LBNL-1006675

Federal/State Jurisdictional Split: Implications for Emerging Electricity Technologies

Authors:

Jeffery S. Dennis,[1] Suedeen G. Kelly,[1] Robert R. Nordhaus,[2] and Douglas W. Smith[2]

[1] Akin Gump Strauss Hauer & Feld LLP, [2] Van Ness Feldman, LLP

Energy Analysis and Environmental Impacts Division
Lawrence Berkeley National Laboratory

December 2016

This work was supported by the U.S. Department of Energy's Office of Energy Policy and Systems Analysis under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

Disclaimer

Acknowledgements

The work described in this study was funded by the U.S. Department of Energy's Office of Energy Policy and Systems Analysis under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

We thank Larry Mansueti, Karen Wayland, and Kate Marks of the U.S. Department of Energy's Office of Energy Policy and Systems Analysis for their support of this work. For reviewing drafts of this report and providing comments, we thank James Ramsay (National Association of Regulatory Utility Commissioners), and Jeff Genzer (National Association of State Energy Officials).

About the Authors

Jeffery Dennis is a Senior Counsel in the Washington, D.C., office of Akin Gump Strauss Hauer & Feld LLP, and previously served in senior legal and policy positions at the Federal Energy Regulatory Commission. Mr. Dennis can be reached at jdennis@akingump.com.

Suedeen Kelly is a partner in the Washington, D.C., office of Akin Gump Strauss Hauer & Feld LLP, and previously served as a Commissioner at the Federal Energy Regulatory Commission and as Chair and Commissioner of the New Mexico Public Service Commission. Ms. Kelly can be reached at skelly@akingump.com.

Robert Nordhaus is a partner in the Washington, D.C., office of Van Ness Feldman, LLP, and previously served as General Counsel to the Federal Energy Regulatory Commission and as General Counsel to the U.S. Department of Energy. Mr. Nordhaus can be reached at rrn@vfn.com.

Doug Smith is a partner in the Washington, D.C., office of Van Ness Feldman, LLP, and previously served as General Counsel to the Federal Energy Regulatory Commission and as Deputy General Counsel for Energy Policy at the U.S. Department of Energy. Mr. Smith can be reached at dws@vnf.com.

The views expressed in this paper are those of the authors, and do not necessarily reflect the views of the law firms with which they are associated or the clients of those firms.

Table of Contents

Executive Summary

The first Administration-wide Quadrennial Energy Review (QER), released in April 2015, found that the "interacting and overlapping" division of authority between "federal, regional and state institutions and regulatory structures" for the electricity sector could "impede development of the grid of the future [and] . . . the development of markets that efficiently integrate" new and emerging technologies.[1] While "technology is indifferent to state-Federal boundaries and jurisdictions," the QER explained, "technology users cannot be."[2] The report concluded that "[b]oth Federal and state governments need to play constructive and collaborative roles in the future to ensure that consumers and industry are able to maximize the value of new technologies."[3]

The QER recommended that the Department of Energy ("DOE") facilitate such collaboration by playing a "convening role" to bring together state and federal regulators and other stakeholders to consider these issues.[4] This paper provides background and analysis on these jurisdictional issues and the impact they may have on adoption of emerging energy technologies and coordination of markets for those technologies, in support of future dialogs on these subjects.

In particular, this paper reviews the structure of the Federal Power Act ("FPA"),[5] and compares the division of authority between the federal and state governments adopted there with other federal energy and energy-related statutes. It then goes on to review some of the key decisions from the Supreme Court that further shaped this jurisdictional split, and some recent and current jurisdictional disputes that are bringing the FPA's division of authority back into focus. This review leads to the following key observations:

- <u>The Federal Power Act established a "bright line" between federal and state regulation based on the electricity sector that existed in 1935</u>. The FPA assigned some electricity sector regulatory functions to the federal government, and explicitly reserved other functions to the states. This so-called "bright line" between federal and state regulation – federal regulation of wholesale sales and transmission in interstate commerce and state regulation of generation, distribution, and retail sales – was laid out with the electricity industry of 1935 in mind, and was further defined by courts based on the traditional, vertically-integrated industry structure that existed for most of the 20th century.

- <u>Recent technology innovations were not anticipated by the FPA</u>. New technologies – such as distributed generation, storage, sophisticated load controls that facilitate active demand

[1]Quadrennial Energy Review: Energy Transmission, Storage, and Distribution Infrastructure (April 2015), 3-22, *available at* http://energy.gov/sites/prod/files/2015/07/f24/QER%20Full%20Report_TS%26D%20April%202015_0.pdf ("QER").
[2] QER at 3-27.
[3] QER at 3-27.
[4] QER at 3-27.
[5] 16 U.S.C. §§ 791 *et seq*. (2012).

management, and microgrids – have different attributes than the electricity technologies that existed when the FPA was enacted. These differing attributes have driven, and will continue to drive, new jurisdictional issues and tensions. (Given the pace of innovation, it is entirely conceivable that there will be future technologies not yet invented that also will raise jurisdictional issues and tensions.) Such technologies are capable of providing multiple services across the traditional generation, transmission, and distribution classifications, making the "bright line" between federal and state jurisdiction less "easily ascertained." For example:

- When end-users adjust their retail demand in response to price signals in wholesale markets or to provide a wholesale service (such as capacity), which side of the federal-state bright line does that fall on?
- When residential customers install rooftop solar and provide any generation beyond their immediate needs to the local utility, do they become subject to federal utility regulation?
- When a distributed generation resource, energy storage asset, or other new technology is capable of providing both retail and wholesale services simultaneously, can it provide those services across both state and federal regulatory structures?

– <u>Judicial resolution of jurisdictional disputes may not lead to outcomes that support collaboration among federal and state policymakers</u>. When jurisdictional disputes under the FPA are arbitrated in the courts, they are generally resolved by "picking sides" – i.e., the legal question presented is whether or not the Federal Energy Regulatory Commission ("FERC") or the state acted within the constraints of the FPA. The recent *FERC v. Electric Power Supply Ass'n*[6] and *Hughes v. Talen Energy Marketing, LLC*[7] Supreme Court decisions provide examples of the courts applying the FPA's jurisdictional division to new sets of technology and market challenges. (In both of those cases, the Court found for the broader view of the federal role.) The jurisdictional provisions of the FPA do not explicitly provide tools for regulators and policymakers to develop middle ground, "win-win" approaches that would allow for shared authority or encourage coordination across jurisdictions and markets.

– <u>Competitive interests can drive jurisdictional disputes</u>. In today's electric sector, federal regulators (and in some cases state regulators) rely on competitive markets to ensure just and reasonable outcomes for consumers. The value of very significant investments in those markets is determined by regulatory decisions concerning market rules and market structure. New entrants – including developers of new generation resources, demand response and energy efficiency developers, non-traditional transmission developers, and

[6] 136 S. Ct. 760 (2016) ("*EPSA*").
[7] 136 S. Ct. 1288 (2016) ("*Hughes*").

new technology developers – are challenging incumbent generators and utilities. The federal-state jurisdictional divide can sometimes be used as a tool in efforts to gain or preserve market share. The recent *EPSA* and *Hughes* cases both illustrate this phenomenon: both pit new entrants (demand response in *EPSA*, new developers of generation resources that may displace existing resources in *Hughes*) against incumbent market participants. As new distributed technologies seek to gain greater market share, jurisdiction is likely to continue to be a point of leverage.

After reviewing the current jurisdictional map and the historic, recent, and foreseeable future jurisdictional issues and disputes, the paper explores several available approaches to better align jurisdiction so it does not become a roadblock to advanced technology adaptation:

- Muddling through. Most often, questions regarding the scope of federal and state authority under the FPA are resolved on a case-by-case basis. The Supreme Court cases decided in the last two terms each made a fact-bound determination regarding the jurisdictional question presented, and did not attempt to establish a new "bright line" between federal and state authority or establish broader principles for federal-state coordination that might cleanly resolve future disputes. Without further action by Congress to address the issues presented by the current regulatory divide, regulators, policymakers, and the courts will have to try to apply the existing framework to new technologies in a workable fashion. Such "muddling through" will entail litigation, uncertainty, and delay. Moreover, even where both federal and state governments operate within their "jurisdictional lane," they may still end up reaching results that frustrate the other's policy goals.

