



HARVARD LAW SCHOOL
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THE CASE AGAINST DIRECT FERC REGULATION OF DISTRIBUTED ENERGY RESOURCES

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THE CASE AGAINST DIRECT FERC REGULATION OF DISTRIBUTED ENERGY RESOURCES

Introduction

The utility business model and power generation industry are built upon a century-old legal regime. Federal and state laws are premised on power flowing from large-scale infrastructure to captive consumers paying regulated rates to a monopoly utility. Today, electric power and money can flow in the opposite directions. Services supplied through utility-owned distribution grids, including storage, energy production, and demand response, upend long-standing industry assumptions about infrastructure investments, consumer behavior, and rate setting. In doing so, distributed energy resource (DERs) threaten incumbent businesses and challenge entrenched regulatory regimes.

Regulation of the electric industry is pervasive and will determine where DERs are deployed, the services they may provide, the prices they are paid, and who is allowed to own them. A threshold issue in addressing the future of DER regulation is the roles that federal and state regulators will play in making these decisions.

This paper pieces together, from numerous FERC orders and federal court decisions, how the Federal Energy Regulatory Commission's (FERC) jurisdiction over interstate wholesale energy sales and transmission service applies to DERs. It finds that FERC has disclaimed authority over DER sales that offset a ratepayer's retail consumption but federal law applies to other sales. FERC's current approach to these other energy transfers splits authority with state regulators based on various factors, including technology and location on the grid. This fragmented regulatory regime could doom DERs to segmented markets, preventing the creation of a coherent framework for DER development.

This paper suggests that FERC should simplify the overlapping web of state and federal regulation by disclaiming jurisdiction over DER energy sales. Doing so would allow states to regulate sales by all types of DERs to local buyers, such as a utility or aggregator. States would then have clear authority to develop comprehensive DER development models. It would also free FERC from the potentially onerous task of directly regulating millions of small-scale resources, while allowing FERC to invite aggregations of DERs to sell directly into regional wholesale markets.

The Disruptive Potential of DERs

Electricity distribution is monopolized by local and regional utilities. Investor-owned utilities, typically publicly traded companies that are subject to extensive state regulation, distribute power to approximately three-quarters of U.S. homes, with municipally owned and rural cooperative utilities, which are largely self-regulated, distributing most of the remainder.¹ For much of the industry's history, these utilities generated and distributed nearly all electric power.

The industry's technical architecture—characterized by large power plants interconnected with high-voltage transmission lines terminating at utility-owned distribution grids—required enormous sums of capital to build. Utilities were able to raise that money by collecting administratively set rates that reimburse the utility for its costs and provide a profit margin on infrastructure investments. The state-regulated ratemaking process separates captive consumers into various classes, such as residential, commercial, and industrial. Consumers within a class pay the same rate, under the theory that the rate reflects the cost of serving the average consumer in that class.

This business model was devised in the early twentieth century when expanding infrastructure and enabling greater consumption were in the public interest. By providing utilities with a rate of return on their capital investments, rates allowed utilities to capture the profits of expansion and incentivized them to build more capacity. For consumers, this financial model was initially acceptable because the cost of power generation declined for much of the industry's history. Supply grew sharply as power prices went down, and ratepayers and regulators expressed little concern about conservation or efficient consumption.

By the 1970s, the industry's economics had turned. Power generation costs rose, and the steady demand growth that had fueled the industry's rapid expansion levelled off. Nonetheless, the amount of power that ratepayers consumed during the highest demand periods continued to grow. The industry's need to meet escalating peak demand provided a basis for continued infrastructure expansion.

Utility regulators in many states recognized that energy savings could be a cost-effective substitute for power generation. Because utilities have historically had little

incentive to reduce sales and growth, many states began to require utilities to provide energy efficiency services to consumers, including programs targeted at reducing consumption during peak demand periods.² These mandates are typically aimed at capturing cost-effective demand reductions, as determined by regulators.

The widespread acknowledgement that demand need not be treated merely as a static input into the utility's planning process but could be managed by the utility and consumers represented fundamental change. Rather than building large-scale infrastructure to meet system needs, utilities could invest in efficiency and demand response to eliminate the need for new projects or reduce their scale. The recognition in the 1970s by regulators that doing so might be less expensive and be better for the environment established the foundation for widespread DER deployment.

Implementing this theoretical breakthrough in power system planning was limited by the regulatory construct and available technology. The administrative ratemaking process rewarded utilities for building physical projects and encouraged them to sell as much power as possible. Conservation, efficiency, and small-scale generation owned by consumers and third parties cut against both incentives. In addition, few cost-effective DER technologies were available in the 1970s.

More recent improvements in energy efficient appliances, lighting, and building materials have accelerated efforts to harvest demand reductions. Advances in communications and computing allow for centrally dispatched demand response programs that reduce usage during high-cost periods. Improvements in other DER technologies, such as solar panels, fuel cells, and batteries, are providing consumers with new flexibility and offering utilities decentralized, cost-effective, and scalable options for keeping the grid in balance.

The potential for proliferation of DERs fundamentally challenges the traditional utility model in several ways.

First, DERs can reduce the need for utility infrastructure. For instance, in 2016 California transmission planners cancelled nearly \$200 million of upgrades in light of demand reductions stemming from energy efficiency and rooftop solar.³ The cancellations highlight that DERs can erode utility profit opportunities.

Second, DERs change utility operations and planning. Historically, power flowed in one direction, from industrial-sized power plants to high-voltage transmission lines to distribution grids connected to consumers. Utility planning focused on large-scale projects built to meet demand and maintain reliability. DERs can be cost-effective substitutes for these traditional projects. Assessing how DERs can obviate new construction and maintaining reliable bidirectional power flows with high penetration of DERs may require innovative operational tools and planning methods.

Third, DERs defy assumptions embedded in traditional ratemaking. With regulators' approval, utilities have lumped ratepayers together in classes and charged all members of each class uniform rates. With DERs, consumers within a class may have very different consumption patterns and be able to provide different services to the utility, such as the ability to reduce or increase consumption on command. Rates have not historically accounted for these differences among individual consumers.

Fourth, DERs raise the prospect that entities that are not ratepayers may seek to connect to the distribution grid. Most DERs are located "behind-the-meter" and tied to a ratepayer's utility account. DER developers may want to bypass this traditional model and sell energy and other services to the local utility without a ratepayer intermediary.

Regulation will play a dominant role in determining the rate of growth of DERs. Regulators will define the

market, set terms and conditions for entering the market, and approve price-setting mechanisms. Regulators may also scrutinize utility planning and demand that utilities explore whether DERs are cost-effective alternatives to traditional infrastructure, and even conduct competitive procurements. Absent regulatory interventions, utilities might seek to maintain the status quo and stifle DER development by offering unfavorable rates, limiting opportunities to interconnect, and ignoring opportunities for cost-effective deployment.

A threshold question is the relative influence that state and federal regulators will have on these determinations. The state-regulated distribution grid will bear the direct costs and benefits of DER growth. Utility operations and planning and the rates for distribution service may require fundamental change to accommodate two-way power flows and foster flexible consumption. There is little doubt that states have direct authority over these issues and over DER siting.

Rates paid for DER services will be an important factor driving growth. Although DER sales have significant and direct local effects, authority over rates is divided between states and FERC by decades old federal laws. The bulk of this paper focuses on the resulting incoherent ratemaking regime and argues that FERC has the authority to simplify it by disclaiming jurisdiction over DER energy sales. States would then have clear jurisdiction to set rates for all DER sales and services and could unify regulation of utility operations and planning, distribution service rates, and DER sales.

Regulation will play a dominant role in determining the rate of growth of DERs. Regulators will define the market, set terms and conditions for entering the market, and approve price-setting mechanisms.

Federal Jurisdiction over Sales by DERs

The legal landscape for DERs is fractured by laws written for other resources. The Federal Power Act (FPA), signed into law by President Roosevelt in 1935, was written to provide the federal government with authority over utility-to-utility energy sales and transmission service. The only amendment to the statute relevant to FERC's authority over DERs is the Public Utility Regulatory Policies Act of 1978 (PURPA), which aimed to break the utility monopoly over power generation and encourage development of technologies that burn fossil fuels efficiently or are powered by renewable fuel.

