatory Commission (FERC).[32] The FERC's regulatory duties include reviewing and approving ISO/RTO-developed tariffs that set out rules for wholesale market operation.[33]

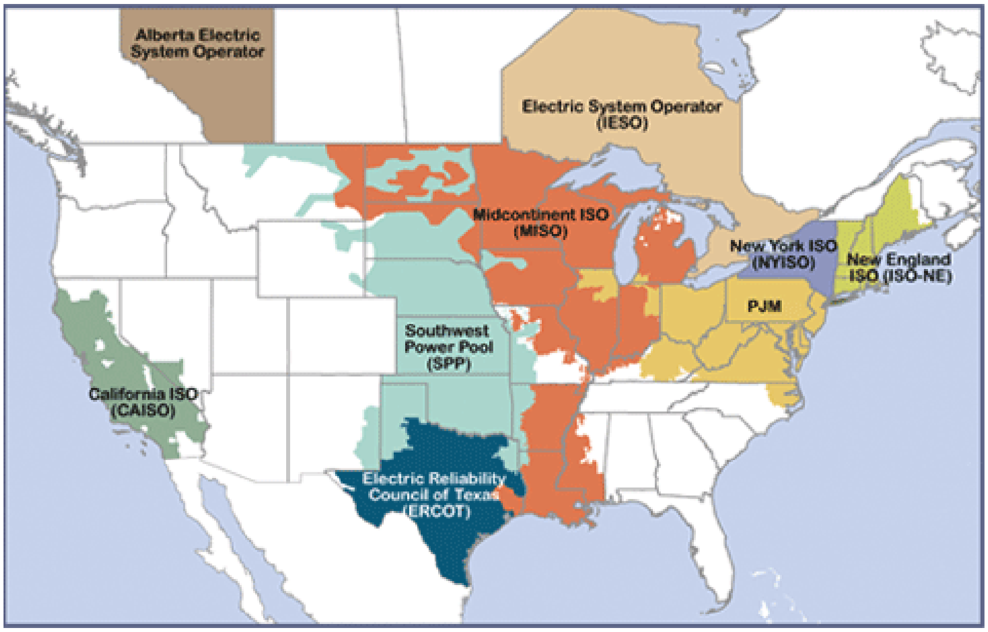

Figure 1: ISO/RTOs Operating in the U.S.[34]

While rules governing wholesale markets vary across ISO/RTOs, all use bid-based auctions to balance supply and load. In simple terms, wholesale energy market participants submit bids indicating the price at which they are willing to supply electricity based on their marginal costs.[35] Suppliers are dispatched based on their bids, from lowest to highest, until load is satisfied.[36] The bid of the last

32. The FERC does not regulate the markets operated by the Electric Reliability Council of Texas (ERCOT). *See* FERC: ERCOT RTO/ISO, https://www.ferc.gov/industries/electric/indus-act/rto/ercot.asp (Nov. 17, 2015). The FERC has jurisdiction over the sale of electric energy at wholesale in interstate commerce. *See* 16 U.S.C. § 824(a) (2015). A sale "at wholesale" is any transfer of electric energy to another person for resale. *See id.* § 824(d). Those sales are considered to occur "in interstate commerce" if the electric energy moves from the seller to the buyer via an interstate transmission grid. *See* Fed. Power Comm'n v. Fla. Power & Light Co., 404 U.S. 452 (1972).

33. 16 U.S.C. § 824 (2015).

34. FERC: REGIONAL TRANSMISSION ORGANIZATIONS (RTO)/INDEPENDENT SYSTEM OPERATORS (ISO), https://www.ferc.gov/industries/electric/indus-act/rto.asp (May 11, 2017).

35. Generators' bids typically reflect their variable costs of operation, including operations and maintenance costs, fuel costs, and emissions costs (e.g., the cost of acquiring emissions permits). SUSAN F. TIERNEY & PAUL J. HIBBARD, ANALYSIS GROUP: CARBON CONTROL AND COMPETITIVE WHOLESALE ELECTRICITY MARKETS: COMPLIANCE PATHS FOR EFFICIENT MARKET OUTCOMES 35 (2015).

36. An ISO/RTO may elect not to dispatch generators on the basis of cost if doing so would threaten the security of the electricity system. Thus, for example, an ISO/RTO may choose not to dispatch the least-cost

supplier dispatched determines the market-clearing price paid to all dispatched suppliers.[37] Ordinarily, if there were no transmission or other constraints restricting the flow of electricity, a single price would apply across the entire ISO/RTO region. However, because such constraints often force some areas to rely on more expensive electricity than others, ISO/RTOs price electricity using the locational marginal price (LMP) at various nodes on the transmission system.[38]

Generators are currently the principal suppliers in energy markets. Steps have, however, recently been taken to facilitate the supply of services by demand response resources. In a series of orders issued in the early 2000s, FERC approved proposals by several ISO/RTOs to allow wholesale and certain retail customers to bid demand response into the day-ahead and real-time energy markets, alongside generation.[39] Subsequently, in 2008, FERC issued Order 719 requiring all ISO/RTOs to accept bids from demand response aggregators acting on behalf of retail customers.[40] To eliminate barriers to participation by aggregators and customers, FERC issued Order 745 in 2011, requiring the full LMP to be paid to certain demand response resources that are dispatched to balance supply and load.[41]

Other DERs, including generation and storage resources, currently have more limited opportunities to participate in energy markets.[42] According to FERC:

> [DERs] tend to be too small to participate directly in the organized wholesale electric markets on a stand-alone basis. First, they often do not meet the minimum size requirements to participate in these markets under existing participation modes. Second, they may have difficulty satisfying all of the operational performance requirements of the various participation models due to their small size.[43]

While DERs could be aggregated to meet the minimum size and performance requirements for market participation, most ISO/RTOs currently only allow DER

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generator if doing so would result in transmission congestion or other operational problems. This approach is known as "security constrained least-cost" dispatch. *See* FERC: SECURITY CONSTRAINED ECONOMIC DISPATCH: DEFINITION, PRACTICES, ISSUES, AND RECOMMENDATIONS 5–6 (2006).

37. Gundlach & Webb, *supra* note 24, at 9.

38. FERC, SECURITY CONSTRAINED ECONOMIC DISPATCH: DEFINITION, PRACTICES, ISSUES, AND RECOMMENDATIONS 8-9 (2006).

39. *See N.Y. Indep. Sys. Operator, Inc.*, 95 F.E.R.C. ¶ 61,223 (2001); *New England Power Pool & ISO New England, Inc.*, 100 F.E.R.C. ¶ 61,287, *order on reh'g*, 101 F.E.R.C. ¶ 61,344 (2002), *order on reh'g*, 103 F.E.R.C. ¶ 61,304, *order on reh'g*, 105 F.E.R.C. ¶ 61,211 (2003); *PJM Interconnection, L.L.C.*, 99 F.E.R.C. ¶ 61,227 (2002).

40. Final Rule, *Wholesale Competition in Regions with Organized Electric Markets,* 125 F.E.R.C. ¶ 61,071 at P 154 (Oct. 17, 2008) (requiring "RTOs and ISOs to amend their market rules as necessary to permit an ARC [i.e., an aggregator of retail customers] to bid [DR] on behalf of retail customers directly into the RTO's or ISO's organized markets, unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate").

41. 134 F.E.R.C. ¶ 61,187 at P 2 (providing that "when a demand response resource participating in an organized wholesale energy market administered by a Regional Transmission Organization (RTO) or Independent System Operator (ISO) has the capability to balance supply and demand as an alternative to a generation resource and when dispatch of that demand response resource is cost-effective . . . [it] must be compensated for the service it provides to the energy market at the market price for energy, referred to as the locational marginal price"), *aff'd* FERC v. Elec. Power Supply Ass'n, 136 S.Ct. 760 (2016).

42. FERC Order 719 aimed solely to remove barriers to wholesale market participation by demand response resources. The FERC expressly refused a stakeholder proposal to expand the order to also address barriers to participation by distributed generation and storage. 125 F.E.R.C. ¶ 61,071 at P 276.

43. 157 F.E.R.C. ¶ 61,121 at P 105.

aggregations to serve as demand response resources and prohibit them from exporting power to the grid or providing ancillary services.[44]

B. Proposals for Enhancing Wholesale Market Integration of DERs

Several individual ISO/RTOs—and FERC, in response—are considering wholesale market reforms to facilitate greater participation by DERs.[45] Recognizing that DERs are generally smaller than other resources connected to the grid (e.g., centralized generation), and thus may not individually meet the minimum size and other requirements for wholesale market participation, the ISO/RTOs (and FERC) have proposed allowing DERs to participate on an aggregated basis.[46] CAISO is the furthest along having undertaken a multi-year stakeholder consultation process to explore market participation models for DER aggregations.[47] Following the completion of phase 1 of that process, in March 2016, CAISO applied to revise its Market Administration and Control Area Services Tariff (MST) to enable participation by DER aggregations.[48] The revisions, which were approved by FERC in June 2016, establish a framework for DER aggregations to participate in CAISO's real-time and day-ahead wholesale energy markets and ancillary services markets (the "DER program").[49] The rules governing market participation are discussed in Part IV(B)(3) below.