- Judicious interpretation or exercise of jurisdiction. FERC has, at least at times, tread softly in areas where it might have a claim of jurisdiction, but where it did not have a policy interest in overriding state regulation. In Order No. 888, for instance, FERC chose not to exercise jurisdiction over the transmission component of bundled retail rates, and the majority of the Supreme Court deferred to its choice (while noting that FERC could have gone further). Likewise, FERC has interpreted net metering not to involve a wholesale sale, and thus has avoided triggering federal regulation. And in its demand response orders, FERC made clear that states may "opt out," i.e., choose not to allow retail customers to participate as demand response resources in organized markets. These examples, and the Court's favorable view of FERC's "notable solicitude toward the States" in *EPSA*, suggest that the creation of frameworks that explicitly recognize and accommodate state policy goals and jurisdictional responsibilities could be a tool at FERC's disposal to address jurisdictional uncertainty and market integration problems impacting new and emerging technologies.

- Adoption of frameworks for federal/state collaboration under existing law. FERC and the states have pursued efforts to collaborate on shared priorities, and could do so again in the context of new and emerging energy technologies. For example, FERC and the National Association of Regulatory Utility Commissioners ("NARUC") have conducted "joint collaboratives" on topics such as demand response, smart grid, and other issues. In addition, just as FERC has chosen to cautiously exercise its jurisdiction to respect the impact it may have on the states, FERC has also adopted frameworks in its own rules to explicitly account for state and local public policies. In Order No. 1000, for example, FERC required that regional and local transmission planning processes consider transmission needs driven by state policies. Such frameworks could be a tool for FERC and states to reconcile their respective jurisdictional authorities and account for the ability of new and emerging energy technologies to simultaneously provide services in both wholesale and retail markets.

- <u>Formal collaboration/delegation under existing but rarely used FPA provisions</u>. The FPA authorizes FERC to hold joint hearings with state commissioners. The joint hearing provision permits FERC and states to hear cases together, but provides for no joint decisional procedure. The FPA also authorizes FERC to set up joint boards, consisting of state utility commissioners, to consider matters otherwise within FERC's jurisdiction. This is essentially a limited delegation of FERC decision-making to a board of state commissioners (there is no federal representation on a joint board.) While rarely used, these provisions of existing law may provide potential tools to improve federal/state coordination on particular issues.

- <u>Legislative changes</u>. It may not be possible to address some jurisdictional obstacles to deployment of advanced technologies without legislative changes. Such changes could be specific to a particular technology (e.g., legislation on regulatory treatment and jurisdiction over energy storage), or changes to authorize FERC and state regulators to agree to issue-specific adjustments to jurisdiction.

I. Introduction

On April 21, 2015, Vice President Biden on behalf of the Administration's Quadrennial Energy Review Task Force released the first installment of the Quadrennial Energy Review. The QER addresses the nation's energy transmission, storage and distribution infrastructures and the implications that recent significant changes in the energy landscape have had on them. It notes the critical role that a "more robust and resilient" energy delivery infrastructure can play in creating new economic, consumer and energy reliability benefits, and observes that "good decisions on [transmission, storage, and distribution] infrastructure can also provide flexibility in taking advantage of new opportunities to achieve our national energy objectives."[8]

Chapter Three of the QER focuses on opportunities to modernize the U.S. electric grid. Among other things, this chapter describes how new and emerging energy technologies are driving change on the grid, and how those technologies may ultimately become a part of a "grid of the future" that is more reliable, resilient, and secure, and that promotes affordability, efficiency, and environmental improvements.[9]

The QER finds, however, that the "interacting and overlapping" division of authority between "federal, regional and state institutions and regulatory structures" – introduced when the Federal Power Act of 1935 extended federal oversight to elements of the electricity sector – could "impede development of the grid of the future [and] . . . the development of markets that efficiently integrate" new and emerging technologies.[10] While "technology is indifferent to state-Federal boundaries and jurisdictions," the QER explains, "technology users cannot be."[11] Accordingly, it concludes that "[b]oth Federal and state governments need to play constructive and collaborative roles in the future to ensure that consumers and industry are able to maximize the value of new technologies."[12] To facilitate such collaboration, the QER recommends that DOE play a "convening role" to bring together state and federal regulators and other stakeholders to "explore approaches to integrate markets, while respecting jurisdictional lines, but allowing for coordination of goals across those lines."[13]

This paper explores the impact that "interacting and overlapping" federal and state jurisdiction over the electricity industry could have on deployment of new and emerging technologies.[14] It is intended to

---

[8] QER at S-2.
[9] QER at 3-5.
[10] QER at 3-22.
[11] QER at 3-27.
[12] QER at 3-27.
[13] QER at 3-27.
[14] This paper focuses on the jurisdictional boundaries between federal and state regulation over entities subject to the full reach of regulation under the FPA, that is, investor-owned entities operating in interstate commerce. Publicly-owned and many cooperatively owned utilities are subject to only some elements of the FPA. 16 U.S.C. §§ 824(f), 824(b)(2). Moreover, the entities found not to be operating in interstate commerce, i.e., entities in Alaska, Hawaii, and the Electric Reliability Council of Texas ("ERCOT") portion of Texas, are also subject to only limited FPA Part II jurisdiction.

provide background and analysis that will support DOE's efforts to convene a dialog among regulators and other stakeholders, as described in the QER. Specifically, the paper:

- Describes the legal foundations of the current division of jurisdiction between the federal government and the states, with a primary focus on the "bright line" between the jurisdiction of FERC and the states drawn by the FPA;

- Explores the implications of past jurisdictional disputes, as well as the Supreme Court's recent decisions in *FERC v. Electric Power Supply Association* and *Hughes v. Talen Energy Marketing, LLC* addressing jurisdiction issues under the FPA.

- Identifies, through brief examples, how the different operational attributes of new and emerging technologies, changes in the structure of the electricity industry and electricity markets, and the pursuit of new policy initiatives to address new technologies and industry changes, can all drive jurisdictional uncertainty and market integration challenges; and

- Suggests potential tools that could help resolve jurisdictional issues and market integration challenges that may face emerging energy technologies, while aligning goals and markets to maximize potential value across both federal and state jurisdictions.

The examples used in this paper, and the potential jurisdiction and market integration challenges identified, are intended to be illustrative only. Discussing these challenges, and potential tools that may be available to address them, is not intended to suggest that any one approach will provide a "silver bullet." Rather, the discussion is intended to serve as the starting point for the broader collaborative dialog between federal and state regulators and other policymakers and stakeholders envisioned by the QER, where additional examples and potential tools to address them will surely be identified.

II. Division of Regulatory Authority Between the Federal and State Governments Under Federal Law

A. The Division of Authority under FPA Part II

The current jurisdictional allocation of regulatory authority between the federal government and the states, established in the FPA and clarified by subsequent Supreme Court and lower court decisions, is the result of the evolution of a regulatory scheme that was once governed predominantly by state and local agencies. In the early 1900s, state and local governments regulated nearly all generation, transmission, distribution, and sales of electricity.[15]

[15] *EPSA*, 136 S. Ct. at 767 (noting "In the early 20th century, state and local agencies oversaw nearly all generation, transmission, and distribution of electricity."); Jeffery S. Dennis, "Federalism, Electric Industry Restructuring, and the Dormant Commerce Clause: *Tampa Electric Co. v. Garcia* and State Restrictions on the Development of Merchant Power Plants," Natural Resources Journal 43 (2003), 624 ("Dennis"). Part I of the FPA extended federal regulation to hydroelectric generating facilities in 1920. 16 U.S.C. §§ 791-823d.