FERC has asserted jurisdiction over various DER transactions under two different FPA provisions. Section 201 of the FPA provides FERC with jurisdiction over “the sale of electric energy at wholesale in interstate commerce.”⁴ FERC argues that this grant of authority allows it regulate rates paid for all energy injections into the electric grid, unless the transfer is netted against a ratepayer's consumption (net metered). Sections 205 and 206 of the FPA require that all such rates, as well as practices “directly affecting” those rates, be “just and reasonable.”⁵ The provisions provide FERC with authority to regulate rates paid for wholesale services that reduce consumption (demand response) and to set all wholesale market rules, including those about the types of resources that may sell in those markets.

PURPA requires utilities to purchase all power generated by Qualifying Facilities (QF), defined to include renewable energy generators smaller than 80 megawatts, and grants states authority to regulate rates for those purchases. The law thus provides states with authority to set rates for DERs' renewable energy sales and instructs states to set rates that correspond to a utility's cost of purchasing or generating energy that it would have needed but-for the QF's energy.⁶ Notably, PURPA does not provide states with authority over QF sales to non-utility entities, such as aggregators that package multiple DERs into a single wholesale market offer.

State net metering programs, which allow consumers to offset their utility bills with energy they inject into the grid, do not fit neatly under FERC's FPA authority or state PURPA ratemaking regimes. FERC has disclaimed jurisdiction over these energy transfers but claims authority over “net sales” from a ratepayer to a utility over and above the ratepayer's consumption. FERC's determination results in a single resource being regulated under different ratemaking regimes depend-

ing on the consumption of the associated ratepayer. While all resources are under state authority for transfers that offset consumption, the regulation of net sales is split between FERC and states depending on whether the resource is a QF.

FERC has no authority over sales of demand response service from a consumer to a utility or an aggregator. However, demand response service sold by a consumer or by an aggregator of consumers to an interstate wholesale market operator “directly affects” wholesale rates and is within FERC's jurisdiction.

This section explores how decades-old federal laws divide authority over DER sales.

FERC Regulation of DER Energy Sales as Wholesale Sales in Interstate Commerce

When Congress passed the FPA in 1935, most states had already developed a comprehensive scheme for electric utility regulation. The Act provides FERC with jurisdiction over rates for electric transmission and wholesale power sales “in interstate commerce,” which the Supreme Court had ruled were beyond states' Constitutional authority.⁷ In bringing the industry's interstate transactions under federal control, Congress made “federal and state powers ‘complementary’ and ‘comprehensive,’”⁸ intending the Act “to be a complement to and in no sense a usurpation of State regulatory authority.”⁹ Congress therefore explicitly denied FERC authority over generation facilities and “facilities used in local distribution,” as well as “any other sale” that was not a wholesale sale in interstate commerce.¹⁰ Those transactions and facilities been subject to state regulation, and there was no Constitutional reason compelling a switch to federal oversight.

This division of authority accorded with the industry structure and technology that existed at the time. Its straightforward application meant that FERC had jurisdiction over the rates for interstate transmission and energy sales between utilities, where the utility intended to resell the purchased energy to its ratepayers. States retained their then-existing authority under public utility laws over sales to consumers, power plant operations, utility-owned distribution grids, and infrastructure siting. None of these laws contemplated DERs.

FERC has long held that its jurisdiction over a particular energy sale depends on the nature of the sale and the counterparties, and not on the location of the sale. For example, in 1951 FERC rejected an argument that it did not have authority over certain wholesale energy sales because the energy only traversed facilities used for local distribution in the state where the energy was consumed. FERC explained that “nothing in the [FPA] makes our jurisdiction . . . over sales of electric energy dependent upon the nature of the facilities involved in effecting the sale.”¹¹ Fourteen years later, FERC rejected similar argument, holding that “there is nothing in the Power Act that makes Commission jurisdiction over sales dependent on whether the facilities used are local distribution facilities.”¹² In both cases, federal appeals courts upheld FERC’s decisions.

In 2010, FERC rejected a utility’s request that the Commission disclaim jurisdiction over sales by generators connected to a utility-owned distribution system. According to the requesting utility, sales of energy by a DER should not be subject to FERC’s jurisdiction because they are not “in interstate commerce.” The utility argued that “as a physical matter sales of power over lower voltage distribution wires are unlikely, on account of impedance, to enter the [interstate] bulk power system.”¹³ It cautioned that “a decision asserting Commission jurisdiction over all distribution-level power sales to utilities would necessarily bring within the Commission’s regulatory reach literally millions of homeowners, farmers or businesses . . . who sell power to their local utility.”

FERC tersely declined the invitation to distinguish between wholesale sales effectuated over the transmission network and those executed on a distribution system, restating its longstanding position that its authority “to regulate sales for resale of electric energy . . . in interstate commerce by public utilities is not dependent on the location of generation . . . but rather on the definition of . . . wholesale sales contained in the FPA.”¹⁴ FERC’s order was not reviewed by any court.

FERC’s claim of jurisdiction over all energy sales, including those by DERs, is limited by PURPA. The law has traditionally been understood by state regulators as limiting their ratemaking authority to rates based on a utility’s costs. However, provided a utility offers a so-called avoided-cost rate, FERC has recently held that a utility may offer QFs other rates too.¹⁵ In effect, this allowance by FERC, which has never been challenged in court, may allow states to set any rate for utility QF purchases by requiring the utility to offer the state’s desired rate, provided the utility also offers an

avoided cost rate. However, FERC’s orders sanctioning this approach appear to suggest that the utility may voluntarily offer QFs any other rate and do not explicitly endorse a state-mandated rate. Thus, a state setting a rate for QF sales that is not based on avoided costs is assuming some legal risk.

This uncertainty over the scope of state ratemaking authority under PURPA is compounded by the law’s limited reach. PURPA assumes that QFs sell energy only to a utility and is silent on whether states have authority to set rates for QF sales to other entities, such as aggregators who purchase energy from multiple DERs and resell the package through an interstate wholesale market. Assuming PURPA does not apply to DER energy sales to non-utility entities, FERC would have exclusive authority over these sales.

Finally, energy sales by public power entities, such as municipal utilities, and rural cooperative utilities are not regulated by FERC.¹⁶ A sale by a government-owned DER would therefore not be under FERC’s authority. However, such exempt entities that participate in interstate wholesale markets run by a Regional Transmission Operator (RTO) or Independent System Operator (ISO)^a must comply with the FERC-jurisdictional market’s rules.¹⁷ Sales to exempt entities are FERC-jurisdictional, assuming the seller is not also an exempt entity.¹⁸

To recap, FERC claims that energy sales by DERs are wholesale sales “in interstate commerce” and therefore under its exclusive authority. PURPA provides a carve-out, granting states permission to set rates for DER sales of renewable energy so long as the purchaser is a utility. State regulation of these rates must adhere to PURPA’s parameters. As discussed below, FERC allows energy transferred pursuant to state net-metering programs to escape its jurisdiction.

Split Jurisdiction over Net-Metered DERs

Jurisdiction over energy sales from a net-metered resource depends on: 1) the ratio of the ratepayer’s consumption to production at the time of the energy transfer and 2) whether the resource is a QF under PURPA. As a legal matter, these factors determine whether a net-metered energy transfer is regulated pursuant to states’ plenary authority over retail sales, under states’ limited PURPA ratemaking authority, or by FERC under the FPA. As a practical matter, states enjoy wide discretion to set rates for net-metered resources, and FERC has not challenged their legality. Nonetheless, the potential for a legal challenge and the current tangled jurisdictional web clouds the long-term

^a The term RTO/ISO is abbreviated as RTO for the remainder of this paper.

viability of the regulatory framework for energy transfers from behind-the-meter resources.