Following CAISO's lead, other ISO/RTOs are also considering revising their tariffs to facilitate wholesale market participation by DERs.[50] As an example, since January 2016, PJM Interconnection (PJM) has been actively engaged in discussions with stakeholders about market rule changes required to better integrate DERs.[51] Current PJM rules allow DERs to participate in wholesale markets as demand response, but limit their ability to serve as generators and export power to the grid.[52] The stakeholder process aims to develop a framework through which

44. *Id.* at P 106 (finding that "the majority of distribution-connected electric storage and other distributed energy resources that seek to access the organized wholesale electric markets must do so by participating as behind-the-meter demand response"). *See also id.* at PP 103-10 (discussing existing ISO/RTO rules regarding the participation of DER aggregations in wholesale energy markets).

45. 157 F.E.R.C. ¶ 61,121 at PP 78-81.

46. *Id.* at P 124 (finding that "the ability to meaningfully participate in the organized wholesale electric markets for these smaller distributed energy resources is through aggregations").

47. For information about the consultation process, *see* CAISO: ENERGY STORAGE AND DISTRIBUTED ENERGY RESOURCES, STAKEHOLDER PROCESSES, https://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorage_AggregatedDistributedEnergyResources.aspx (last visited Aug. 14, 2017).

48. 155 F.E.R.C. ¶ 61,229 at P 1.

49. *Id.*

50. PJM operates the bulk power system in Delaware, Maryland, New Jersey, Pennsylvania, Virginia, the District of Columbia, and parts of Illinois, Indiana, Kentucky, Michigan, North Carolina, Ohio, Tennessee, and West Virginia. *See* PJM, PJM VALUE PROPOSITION, http://www.pjm.com/about-pjm/value-proposition.aspx (last visited Aug. 14, 2017); PJM, DISTRIBUTED ENERGY RESOURCES IN PJM MARKETS, https://perma.cc/WAH2-YMDN (last visited Apr. 27, 2017).

51. *Id.*

52. A.F. MENSAH, DISTRIBUTED RESOURCES IN PJM MARKETS: PROBLEM STATEMENT AND OPPORTUNITY (2016).

DERs can participate in wholesale markets as a source of energy, capacity, and ancillary services.[53] Details of the framework have yet to be publicly released.[54]

The New York ISO (NYISO) has also launched a stakeholder process to explore ways to facilitate wholesale market participation by DERs.[55] To inform the process, in January 2017, NYISO released a *DER Roadmap* identifying key barriers to participation and outlining its vision for eliminating them.[56] The Roadmap recognizes the importance of "allowing [m]arket [p]articipants to aggregate individual DER[s] to meet wholesale market eligibility and performance requirements."[57] It calls for the adoption of aggregation rules that are "technology agnostic," allowing a mix of resources (e.g., demand response, generation, and storage) to be included in a single DER aggregation.[58] Notably, however, NYISO has suggested that aggregations should be geographically limited, only consisting of resources connected to the same transmission node.[59] NYISO has also proposed requiring all aggregations to be at least 100 kW in size.[60] It would restrict aggregations of less than 1 megawatt (MW) to participating in wholesale energy markets only, but allow larger aggregations to participate in markets for both energy and ancillary services.[61]

In response to these proposals, in November 2016, FERC announced that it was considering requiring:

> each RTO/ISO to revise its tariff as necessary to allow [DER] aggregators to offer to sell capacity, energy, and ancillary services in the organized wholesale electric markets. Specifically, we propose to require each RTO/ISO to revise its tariff to define [DER] aggregators as a type of market participant that can participate in the organized wholesale electric markets under the participation model that best accommodates the physical and operational characteristics of its distributed energy resource aggregation.[62]

53. PJM, ISSUE CHARGE: DISTRIBUTED RESOURCES IN PJM MARKETS (2016).

54. In August 2017 PJM announced that it would expand its review, i.e., beyond the development of new market rules for DERs, to also look at how to coordinate with UDCs. *See* PJM, *Special MIC on DER Moves Into Electric Distribution Coordination Phase*, PJM INSIDE LINES (Aug. 7, 2017), http://insidelines.pjm.com/special-mic-on-der-moves-into-electric-distribution-coordination-phase.

55. NYISO manages the bulk power system in the state of New York. *See* NYISO: ABOUT NYISO, https://perma.cc/DW2C-Z6YT (last visited Aug. 14, 2017). *See also* James Pigeon, *DER Aggregations: Concept Proposal*, NYISO (Apr. 24, 2017), http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2017-04-24/Distributed%20Energy%20Resource%20Aggregations%20MIWG%20042417.pdf.

56. NYISO, DISTRIBUTED ENERGY RESOURCES ROADMAP FOR NEW YORK'S WHOLESALE ELECTRICITY MARKETS, https://perma.cc/ACA2-VEQ4 (last visited Jan. 31, 2018). NYISO defines DERs "as a resource, or a set of resources, typically located on an end-use customer's premises that can provide wholesale market services but are usually operated for the purpose of supplying the customer's electric load. DER can consist of curtailable load (demand response), generation, storage, or various combinations aggregated into a single entity." *See id.* at 5.

57. *Id.* at 17.

58. *Id.*

59. *Id.*

60. *Id.* at 19.

61. NYISO, *supra* note 57, at 19.

62. 157 F.E.R.C. ¶ 61,121 at P 124. The FERC defines "DERs" as any "source or sink of power that is located on the distribution system, any subsystem thereof, or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, thermal storage, and electric

Under FERC's proposal, each ISO/RTO would have to file tariff revisions to comply with this requirement, and implement any other necessary reforms (e.g., changes to the ISO/RTO's technological systems and/or business practices).[63] If an ISO/RTO believes it is already in compliance, and FERC agrees, it need not implement further reforms.[64] Currently, the only ISO/RTO that is potentially in compliance is CAISO, due to the existence of its DER program. The FERC appears to view that program as consistent with the above requirement, noting that its proposed tariff changes are "similar to CAISO's market rules that establish a [DER] provider as a new type of market participant."[65] Notably, commenters on FERC's proposal have expressed significant concerns with its practicability.

C. Benefits and Challenges of Enhanced Integration

Integrating DERs into wholesale markets can offer several mutually reinforcing benefits: it can improve power quality and reliability while making operations more energy efficient and cost-effective. Those benefits, and the challenges of enhancing DER integration, are described here. It should be noted that the degree to which a DER provides these benefits will depend on several features of its physical and regulatory context, including, most importantly, its location relative to load and to other distribution and bulk power system resources and facilities.[66] It should also be noted that, even if the "right" resources are deployed in the "right" places, these benefits will not accrue to all stakeholders equally.[67] In this paper, we focus on the benefits DER provides to the wholesale electricity marketplace, and the economic actors that look to it to cost-effectively deliver safe and reliable power. The key benefits arising in this context are discussed below.

More cost-effective electric system reliability. Electric system operators have traditionally sought to ensure reliability by building enough capacity to offset the sudden loss of a major generating unit or the failure of a key transmission line.[68] Several features of DERs allow them to support reliability at a lower cost. Studies have shown that, by increasing the diversity of supply, DERs can help to improve system adequacy.[69] Given the small size of DERs, the loss of any one resource will have lesser impact, compared to centralized generation.[70] Moreover,

vehicles and their supply equipment." *See id*. at 1 n.2. The FERC defines a "participation model" as "a set of tariff provisions that accommodate the participation of resources with particular physical and operational characteristics in the organized wholesale electric markets of the RTOs and ISOs." *See id.* at 2 n.5. *See also id.* at 94.

63. *Id.* at P 159.

64. *Id.* at P 161.

65. *Id.* at P 124.

66. Tierney, *supra* note 11, at 31-36.

67. *See generally id.* (discussing benefits of DER to the distribution system as a whole, rather than to particular participants in it, and thus also not to the bulk power system or its participants).

68. U.S. DEPARTMENT OF ENERGY, THE POTENTIAL BENEFITS OF DISTRIBUTED GENERATION AND RATE-RELATED ISSUES THAT MAY IMPEDE ITS EXPANSION 2-2 (June 2007).

69. *Id.* at 2-6 (indicating that distributed generation "can add to supply diversity and thus lead to improvements in overall system adequacy"). *See id.* (quoting a 2005 study finding that "a distributed network of smaller resources provides a greater level of adequacy than a centralized system with fewer large sources, reducing both the magnitude and duration of failures").