However, in 1927, the Supreme Court significantly constrained state regulation when it decided *Public Utilities Commission of Rhode Island v. Attleboro Steam & Electric Co*.[16] In that case, the Public Utilities Commission of Rhode Island sought to regulate the terms of a wholesale sale between a utility in Rhode Island and a utility in Massachusetts. The Court held that the Dormant Commerce Clause barred Rhode Island from regulating interstate wholesale electricity sales, stating "such regulation . . . can only be attained by the exercise of the power vested in Congress."[17] This decision left interstate, wholesale electricity sales unregulated, a regulatory void that would come to be known as the "*Attleboro* gap."[18] Congress had the authority to regulate interstate electricity sales under the Commerce Clause, but unless it acted, no federal agency existed to regulate interstate wholesale electric sales.[19]

In 1935, Congress enacted the FPA to fill the *Attleboro* gap.[20] In the FPA, Congress set out the basic division of regulatory authority between the federal government and the states that exists to this day. Under section 201(b)(1) of the FPA, the Federal Power Commission ("FPC"), the predecessor to FERC,[21] was granted the authority to regulate "the transmission of electric energy in interstate commerce" and "the sale of electric energy at wholesale in interstate commerce."[22]

However, in that same section of the FPA, Congress specifically excluded from FERC's jurisdiction: (1) facilities used for the *generation* of electricity, (2) facilities used for *local distribution* of power to retail customers, (3) facilities used for transmission of electricity strictly *in intrastate commerce*, and (4) transmissions of electricity to be *used entirely by the transmitter*.[23] Furthermore, section 201(a) of the FPA states that "[f]ederal regulation . . . extend[s] only to those matters which are not subject to regulation by the states."[24]

The FPA thus not only establishes an affirmative grant of authority to the federal government to regulate wholesale sales and transmission of electricity in interstate commerce, but also draws a line where that exclusive authority ends and the state's exclusive authority to regulate other matters (principally electric generation and distribution facilities, and retail sales of electricity) begins.

---

[16] 273 U.S. 83, 89-90 (1927) ("*Attleboro*").

[17] *Attleboro*, 273 U.S. at 90.

[18] Robert R. Nordhaus, "The Hazy 'Bright Line': Defining Federal and State Regulation of Today's Electric Grid," *Energy Law Journal* 36 (2015), 205 ("Nordhaus").

[19] Nordhaus at 205; *Attleboro*, 273 U.S. at 90.

[20] *EPSA*, 136 S. Ct. at 767; Nordhaus at 205.

[21] FERC succeeded in 1977 to almost all of the FPC's functions. Department of Energy Organization Act, Pub. L. No. 95-91, §§ 204, 402; 91 Stat. 565, 571-72, 583-585 (1977) (codified as 42 U.S.C. §§ 7134, 7172 and 16 U.S.C. §§ 792, 824, 824a).

[22] 16 U.S.C. § 824(b)(1).

[23] 16 U.S.C. § 824(b)(1). There are other limitations on FERC jurisdiction under the FPA. Publicly-owned and many cooperatively owned utilities are subject to only limited elements of the FPA. 16 U.S.C. §§ 824(f), 824(b)(2). Moreover, the entities found not to be operating in interstate commerce, i.e., entities in Alaska, Hawaii, and the ERCOT portion of Texas, are also subject to only limited FPA Part II jurisdiction.

[24] 16 U.S.C. § 824(a).

B. Alternative Models for Federal/State Jurisdictional Split in Energy Law

The "bright line" in Part II of the FPA uses factors such as transaction and customer type (wholesale v. retail), facility type (generation v. transmission v. distribution), geography (interstate commerce v. intrastate commerce), and regulatory action (e.g., rate regulation v. facility permitting) to divide exclusive regulatory responsibilities between federal and state regulators. Congress has chosen different approaches for defining federal and state regulatory responsibilities in other energy-related statutes, however. The principal differences in approach are (1) while Part II of the FPA contemplates *exclusive* authority for each regulator, other federal statutes provide for some shared authority; and (2) while Part II provides the federal government with no authority over energy facility siting or development, leaving such matters exclusively to the states, other federal statutes (including other federal statutes defining FERC's responsibilities) provide for such authority.

1. Natural Gas Act

The Natural Gas Act is substantially similar to Part II of the FPA, but provides for broader federal authority over facilities regulation. Under the Natural Gas Act, FERC regulates the rates, terms, and conditions of transportation of natural gas in interstate commerce, but not production, gathering, or distribution – analogous to FERC's regulation of transmission service in the electricity sector.[25] The Natural Gas Act also provides for regulation of wholesale (but not retail) sales of natural gas, [26] like Part II of the FPA (although subsequent federal statutes have limited that authority under the Natural Gas Act such that it is not as extensive as the FPA).

Unlike the FPA, however, the Natural Gas Act requires developers of interstate natural gas pipelines to first obtain a certificate of public convenience and necessity from FERC. Certificate holders may use federal eminent domain to take property if necessary to obtain right of way.[27] There is no comparable provision for electric transmission lines in Part II of the FPA,[28] so multi-state transmission line developers must obtain certificates from each of the states (and in some cases even local governments) in which the line is to be located.

2. Part I of the FPA

Part I of the FPA,[29] originally enacted 15 years before Part II, provides FERC with authority over licensing hydroelectric facilities on navigable waterways.[30] The FPA, along with the Clean Water Act, provides

[25] 15 U.S.C. § 717(b) (2012).
[26] 15 U.S.C. § 717(b). Wholesale sales of natural gas are now largely deregulated.
[27] 15 U.S.C. § 717f(h).
[28] Section 216 of the FPA provides for limited federal authority to grant construction permits for electric transmission facilities within certain Department of Energy-designated "national interest electric transmission corridors" if "a State commission or other entity that has authority to approve the siting of the facilities has . . . withheld approval for more than 1 year . . . or . . . conditioned its approval in such a manner that the proposed" project will not reduce transmission congestion or will become uneconomic to construct. 16 U.S.C. § 824p.
[29] 16 U.S.C. §§ 791-823d.
[30] 16 U.S.C. § 797.

specific regulatory roles for state agencies with respect to such facilities. For example, under the FPA "resource agencies," including state environmental agencies, may make recommendations for conditions to be included in the license. Section 401 of the Clean Water Act also requires that a license applicant obtain a state-issued water quality certification, and precludes FERC from issuing a license under the FPA if the relevant state agency has denied the certification. This provision thus gives states an important jurisdictional lever over FERC's hydropower licensing process.[31]

3. Public Utility Regulatory Policies Act

Title I of the Public Utility Regulatory Policies Act of 1978 ("PURPA")[32] reflects an effort by Congress to influence states' policy choices in areas that are traditionally in their regulatory domain (such as retail ratemaking), without preempting state law. PURPA section 111 established "federal standards" on issues such as cost-of-service rates for different customer classes; eliminating declining block pricing; using time-of-day, seasonal, or interruptible rates; and load management techniques.[33] PURPA does not require states to adopt these standards. Instead, it requires states (and utilities not regulated by states including many public power and cooperative utilities) to conduct proceedings to consider such electricity policy changes. The constitutionality of Congress' instruction to the states to consider these policies was the subject of litigation, resulting in a Supreme Court decision holding that Congress could require states to consider certain policies as long as it did not require state adoption of the policies.[34]

Another provision of PURPA requires utilities to procure the output of qualifying cogeneration facilities and small renewable generators, termed qualifying facilities ("QFs"), at the utility's "avoided cost."[35] FERC promulgated regulations providing an overarching framework defining QF criteria and utility obligations. However, states still have significant implementation responsibilities, including in most cases the responsibility to determine what constitutes a particular utility's avoided cost.