Under a typical net metering arrangement, a ratepayer's behind-the-meter energy production, such as from rooftop solar, is netted against her consumption to determine her total monthly utility bill. In 2001, FERC rejected the claim that "every flow of power constitutes a sale" under the FPA and determined that there is no jurisdictional sale when a consumer "installs generation and accounts for its dealings with the utility through the practice of netting."¹⁹ However, when a ratepayer's production exceeds her consumption over a billing period, FERC held that federal jurisdiction attaches to that net sale.²⁰

In 2009, FERC reiterated its 2001 determinations, explaining that its jurisdiction over a flow of power depends on the whether a "customer participating in the [state-regulated] net metering program produces more energy than it needs over the applicable [state-regulated] billing period."²¹ The practical result of FERC's holding is that federal jurisdiction applies only at the conclusion of a retail billing period when the total production and consumption have been measured. Only then is it possible to determine how much energy was transferred pursuant to federal authority.²²

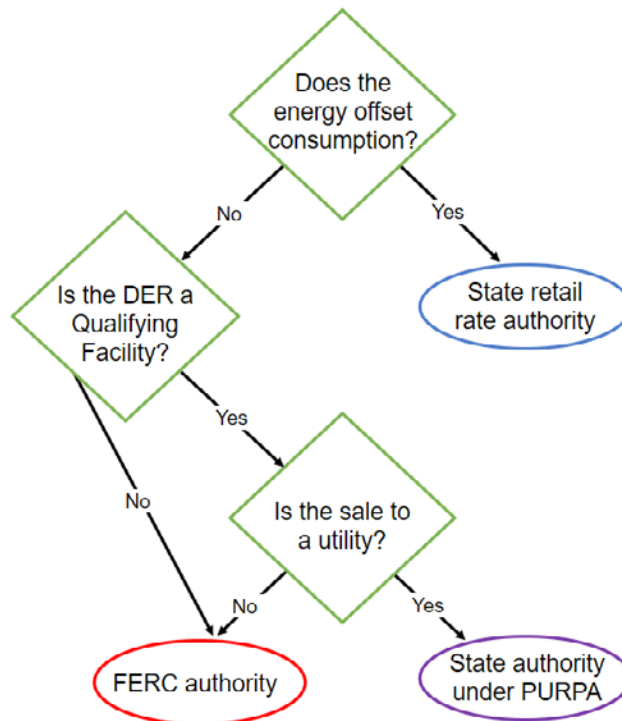
FERC's assertion of jurisdiction over "net sales" has limited practical effect because states have authority under Public Utility Regulatory Policies Act (PURPA) to set rates for most of these sales. States may therefore set rates for net sales from QFs but must follow PURPA's parameters. However, some DERs that inject energy into the grid and could be net metered, such as batteries that charge from the grid and fuel cells, are not QFs.²³ FERC claims that states have no authority to set rates for net sales from these resources.

For these non-QF DERs, FERC claims exclusive jurisdiction to set rates for net sales. Unlike QFs, these resources must also comply with FPA filing requirements, such applying for permission to sell at market-based rates, and meet FERC's accounting standards.²⁴ FERC has held that it "has no authority to grant blanket de minimis exemptions from rate regulation" for these resources.²⁵

To summarize, the decision tree below depicts the factors that determine jurisdiction over DER energy sales. Those factors are whether: 1) the energy offsets retail consumption; 2) the resource is a QF; and 3) the energy is transferred to a utility.

The result of this legal morass is that identical resources might receive different rates depending on these

Jurisdiction over DER energy sales under current FERC orders



factors. For example, a 100-kilowatt solar array located behind a meter would be under state ratemaking authority – although it might be paid different rates at different times of the retail billing period. An otherwise identical solar array connected directly to a utility distribution system would receive state-set PURPA rates at all times. Batteries co-located with each resource that charge both from the grid and the array would be under different ratemaking regimes from the solar arrays. Net sales from the behind-the-meter battery would be under FERC’s authority, while other energy transfers could be net metered. For the other battery, all sales would be subject to FERC’s jurisdiction.

This fractured regulatory framework, a creature of decades-old laws, imposes inconsistent ratemaking criteria on DER energy sales and forces them into fragmented and incompatible markets. Rates based on administrative frameworks not designed for DERs may inhibit competition among DER providers and fail to capture the values DERs provide to the grid.

FERC’s Invitations to DERs to Sell through Interstate Wholesale Markets

FERC’s primary task under the FPA is to ensure that wholesale energy rates are “just and reasonable” and not unduly discriminatory. When FERC finds that “any rule, regulation, practice, or contract affecting such rate” is unjust and unreasonable or unduly discriminatory, FERC must order the utility to modify the offending tariff.²⁶

In 2016, the Supreme Court held that FERC’s authority over “practices” that “affect” wholesale rates applies only to rules or practices that directly affect wholesale rates. The Court intended that this “common-sense” construction of the statute would avoid reading the FPA to grant FERC with authority over “indirect or tangential” impacts on wholesale rates. After all, as the Court observed, “markets in just about everything—the whole economy, as it were—” can affect electricity markets. Clearly, Congress did not intend for FERC’s authority to extend so far.²⁷

FERC has concluded that its jurisdiction over “practices” that “directly affect” wholesale rates provides it with exclusive authority to determine the criteria for participation in RTO markets.²⁸ According to FERC, the “authority to determine which resources are eligible to participate in the wholesale markets is a fundamental component of the regulation of the wholesale markets.”²⁹

Since the Court’s 2016 decision, FERC has finalized an order that invites energy storage resources, including those that are behind the meter, to participate in RTO markets and proposed a rule that would allow DER aggregators to offer into RTO markets. It has also held that states may not prohibit energy efficiency resources from offering into RTO capacity markets. This section details these recent developments, beginning with FERC’s demand response regulations.

Demand Response

Demand response service is a reduction in the consumption of electricity in response to high energy prices or payments intended to induce lower usage.³⁰ In two separate orders, FERC ordered all RTOs to accept bids from aggregators of retail customers providing demand response services, unless state regulators prohibited retail customers from providing that service, and required market operators to pay demand response the same rate they pay generation.³¹ FERC believed that these reforms would increase competition, reduce barriers to entry, moderate prices, enhance reliability, limit generator market power, and ensure that wholesale rates are just and reasonable.³²

Because demand response service is not a wholesale sale of energy in interstate commerce, opponents of the orders argued that FERC did not have authority to regulate rates paid to demand response providers. In 2016, the Supreme Court ruled otherwise, concluding that rules governing wholesale demand response “directly affect” wholesale rates and are therefore within FERC’s authority. Acknowledging that demand response “is a complex matter that lies at the confluence of state and federal jurisdiction,”³³ FERC claimed that its rules

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governing demand response participation in wholesale markets do not intrude on state jurisdiction over retail rates.³⁴ The Supreme Court agreed, concluding that FERC’s “justifications for regulating demand response are all about, and only about, improving the wholesale market.”³⁵

FERC’s orders do not allow a wholesale market operator to accept a bid from a demand response aggregation that includes retail customers prohibited from participating in wholesale markets by state regulators.³⁶ That concession by FERC allows states to opt-out of wholesale demand response by enacting legislation or regulations that prohibit retail customers from contracting with aggregators.

Importantly, FERC does not have jurisdiction over demand response service provided by an individual consumer and sold to a non-RTO entity, such as a local utility or aggregator. Under FERC’s orders and the Supreme Court’s decision, only demand response sold to RTOs directly affects wholesale rates. FERC therefore has no basis for asserting jurisdiction over other demand response service because it is neither a wholesale sale of energy in interstate commerce nor a practice that directly affects wholesale rates.

Energy Storage

In February 2018, FERC ordered RTOs “to establish market rules that, recognizing the physical and operational characteristics of electric storage resources, facilitate their participation in the RTO markets.”³⁷ FERC found that existing market rules fail to reflect the full range of services that electric storage resources are capable of providing and thus impede storage’s economical participation in the market. FERC justified the storage mandate by tying it to its oversight of wholesale rates in RTO markets. By eliminating barriers to entry for storage, FERC aimed to enhance competition and market efficiency and thereby fulfill its legal duty of ensuring that rates are just and reasonable.³⁸

Unlike demand response resources that do not inject energy into the grid, storage resources are generally capable of making energy sales. FERC therefore argued that it has jurisdiction over sales by storage resources because a “storage resource that injects electric energy back to the grid for purposes of participating in an RTO/ISO market engages in a sale of electric energy at wholesale in interstate commerce.”³⁹ The order requires RTOs to accept offers from all storage resources larger than 100 kilowatts that inject energy into the grid, including those connected to a utility-owned distribution

system or behind a ratepayer’s meter.⁴⁰ FERC’s decision not to distinguish storage resources by location on the grid is consistent with its long-standing position, described above, that its jurisdiction over energy sales is premised on the nature of the sale and not the location of the energy transfer.

FERC explicitly rejected requests to require RTOs to accept offers from behind-the-meter storage resources that do not inject energy into the grid.⁴¹ These resources are generally allowed to participate in RTO markets under market rules for demand response resources. States could potentially prohibit these behind-the-meter storage resources from participating in RTO markets by exercising authority sanctioned by FERC in its demand response orders.