70. *Id.* at 2-3 (quoting a review of power issues in Pennsylvania, which found that "distributed generation can increase the system adequacy by . . . reducing the size of generators").

whereas centralized generation often occurs far from load, DERs are typically located close to it, reducing the potential for system outages due to transmission line faults and failures.[71]

More efficient and cost-effective load management. Electricity load fluctuates across seasons, days, and hours: summer peaks are generally highest, weekdays see higher peaks than weekends, and daily peaks occur in mid-afternoon or early evening. During peak times, grid operators must dispatch higher-cost generators to meet load, leading to higher prices.[72] These price spikes can, however, be avoided using DERs.[73] Storage can be used to shift load from peak to off-peak times; demand response can be used to simply reduce load at peak times. Both thereby eliminate the need to dispatch the most expensive generators—sometimes called "peak shaving."[74]

Avoided or deferred investment in new facilities. Investment in new generating capacity is typically driven by the risk that peak load will exceed available capacity.[75] By shifting load to off-peak times, demand response may enable generation investment to be deferred, or avoided altogether. It may also reduce the need for investment in transmission and distribution systems by reducing the stress on system components and thereby extending their useful life.[76]

Reduced electricity line losses. When electric current flows through a transmission or distribution line some of the energy is lost in the form of heat.[77] Such losses are currently estimated at approximately 5% of total generation.[78] The extent of losses could, however, be reduced by using distributed or behind-the-meter generating facilities.[79] As noted above, use of those facilities results in a decline in peak load, reducing the amount of electric current flowing through the system.[80] Moreover, as the facilities are located close to load, the distance over which electricity must be moved is reduced.[81] Both of these factors can lead to a decline in losses.[82]

Notwithstanding these benefits, integrating DERs into the wholesale market also presents challenges and sometimes even risks to power quality or system stability.[83] The electric system was designed to carry one-way flows of power from centralized generating facilities via large transmission lines to substations, and

71. *Id.* at 2-8 (quoting a 2005 study comparing the impact of "transmission system failures on two 2,850 MW peak load systems. The first was a central generation system with 32 generators with capacities from 12 to 400 MW. The second met the load with 500 kW natural-gas fired distributed generators. In reliability models . . . the distributed generation system had roughly 25 times the reliability of the central generation system").

72. U.S. DEPARTMENT OF ENERGY, *supra* note 69, at 3-3.

73. *Id.* at 3-5 - 3-7.

74. *Id.* at 3-6.

75. *Id.* at 3-12.

76. *Id.* at 3-10 - 3-11.

77. U.S. DEPARTMENT OF ENERGY, *supra* note 69, at 3-11.

78. ENERGY INFO. ADMIN., HOW MUCH ELECTRICITY IS LOST IN TRANSMISSION AND DISTRIBUTION IN THE UNITED STATES? (Feb. 16, 2017), https://www.eia.gov/tools/faqs/faq.php?id=105&t=3.

79. U.S. DEPARTMENT OF ENERGY, *supra* note 69, at 3-18.

80. *Id.*

81. *Id.* at 3-8.

82. *Id.* at 1-12.

83. *Id.* at 2-12.

from there, to smaller distribution lines for delivery to customers.[84] For behind-the-meter generating facilities to export electricity to the grid, their connection must be able to carry power to and from the end-user—a two-way flow.[85] This often requires the upgrading of power lines, transformers, meters and other physical components of the grid. Moreover, for grid operators to maintain the crucial balance between generation and load amid this two-way flow, they must also accommodate and manage new patterns of end-user behavior and new sources of power. For both transmission and distribution grid operators, limited "visibility" into each other's transactions and operations can make such management difficult. Distribution grid operators lack full information about coming changes to wholesale prices and congestion levels; ISO/RTOs lack full information about dynamic factors that enable or prevent behind-the-meter generation or other resources from responding to a dispatch order.[86]

IV. PARTICIPATION OF DISTRIBUTED ENERGY RESOURCES IN CAISO'S WHOLESALE MARKETS

A. Introduction to the CAISO

CAISO is a non-profit corporation responsible for managing electricity transmission and wholesale sales in most (though not all) of California and a sliver of Nevada.[87] Like other ISO/RTOs, CAISO operates wholesale markets for energy, capacity, and ancillary services, facilitating over 28,000 transactions annually.[88] Through CAISO's energy markets, approximately 260 million MWh of electricity is traded annually, with most purchased by UDCs for resale to residential, commercial, and industrial customers.[89] An estimated 30 million customers currently receive electricity that was purchased in CAISO's energy markets.[90]

Much of the electricity traded in CAISO's markets is generated by natural gas-fired power plants, which currently account for over 50% of installed capacity in the region (see Figure 2).[91] Natural gas generation is declining, however, with the difference made up by renewables.[92] This trend is expected to continue over the next decade, with increases in renewable generation likely to be driven by California's Renewable Energy Portfolio Standard, which requires 33% of the

84. U.S. DEPARTMENT OF ENERGY, *supra* note 69, at 2-11.

85. *Id.*

86. For a discussion of this issue, *see* Jeff St. John, *As California Prepares for Wholesale Distributed Energy Aggregation, New Players Seek Approval*, GREENTECH MEDIA (Mar. 14, 2017), https://www.greentechmedia.com/articles/read/California-companies-are-vying-for-aggregated-distributed-energy#gs.xuAP6QQ.

87. CAISO, ABOUT US: UNDERSTANDING THE ISO, https://www.caiso.com/about/Pages/OurBusiness/Default.aspx (last visited Aug. 14, 2017).

88. *Id.*

89. CAISO, ABOUT US: HOW POWER FLOWS IN CALIFORNIA, https://www.caiso.com/about/Pages/OurBusiness/How-power-flows-in-California.aspx (last visited Aug. 14, 2017).

90. *Id.*

91. CAISO, WHAT ARE WE DOING TO GREEN THE GRID?, https://perma.cc/2T24-CLNR (last visited Aug. 14, 2017).

92. Energy Info. Admin., *Today in Energy: California Energy Mix in 2017 has Involved More Renewables, Less Natural Gas* (May 17, 2017), https://www.eia.gov/todayinenergy/detail.php?id=31252.

state's electricity to be generated from renewable sources by 2020, and 50% by 2030.[93]

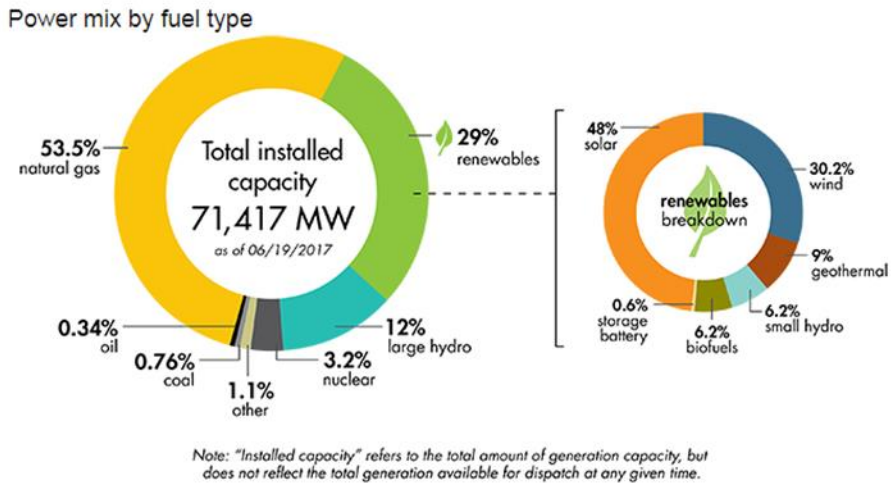

Figure 2: CAISO Generation Mix (2017)[94]

The growth in renewable generation has significant implications for the wholesale market, not least because such generation tends to be poorly correlated with load. Currently, in the CAISO region, load is generally lowest around mid-day and then increases sharply in the late afternoon and early evening.[95] However, due to the large number of solar energy systems in the region, generation follows the opposite pattern (i.e., it is highest during the middle of the day and declines in the afternoon and evening).[96] This results in a phenomenon known as the "duck curve" (see Figure 3), wherein net load drops significantly during the middle of the day, then jumps in the late afternoon, requiring large volumes of generation to ramp up quickly.[97] This has implications for wholesale prices: average prices in CAISO's day-ahead and real-time energy markets now mirror the net load pattern of the duck curve, with the highest prices in the morning and evening and low (often negative) prices during midday hours.[98]

93. CAISO, ANNUAL REPORT ON MARKET ISSUES AND PERFORMANCE 16 (2016) (indicating that "[t]he ISO anticipates a continued increase in new nameplate renewable generation in the coming years to meet the state's goal to have 33% renewable generation by 2020 and 50% by 2030").

94. CAISO, *supra* note 92.

95. CAISO, *supra* note 94.

96. Solar energy systems currently account for approximately 14% of total generation in California. *See* CAISO, *supra* note 92.

97. For a discussion of this issue, *see* SCOTT MADDEN MANAGEMENT CONSULTANTS, REVISITING THE CALIFORNIA DUCK CURVE: AN EXPLORATION OF ITS EXISTENCE, IMPACT, AND MIGRATION POTENTIAL 2 (2016), http://www.scottmadden.com/wp-content/uploads/2016/10/Revisiting-the-Duck-Curve_Article.pdf.