---

[31] 33 U.S.C. § 1313 (2012).

[32] 16 U.S.C. § 2601 *et seq*.

[33] 16 U.S.C. § 2621(d). Subsequent amendments added federal standards on issues including: integrated resource planning; investments in conservation, demand management, and energy efficiency; evaluating utility costs of capital; net metering; fuel diversity; fossil fuel efficiency; time-based metering; and a requirement to interconnect with any generator capable of meeting technical criteria. 16 U.S.C. § 2621(d).

[34] *FERC v. Mississippi*, 456 U.S. 742, 765 (1982) ("Congress … allowed the States to continue regulating in the area on the condition that they consider the suggested federal standards. While the condition here is affirmative in nature – that is, it directs the States to entertain proposals – nothing in this Court's cases suggests that the nature of the condition makes it a constitutionally improper one. There is nothing in PURPA 'directly compelling' the States to enact a legislative program.") (internal citations omitted).

[35] 16 U.S.C. § 824a-3(d) (the statute uses the term "incremental cost of alternative electric energy," for which "avoided cost" has since become shorthand). Amendments in 2005 and subsequent regulatory actions have terminated the obligation of utilities to purchase the output of larger QFs (over 20 megawatts) that have access to a centrally organized wholesale electricity market.

4. Atomic Energy Act

The Atomic Energy Act ("AEA")[36] establishes federal regulatory authority over civilian uses of nuclear materials and facilities, exercised through the Nuclear Regulatory Commission ("NRC").[37] The licensing of nuclear plant construction and operation are exclusively in the federal domain, as is waste disposal. States retain oversight of generation planning by vertically integrated utilities (e.g., questions of whether or not to construct nuclear facilities in the first place). The Supreme Court has stated that under the AEA, "the Federal Government maintains complete control of the safety and 'nuclear' aspects of energy generation, whereas the states exercise their traditional authority over economic questions such as the need for additional generating capacity, the type of generating facilities to be licensed, land use, and ratemaking."[38] Additionally, the statute allows for an agreement between the NRC and a state to allow a state to assume certain limited responsibilities regarding treatment of hazardous nuclear materials.[39]

5. Clean Air Act

Several environmental statutes – most notably the Clean Air Act[40] – present a different model. In contrast to the FPA, the Clean Air Act expressly provides that the Environmental Protection Agency ("EPA") and the states share responsibility for establishing and implementing emissions reduction measures. For example, for criteria pollutants the EPA is directed to establish National Ambient Air Quality Standards, and states must submit and implement State Implementation Plans containing regulatory measures designed to bring the state into compliance with the EPA-established standards.[41] If a state does not submit a plan or if the submitted plan is deemed inadequate, the EPA will then impose a federal implementation plan as a backstop.[42] Thus, states typically have the choice of whether to meet an EPA-set goal on their own terms or to instead let EPA take responsibility for implementation. These standards and implementation plans are not limited to electric generator emissions, but generators are among the largest emitters of many of the pollutants (e.g., particulates, sulfur dioxide, nitrogen oxides) regulated in this matter, and thus these regulations significantly shape the electricity sector.

---

36 42 U.S.C. §§ 2011-2297h-13 (2012).

37 "Governing Legislation," U.S. Nuclear Regulatory Commission, accessed Aug. 17, 2016, http://www.nrc.gov/about-nrc/governing-laws.html. The NRC has authority over regulation of civilian uses, while the DOE has responsibility for developing and producing nuclear weapons and promoting nuclear power. Prior to 1974, these functions were housed in a single agency, the Atomic Energy Commission.

38 *Pac. Gas & Elec. Co. v. State Energy Res. Comm'n*, 461 U.S. 190, 191 (1983).

39 42 U.S.C. § 2021(k). The AEA is clear that nothing in section 2021(k) "shall be construed to affect the authority of any State or local agency to regulate activities for purposes other than protection against radiation hazards."

40 42 U.S.C. §§ 7401-7671q.

41 42 U.S.C. § 7407(a) ("Each State shall have the primary responsibility for assuring air quality within the entire geographic area comprising such State by submitting an implementation plan for such State which will specify the manner in which national primary and secondary ambient air quality standards will be achieved and maintained within each air quality control region in such State.").

42 *See, e.g.*, 42 U.S.C. § 7410(c).

In 2015, the EPA finalized its Clean Power Plan ("CPP"), a rule regulating carbon dioxide ("CO_2") emissions from existing fossil-fired generators under Clean Air Act section 111(d).[43] Consistent with this section of the Clean Air Act, the rule establishes state-specific CO_2 emission limits, and provides for states to develop and submit compliance plans. This leaves states with considerable discretion to choose the approach the state will take. The rule is the subject of ongoing litigation. As of this writing, the CPP has been stayed by the Supreme Court,[44] and it will not take effect (if at all) until judicial review is completed – likely in 2017 or 2018.

III. Technology and Industry Structure Changes That May Drive Future Jurisdictional Uncertainty and Market Integration Challenges

The new and emerging technologies that are gaining an increasing presence on the system today have significantly different operational characteristics than those that existed when the FPA and its jurisdictional "bright line" were written. Moreover, the structure of the industry has changed dramatically in some regions, from one characterized by vertically-integrated monopolies operating under cost-of-service regulation to one characterized by wholesale competition among diverse entities. These changes in technologies and generation sources, and significant changes in the structure of the electricity industry, can result in jurisdictional uncertainty and difficult market alignment issues.

A. 20th Century Technologies and Industry Structure

The electricity grid that existed in the U.S. at the time of the enactment of the FPA in 1935, and that in many ways continues to exist today, is one composed of: (1) large central station generating plants; (2) high voltage transmission lines to deliver the energy created at those plants over long distances; (3) lower voltage distribution lines to deliver that energy to end users; and (4) end use consumers themselves, including industrial, commercial and residential customers.[45] This technological structure had power and services flowing in a single direction from the power plants, through the transmission and distribution systems to end users.[46]

For most of the history of the FPA, the electric industry was primarily vertically-integrated, with a single entity (the utility) owning the generation, transmission, and distribution facilities.[47] While early utility systems were localized, serving small numbers of nearby customers, they rapidly developed into vertically-integrated monopolies serving franchised service territories with "bundled" cost-based rates

---

[43] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,662 (Oct. 23, 2015).

[44] *Chamber of Commerce v. EPA*, No. 15A787 (U.S. stay issued Feb. 9, 2016), *available at* http://www.supremecourt.gov/orders/courtorders/020916zr3_hf5m.pdf.

[45] *See, e.g.*, QER at 3-3.

[46] QER at 3-3.

[47] The exception is the several thousand small public power and cooperative electric utilities that own only distribution facilities. While distribution-only utilities are numerous, the majority of customers were served by vertically integrated utilities.

that recovered the costs of all of these facilities. These individual utilities planned and built generation, transmission and distribution primarily to meet their own load growth (and perhaps that of a few large wholesale customers). While there was some power pooling and wholesale sales between these utilities, resource sharing was not prevalent early on, and almost no generation resources were owned by non-utilities.

Under this traditional technological and business structure, the jurisdictional divide between FERC (previously the FPC) and the states was relatively straightforward. Under section 201(b) of the FPA, FERC regulated the initial portions of the "one-way" flow of power – wholesale sales of generated power between utilities in interstate commerce and the associated high-voltage transmission of electric energy in interstate commerce. Where the transmitted power was "stepped down" to distribution voltage and delivered for retail sales, FPA section 201(b)'s reservation of authority to the states to regulate "any other sale of electric energy" and "facilities used in local distribution" took over. Thus, one could generally look to the voltage level of a particular facility, and where in the chain of generation to end use a transaction was taking place, to determine jurisdiction.