FERC’s storage order does not compel any storage resource to sell to RTOs. Citing to its net metering decisions, FERC’s order also notes that “injections of electric energy back to the grid do not necessarily trigger the Commission’s jurisdiction.”⁴² Thus storage resources could continue to inject energy under state-jurisdictional net metering tariffs, pursuant to the rules described in the previous section.

The rule’s threshold size requirement means that the rule will not directly affect individual electric vehicles or batteries designed to service a single household. The 100 kW minimum could capture batteries installed at commercial buildings or industrial facilities. Once FERC’s order is implemented by market operators, such commercial and industrial scale behind-the-meter storage resources could sell directly into RTO markets.

Energy Efficiency

Three of the four RTOs with capacity markets allow energy efficiency resources (EER) to bid into those markets. FERC has recognized that these projects “should be treated comparably to other types of resources, by being allowed to participate in [capacity] auctions and be paid the auction clearing price when they are accepted in the auction.”⁴³

Capacity markets are designed to ensure that a region has sufficient resources to meet projected peak demand in a future year. In the PJM region, allowing EERs to participate in the capacity market aims to “correct a mismatch between EE-related load reductions and capacity requirement levels.”⁴⁴ PJM explained in its proposal to FERC that “there is a four-year lag after an EE resource is initially installed before its load-reducing effects are reflected in the capacity market demand.”⁴⁵

PJM therefore pays EERs for four years of energy savings. After that, the savings should be accounted for in peak demand projections.

FERC does not require RTOs to allow EERs to bid into capacity markets, but it has concluded that states may not prohibit consumers from bidding their savings into capacity markets that accept such bids. FERC determined that state action that limits EERs' participation in the wholesale market "directly impacts" which EERs are eligible to participate in the market.⁴⁶ Because terms of eligibility have a "direct effect on wholesale rates," FERC concluded that it has exclusive authority to set those terms and a duty to ensure that those terms result in just and reasonable rates.⁴⁷

Opponents of FERC's order argued that EER participation must be under state authority in part because it may impact retail rates and affect utility planning. FERC rejected this argument, citing the Supreme Court's statement in the demand response decision that "[w]hen FERC regulates what takes place on the wholesale market, as part of carrying out its charge to improve how that market runs, then no matter the effect on retail rates, [the FPA's reservation of state authority over retail rates] imposes no bar."⁴⁸

FERC also concluded that the Court's approval of a state opt-out for demand response does not compel a similar option for EERs. According to FERC, the Court's "mere observ[ation]" that FERC's opt-out respected state decisions is not necessary to its holding. FERC also determined that differential treatment of EERs and DR is warranted for practical reasons. According to FERC, "unlike demand response resources, EERs are not likely to present the same operational and day-to-day planning complexity that might otherwise interfere with [a utility's] day-to-day operations."⁴⁹

Nonetheless, FERC indicated that it would entertain state requests for an opt out on a case-by-case basis. FERC did not explain what criteria it might use to evaluate an application.

DER Aggregations

In June 2016, FERC approved California ISO (CAISO) rules that allow DER aggregators to sell energy and ancillary services.⁵⁰ FERC concluded that allowing DERs to sell to the market through an aggregator will "increase participation and competition" in the wholesale market and thus ensure that rates are just and reasonable.⁵¹

The CAISO defines DERs as resources connected to a

utility distribution system, including behind-the-meter. DERs selling under state-regulated net metering tariffs are ineligible because, as the CAISO explained, net metered DERs have "no energy available to offer into the CAISO markets because excess energy is banked for later withdrawal" under California law.⁵²

FERC's order approving the CAISO tariff revisions does not discuss the Commission's legal authority. While the order was not challenged in federal court, utilities and utility trade associations have argued in comments filed at FERC that the Commission does not have authority to regulate sales by DER aggregators. Those comments were in response to a November 2016 proposal that would require RTOs to implement rules that facilitate DER aggregators' participation.

Although FERC has not justified its legal authority to regulate sales by DER aggregators, its prior jurisdictional determinations about other DERs support its authority to invite DER aggregators into RTO markets and regulate their rates. FERC has said repeatedly that it has a duty to remove barriers that prevent resources that are technically capable of providing service to an RTO from participating in wholesale markets because doing so "enhances competition" and ensures that rates are just and reasonable.⁵³ This responsibility, combined with FERC's exclusive authority to determine which resources are eligible to participate in wholesale markets, empowers FERC to require RTOs to accept offers from DER aggregators.

Under straightforward readings of FPA section 201 and the Supreme Court's decision about demand response, FERC has authority to regulate the rates RTOs pay to DER aggregators. When DER aggregators sell energy to an RTO, those sales are undoubtedly "wholesale sales in interstate commerce" and therefore under FERC's jurisdiction under FPA section 201. When DER aggregators sell demand response services, those sales are FERC-jurisdictional because they directly affect wholesale rates under the logic of the Court's demand response decision.

Importantly, FERC's proposal would not place requirements on individual DERs. FERC observes that individual DERs "will likely fall under the purview of multiple organizations (e.g., the RTO/ISO, state regulatory commissions, relevant distribution utilities, and local regulatory authorities)."⁵⁴ FERC therefore proposed that RTOs establish protocols for communication with the distribution utility and aggregator. Following the California ISO's lead, FERC also proposed that DERs selling under net metering tariffs will

not be eligible to participate in an aggregation selling to an RTO.

Summary: Jurisdictional Quandaries Impede Coherent DER Development

FERC's most recent reforms invite, rather than compel, DERs to sell into RTO markets and receive rates set by RTO auctions. For storage, FERC allows resources above a specified size to sell directly to RTOs. For DR and EERs, where FERC's authority is premised on those resources "directly affecting" rates, FERC's orders allow intermediaries (aggregators) to sell DERs' bundled services to RTOs.

FERC has never directly addressed its jurisdiction over the initial sale from the service provider to an aggregator of demand response, energy efficiency, or energy-injecting DERs. For demand response and energy efficiency resources, which do not inject energy into the grid, there is no basis for FERC to claim authority over the initial sale. FERC's jurisdiction over aggregated sales of these consumption-reducing services to an RTO is premised on those wholesale services "directly affecting" wholesale rates. The initial sale, one-step removed from those direct effects, at most indirectly affects wholesale rates and is beyond FERC's reach.

For resources that inject energy into the grid, jurisdiction would depend on the various factors discussed in the previous section. To date, FERC has not filed lawsuits in federal court or issued orders to preempt state DER programs or otherwise sought to regulate sales from DERs. In fact, FERC has recently declined opportunities to do so.⁵⁵

But FERC's look-the-other-way approach requires states to assume legal risk as they develop DER rates and business models. A utility dissatisfied with a state's DER policy might file a complaint at FERC or in a federal court arguing that the state is overstepping its authority under FERC's current framework. FERC itself might take a more activist approach and seek to preempt state DER programs. State policymaking is being conducted under a cloud of legal uncertainty.

Moreover, as technologies evolve and DER deployment advances, the current jurisdictional framework may be increasingly incompatible with competitive markets. DERs unassociated with a utility ratepayer and net energy transfers from behind-the-meter resources will be regulated under a dizzying array of rate structures that might allow them to sell energy to: 1) a utility pursuant to PURPA or the FPA, depending on whether the resource is a QF; 2) an RTO if the DER meets market eligibility rules; or 3) an aggregator that could be subjected to FERC regulation. Meanwhile, DER energy transfers and services that offset retail consumption will be regulated by states under their plenary retail ratemaking authority.

These fragmented ratemaking regimes, premised on decades-old federal laws, trap DERs in regulatory regimes designed for other purposes.

As technologies evolve and DER deployment advances, the current jurisdictional framework may be increasingly incompatible with competitive markets. DERs unassociated with a utility ratepayer and net energy transfers from behind-the-meter resources will be regulated under a dizzying array of rate structures.

Enabling a Cohesive Market Framework by Untangling the Jurisdictional Knots

In its net metering orders, FERC set a limit on its own jurisdiction and rejected the notion that it has authority over every flow of energy into the grid. Yet by separately asserting jurisdiction over all wholesale sales, regardless of location, FERC has established the legal foundation for regulating emerging DER markets.