98. *Id.*

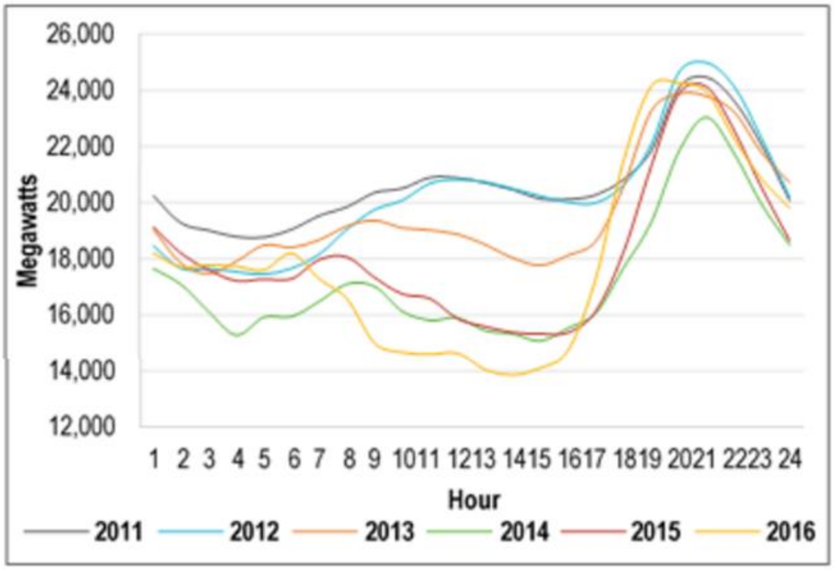

Figure 3: Net Load in California (2011-2016)[99]

B. *CAISO's Distributed Energy Resource Program*

As noted in Part III (B) above, in June 2016, CAISO received approval from FERC to amend its MST to "enable aggregations of energy resources connected to distribution systems [i.e., DERs] within [its] balancing area to participate in its energy and ancillary services markets."[100] Under CAISO's amended MST, DER aggregations are recognized as a new type of market resource that may supply energy and ancillary services, similar to traditional generating facilities.[101]

1. Distributed Energy Resource Aggregations

CAISO defines a "DER aggregation" as any resource comprised of one or more DERs, with a first point of interconnection to a distribution system or metered subsystem.[102] Aggregations may comprise any type of DER—i.e., generation, storage, and/or demand-side resources—except:

- demand response resources that participate in CAISO's wholesale markets as "Proxy Demand Response" (PDR) or "Reliability Demand Response" (RDR) resources;
- distributed and behind-the-meter generating facilities:
  - with a capacity greater than 1 MW; or
  - with a capacity of 0.5 to 1 MW that elect to become wholesale "Participating Generators;" and

99. *Id.*
100. Letter from Andrew Ulmer, CAISO, to FERC Sec'y Kimberly Bose (Mar. 4, 2016).
101. *Id.* at 8. *See* 155 F.E.R.C. ¶ 61,229 at P 8.
102. 155 F.E.R.C. ¶ 61,229 at P 3. *See* Letter from Ulmer to Bose, *supra* note 101, at 5, 8.

- any resource, regardless of type or size, that participates in a retail NEM program.[103]

There are no restrictions on the number of individual resources that can be aggregated.[104] Aggregations may include one or more resource types.[105] The resources in an aggregation may span multiple pricing nodes, but must be within a single sub-load aggregation point, i.e., on the same side of a transmission constraint identified by CAISO.[106] The combined capacity of all resources must be at least 0.5 MW and, if the aggregation includes resources located at different pricing nodes, must not exceed twenty MW.[107] There is no maximum size for aggregations limited to one pricing node.[108]

An aggregation may include DERs located in-front-of and/or behind-the-meter.[109] Each DER must be interconnected to the distribution system in accordance with the rules of the relevant UDC.[110] Each UDC has two sets of interconnection rules: the Wholesale Distribution Access Tariff (WDAT) it files with FERC and the Electric Rule 21 tariff it files with the California Public Utilities Commission (CPUC).[111] These apply to different types of resources. Generally, resources supplying electricity into the wholesale market (e.g., through the DER program) must be interconnected under the WDAT.[112] Interconnection is only permitted under

103. Both "Proxy Demand" and "Reliability Demand Response" resources comprise load(s) that are capable of measurably and verifiably reducing electric demand in response to CAISO dispatch instructions. The key difference between the two is that Reliability Demand Response resources only reduce demand at times of emergency whereas Proxy Demand resources may do so at any time. *See* Order Conditionally Accepting Tariff Changes and Directing Compliance Filing, 132 F.E.R.C. ¶ 61,045 (2010); Order Accepting Tariff Revisions, 146 F.E.R.C ¶ 61,233 (2014). CAISO defines a retail NEM as any program that allows participating resources to net excess generation against future electricity bills. According to CAISO, "[b]ased on this netting approach, there is no energy available to offer into the CAISO markets since excess energy is banked for later withdrawal." *See* Letter from Ulmer to Bose, *supra* note 101, at 6-7. *See also* 155 F.E.R.C. ¶ 61,229 at PP 6.

104. Letter from Ulmer to Bose, *supra* note 101, at 2.

105. *Id.* at 4.

106. *Id* at 10. According to CAISO, a "sub-load aggregation point" or sub-LAP "is a [] defined subset of pricing nodes within a default load aggregation point. . . . Sub-LAPs were initially developed with the advent of congestion revenue rights to reflect major transmission constraints within each utility service territory." *Id.* at 10 n.24. CAISO currently has twenty-three sub-LAPs. *Id.* at 10.

107. Letter from Ulmer to Bose, *supra* note 101, at 9.

108. Memorandum from Keith Casey, Vice President, Market and Infrastructure Development, CAISO to CAISO Board of Governors (Jul. 9, 2015) (on file with the authors).

109. 155 F.E.R.C. ¶ 61,229 at P 3.

110. Memorandum from Casey to Board of Governors, *supra* note 109, at Attachment A (indicating that "it is the distribution utility and not the ISO that species and administers the connection of resources to a distribution system").

111. SAN DIEGO GAS & ELECTRIC: OVERVIEW OF GENERATION INTERCONNECTIONS, https://www.sdge.com/generation-interconnections/overview-generation-interconnections (last visited Jul. 21, 2017).

112. SOUTHERN CALIFORNIA EDISON, SCE'S GENERATOR INTERCONNECTION PROCESSES: AN INTRODUCTION TO WHAT YOU NEED TO KNOW BEFORE REQUESTING INTERCONNECTION 9 (2017); SOUTHERN CALIFORNIA EDISON, FREQUENTLY ASKED QUESTIONS FOR SCE'S RULE 21 TARIFF 5 (2016).

Rule 21 if the resource will participate in a NEM program under the jurisdiction of the CPUC.[113]

Each DER in an aggregation must be equipped with a revenue meter capable of accurately measuring the amount of energy produced and consumed by the resource each hour.[114] The meter must comply with any standards prescribed by the relevant local regulatory authority (LRA) (i.e., the authority responsible for overseeing the UDC to whose distribution network the DER is interconnected) or, if no such standards exist, rules developed by CAISO.[115] The meter must be certified by the LRA or, if covered by CAISO rules, the scheduling coordinator for the relevant DER aggregation.[116]

2. Becoming a Market Participant

The owner or operator of a DER aggregation—known as a DER Provider or DERP—may participate in CAISO's energy and ancillary services markets.[117] To become a market participant, the DERP must:

- execute an agreement with CAISO indicating that it accepts and will abide by the MST;
- provide CAISO with a list of the DERs that will comprise its aggregation(s);
- notify the UDC or metered subsystem in whose service area the DERs are located;
- obtain a concurrence letter from the UDC or metered subsystem, indicating that it has no concerns about the DER's wholesale market participation; and
- complete CAISO's new resource implementation process, including a ten-day trial operation period.[118]

3. Rules for Wholesale Market Participation

Like other market participants, DERPs may only bid into wholesale energy and ancillary services markets through a scheduling coordinator, which has been certified by CAISO.[119] A DERP may elect to become a scheduling coordinator itself or retain another scheduling coordinator to act on its behalf.[120]

113. SOUTHERN CALIFORNIA EDISON, SCE'S GENERATOR INTERCONNECTION PROCESSES: AN INTRODUCTION TO WHAT YOU NEED TO KNOW BEFORE REQUESTING INTERCONNECTION 11 (2017); SOUTHERN CALIFORNIA EDISON, FREQUENTLY ASKED QUESTIONS FOR SCE'S RULE 21 TARIFF 4 (2016).

114. Letter from Ulmer to Bose, *supra* note 101, at 16, 22. *See* CAISO, Fifth Replacement FERC Electric Tariff, clause 10.3.7, https://www.caiso.com/Documents/ConformedTariff_asof_Jul10_2017.pdf [hereinafter CAISO Tariff].