B. New and Emerging Technologies and the Development of Competitive Electricity Markets

New and emerging energy technologies have different operational characteristics than many of the traditional technologies that have characterized the U.S. electric grid, and can provide new and different services. Deployments of smaller distributed generation (e.g., rooftop solar photovoltaic systems, fuel cell-based systems), energy storage, advanced metering, more intelligent grid-sensing devices and building management systems, advanced power controls, and software applications are all increasing, and are expected to accelerate in the future. Many of these new and emerging technologies facilitate customers' ability to generate their own power and more dynamically control their consumption, allowing them to provide demand response services in more ways. As the QER explains, taken together these technologies are creating a "grid of the future" where "two-way power flow will be common on both long-distance, high-voltage transmission lines and the local distribution network."[48]

These operational characteristics of new and emerging energy technologies do not fit as neatly into the FPA's jurisdictional divisions. With two-way power flow, there is not the same conceptual "hand off" of jurisdiction from federal to state regulation as power flows (and increases or decreases in voltage) from generation through delivery to ultimate consumption. Instead, new distributed energy resources (including energy storage) can be interconnected to either the FERC-jurisdictional high-voltage transmission system or the state-jurisdictional low-voltage local distribution system (or behind the customer's meter). In addition, the types of advanced technologies noted above and described further in the Appendix can provide services in both wholesale and retail markets. Because different types of service are subject to different jurisdictions and regulatory structures, allowing users of these

[48] QER at 3-4.

technologies to provide multiple services and receive compensation for the multiple benefits they provide can be more challenging,[49] as discussed below and in the Appendix.

All of these technological advancements are happening in the context of an electric industry that, in many places in the U.S., looks much different than the traditional vertically integrated utility model that was predominant for most of the history of the FPA. In large segments of the nation – especially in some of the regional transmission organization ("RTO") and independent system operator ("ISO") regions – vertically-integrated utilities are less common and multiple third parties compete with each other in wholesale markets to provide generation services. Additionally, a number of states have chosen to allow retail competition. Non-utility market participants include independent merchant power suppliers, new competitive transmission developers, and end-use customers themselves (or their aggregators) using demand response resources to provide wholesale services (including capacity, energy, and ancillary services). This evolution of the wholesale markets and increase in the number of market participants can spawn its own jurisdictional challenges, particularly as end-use customers become more active participants. As discussed below, the recent *EPSA* case demonstrates this potential.

IV. Historic and Current Jurisdiction Issues

Disputes about the meaning and application of the jurisdictional boundaries contained in the FPA are not new. Historically, courts were asked to draw the line between federal and state jurisdiction in a vertically-integrated industry that was increasingly becoming more interconnected. The recent and current jurisdiction issues facing the industry reflect not only the impact of a more interconnected industry, but also the rise of expanded regional markets where multiple sellers compete to provide service. Importantly, regulatory jurisdiction can shift because of changes in law (e.g., amendments to the FPA or court interpretations of the FPA), but can also change because of changes in material facts and industry circumstances. For instance, the volume of wholesale sales subject to FERC regulatory oversight has expanded greatly with the rise of organized wholesale markets and the divestiture of generation resources by many utilities.[50] The recent and current jurisdictional challenges also reflect the impact that technological changes can have on the division of federal and state regulatory authority.

---

[49] QER at 3-14 (noting that "developing appropriate rate structures for the benefits these technologies provide to the customer and the grid can be difficult").

[50] The increase in the volume of FERC-jurisdictional wholesale sales also impacts states. While rates paid by load-serving entities in wholesale markets are FERC-jurisdictional, the costs of such purchases must be passed through to customers in retail rates by state regulators without reassessing whether the wholesale rates were just and reasonable. *Nantahala Power & Light v. Thornburg*, 476 U.S. 953 (1986); but *see also Pike Cty. Light & Power Co. v. Penn. Pub. Util. Comm'n*, 77 Pa. Commw. 268, 465 A.2d 735 (1983) (holding that while a state may not independently judge the reasonableness of wholesale rates accepted by FERC, it may assess whether a retail utility under its jurisdiction reasonably "incur[red] such costs in light of available alternatives").

A. Historic Jurisdiction Issues

From the beginning, the Supreme Court and lower courts have wrestled with the line drawn in section 201 of the FPA, the limits it places on federal authority, and how those limits apply given the technical realities of the power sector.

For example, in *Connecticut Light & Power Co. v. FPC*, decided in 1945, the Court noted that the interconnected nature of the grid is "such that if any part of a supply of electric energy comes from outside of a state it is, or may be present in every connected distribution facility."[51] As a result, following the flow of electricity in interstate commerce would in theory extend federal regulation to "a toaster on the breakfast table."[52] The Court explained that the limiting language of sections 201(a) and (b)(1) of the FPA prevent this result, and establish a legal, rather than scientific, test to determine jurisdiction.[53]

One longstanding issue was whether the transmission of electricity between two points in a state, or a wholesale sale between two parties in a single state, was in interstate commerce and thus subject to regulation under the FPA. In 1964, the Supreme Court addressed this question in its "*Colton*" decision: *FPC v. Southern California Edison Co*.[54] *Colton* involved a wholesale sale of out-of-state power by an investor-owned utility, Southern California Edison Company ("SCE"), to a municipal utility in the same state, the City of Colton. SCE and the State of California argued, and the United States Court of Appeals for the Ninth Circuit ("Ninth Circuit") held, that SCE's wholesale sale would not be subject to the FPA, and thus, not subject to federal jurisdiction.[55] In finding that the wholesale sale was subject to *state* regulation, the Ninth Circuit relied on the limiting language of FPA section 201(a) – that the FPC's jurisdiction "extend[s] only to those matters which are not subject to regulation by the states."[56] Under the Ninth Circuit's interpretation of FPA section 201(a), "the FPC could not assert its jurisdiction over a sale which the Commerce Clause allowed a State to regulate."[57]

The Supreme Court disagreed with the Ninth Circuit's reasoning and reversed, finding that wholesale electricity sales, including those from SCE to the City of Colton, are subject to federal jurisdiction.[58] Specifically, the Supreme Court noted that when Congress filled the *Attleboro* gap by enacting the FPA, it did not intend to "adopt[] this flexible approach . . . applied by the Court of Appeals in the instant case."[59] Rather, Congress intended to "adopt the test developed in the *Attleboro* line which denied state power to regulate a sale 'at wholesale to local distributing companies' and allowed state regulation of a sale at 'local retail rates to ultimate consumers.'"[60] Regarding the FPA's grant of

51 324 U.S. 515, 529 (1945).
52 *Conn. Light & Power Co. v. FPC*, 324 U.S. at 529.
53 *Conn. Light & Power Co. v. FPC*, 324 U.S. at 529-31.
54 376 U.S. 205 (1964) ("Colton").
55 *Colton*, 376 U.S. at 210-11.
56 *Colton*, 376 U.S. at 209-10.
57 *Colton*, 376 U.S. at 210.
58 *Colton*, 376 U.S. at 216.
59 *Colton*, 376 U.S. at 214.
60 *Colton*, 376 U.S. at 214-15.

authority to the FPC, the Court clarified that "Section 201(b) embodies a clear grant of power."[61] By contrast, when addressing the limiting clause of section 201(a) that the Ninth Circuit relied upon to find state jurisdiction, the Court further clarified, "§ 201(a) was merely a 'policy declaration . . . of great generality. It cannot nullify a clear and specific grant of jurisdiction, even if the particular grant seems inconsistent with the broadly expressed purpose.'"[62]

Thus, the Court concluded by stating that "Congress meant to draw a *bright line* easily ascertained, between state and federal jurisdiction . . . making FPC jurisdiction *plenary* and extending it to all wholesale sales in interstate commerce except those which Congress has made explicitly subject to regulation by the States."[63] With some adjustments,[64] this "bright line" has remained the jurisdictional division between federal and state agencies in electricity regulation.