Neither of FERC's positions is set in stone. FERC could disclaim jurisdiction over DER energy sales entirely, or it might try to expand its authority to include all currently net-metered energy transfers. The Supreme Court has explained that an "agency action representing a policy change [need not] be justified by reasons more substantial than those required to adopt a policy in the first instance."⁵⁶ An agency "must show that there are good reasons for the new policy. But it need not demonstrate to a court's satisfaction that the reasons for the new policy are better than the reasons for the old one; it suffices that the new policy is permissible under the statute, that there are good reasons for it, and that the agency believes it to be better."⁵⁷

As explained below, FERC should interpret the FPA differently, particularly in light of new facts about DER deployment, and disclaim jurisdiction over DER energy transfers to a local buyer. Doing so would allow states to regulate all DER transactions, enabling states to create frameworks that unify energy transfers and services that offset retail consumption with those that are considered net sales and currently subject to the FPA or PURPA. Under such a framework, aggregations of DERs would be able to continue to sell to RTOs, and FERC would retain authority over DERs that participate directly in RTO markets.

FERC Should Disclaim Jurisdiction over DER Energy Sales to a Local Buyer

The FPA specifies that FERC has jurisdiction over "the sale of electric energy at wholesale in interstate commerce" but not over "any other sale of electric energy."⁵⁸ The Supreme Court's demand response decision notes that the latter provision "reserv[es] regulatory authority over retail sales (as well as intrastate wholesale sales) to the States."⁵⁹ Outside of Texas, most of which is not electrically connected across state lines, FERC does not recognize the existence of "intrastate wholesale sales" in the continental United States and applies the FPA's reservation of authority over "any other sale"

only to retail sales. FERC should reverse its 2010 order (discussed above) and determine that DER sales are intrastate wholesale sales and therefore "other sales" that are subject to state authority.^b

The key legal issue is the meaning of the phrase "in interstate commerce." FERC's analysis should start with the text of the FPA and the parallel Natural Gas Act (NGA). Both statutes suggest that states have authority over DER energy sales because the energy does not cross state lines. The Act states explicitly that "electric energy shall be held to be transmitted *in interstate commerce* if transmitted from a State and consumed at any point outside thereof."⁶⁰ The NGA, which provides FERC with authority over the transportation of natural gas "in interstate commerce" similarly defines "interstate commerce" literally as transactions involving gas that traverse state borders.

Courts have likewise understood the word "interstate" as applied to wholesale power sales. In its first major FPA decision, the Supreme Court remarked that "[t]he primary purpose of . . . the Federal Power Act . . . was to give a federal agency power to regulate the sale of electric energy *across state lines*."⁶¹ The Seventh Circuit therefore concluded FERC had jurisdiction over a sale where there was sufficient evidence "to show that *out-of-state energy* reached . . . wholesale customers."⁶² The Eighth Circuit similarly affirmed FERC's jurisdiction in another case where there was "substantial evidence in support of the finding that *interstate energy* was supplied."⁶³

Under the Natural Gas Act, the Supreme Court has stated that its decisions "make the sale of gas which *crosses a state line* at any stage of its movement from wellhead to ultimate consumption 'in interstate commerce' within the meaning of the Act."⁶⁴ Applying this test, a federal appeals court understood that the threshold jurisdictional "question is whether the gas is transported in interstate commerce."⁶⁵ When there was "no question that the gas had been *physically transported interstate*,"⁶⁶ the service could only escape FERC jurisdiction if it was provided to consumers and was not for resale.

The Supreme Court ultimately rejected the need for such "case-by-case analysis" to determine FERC's authority over wholesale sales, and concluded that the FPA makes FERC's jurisdiction "plenary [] extending

^b See Frank R. Lindh and Thomas W. Bone, *State Jurisdiction over Distributed Generators*, 34 ENERGY L.J. 499 (2013) for a more detailed legal argument.

it to all wholesale sales in interstate commerce.”⁶⁷ The Court did not define interstate commerce, but the facts of that case suggest a literal meaning. The sale at issue, which the Court held was subject to FERC’s regulation, was by a California utility to a California municipality and included energy generated out-of-state and transmitted into California. This understanding of “interstate commerce” is consistent with numerous prior decisions holding that any amount of interstate energy imbues the sale with an “essential interstate character.”⁶⁸

DER energy transfers do not include out-of-state energy and therefore do not fit neatly on either side of the “bright line” that the Court drew in that case. However, an earlier jurisdictional test that the Court applied to electric transmission supports state authority over DER sales. The Court held that FERC’s “initial jurisdiction determination ‘was to follow the flow of electric energy,’” but that this “engineering and scientific test” is superseded by a “legalistic or governmental test.”⁶⁹ Applying this test, states have jurisdiction over DER energy sales because the energy is sold and consumed within a single state.

If DER-generated energy does flow from a distribution grid to the “vast pool of energy that is constantly moving in interstate commerce”⁷⁰ on the transmission network, FERC should disclaim jurisdiction under the “governmental test” that it currently applies to net-metered transfers. FERC’s blanket exemption for net-metered sales does not consider the rare case where an injection from a DER contributes to a flow of power on the transmission network. Applying this exemption to *all* DER energy sales is consistent with this approach and avoids the case-by-case analysis that the Court has rejected.

There is no legal basis for concluding that such “commingling”⁷¹ of DER-generated energy with out-of-state energy necessarily places all DER energy sales under FERC’s authority. Nor does the unbroken electrical path between the DER and the FERC-jurisdictional interstate transmission network place the energy injection under FERC’s authority. The Supreme Court has explicitly declined to weigh in on FERC’s theory that it has jurisdiction over transmission facilities based on the “electromagnetic unity” that pervades the entire electric power system.⁷² FERC therefore is not compelled to apply it to DER energy sales. Moreover, extending that theory from transmission facilities to wholesale sales would require FERC to regulate every energy injection, an approach that it has rejected on numerous occasions, including in its net metering orders and recent

energy storage rule.

The fact that a DER energy sale may be “intended for interstate commerce”⁷³ because the energy might ultimately be resold by the local buyer to an out-of-state entity does not give FERC jurisdiction over the initial sale. The Supreme Court has held that such intent may be relevant in assessing whether Congress has authority under the Commerce Clause to regulate the transaction. Here, the relevant question is not whether Congress has the power to regulate DER sales — surely it does⁷⁴ — but rather whether Congress actually provided that power to FERC in the FPA. In specifying that FERC has jurisdiction only over wholesale sales “in interstate commerce,” Congress preserved state authority over sales that are essentially local in character, including intrastate wholesale sales.

Even if FERC could conclude that DER sales are within the meaning of the phrase “interstate commerce,” FERC can decline to assert jurisdiction over those transactions. In a decision about a FERC order that enabled the creation of RTO markets, the Supreme Court held that FERC “had discretion to decline to assert [] jurisdiction [over certain transactions], in part because of the complicated nature of the jurisdictional issues.”⁷⁵ The Court concluded that FERC had made a “statutorily permissible policy choice” to limit the scope of its authority, even though it arguably could have asserted jurisdiction over certain state-regulated transactions. That principle applies with equal force here.

A determination by FERC that energy sales by DERs to in-state buyers are “other sales” under the FPA, and not wholesale sales in interstate commerce, would meet the Supreme Court’s test for a change of agency policy. Most importantly, FERC’s interpretation would be “permissible under the statute,” as discussed. FERC might conclude that the proliferation of DERs provides a “good reason” for changing its policy. The FPA, largely unchanged since it was enacted in 1935, did not contemplate that millions of small resources injecting energy into utility-owned distribution grids might be subject to federal regulation. Another “good reason” for a policy change is to remedy FERC’s disparate treatment of energy sales based on DER technology and whether there is a net export, as described above.

Creating a Unified DER Market

FERC’s disclaimer of jurisdiction over DER energy sales will allow states to regulate all DER sales to local utilities or aggregators, regardless of the technology or service. State jurisdiction over sales to local buyers would not prevent a DER from selling directly to an RTO, if the resource meets the RTO’s eligibility

requirements. The identity of the purchaser would determine whether or not the sale is “in interstate commerce” and subject to FERC’s authority or “any other sale” and thus regulated by a state.