115. CAISO Tariff, *supra* note 115, clause 10.3.7.

116. *Id.* clause 10.3.9.

117. This article does not explore the operation of DER aggregators outside of CAISO's wholesale market.

118. CAISO, DISTRIBUTED ENERGY RESOURCE PROVIDER PARTICIPATION GUIDE WITH CHECKLIST (2016), https://www.caiso.com/Documents/DistributedEnergyResourceProviderParticipationGuideandChecklist.pdf. *See also* CAISO, *New Resource Implementation Process and Requirements*, https://www.caiso.com/participate/Pages/NewResourceImplementation/Default.aspx (last visited Aug. 8, 2017).

119. Letter from Ulmer to Bose, *supra* note 101, at 5.

120. *Id.* at 3.

Generally, when acting for a DERP, scheduling coordinators may submit bids in the same way as they do for other types of market participants.[121] The key exception is when the resources in the DERP's aggregation span multiple pricing nodes. In such cases, the bids submitted by the scheduling coordinator must include generation distribution factors, reflecting the share of resources at each node.[122] So, if an aggregation is comprised of resources spanning two pricing nodes (P1 and P2) that are capable of providing 0.7 MWh at P1 and 0.3 MWh at P2, the scheduling coordinator would submit a 1 MWh bid with distribution factors of 0.7 at P1 and 0.3 at P2.[123]

In responding to bids on behalf of DERPs, CAISO will treat the aggregation as a single resource, regardless of the location of the individual DERs.[124] CAISO will issue dispatch instructions at the level of the aggregation and it will then be up to the DERP to disaggregate those instructions to the DERs.[125] The DERs must, together, provide a net response at the pricing node level that is consistent with CAISO's dispatch instructions and the generation distribution factors in the bid (if any).[126] Notably, however, energy may flow from individual resources in different directions, with some exporting energy to the grid and others taking energy from it.[127]

Two key mechanisms are used to verify that DER aggregations operate in accordance with CAISO's dispatch instructions and any applicable generation distribution factors. These are:

- *Telemetry*: CAISO will require certain aggregations to submit "real-time" data through telemetry. Data need only be submitted for the aggregation as a whole and not for each individual DER.[128] Initially, only aggregations providing ancillary services or with a rated capacity of 10 MW or more will be required to submit data, but CAISO may "reduce the size of resources at which these requirement[s] apply" in the future.[129]

121. *Id.* at 12.

122. *Id.* at 13.

123. For further examples, *see id.* at 13-16.

124. Letter from Ulmer to Bose, *supra* note 101, at 8-9.

125. *Id.* at 3.

126. *Id.* at 12; *see also* 155 F.E.R.C. ¶ 61,229 at P 11.

127. Tom Flynn, *Decision on Expanding Metering and Telemetry Options (Distributed Energy Resources Provider)*, Presentation at the CAISO Board of Governors Meeting (Dec. 17–18, 2015). CAISO had originally proposed that, in the case of aggregations spanning multiple pricing nodes, "all sub-resources must be homogenous and must move in the same direction as the ISO dispatch instructions . . . for aggregations of energy storage, all sub-resources must be operating in the same mode (that is, charging or discharging, but not a mix of the two) in response to an ISO dispatch instruction." Memorandum from Casey to Board of Governors, *supra* note 109, at 3 (July 9, 2015), https://www.caiso.com/Documents/Decision_ExpandingMetering_TelemetryOptions-Memo-Jul2015.pdf. This requirement was later removed after CAISO determined that it is not "necessary to manage congestion and other transmission constraints." Memorandum from Keith Casey, Vice President, Market and Infrastructure Development, CAISO, to FERC Sec'y Kimberly Bose (March 4, 2016) https://www.caiso.com/Documents/Mar4_2016_TariffAmendment_DistributedEnergyResourceProvider_ER16-1085.pdf (included as Attachment D).

128. Letter from Ulmer to Bose, *supra* note 101, at 17.

129. *Id.* at 16-17.

- *Metering*: CAISO will require the scheduling coordinator to collect, for each DER in an aggregation, data reflecting its actual production and/or consumption of energy (i.e., as recorded by its revenue meter).[130] Aggregated data, reflecting the total production or consumption of all DERs in the aggregation, must be submitted to CAISO daily.[131] The data must cover every hour of the day (24/7 settlement), regardless of whether the aggregation bid into the market and/or was dispatched.[132]

Based on the metering data submitted by the scheduling coordinator, CAISO will calculate the DERP's "settlement balance," reflecting the amount owed to or by it.[133] If all of the DERs are located within a single pricing node, settlement will be based on the LMP for that node.[134] For aggregations spanning multiple pricing nodes, CAISO will use a weighted LMP, based on the prices at each pricing node.[135]

C. Current Wholesale Market Participation by Distributed Energy Resource Providers

In an informational report submitted to FERC in November 2016, CAISO indicated that four companies had executed agreements to become DERPs.[136] Through interviews conducted with interested parties between June and August 2017, we learned of one additional company that is looking to execute an agreement in coming months. No other interviewees expressed interest in doing so, though several indicated that they may look at becoming a DERP in the future, particularly if CAISO takes steps to address current problems with the DER program (discussed in Part IV(D) below).

None of the companies that have registered as DERPs are currently participating in CAISO's energy and/or ancillary services markets. One company representative indicated that, despite registering as a DERP, it has no concrete plans to enter the market at this time. The other three companies expressed interest in entering the market, with one stating that it is "looking to be the first" to enter in late 2017, while another indicated that it is aiming to enter by early 2018. Despite this, there was broad agreement among interviewees that participation was likely to be limited in the short- to medium-term. Many pointed to the experience with CAISO's PDR and RDR programs, which remained largely unused for several years after their introduction, and suggested that the DER program develop similarly.

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130. The data cannot be derived using a baseline or otherwise estimated (e.g. from statistical sampling). *See id.* at 16.

131. CAISO does not directly "poll" the meters of DERs, but rather relies on the Scheduling Coordinator to collect and submit meter data. *See id.*

132. *Id.* at 8.

133. Letter from Ulmer to Bose, *supra* note 101, at 8.

134. 155 F.E.R.C. ¶ 61,229 at P 11.

135. *Id.*

136. The four companies are Apparent Energy, Inc., Galt Power, Inc., Olivine, Inc., and San Diego Gas and Electric Company. *See* CAISO, *supra* note 5.

D. Barriers to Wholesale Market Participation by Distributed Energy Resource Providers

Several forms of DERs could provide services valued by CAISO energy and ancillary services markets if rules and business models existed to allow them to do so—so goes the theory of the DER program. The program was intended to enable realization of the value of DERs by establishing a framework under which DER aggregations may participate in CAISO markets.[137] However, participation is currently limited and is expected to remain so in the short- to medium-term. Chief among the DERs whose services are not currently engaged as fully as they might be are storage resources, including the batteries in electric vehicles.

The authors' interviews with parties engaged in some fashion with CAISO's DER program indicate that there are three types of barriers to aggregators' participation: regulatory, economic, and technical. As explained below, the sources of these barriers are interwoven, such that changes to one will affect the others.

1. Regulatory Barriers

Interviewees remarked on various regulatory barriers to wholesale market participation by DER aggregations. Many of these barriers arise from CAISO's attempts to treat DER aggregations on the same basis as conventional generating facilities. According to CAISO, in developing the DER program, it relied "on existing market models and tariff rules to the maximum extent possible."[138] These existing models and rules are, however, often poorly suited to DER aggregations.

a. 24/7 Settlement Requirement

The most significant regulatory barrier to participation appears to be CAISO's requirement of 24/7 settlement. This was identified as a barrier by all interviewees, with some suggesting that it may be insurmountable.

The reasons for the 24/7 settlement requirement are straightforward: CAISO wants DER aggregations to provide service as reliably and transparently as conventional generators, and does not want them to be able to take advantage of price fluctuations by stepping out of the marketplace at times when they might have to buy power at high prices or sell at low ones. Whatever the reasons for imposing it, this requirement seems to have discouraged DER program participation. It is especially consequential for behind-the-meter battery systems, a resource type that would otherwise be well suited to participate in the DER program, for two reasons:

- Requiring 24/7 settlement results in behind-the-meter batteries paying twice for the energy they use to charge. Battery owners must pay both retail prices for energy drawn through the meter and the wholesale LMP for the same energy.[139]

137. Letter from Ulmer to Bose, *supra* note 101, at 2.

138. *Id.*

139. *See* CAL. ENERGY STORAGE ALLIANCE, COMMENTS ON THIRD REVISED ENERGY STORAGE AND DISTRIBUTED ENERGY RESOURCES (ESDER) PHASE 2 STRAW PROPOSAL 7 (May 18, 2017), http://www.storagealliance.org/sites/default/files/Filings/2017-05-18%20CESA%27s%20Comments%20on%20ESDER%20Third%20Revised%20Straw%20Proposal%20-%20FINAL.pdf ("energy used to charge the storage is assessed the Locational Marginal Price (LMP), in addition

- Due to the 24/7 settlement requirement, if a battery discharges to meet onsite electricity needs at a time when the LMP is negative, the owner must make payments into the wholesale market, despite the fact that no power was exported onto the bulk grid.[140]

Given the above, requiring 24/7 settlement effectively prohibits any behind-the-meter operation, and thus also effectively prohibits at least some of the multiple-use application functions that make batteries an economical investment.[141] That is, while it is technically possible for batteries to serve onsite electricity needs at certain times and export to the grid at others, this dual usage is effectively prohibited by the 24/7 settlement requirement. Given that many of the DERs that might participate in the DER program were acquired primarily if not exclusively to meet onsite electricity needs, this is likely to discourage them from participating in the wholesale market. To the extent that DERs do participate, they are likely to do so through CAISO's PDR/RDR programs, which do not require 24/7 settlement. Under those programs, however, DERs cannot provide energy or ancillary services to the bulk power system and thus their full value cannot be realized.