Later cases developed the standard used today in determining federal versus state jurisdiction, which is a "comingling" test formally adopted in 1972. Under this test, particular facilities (and consequently the entities owning or operating them) fall under FPA jurisdiction if any portion of the electricity involved is transmitted to or from another state;[65] practically speaking, this covers the entire United States with the exceptions of Alaska, Hawaii, and the ERCOT portion of Texas. Thus, wholesale sales or transmission services that use the interconnected interstate transmission system are generally considered to be in interstate commerce.

The extent of federal authority over transmission of electric energy in interstate commerce was later considered in *New York v. FERC*.[66] In that case, the Court upheld FERC's landmark Order No. 888, which advanced wholesale competition by requiring transmitting utilities to provide open, non-discriminatory access to their transmission facilities and to unbundle their transmission and wholesale sales services.[67] In particular, the Court upheld FERC's authority to apply Order No. 888's requirements to *unbundled* retail transmission of electricity[68] against a challenge from New York, which asserted that such

---

[61] *Colton*, 376 U.S. at 215.
[62] *Colton*, 376 U.S. at 215 (citing *Conn. Light & Power Co. v. FPC*, 324 U.S. at 527).
[63] *Colton*, 376 U.S. at 215-16 (emphasis added).
[64] *See, e.g.*, Public Utility Regulatory Policies Act of 1978 (PURPA) § 210, 16 U.S.C. § 824a-3; *see also* FPA §§ 210-11, 215, 221-22, 16 U.S.C. §§ 824i, 824j, 824o, 824u, 824v (amended by the Energy Policy Act of 1992 and Energy Policy Act of 2005).
[65] *FPC v. Fla. Power & Light Co.*, 404 U.S. 453, *reh'g denied*, 405 U.S. 948 (1972). This comingling test was not without controversy at the time it was adopted. As Justice Douglas' dissent presciently stated, "the comingling method will now mean that every privately owned interconnected facility… is within the FPC's jurisdiction. *FPC v. Fla. Power & Light Co.*, 404 U.S. at 471 (Douglas, J., dissenting).
[66] 535 U.S. 1 (2002).
[67] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Servs. by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, 81 FERC ¶ 61,248 (1997), *order on reh'g*, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002)
[68] Unbundled retail transmissions were those made by utilities that either voluntarily, or at the direction of their State regulator, separated the transmission function from the retail sales function, offered their customers retail access, and transmitted retail power sold by others to them.

transmission support a retail transaction and are thus subject to state retail regulatory authority.[69] The Court concluded that such transmission services "are indeed transmissions of 'electric energy in interstate commerce,' because of the nature of the national grid," and that "[t]here is no language in the statute limiting FERC's *transmission* jurisdiction to the wholesale market, although the statute does limit FERC's *sale* jurisdiction to that at wholesale."[70] As discussed below, a later court decision relied on this language to uphold FERC actions related to transmission planning in Order No. 1000.

FERC was careful in Order No. 888, however, to interpret its jurisdiction narrowly so as to avoid potentially disruptive shifts of jurisdiction and avoid confronting a thorny jurisdictional question. Specifically, while FERC required the separation of wholesale transmission and generation services, and asserted jurisdiction over "unbundled" wholesale and retail transmission in interstate commerce,[71] it specifically declined to assert authority over the transmission portion of *bundled* retail transactions.[72] The Court in *New York v. FERC* concluded that this was a "statutorily permissible policy choice," without deciding the issue of whether FERC could have asserted such authority.[73] As discussed below, this case suggests that FERC has discretion in interpreting its own mandatory jurisdiction under the FPA, and that such interpretations will receive particular deference where they are respectful of the jurisdiction reserved to state regulation under the statute.

B. Current Jurisdiction Issues

1. Net Metering for Distributed Generation

States have developed net metering policies that allow a customer with a solar photovoltaic rooftop installation, for instance, to net distributed generation sales to the utility against retail purchases from the utility.[74] In economic effect, these policies require distribution utilities to purchase surplus output of rooftop solar generation and similar resources at the utility's retail rate – usually far in excess of avoided cost. The jurisdiction question is whether the sale of excess electricity (i.e., the amount of electricity generated by the photovoltaic device that exceeds the property's electricity usage at any time) is a wholesale sale subject to FERC jurisdiction, which could in turn subject the homeowner to public utility regulation.

---

[69] *New York v. FERC*, 535 U.S. at 16.
[70] *New York v. FERC*, 535 U.S. at 17.
[71] An unbundled transaction separates out the various elements – most notably, electricity sales and transmission service.
[72] Order No. 888, 61 Fed. Reg. at 21,577-78.
[73] *New York v. FERC*, 535 U.S. at 27-28 ("even if we assume … that … the FPA gives FERC the authority to regulate the transmission component of a bundled retail sale, we nevertheless conclude that the agency had discretion to decline to assert such jurisdiction in this proceeding in part because of the complicated nature of the jurisdictional issues."). The Court did, however, agree with FERC that the prospect of asserting jurisdiction over all retail transmissions would have "implications for the States' regulation of retail sales – a state regulatory power recognized by the same statutory provision that authorizes FERC's transmission jurisdiction." *New York v. FERC*, 535 U.S. at 28.
[74] In 2005 Congress amended Title I of PURPA to require state commissions and non-regulated utilities to consider and determine whether to implement net metering, among other policies. PURPA § 111(d)(11), 16 U.S.C. § 2621(d)(11) (enacted by Energy Policy Act of 2005, Pub. L. No. 109-58, § 1251, 119 Stat. 594, 962 (2005)).

Over the past 15 years, FERC has issued a series of orders largely disclaiming jurisdiction over sales from resources under net metering programs. In a 2001 order, FERC considered whether on-site generation owned by the retail customer and metered using a single meter constituted a wholesale sale subject to the FPA, and found that it was not so long as the sales to the utility were netted against purchases from the utility.[75] In a 2004 order, FERC held that "under most circumstances the Commission does not exert jurisdiction over a net energy metering arrangement when the owner of the generator receives a credit against its retail power purchases from the selling utility."[76] FERC clarified that the period over which FERC would permit the netting determination to be made was the utility's *billing* period, but did not specify what would constitute an acceptable billing period. Most recently, in 2009, FERC expanded its exemption to include sales of electricity made by a third-party owner of a distributed generation system to the on-site retail customer, so long as that customer had a net metering arrangement with its utility and did not sell more electricity than it purchased over a billing period.[77]

In sum, FERC has made a series of interpretations of its jurisdiction that allow state net metering programs to continue without triggering federal regulatory applicability that could stymie such state initiatives. These decisions rest on a common regulatory construct – that consumers with on-site generation are merely "offsetting" consumption and not selling at wholesale. To date, the courts have not been called on to address this construct or whether net metering arrangements in fact constitute a sale for resale in interstate commerce that would trigger FERC jurisdiction.

2. Federal Jurisdiction and Demand Response Resources

Since 2000-2001, RTOs/ISOs have allowed retail end-users of electricity to submit offers "to decrease electricity consumption by a set amount at a set time for a set price"[78] – better known as "demand response" – into wholesale energy and capacity markets, just as if these offers to reduce consumption were offers to supply generation.[79] The Supreme Court has noted that "[t]he wholesale market operators treat those [demand response] offers just like bids from generators to increase supply."[80] FERC supported RTO/ISO efforts to reduce barriers to the participation of demand response resources in the organized wholesale markets, and in some cases even directed the RTOs/ISOs to consider further measures to reduce such barriers.[81] In addition, in the Energy Policy Act of 2005, Congress encouraged