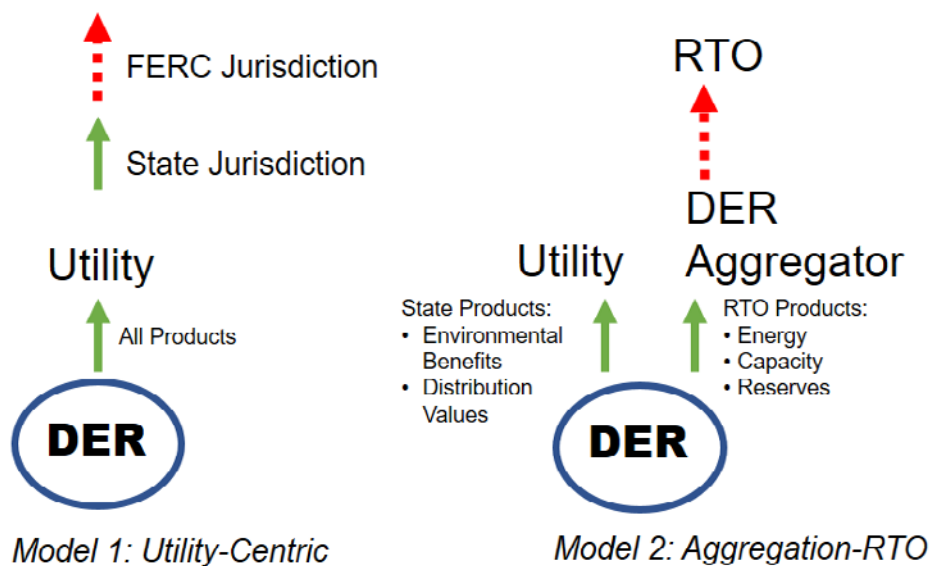
While FERC might prefer to instead preempt state DER programs, rather than disclaim jurisdiction (see below addressing legal and practical challenges of preemption), doing so could not enable the creation of a unified DER framework for at least two reasons. First, FERC cannot eviscerate state authority under PURPA to set rates for energy sales from DERs. Thus, regardless of whether currently net-metered resources remain under state retail authority, they will continue to receive state-set rates.

Second, even if FERC could claim jurisdiction over all

allow states to choose between DER development models. For example, states might separate values that are not compensable in RTO markets, such as avoided pollution and operational benefits to the distribution grid and require utilities to pay for those attributes while allowing DERs to sell energy, capacity and reserves to competing DER aggregators. Alternatively, a state whose utilities do not participate in an RTO might require utilities to purchase all DER products.

Model 2 is compatible with emerging state efforts to create market platforms that accept offers from DERs to provide energy and services and resell the aggregated products to the RTO. New York regulators, for example, envision utilities acting as “Distribution System Platforms” that will operate “retail DER markets” and “facilitate retail interactions with the wholesale mar-

Potential State DER Development Models



DER energy sales, it cannot regulate demand response sales to a non-RTO. As FERC determined in one of its demand response orders, energy and demand response “can have the same effect of balancing supply and demand at the margin.”⁷⁶ This equivalency motivated FERC’s decisions to require RTOs to accept bids from demand response providers and pay those resources the same rate as generation under certain circumstances. FERC’s preemption of net metering would recreate the same discontinuity that once existed at the wholesale market, but FERC would be powerless to provide any remedy.

Disclaiming jurisdiction over DER energy sales would

kets.⁷⁷ While the concept still needs to be fleshed out, FERC’s disclaimer of jurisdiction over DER energy sales would remove a legal obstacle to state supervision of this developing market model.

Can FERC Preempt State Net Metering Programs?

FERC might argue that preemption of state-regulated net metering tariffs is an inevitable result of its jurisdiction over all energy injections. Doing so, however, would be challenging to implement and legally questionable.

As discussed, FERC has long argued that it has jurisdiction over energy injections, regardless of the

generator's location. Most recently, in the storage rule FERC asserted that there is no jurisdictional distinction between front-of-the-meter and behind-the-meter sales. FERC could argue that the practice of retail netting impermissibly transforms a jurisdictional sale into a state-regulated billing practice. In claiming jurisdiction over currently net metered energy transfers, FERC would argue that it is restoring its authority over transactions that should have always been subject to its ratemaking powers.

To rationalize this jurisdictional switch, FERC might claim that its prior understanding of net metering as a method of measuring retail sales was premised on the metering technology available at the time. FERC explained in 2004 that the retail meter “runs backwards” when the ratepayer produces more energy than she consumes. Today, distributed generation systems are typically capable of measuring their instantaneous production. This advance might provide a “good reason” for a policy change.

As a practical matter, most net-metered resources are QFs and could continue to receive state-regulated rates for sales to the local utility. FERC's assertion of jurisdiction over sales from DERs would effectively end state net metering programs as a legal matter, but states could still set rates pursuant to PURPA for the vast majority of currently net metered resources. Whether those rates would approximate currently available net metered rates would depend on each state's implementation of PURPA.

Although the transition from state-regulated net metering to state-set PURPA rates might leave prices unchanged, it could add to FERC's workload. QFs and utilities can file complaints at FERC about contract formation, interconnection, pricing, and other disputes about PURPA implementation.⁷⁸ Explicitly moving net-metered resources into the PURPA framework could federalize such disputes that are currently handled by state regulators.

For non-QFs, FERC's assertion of jurisdiction would require FERC to regulate rates of previously net-metered transfers under the FPA. It is not clear how FERC would determine whether the price paid to a small-scale behind-the-meter resource is “just and reasonable.” Historically, FERC applied cost-of-service principles, equating the rate to the seller's costs of generating the energy plus a rate of return. Establishing cost-based rates for small-scale resources would be infeasible.

FERC also allows for negotiated rates but requires sellers to apply for market-based rate authority. Processing thousands of applications from small-scale batteries and other resources would be impossibly burdensome, and FERC has said that it has no authority to exempt a resource that is not a QF. Moreover, until FERC finalizes its DER aggregation proposal, there is no “market” for DER energy. In regions without an RTO, the utility would likely be the only potential buyer.

FERC's preemption of state net metering programs would undoubtedly be opposed by states, DER developers, and others. These opponents might deploy at least three arguments in defense of FERC's current approach, in addition to the argument that DER energy transfers are “other sales” under the FPA.

First, the D.C. Circuit issued two decisions about traditional generators that are consistent with FERC's net metering approach. At issue in those cases was whether FERC could determine the formula for netting power consumed by generators (so called “station power”) against the generator's production. FERC had concluded that when a generator produces more power than it consumes over a given interval, there is no retail sale. Reviewing that order, the court questioned “why FERC is empowered to conclude that a retail sale has not taken place unless it can claim the transaction is, instead, a wholesale sale or a transmission. . . . Unless a transaction falls within FERC's wholesale or transmission authority, it doesn't matter how FERC characterizes it.”⁷⁹

The court remanded to FERC, which subsequently determined that it did not have jurisdiction to determine when the provision of station power constitutes a retail sale. FERC stated that it would continue to determine the amount of station power that is transmitted on the interstate transmission grid but that states have exclusive authority over the amount of station power that is sold at retail to the generator.⁸⁰ The D.C. Circuit affirmed FERC's order.⁸¹

Explicitly moving net-metered resources into the PURPA framework could federalize disputes that are currently handled by state regulators.

With regard to both net metering and station power, FERC is not dictating to states whether a retail energy sale has occurred or how to measure retail energy sales. With both policies, FERC is simply declining to assert jurisdiction over an energy sale, leaving states with authority to determine the quantity of retail sales.⁸²

Second, opponents of FERC preemption of net metering could argue that net metering is part of state-regulated “bundled” retail service and therefore beyond its jurisdiction. FERC’s Order No. 888, which facilitated the creation of competitive wholesale power markets, includes the essential elements of the argument. In that order, FERC required utilities to “unbundle” wholesale service by stating separate rates for generation and transmission, and to provide equal transmission service to all customers. Recognizing that some states intended to allow non-utilities to sell energy to consumers, FERC imposed the same open-access requirement on retail transmissions that a state chose to unbundle. However, FERC declined to require states to unbundle retail transactions and did not impose any requirements on retail sales that bundle energy and transmission.⁸³

FERC explained that because the FPA provides it with jurisdiction over all transmissions but only over wholesale sales, when a state separates retail transmission service from retail energy sales FERC has jurisdiction over the transmission service while states have authority over the energy sale.⁸⁴ It therefore had clear authority over the unbundled retail transmission. The Supreme Court upheld FERC’s approach but declined to decide whether FERC has authority to mandate unbundling of retail products.

This distinction between unbundled and bundled sales is relevant to net metering. In requiring utilities to offer net metering, states are creating a bundled retail product. To preempt net metering, FERC would argue that it has authority to mandate unbundling and reclassify utility offtake service as a wholesale sale. The Court’s decision does not foreclose this argument, but it does suggest that a service so closely tied to retail energy sales might be beyond FERC’s reach.