In view of these problems, several interviewees said that removal or relaxation of the 24/7 settlement requirement would encourage participation in the DER program. Many supported allowing DERPs to "opt-out" of the wholesale market when performing behind-the-meter operations and only subjecting them to wholesale market settlement at times when they have opted in (i.e., when the DERP, through its scheduling coordinator, bids into the wholesale market and is dispatched by CAISO). As other interviewees pointed out, however, this approach could lead to difficulties, particularly with respect to behind-the-meter storage. One utility described an example of these difficulties in written comments filed with CAISO, explaining that there is no way to "split" the electricity used to charge a storage device such that wholesale rates would only apply to energy later discharged as exports into the bulk power system (and compensated by CAISO markets) and retail rates would only apply to electricity later discharged to meet onsite load.[142] Perhaps for this reason, CAISO has, to date, refused to reconsider the 24/7 settlement requirement on the basis that doing so would be "complex and may have broad implications" for market operation.[143] Whatever the actual reason or reasons, the tension CAISO faces on this point is clear: maintaining this requirement assures uniformity and system stability on the one hand, but shuts out the participation of potentially valuable resources on the other.

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to the hosts' costs for paying the applicable retail rate for the charging energy drawn through the retail meter. The DERP-host customer combination thus pay double for each KWh used to charge the storage system").

140. Any decision to exempt DER from this requirement would be almost certainly be challenged as violating the FPA's prohibition on discrimination among resources.

141. *See* GARRETT FITZGERALD ET AL., THE ECONOMICS OF BATTERY ENERGY STORAGE (2015).

142. For a discussion of this issue, *see* PACIFIC GAS & ELECTRIC, COMMENTS ON ENERGY STORAGE AND DISTRIBUTED ENERGY RESOURCES (ESDER) REVISED ISSUE PAPER AND STRAW PROPOSAL (2015).

143. Only resources participating in the market via the PDR or RDR program are exempt from the 24/7 settlement requirement. *See* CAISO, ENERGY STORAGE AND DISTRIBUTED ENERGY RESOURCES STAKEHOLDER INITIATIVE PHASE 2 ("ESDER 2"): STRAW PROPOSAL 34 (2016).

b. Metering and Telemetry Requirements

Several interviewees also raised concerns about the metering and telemetry requirements imposed on DERPs, though most saw this as only a moderate barrier to wholesale market participation and much less significant than the 24/7 settlement requirement.

Under the DER program, CAISO has imposed the same metering and telemetry requirements on DERPs as apply to traditional generators, despite their different capabilities.[144] With respect to metering, for example, CAISO requires each DER in an aggregation to be equipped with a revenue meter or other device that accurately records the amount of energy produced and consumed.[145] In addition, where the aggregation provides ancillary services, telemetry systems capable of transmitting data at one minute intervals must also be installed.[146] While this is unlikely to be an issue for all DERPs, for some small operators, the cost of metering and telemetry may be prohibitive.

Given the above, some interviewees argued that the existing metering and telemetry requirements should be relaxed, for example, to allow the use of alternative meter data. They noted that, under the PDR and RDR programs, meter data may be derived from baselines or estimated in other ways (e.g., from statistical sampling, such as NYISO is considering) and recommended that similar options be made available in the DER program.[147] However, this approach may be opposed by utilities, at least one of which has welcomed the existing meter requirements on the basis that they ensure data accuracy.[148] Retention of the existing requirements is also likely to be supported by conventional generators, with one industry association arguing "CAISO should not lessen or diminish its metering standards in order to accommodate business models unable to finance the requisite metering to participate in wholesale markets."[149]

c. Interconnection Requirements

Interviewees also remarked that CAISO's WDAT interconnection process, which must be completed by all DERs wishing to participate in the wholesale market, is extremely cumbersome. This owes both to the direct costs that the WDAT imposes, such as fees and hardware requirements, and to the long timeframe it creates for DERs seeking wholesale market access.[150] As well as being cumbersome, the requirements of the WDAT (which is slightly different for each UDC) exceed those of Rule 21, which governs NEM participants' market

144. CAISO, EXPANDED METERING AND TELEMETRY OPTIONS PHASE 2, DISTRIBUTED ENERGY RESOURCE PROVIDER: DRAFT FINAL PROPOSAL 13-15 (2015).

145. Letter from Ulmer to Bose, *supra* note 101, at 16, 22.

146. *Id.* at 152.

147. For aggregations of less than 1 MW, NYISO has said it will consider requiring aggregators to provide real-telemetered data for only a sample set (at least 30%) of participating DERs. NYISO, *supra* note 57, at 21.

148. PAC. GAS & ELEC. CO., COMMENTS ON EXPANDED METERING & TELEMETRY OPTIONS PHASE 2 DRAFT FINAL PROPOSAL 3 (Jun. 25, 2015).

149. INDEP. ENERGY PRODUCERS ASS'N, COMMENTS ON ENERGY STORAGE AND DISTRIBUTED ENERGY RESOURCES (ESDER) PHASE 2 REVISED STRAW PROPOSAL 4 (2017).

150. *See* STEM & EMOTORWERKS, JOINT COMMENTS ON THIRD REVISED ENERGY STORAGE AND DISTRIBUTED ENERGY RESOURCES (ESDER) PHASE 2 STRAW PROPOSAL 6 (2017).

access.[151] As a DER that was interconnected under Rule 21 must, before entering the wholesale market, reapply for interconnection in conformity with the WDAT's heftier rubric, this constitutes yet another source of costs and uncertainties for DER owners considering whether to participate in the wholesale market. Interviewees suggested that it would be possible to alleviate this burden by promulgating a less cumbersome "WDAT lite," but did not specify how it would differ from the WDAT.

d. Wholesale/Retail Market Interaction

In the background of all of these issues are efforts by both CAISO and the CPUC to sort out answers to jurisdictional issues raised by any proposal to pay DERs, whose physical operation straddles the retail/wholesale divide, for the full scope of their functionality. These include both legal questions (such as "Who decides what?") as well as practical questions (such as "What communications and telemetry capabilities are necessary?" "What visibility can/must UDCs and CAISO have into each other's operations?"). CAISO has, by all accounts, begun working to address these issues in collaboration with the CPUC and other interested parties, but progress has been slow owing in large part to these entities' limited staff complements and large volumes of other work.[152]

2. Economic Barriers

Economic barriers to participation in the DER program take two forms: low (or negative) net revenues available from such participation, and more remunerative revenue streams available to operators from participation in wholesale PDR/RDR or retail NEM programs. Both of these relate to "regulatory barriers," but they are also the result of features of the electricity sector that neither CAISO nor the CPUC can change merely by amending existing rules.

a. Low Net Revenues

Almost all interviewees expressed concern that wholesale market participation may be unprofitable for DERPs. Many noted that the revenues generated by individual DERs are likely to be low—i.e., due to their small size—making it necessary to aggregate a large number of resources to cover costs. However, large aggregations require significant upfront investment, creating the potential for

151. CAISO Presentation, INTERCONNECTION BASICS (Nov. 2014).

152. CAISO and the CPUC have worked with UDCs to address their concerns about the potential impact of DERs' wholesale market participation on the distribution system, including the potential for DER owners to avoid paying for their use of the distribution grid. *See* PAC. GAS & ELEC. CO., COMMENTS ON ENERGY STORAGE AND DISTRIBUTED ENERGY RESOURCES (ESDER) REVISED ISSUE PAPER AND STRAW PROPOSAL (2015). Some DERPs expressed concern about the approach taken to address distribution-related issues. For example, some objected to the requirement to obtain a concurrence letter from the relevant UDC, arguing that this effectively gives UDCs "veto power" over wholesale market participation by DERPs. While most felt that this was unlikely to be a problem in California, where UDCs generally support increasing use of DERs, it may create tensions in other areas. To address this issue, one interviewee recommended that DERPs only be required to consult with UDCs, and not obtain approval therefrom. Any objections raised by the UDC should, according to the interviewee, be subject to review by an independent third party to confirm their validity.

losses, particularly in the short- to medium-term. Indeed, according to one interviewee, most DERPs are likely to operate at a loss for the first few years after market entry.