[75] *MidAmerican Energy Co.*, 94 FERC ¶ 61,340, at p. 62,264 (2001).
[76] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, at P 747, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008).
[77] *SunEdison LLC*, 129 FERC ¶ 61,146, at P 18 (2009), *order on reh'g*, 131 FERC ¶ 61,213 (2010).
[78] *EPSA*, 136 S. Ct. at 770.
[79] *See, e.g.*, *PJM Interconnection, L.L.C.*, 95 FERC ¶ 61,306 (2001); *Cal. Indep. Sys. Operator Corp.*, 91 FERC ¶ 61,256 (2000).
[80] *EPSA*, 136 S. Ct. at 770.
[81] *See, e.g.*, *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274 (2006) (encouraging further incorporation of demand response into the redesign of the CAISO markets); *Midwest Indep. Transmission Sys. Operator, Inc.*, 116 FERC ¶ 61,124 (2006) (directing a technical conference to consider, *inter alia*, the integration of demand response in MISO's procedures for addressing shortage and emergency conditions occurring in the real-time energy market.

the industry and FERC to continue to reduce barriers to participation of demand response in wholesale markets.[82]

After pursuing greater participation of demand response on a case-by-case basis, FERC issued Order No. 719 in 2008,[83] in which it made several generic reforms to further eliminate barriers to demand response participation in organized energy markets. In doing so, FERC recognized that its actions could have jurisdictional implications. Among other changes, FERC required RTOs/ISOs to (1) accept bids from demand response resources in their markets for certain ancillary services on a basis comparable to other resources, and (2) permit aggregators of demand response to bid demand response on behalf of retail customers directly into the RTO's/ISO's organized markets, "unless the laws or regulations of the relevant electric retail regulatory authority [*i.e.*, state authority] do not permit a retail customer to participate."[84] Therefore, FERC's wholesale demand response policy was subject to the limitation that state authorities could "opt out" and prevent their demand response resources from participating in the wholesale markets. This feature of Order No. 719 apparently addressed, at least for the time being, any jurisdictional concerns, as no challenges to FERC's jurisdiction were pursued.

In 2011, FERC took further steps in its expansion of wholesale demand response by issuing Order No. 745, which required, subject to condition, that a "demand response resource *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* (LMP)."[85] By setting a single pricing standard for demand response resources applicable to all RTO/ISO markets, FERC revised its prior approach to compensation of demand response resources, under which "each RTO and ISO [could] develop its own compensation methodologies for demand response resources."[86]

Order No. 745 faced significant opposition from generators that compete with demand response in the wholesale markets, as well as from utilities and some state commissions. They argued, in part, that FERC lacked authority to regulate the price paid to demand response resources because demand response involves retail consumption and retail sales, which are matters subject to the authority of the states. FERC rejected these arguments.

---

[82] Energy Policy Act of 2005, Pub. L. No. 109-58, § 1252(f), 119 Stat. 594, 965 (2005) ("It is the policy of the United States that . . . unnecessary barriers to demand response participation in energy, capacity, and ancillary service markets shall be eliminated.").

[83] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 125 FERC ¶ 61,071 (2008), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[84] Order No. 719 at PP 47, 53.

[85] *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, FERC Stats. & Regs. ¶ 31,322, at PP 2, 47 (emphasis added), *order on reh'g & clarification*, Order No. 745-A, 137 FERC ¶ 61,215 (2011), *reh'g denied*, Order No. 745-B, 138 FERC ¶ 61,148 (2012), *vacated sub nom. Elec. Power Supply Ass'n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014), *rev'd & remanded sub nom. FERC v. Elec. Power Supply Ass'n*, 136 S. Ct. 760 (2016).

[86] Order No. 745 at P 14.

In *Electric Power Supply Ass'n v. FERC*,[87] the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") vacated Order No. 745, agreeing with opponents that FERC lacked jurisdiction to regulate the participation of demand response resources in the wholesale market. Specifically, while acknowledging that demand response compensation is a practice that "affects the wholesale market," the court found that FERC's "jurisdiction to regulate practices 'affecting rates' does not erase the specific limit[]" imposed by the FPA on FERC regulation of retail rates.[88] The court held that Order No. 745 exceeded this limit because, in "'luring . . . retail customers' into the wholesale market, and causing them to decrease 'levels of retail electricity consumption,' the Rule engages in 'direct regulation of the retail market.'"[89]

In *EPSA*, the Supreme Court reversed the D.C. Circuit's jurisdictional determination and upheld Order No. 745.[90] First, the Court found that FERC's assertion of authority in the order fit within its authority under section 206 of the FPA to remedy "any rule, regulation, *practice*, or contract affecting" a rate or charge subject to its jurisdiction. In reaching this conclusion, the Court acknowledged that FERC's authority to address "practices" affecting wholesale rates is not boundless, adopting the D.C. Circuit's reasoning in a separate case that such practices must *directly* affect jurisdictional rates.[91] Applying that "common-sense" limit the Court concluded that "the practices at issue in the Rule – market operators' payments for demand response commitments – directly affect *wholesale* rates."[92] Specifically, the Court noted that "*wholesale* market operators employ demand response bids in competitive auctions that balance *wholesale* supply and demand and thereby set *wholesale* prices," and concluded, "[w]holesale demand response, in short, is all about reducing wholesale rates . . . ."[93]

Secondly, the Court found that Order No. 745 does not directly regulate retail electricity sales, contrary to the holding of the D.C. Circuit. While the Court conceded that any regulation of wholesale electricity sales will naturally affect retail rates in some way, it made clear that such affect "is of no legal consequence."[94] The Court stated:

> [A] FERC regulation does not run afoul of § 824(b)'s proscription just because it affects – even substantially – the quantity or terms of retail sales. It is a fact of economic life that the wholesale and retail markets in electricity, as in every other known product, are not

---

[87] *Elec. Power Supply Ass'n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014) ("*EPSA v. FERC*"), *rev'd & remanded sub nom. FERC v. Elec. Power Supply Ass'n*, 136 S. Ct. 760 (2016).
[88] *EPSA v. FERC*, 753 F.3d at 222.
[89] *EPSA*, 136 S. Ct. at 772 (summarizing the D.C. Circuit's analysis)
[90] 136 S. Ct. 760.
[91] *EPSA*, 136 S. Ct. at 764 (citing *Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 403 (D.C. Cir. 2004)).
[92] *EPSA*, 136 S. Ct. at 773 (emphasis added).
[93] *EPSA*, 136 S. Ct. at 774 (emphasis added). In considering whether FERC's action in Order No. 745 amounted to an impermissible direct regulation of retail rates, the Court also looked to the "'target at which [it] . . . aims,'" and concluded that FERC's rationale for the order was "all about, and only about, improving the wholesale market." *EPSA*, 136 S. Ct. at 776-77 (citing *Oneok, Inc. v. Learjet, Inc.*, 135 S. Ct. 1591, 1599 (2015) ("*Oneok*")).
[94] *EPSA*, 136 S. Ct. at 764, 776.

> hermetically sealed from each other. To the contrary, transactions that occur on the wholesale market have natural consequences at the retail level.
>
> . . .
>
> When FERC sets a wholesale rate, when it changes wholesale market rules, when it allocates electricity as between wholesale purchasers – in short, when it takes virtually any action respecting wholesale transactions – it has some effect, in either the short or the long term, on retail rates. That is of no legal consequence. . . . When 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, § 824(b) imposes no bar. And in setting rules for demand response, that is all FERC has done.[95]

Two other aspects of the Court's *EPSA* decision are also important to note in the context of this paper. First, the Court found that FERC's "notable solicitude toward the States" – specifically its decision to continue to allow states to "opt out" and prohibit their retail customers from participating in the wholesale market – "removes any conceivable doubt as to [Order No. 745's] compliance with [the FPA's] allocation of federal and state authority."[96] As discussed below, this language suggests that FERC's choice to structure its demand response compensation rule as "a program of cooperative federalism"[97] may have improved its chances of surviving jurisdictional challenge.