Third, opponents could point to a provision in the Energy Policy Act of 2005 that requires state regulators to consider adopting net metering regulations.⁸⁵ The provision reflects Congress’s understanding that states – and not FERC – have authority over net-metered energy transfers.

FERC’s Enduring Influence Over DER Deployment

Even if FERC does disclaim jurisdiction over DER energy sales to local buyers, FERC will retain influence over DER deployment. This section discusses two aspects of FERC’s regulation of transmission service or wholesale markets that intersect with DER deployment.

Transmission Planning

FERC requires utilities to engage in regional transmission planning that must adhere to specified planning principles. In the planning process, utilities must consider technologies that can replace or delay the need for new transmission, such as DERs, “on a comparable basis” to transmission expansion.⁸⁶ FERC chose not to mandate a set of technologies that must be considered or how these non-transmission alternatives should be measured against proposed transmission solutions, leaving implementation to each planning region.⁸⁷

FERC’s 2011 order marks a noteworthy, but limited, assertion of jurisdiction. For the first time, there are federally regulated forums that must evaluate deployment of DERs or other technologies that can displace transmission. However, FERC’s current rules and the nature of transmission planning are “unlikely to result in selection and implementation of non-transmission solutions.”⁸⁸ It is possible (although perhaps currently implausible) that these processes and the participating utilities might evolve to more seriously consider DERs as alternatives to transmission.

FERC’s authority over transmission planning does not provide it with authority to set rates for DERs, apart from the authorities discussed elsewhere in this paper. However, when DER technologies, particularly batteries, are connected to the transmission network, they may be eligible to receive cost-of-service transmission rates rather than market-based rates for selling into energy and ancillary services markets.⁸⁹

Importantly, FERC has no authority to site DERs — or any electric infrastructure. Even if a FERC-regulated planning process chooses a DER solution, states will ultimately be responsible for implementation.

RTO Market Rules

Recent rules requiring RTOs to accept bids from DERs or DER aggregators represent first steps in providing DERs with access to wholesale markets. FERC maintains ongoing oversight responsibilities and must ensure that RTOs implement the rules in a non-discriminatory manner that does not create unnecessary

barriers to market participation.

That oversight includes reviewing RTO tariff amendments that aim to comply with FERC's directives and adjudicating any future complaints filed by market participants about the rules. As DER technologies evolve, amendments and new rules may be necessary to ensure that all DERs that are technically capable of providing services to the RTO are allowed to do so and are compensated fairly.

Other RTO rules that are not specifically targeted at DERs can affect DER deployment. For example, a rule finalized in 2016 aims to accurately compensate and incentivize the performance of flexible resources that can react quickly to changing supply and demand on the grid.⁹⁰ By ensuring that flexibility is compensated fairly for the values it provides to the grid, FERC improved the economic viability of fast-acting DERs, such as energy storage and demand response.

Capacity market rules are also relevant to DER development. For instance, in 2015 FERC approved PJM rules requiring that resources paid in the capacity market be available to provide energy or demand reductions throughout the year or else face penalties.⁹¹ This new requirement effectively disqualified demand response resources that reduce air conditioner use and are only available in the summer. As a result, demand response participation fell by 24% in the first auction under the new rules, as compared to the previous auction.⁹² In 2018, FERC convened a technical conference to address how so-called seasonal resources might be able to participate in the market. FERC may ultimately review a PJM proposal to address the issue or adjudicate a complaint filed by demand response and other seasonal resource providers arguing that the current rules are not just and reasonable.

Conclusion

The fragmented legal regime governing DER energy sales prevents the development of a cohesive regulatory framework for DERs. Federal law allows FERC to disclaim jurisdiction over DER energy sales, which would enable states to bring all DERs under a single ratemaking regime. FERC should conclude that DER energy sales are outside the scope of its direct authority while continuing to invite DERs to participate in RTO markets through aggregators. This regulatory framework will let states drive DER development and will ensure that RTO markets can provide a competitive platform for all resources.