The high cost of DER aggregations is due, in part, to the need for their contributions to wholesale markets to be predictable, timely, reliable, and transparent for accounting purposes—i.e., records of the resulting transactions must capture who owes what to whom, for what, and when.[153] Practically speaking, these parameters require DERPs and their scheduling coordinators to have highly sophisticated metering capabilities—including telemetry for some participating DERs—as well as facilities and staff capable of managing the planning, operations, and accounting involved in wholesale market participation. A DERP, for example, must invest in systems capable of translating a dispatch order from CAISO into service provision within minutes. And, of course, the cost of these systems and equipment are in addition to the cost of acquiring and installing the DER itself.

While the above costs are, to a certain degree, outside CAISO's control, others are not. Several interviewees mentioned that CAISO requires scheduling coordinators to obtain an identification number (the "SCID") for each DER aggregation at a cost of $1000 per month.[154] The same monthly cost is imposed on conventional generation resources, despite the fact that those resources have significantly greater capacity, and are therefore able to earn higher revenues in the market.[155] While the SCID cost may not be prohibitively high for all would-be DERPs, its uniformity across market participants of all sizes ignores meaningful differences and encumbers DER participation rather than facilitating it.

Crucially, several of the costs of wholesale market participation (particularly those incurred by DER owners and DERP) are generally not subject to economies of scale, meaning that the addition of another DER does not reduce the costs incurred by the provider. In contrast to scheduling coordinators' overhead, for instance, the costs of acquiring DER capacity, interconnection, and metering are simply additive. Reducing these costs would therefore require other solutions, such as cost-reducing technological developments, DERPs handling owner-level transaction costs (e.g., related to interconnection) in a way that would make them subject to economies of scale, or aggregators being permitted to employ consolidated virtual metering in lieu of the individual DER metering currently required by CAISO.[156]

Given the costs involved, most interviewees agreed that operators are unlikely to invest in DERs solely for the purpose of wholesale market participation, at least in the immediate future. The pool of operators participating in the wholesale market is, therefore, likely to be limited to those who have already invested in DERs for other purposes (e.g., to meet onsite electricity needs). Even for those operators, however, wholesale market participation may not make economic sense

153. *Id*. at 3.

154. Jim Price, CAISO, Presentation to WECC Unscheduled Flow Administrative Subcommittee: Briefing on CAISO/PacifiCorp Energy Imbalance Market 18 (Jan. 8, 2014), http://slideplayer.com/slide/733492 (noting $1,000 monthly SCID fee).

155. *See generally id.*

156. Consolidated virtual metering involves the use of mathematical models to estimate energy flows (i.e., as an alternative to using a physical meter).

due to the way in which the DER program has been structured and the restrictions it imposes on the use of resources outside the wholesale market and their inherent diseconomies.

b. Alternative Revenue Streams

Many of the DERs that could participate in the wholesale market via the DER program also have the option of participating in California's retail NEM program or in CAISO's PDR or RDR programs. The DER program was not intended to replace these programs, but ends up competing with them, as participation in the existing programs excludes an operator from also participating in the DER program.[157] This exclusion aims to prevent "double payment," for example, where a resource "receive[s] a retail rate credit for its output under a [NEM] program and also sell[s] the same output to obtain a wholesale market payment."[158] However, forced to choose between programs, operators are unlikely to participate in the DER program as net revenues therefrom would almost certainly be lower than those generated through participation in other programs.

Participation in retail NEM and wholesale PDR/RDR programs imposes few interconnection, metering, and other costs on operators. For example, retail NEM participation has so far only required installation of a meter that is capable of spinning backwards as well as forwards.[159] As for participants in wholesale PDR/RDR programs, they need only be responsive to calls to cease drawing power from the grid, which can be accomplished with fewer and simpler devices than are required for participation as a DERP, and they are not subject to the 24/7 settlement requirement.[160]

In the absence of wholesale PDR/RDR programs, operators would very likely make greater use of the DER program—notwithstanding the relatively low net revenues available—because the alternative would be to forego any payments for the services their DERs could provide to wholesale markets. In contrast, adding costs to or reducing payments from participation in retail NEM would likely do little to boost DER Program participation.[161] This is particularly true for solar

157. *Cal. Indep. Sys. Operator*, 155 F.E.R.C. ¶ 61,229 at P 6 (June 2, 2016) (stating exclusion). Operators could simultaneously participate in the wholesale DER program and a retail NEM program if the latter allowed for wholesale market participation. Currently, however, despite this technical capability, no NEM program allows for such participation.

158. Letter from Ulmer to Bose, *supra* note 101, at 27-28.

159. CPUC Rule 21 governs NEM interconnections. The versions of Rule 21 applied by each of California's three UDCs are available at http://www.cpuc.ca.gov/Rule21. *See also* GO SOLAR CALIFORNIA, NET ENERGY METERING IN CALIFORNIA, http://bit.ly/2unxT1K (last visited Aug. 8, 2017). As California's three utilities implement the NEM Successor Tariff, participation by new entrants will eventually require use of a meter that can also track time of use. *See* Cal. Pub. Util. Comm'n, Decision 16-01-044 at 16 (Jan. 28, 2016); Jeff St. John, *With Net Metering Secure, California Solar Now Faces Uncertainty From Time-of-Use Changes*, GTM: A WOOD MACKENZIE BUSINESS (Feb. 16, 2017), https://www.greentechmedia.com/articles/read/with-net-metering-secure-california-solar-now-faces-threat-from-time-of-use#gs.4o13zEw.

160. *See* CAISO Tariff, *supra* note 115, at §§ 8.4.5 (communication required for ancillary services provision), 8.4.6 (metering required for ancillary services provision), 10.3 (metering requirements for scheduling coordinating entities).

161. The NEM successor tariff generally reduces the amount of money flowing to participants. CPUC, NET ENERGY METERING RULEMAKING (R.) 14-07-002, http://www.cpuc.ca.gov/General.aspx?id=3934 (last vis-

DERs, which generate most of their electricity around midday, when wholesale electricity prices are lowest (see discussion of the "duck curve" phenomenon in part IV(A) above). Currently, under state NEM programs, this generation can be used to offset consumption at times of higher prices.[162] In comparison, under the DER program, DERPs could only bid into wholesale markets during the daytime hours when wholesale prices are low, and would still likely consume power in the evening when prices rise. Combining solar with storage could change this by enabling DERPs to shift the timing of their consumption, but only after the costs of acquiring small-scale storage fall significantly. In the meantime, an indirect and limited way to encourage greater participation in the DER program might be to adjust the NEM program, for instance by incorporating time-of-use pricing.

3. Technical Barriers

This category of barriers is the sparsest of the three because a number of existing technologies would enable the aggregation of DERs for participation in wholesale markets if those technologies were supported or required by CAISO or CPUC rules and/or were economical to deploy. Thus, the problems described here can be thought of as technological or organizational gaps that, if they were bridged, could make it possible to get around some of the regulatory or economic barriers described in Parts IV(D)(1) and IV(D)(2) above.

The most basic technical barrier at issue for the DER program is metering. How can a metering system track energy, ancillary, and capacity services provided simultaneously in retail and wholesale markets pursuant to different tariffs and programmatic requirements? A corollary question: can a meter be made both smart enough and affordable enough to do so for small-scale DERPs? Answers could take the form either of clever meter design, virtual metering shown to be operationally robust and serviceable also for accounting purposes, or—more likely—a combination of technical, organizational, and regulatory developments that improve metering capabilities while also providing off-site support for meters' functionality.

Another technical barrier arises from the need to balance electricity load with supply. This requires grid operators to develop complex systems for tracking, mapping, and predicting load and generation patterns across seasons, days, and hours. This is challenging when electricity flows just one way—from conventional generators to end users—and is made far more difficult by two-way flows to and from systems located at the end of the grid's capillary systems. This barrier

ited Oct. 10, 2017) (NEM successor tariff—already in effect in SDG&E service territory and scheduled for adoption state-wide—now requires payment of one-time interconnection fee and non-bypassable charges, and applies time-of-use rates to NEM accounting).

162. Different states' NEM programs vary in their particulars. The logic, fairness, and effectiveness of NEM program specifications are hotly debated topics. *See* Harvey L. Reiter & William Greene, *The Case for Reforming Net Metering Compensation: Why Regulators and Courts Should Reject the Public Policy and Antitrust Arguments for Preserving the Status Quo*, 37 ENERGY L.J. 373 (2016); Jon Wellinghoff & Steven Weissman, *The Right to Self-Generate as a Grid-Connected Customer*, 36 ENERGY L.J. 305 (2016). Several states are currently revising their NEM programs, for example, to incorporate time-of-use rates. *See* CPUC, NET ENERGY METERING (NEM), http://www.cpuc.ca.gov/General.aspx?id=3800 (last visited Oct. 10, 2017).

exists at both the retail/distribution and wholesale/transmission levels, and is compounded by impediments (technical, practical, and legal) to enabling visibility for system operators responsible for one level or the other.