Endnotes

- ¹ U.S. ENERGY INFO. ADMIN., Form 861 (2014), Spreadsheet labeled “Sales_Ult_Cust_2014.” Three million residential ratepayers are served by other political subdivisions, such as counties, public utility districts, and irrigation districts.
- ² See Jon Wellinghoff and David Morenoff, *Recognizing the Importance of Demand Response: The Second Half of the Wholesale Market Equation*, 28 ENERGY LAW JOURNAL 389, 393 (2007).
- ³ Julia Pyper, GreenTechMedia, “Californians Just Saved \$192 Million Thanks to Efficiency and Rooftop Solar,” May 31, 2016, <https://www.greentechmedia.com/articles/read/californians-just-saved-192-million-thanks-to-efficiency-and-rooftop-solar#gs.wFjAiF4>. See also ISO-New England, Understanding the Impact of Behind-the-Meter Solar on Grid Operations and Regional Planning, June 1, 2017, https://www.iso-ne.com/static-assets/documents/2017/05/clg_meeting_black_panelist_presentation_june_1_2017_final.pdf (showing that peak demand is projected to remain flat due to rooftop solar and energy efficiency).
- ⁴ 16 U.S.C. § 824(b)(1).
- ⁵ 16 U.S.C. § 824d, e; FERC v. Electric Power Supply Assoc., 136 S.Ct. 760 (2016).
- ⁶ 18 CFR § 292.04(a), (d).
- ⁷ Pub. Utils. Comm’n v. Attleboro Steam, 273 U.S. 83 (1927); New York v. FERC, 535 U.S. 1, 21 (“It is, however, perfectly clear that the original FPA did a good deal more than close the gap in state power identified in *Attleboro*.”).
- ⁸ *Electric Power Supply Assoc.*, 136 S.Ct. at 780 (quoting FPC v. Louisiana Power & Light Co., 406 U.S. 621, 631 (1972)).
- ⁹ Conn. Light & Power Co. v. FPC, 324 U.S. 515, 525 (1945) (quoting Hearings on H.R. 5423 Before H. Comm. on Interstate and Foreign Commerce, 74th Cong. 384 (1935)).
- ¹⁰ 16 U.S.C. § 824(b)(1).
- ¹¹ *Wisconsin-Michigan Power Co.*, 10 FPC 170 (1951), *aff’d* Wisconsin-Michigan Power Co. v. FPC, 197 F.2d 472 (7th Cir. 1952).
- ¹² *Re Indiana and Michigan Electric Co.*, 33 FPC 739 (1965), *aff’d* Indiana & Michigan Electric Co., 365 F.2d 180 (7th Cir. 1966); *accord* Arkansas Power & Light Co. v. FPC, 368 F.2d 376, 383 (8th Cir. 1966) (explaining that the Commission’s order in Indiana and Michigan Electric Co. means that “where a company is in fact a public utility, all wholesale sales for resale in interstate commerce are subject to the provisions of Sections 205 and 206 of the Act, regardless of the facilities used.”); see also Transmission Access Policy Study Group v. FERC, 225 F.3d 667, 696 (D.C. Cir. 2000) (the FPA “makes clear that all aspects of wholesale sales are subject to federal regulation, regardless of the facilities used”).
- ¹³ Amendment to Motion to Intervene of the Sacramento Utility District, Docket No. EL10-64-000 (Jun. 10, 2010).
- ¹⁴ *California Public Utilities Commission*, 132 FERC ¶ 61,047 at P 72 (2010).
- ¹⁵ *Otter Creek Solar*, 143 FERC ¶ 61,282 at P 4 (2013) (citing 18 CFR § 292.301(b)), *reconsid. denied*, 146 FERC ¶ 61,192 (2014).
- ¹⁶ *Bonneville Power Admin. v. FERC*, 422 F.3d 908 (9th Cir. 2005) (holding that FPA sections 205 and 206 do not apply to sales from exempt entities listed in section 201(f)).
- ¹⁷ *Sacramento Mun. Util. Dis. v. FERC*, 616 F.3d 520 (D.C. Cir. 2010); Transmission Agency of Northern Cal. v. FERC, 728 F.3d 538 (D.C. Cir. 2010).
- ¹⁸ *Cal. Elec. Power Co. v. FPC*, 199 F.2d 206, 209 (9th Cir. 1952) (“The entire thrust of Part II [of the FPA] is toward the seller at wholesale, not the buyer.”).
- ¹⁹ *MidAmerican Energy Co.*, 94 FERC ¶ 61,340 (2001).
- ²⁰ *Id.*
- ²¹ *SunEdison*, 129 FERC ¶ 61,146 at P 18 (2009).
- ²² FERC’s 2009 order also extended its holding to an arrangement where the generator is owned by a third party that sells the energy to a net-metered ratepayer.
- ²³ FERC has held that a storage resource can be a QF if at least 75 percent of its charge is from renewable resources. *Luz. Dev. & Fin. Corp.*, 51 FERC ¶ 61,078 (1990). A QF charging from the grid is unlikely to meet that threshold. In 2017, fuel cell developer Bloom Energy filed a petition at FERC for a declaratory order finding that its facilities are QFs. Bloom later withdrew its petition. See FERC Docket EL18-10.
- ²⁴ Order No. 841, 162 FERC ¶ 61,127 at P 30, n. 50 (2018).
- ²⁵ Prior Notice and Filing Requirements Under Part II of the Federal Power Act, 64 FERC ¶ 61,139, 61,996 (1993).
- ²⁶ 16 U.S.C. 824(d), (e).
- ²⁷ FERC v. Elec. Power Supply Ass’n., 136 S.Ct. 760 (2016).
- ²⁸ *Advanced Energy Economy*, 161 FERC ¶ 61,245 at P 60–61 (2017), *reh’g denied* 163 FERC ¶ 61,030 at PP 5, 36 (2018) (citing *Elec. Power Supply Ass’n*, 136 S. Ct. at 775 (2016); Order No. 745, 134 FERC ¶ 61,187 at P 112 (2011); Order No. 719-A, 128 FERC ¶ 61,059 at P 47 (2009)).
- ²⁹ *Advanced Energy Economy* at P 36.
- ³⁰ 18 CFR § 35.28(b)(4).
- ³¹ Order No. 719, 125 FERC ¶ 61,071 at P 154 (2008); Order No. 745, at P 47.
- ³² Order No. 719 at P 154; Order No. 719-A at P 47 (2009); Order No. 745 at PP 58–59.
- ³³ Order No. 745 at P 114.
- ³⁴ *Id.*
- ³⁵ *Electric Power Supply Ass’n.*, 136 S.Ct. at 776.
- ³⁶ Order No. 719-A at PP 51, 54.
- ³⁷ Order No. 841, 162 FERC ¶ 61,127 at P 1 (2018).
- ³⁸ *Id.* at PP 19–20.
- ³⁹ *Id.* at P 30.
- ⁴⁰ *Id.* at P 29 (codified at 35.38(b)).
- ⁴¹ *Id.* at PP 32–33.
- ⁴² *Id.* at n. 49.
- ⁴³ *PJM Interconnection*, 126 FERC ¶ 61,275 at P 130 (2009).
- ⁴⁴ *Id.* at P 132.
- ⁴⁵ *Id.*
- ⁴⁶ *Advanced Energy Economy*, 161 FERC ¶ 61,245 at P 61 (2017), *reh’g denied* 163 FERC ¶ 61,030 (2018) at P 36.
- ⁴⁷ *Id.*
- ⁴⁸ *Id.* at P 63 (citing EPSA at 776).
- ⁴⁹ *Id.* at P 63.
- ⁵⁰ *California ISO*, 155 FERC ¶ 61,229 (2016). For analysis of the program, see Justin Gundlach and Romany Webb, Distributed Energy Resource Participation in Wholesale Markets: Lessons from the California ISO. 39 ENERGY LAW JOURNAL 47 (2018).
- ⁵¹ *Id.* at P 41.
- ⁵² *Id.* at P 6.
- ⁵³ See, e.g., Order No. 841 at PP 19–20.
- ⁵⁴ Electric Storage Participation in Markets Operated by RTO/ISOs, Notice of Proposed Rulemaking, 157 FERC ¶ 61,121 at P 157 (2016).
- ⁵⁵ See, e.g., *Otter Creek Solar*, 143 FERC ¶ 61,282 (2013), *reh’g denied*, 146 FERC ¶ 61,192 (2014); *Winding Creek Solar*, 151 FERC ¶ 61,103 (2015).
- ⁵⁶ FCC v. Fox Television Stations, 556 U.S. 502, 513 (2009).
- ⁵⁷ *Id.*
- ⁵⁸ 16 U.S.C. § 824(b)(1).
- ⁵⁹ *Electric Power Supply Ass’n.*, 136 S.Ct. at 775.
- ⁶⁰ 16 U.S.C. 824(c).
- ⁶¹ *Jersey Central Power & Light Co. v. Fed. Power Comm’n.*, 319 U.S. 61, 67 (1943); see also H.R. Rep. No. 1318, 74th Cong., 1st Sess. (1935) (“The percentage of electric generated in the United States that was transmitted across State lines increased from 10.7 in 1928 to 17.8 in 1933 . . . Under the decision of . . . [*Attleboro*], the rates charged in interstate transactions may not be regulated by the States. Part II gives the Federal Power Commission jurisdiction to regulate these rates”).
- ⁶² *Indiana & Michigan Electric Co.*, 365 F.2d at 183.
- ⁶³ *Arkansas Power & Light Co.*, 368 F.2d at 383.
- ⁶⁴ *People of State of Cal. v. Lo-Vaca Gathering Co.*, 379 U.S. 366, 369 (1965).
- ⁶⁵ *Oklahoma Natural Gas Co. v. FERC*, 940 F.2d 699, 702 (D.C. Cir. 1991).
- ⁶⁶ *Id.* (discussing FPC v. East Ohio Gas Co., 338 U.S. 464 (1950) and Pub. Utils. Comm’n of Cal. v. FERC, 900 F.2d 269 (D.C. Cir. 1990)).
- ⁶⁷ FPC v. S. Cal. Edison, 376 U.S. 205, 216 (1964).
- ⁶⁸ *Wisconsin-Michigan Power Co.*, 197 F.2d at 478.
- ⁶⁹ FPC v. Florida Power & Light Co., 404 U.S. 453, 455–57 (quoting Connecticut Light & Power v. FPC, 376 U.S. 515, 529 (1945)).
- ⁷⁰ *New York*, 535 U.S. at 7.
- ⁷¹ *Florida Power & Light Co.*, 404 U.S. at 461.
- ⁷² *Id.* at 460.

- ⁷³ Wickard v. Filburn, 317 U.S. 111, 120 (1942).
- ⁷⁴ FERC v. Mississippi, 456 U.S. 742, 765 (1982) (stating that “Congress could have preempted the field” of retail rate regulation).
- ⁷⁵ *New York*, 535 U.S. at 28.
- ⁷⁶ Order No. 745 at P 49.
- ⁷⁷ New York Public Service Commission, Order Adopting Regulatory Policy Framework and Implementation Plan, Case 14-M-0101 (Feb. 26, 2015).
- ⁷⁸ 16 U.S.C. § 824a-3(h).
- ⁷⁹ Southern Cal. Edison v. FERC, 603 F.3d 996, 1001 (D.C. Cir. 2010).
- ⁸⁰ *Duke Energy Moss Landing v. CAISO*, 134 FERC ¶ 61,151 at P 24 (2011).
- ⁸¹ Calpine Corp. v. FERC, 720 F.3d 41 (D.C. Cir. 2012).
- ⁸² See Jim Rossi, Federalism and the Net Metering Alternative, *THE ELECTRICITY JOURNAL* (JAN.-FEB. 2016).
- ⁸³ *New York*, 535 U.S. at 13.
- ⁸⁴ *Id.* at 25–28.
- ⁸⁵ P.L. 109–58, 119 Stat. 594, 962 (codified at 16 U.S.C. § 2621(d)).
- ⁸⁶ Order No. 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Pub. Util., 136 FERC ¶ 61,051 at P 148 (2011).
- ⁸⁷ *Id.* at P 155.
- ⁸⁸ Shelley Welton, Non-Transmission Alternatives, 39 *HARVARD ENV'T L. REV.* 457, 513 (2015).
- ⁸⁹ *Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery*, 158 FERC ¶ 61,051 (2017).
- ⁹⁰ FERC Order No. 825, 155 FERC ¶ 61,276 at PP 19, 53–56 (2016).
- ⁹¹ *PJM Interconnection*, 151 FERC ¶ 61,208 at P 99 (2015).
- ⁹² Robert Walton, “What’s the Future for Demand Response under PJM’s New Capacity and Aggregation Rules,” *UtilityDive*, May 31, 2017, <https://www.utilitydive.com/news/whats-the-future-for-demand-response-under-pjms-new-capacity-and-aggregat/443833/>
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