V. WHAT CAN FERC AND OTHER RTO/ISOS DRAW FROM CAISO'S EXPERIENCE?

Because each RTO/ISO's particular rules and circumstances are distinct, CAISO's experience thus far with its DER program offers lessons that apply elsewhere to varying degrees. This part suggests several ways in which other wholesale market regulators can make use of CAISO's experience as they consider options for integrating DERs into wholesale markets.

Legacy requirements should be examined. Regulators should treat the occasion of devising a program for integrating the contributions of DERs via aggregation into wholesale markets as an opportunity to reexamine the logic of existing requirements' design and implementation. Whether those legacy requirements relate to interconnection, metering, settlement, or some other aspect of market participation, they were not devised in contemplation of DERs and particularly not of storage, yet RTO/ISOs continue to apply them to DERs. They should be examined to ensure this application is consistent with the aim of just and reasonable rates, nondiscriminatory service, and efficient system management. Recognizing that the barriers described above are often interwoven, the goal of such an examination would be to identify where problematic limitations root in rules, business models, or technologies that could be improved or replaced without impairing the overall operation of electricity markets and where the changes are cost effective over all.

Interactions with existing demand response programs must be carefully considered. DER programs should be structured in a way that, as far as possible, complements rather than competes with existing demand response programs. The full value of many DERs, particularly behind-the-meter generation and storage, cannot be realized through demand response programs, which assign value to load shifting and peak shaving but not to the energy exports and ancillary services available from DERs. To take advantage of these services, ISO/RTOs must take care in structuring wholesale DER programs—and possibly restructuring demand response programs as well—to ensure that maximizing the financial value of DERs does not mean foregoing services other than load shifting and peak shaving. In some cases, changes to retail NEM programs, for example to incorporate time-of-use rates, may also be required.

Jurisdictional issues will persist and can only be managed effectively through ongoing collaboration among regulators. Because DERs operate astride the traditional boundaries between retail/distribution and wholesale/bulk contexts, their greater integration into either context will continue to create challenging practical and legal circumstances. As the ongoing development of DERs and technologies that support their integration into grid operations reveals how existing approaches—regulatory and technical—fail to make optimal use of all available resources, overall improvement is unlikely to follow from bold unilateral steps by federal or state regulators. Rather, improvement will require close collaboration between them, whether in the form of joint proceedings or jurisdictional agreements, or informal dialogue that enables coordinated but formally independent approaches.[163]

Collaboration will also be needed with UDCs, but must be approached cautiously. A close corollary to the need for collaboration between regulators is the need for collaboration with the UDCs that manage distribution system operations. Because integrating DERs into wholesale markets will have major impacts on distribution systems, potentially requiring upgrades to the system's physical components as well as operational changes, UDCs must be consulted about DER integration. The consultation process should reflect local conditions, including whether the relevant UDCs have an incentive to discourage use of DERs, for example because they operate in a state where the volume of power they sell substantially determines their revenues.[164]

Economics will be a key driver of wholesale market participation—at least in the short term. It is clear that economic factors have had a major impact on participation in CAISO's DER program. To maximize participation, ISO/RTOs should take steps to ensure that program rules do not inappropriately restrict the net revenues that can be earned by DERs, for instance by imposing unnecessary costs. Consideration should be given, among other things, to more flexible metering and interconnection requirements that may reduce costs without impairing wholesale market operation. ISO/RTOs should also strive for an optimal balance between placing appropriate restrictions on DER aggregations and maximizing opportunities for aggregation and with it positive network externalities and economies of scale.

It will be important to distill questions that can be answered through research and pilot programs. Stakeholders disagree about the importance of particular risks and benefits related to greater integration of DERs into wholesale markets via aggregation. For instance: Under what circumstances would waiving the 24/7 settlement requirement for DERPs lead to system instability? What volume of additional, serviceable resources would become available following some form of waiver? Developing useful estimates of risks' and benefits' actual importance will likely require pilot studies that can develop answers to such questions by altering some of the factors at work in wholesale and retail markets while holding others constant. The FERC has authority to authorize such studies—it has done so in at least three past instances.[165]

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163. JEFFERY S. DENNIS ET AL., FEDERAL/STATE JURISDICTIONAL SPLIT: IMPLICATIONS FOR EMERGING ELECTRICITY TECHNOLOGIES 27–29 (Dec. 2016) (presenting several options for reconciling state and federal regulatory positions).

164. A number of jurisdictions, including California, have "decoupled" the revenues their utilities can recover from the sale of electricity. *See* CTR. FOR CLIMATE & ENERGY SOLUTIONS, ENERGY SECTOR: DECOUPLING POLICIES, https://www.c2es.org/us-states-regions/policy-maps/decoupling (Nov. 2016). In those jurisdictions, utility compensation is a function of one or more performance targets that do not include simple sales volume. NAT'L RENEWABLE ENERGY LAB., DECOUPLING POLICIES: OPTIONS TO ENCOURAGE ENERGY EFFICIENCY POLICIES FOR UTILITIES (2014), https://www.nrel.gov/docs/fy10osti/46606.pdf. The utilities do not, therefore, have any financial incentive to oppose the use of DERs. Stakeholders interviewed for this study generally agreed that decoupling likely explained why utilities in California have not sought to limit the use of DERs and expressed few concerns about their integration into wholesale markets. Many noted, however, that utilities in other states may be less supportive of DERs.

165. FERC, LICENSING HYDROKINETIC PILOT PROJECTS (Apr. 2008). *See also Verdant Power LLC*, 111 F.E.R.C. ¶ 61,024, *order on reh'g* 112 F.E.R.C. ¶ 61,143 (2005); Order No. 637, *Regulation of Short-Term*

VI. CONCLUSION

Investment in DERs, including small-scale generation and storage facilities, has grown dramatically in recent years. While these facilities are currently principally used behind-the-meter, i.e., to meet onsite electricity needs, if deployed in the right places and under the right conditions, they could also help to enhance reliability and reduce costs in the bulk power system. Seeking to access these benefits, CAISO has established a program through which DERs can participate in its wholesale energy and ancillary services markets on an aggregated basis. Other ISO/RTOs, and FERC, are now considering wholesale market reforms to facilitate participation by DER aggregations.

Adoption of the DER program by CAISO, while an important development, has yet to deliver significant benefits. At the time of writing, just four DER aggregators had signed up, and none of those had begun operating in the wholesale market. Based on discussions with participating aggregators and other stakeholders, we identified several inter-related regulatory, economic, and technical factors that have contributed to this outcome.

While each ISO/RTO's particular rules and circumstances are distinct, the apparent failure of CAISO's DER program offers lessons for other ISO/RTOs and FERC as they consider options for integrating DERs into wholesale markets. Perhaps most importantly, ISO/RTOs and FERC should carefully examine whether legacy requirements, developed for conventional generating facilities, are appropriate for DERs—something CAISO appears not to have done. Key among these is the 24/7 settlement requirement, which seems to have discouraged participation in the DER program, and encouraged many would-be participants to stick with existing demand response programs. Likely interactions with those programs should be considered when developing rules for wholesale market participation by DERs.

CAISO's experience also highlights the jurisdictional issues—both legal and practical—associated with integrating DERs into wholesale markets. Addressing such issues successfully will require ISO/RTOs to engage in ongoing collaboration with state regulators. Consultation will also be needed with UDCs, whose systems may be affected by DERs' operation, but not in a way that invites UDCs to stymie DER participation.

Natural Gas Transportation Services and Regulation of Interstate Natural Gas Transportation Services, F.E.R.C. STATS. & REGS. 31,091 at 31,300, *clarified*, Order No. 637-A, F.E.R.C. STATS. & REGS. 31,099, *reh'g denied*, Order No. 637-B, 92 F.E.R.C. ¶ 61,062 (2000), *aff'd in part and remanded in part sub nom*. Interstate Nat. Gas Ass'n of America v. FERC, 285 F.3d 18 (D.C. Cir. 2002), *order on remand*, 101 F.E.R.C. ¶ 61,127 (2002), *order on reh'g*, 106 F.E.R.C. ¶ 61,088 (2004), *aff'd sub nom*. American Gas Ass'n v. FERC, 428 F.3d 255 (D.C. Cir. 2005); *Secondary Market Transactions on Interstate Natural Gas Pipelines, Proposed Experimental Pilot Program to Relax the Price Cap for Secondary Market Transactions*, 61 Fed. Reg. 41,401 (Aug. 8, 1996), 76 F.E.R.C. ¶ 61,120, *order on reh'g*, 77 F.E.R.C. ¶ 61,183 (1996).