Second, the Court makes an important point regarding the impact of the FPA's jurisdictional division of authority between FERC and the states on the ability to pursue coordinated regulatory programs or integrated wholesale and retail markets. Responding to a hypothetical set forth in Justice Scalia's dissent, under which FERC would by rule allow generators to sell directly to retail consumers and fix all generation, transmission and retail rates, Justice Kagan's majority opinion notes:

> [O]f course neither FERC nor the States could issue such a rule: If FERC did so, it would interfere with the States' authority over retail sales and rates as well as (most) generation; if a State did so, it would interfere with FERC's power over transmission. Thus, to implement such a scheme, the States would need to do something and FERC to do others. And if the one or the other declined to cooperate, then the full scheme could not proceed.[98]

3. State-directed Procurement of Generation Resources within Organized Wholesale Electricity Markets

Several RTOs/ISOs,[99] in addition to administering energy and ancillary services markets, also operate mandatory centralized *capacity* auction markets through which retail sellers of electricity must acquire capacity (i.e., the availability to produce energy when called upon) sufficient to cover their projected

---

95 *EPSA*, 136 S. Ct. at 776.
96 *EPSA*, 136 S. Ct. at 779-80.
97 *EPSA*, 136 S. Ct. at 780.
98 *EPSA*, 136 S. Ct. at 780 n.10.
99 Specifically, PJM Interconnection, L.L.C. ("PJM"), the New York Independent System Operator ("NYISO"), and ISO New England ("ISO-NE").

peak demand.[100] In these bid-based capacity markets, generators submit price offers into an auction to sell capacity for delivery in a future period,[101] and the RTO accepts offers from lowest to highest until it has enough capacity to meet its planning requirements (generally defined as sufficient megawatts to meet demand plus a reserve margin).[102] The highest accepted offer sets the "clearing price," which is the price that all accepted capacity sellers will receive.[103] These capacity markets were developed in part because bid caps and other constraints in wholesale energy markets limited generator revenues and the ability of generators to recover their costs, discouraging construction of new facilities and threatening continued operation of existing generation facilities.[104]

Several states and a number of utilities and other market participants have voiced repeated concerns that these centralized capacity markets raise consumer prices, but do not result in investment in new generation resources.[105] They have also argued that these markets impede their ability to achieve their own energy policy goals, or fail to preserve existing resources needed for reliability or environmental purposes.[106] Some states in regions with these markets have taken steps to encourage or require the development of new generation facilities or preservation of existing resources they regard as necessary to achieve reliability, environmental or consumer protection goals.

In two cases, those state efforts have encountered disputes regarding their authority to take such actions in the context of the PJM capacity market. Maryland and New Jersey, both concerned that the

---

100 *Hughes*, 136 S. Ct. at 1293; *see also* FERC, Energy Primer: A Handbook of Energy Market Basics (2015), 61. PJM's capacity market is known as the Reliability Pricing Model ("RPM"), NYISO's capacity market is called the Installed Capacity Market, and ISO-NE's capacity market is called the Forward Capacity Market. FERC, Staff Report, Centralized Capacity Market Design Elements (2013).

101 *E.g.*, PJM and ISO-NE each operate three-year forward capacity auctions, meaning that generators are bidding to sell capacity that will be committed to the market three years in the future. *See PPL EnergyPlus, LLC v. Solomon*, 766 F.3d 241, 251 (3d Cir. 2014), *cert. denied sub. nom. Fiordaliso v. Talen Energy Mktg., LLC*, 136 S. Ct. 1728 (2016).

102 *Hughes*, 136 S. Ct. at 1293; *N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74, 83-84 (3d Cir. 2014) (describing the mechanics of the PJM RPM); *PPL EnergyPlus v. Solomon*, 766 F.3d at 251 (same).

103 *See, e.g.*, *Hughes*, 136 S. Ct. at 1293 (describing PJM capacity market auction); *N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d at 83 (same); *PPL EnergyPlus, LLC v. Solomon*, 766 F.3d at 251 (same).

104 *See, e.g.*, *N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d at 83 (noting the failures of PJM's pre-RPM capacity procurement mechanism, stating, "In 1999, PJM modified the reliability requirement to allow LSEs to procure capacity up to the day before it was needed, while also instituting market opportunities to purchase 'capacity credits.' . . . Those methods soon proved inadequate, however, as they resulted in supply insufficiencies and volatile capacity prices in certain locations . . . ma[king] the capacity market ineffective at incentivizing development of new generation resources. Therefore, in 2000, PJM began negotiating with its stakeholders to reform the capacity market.").

105 *See, e.g.*, *N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d at 87 ("According to the statute, New Jersey faced an 'electrical power capacity deficit' due to transmission system overloads and aging generation facilities. Because PJM's 'reliability pricing model [had] not resulted in large additions of' generation facilities or load resources, 'the construction of new, efficient generation [had to] be fostered by State policy.'"); *PPL EnergyPlus LLC v. Solomon*, 766 F.3d at 252 ("Indeed, New Jersey regulated the Standard Offer Capacity Rates precisely because the legislature believed that PJM's market-based incentives had failed to encourage new electric generators to construct adequate electric generation facilities.").

106 *See, e.g.*, *New England States Comm. on Electricity v. ISO New England Inc.*, 142 FERC ¶ 61,108 (2013) (denying complaint from state governors alleging that ISO New England's capacity market mitigation rules undermine state laws supporting the development of renewable resources).

PJM capacity auction "was failing to encourage development of sufficient new in-state generation,"[107] sought to support development of generation capacity to be built within the state. While different in some specific details, both the Maryland and New Jersey programs had similar features. Each conducted solicitations for developers to construct new natural gas-fired power plants at a specific location, and required the state's utilities to enter into "contracts for differences" with the winning developer(s). Under the terms of those contracts, the winning bidder was required to participate in and clear the PJM capacity market, and would receive a fixed price set by the contracts for their capacity sales. If the winning bidder did not clear the capacity market, it would receive no payment. Under the contracts, if the PJM market price was lower than the contract rate, the utilities would pay the developer the difference, and recover that additional amount from their customers through retail rates. If the PJM capacity price was higher than the contract price, the developer would return the amount above the contract rate to the utilities, which would use the revenues to lower customer retail charges.

Both programs faced legal challenges from existing generators, which were concerned that the requirement in each program that the selected new generator clear the auction would give the selected generator owner an incentive to submit a capacity below its actual costs to ensure that it would clear the PJM capacity auction, resulting in artificially lower overall capacity market prices.[108] These opponents argued that these state programs, by setting the price that generators would receive for selling capacity, conflicted with the FPA and FERC's capacity market policies and were thus preempted under the Supremacy Clause.[109]

In the case of Maryland, CPV Maryland, LLC ("CPV") ultimately won the right to build a plant under the program. The challenge to Maryland's program and CPV's contract ultimately made its way to the Supreme Court. In *Hughes*, the Court unanimously affirmed the rulings of lower courts holding that Maryland's program impermissibly conflicted with and was preempted by federal law.[110] Relying on the Supremacy Clause and pre-emption doctrine, the Court agreed with their conclusion that the program "sets an interstate wholesale rate, contravening the FPA's division of authority between state and federal regulators."[111] By guaranteeing to CPV a rate for capacity different from the capacity rate resulting from PJM's capacity auction, the Court found that Maryland's program adjusts an interstate wholesale rate, and thus, impermissibly "invades FERC's regulatory turf."[112]

The Court emphasized that its holding was limited. Similar to its conclusion in *EPSA* that the fact that a FERC action setting a wholesale rate or changing wholesale markets may incidentally affect retail rates

---

107 *Hughes*, 136 S. Ct. at 1294; *see also* N.J. Stat. § 48:3-98.2(b); *N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d at 87 ("According to the statute, New Jersey faced an 'electrical power capacity deficit' due to transmission system overloads and aging generation facilities. Because PJM's 'reliability pricing model [had] not resulted in large additions of' generation facilities or load resources, 'the construction of new, efficient generation [had to] be fostered by State policy.'").
108 *See, e.g.*, *N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d at 88 (explaining New Jersey's intent to offer the capacity at a price below actual cost).
109 *Hughes*, 136 S. Ct. at 1296.
110 *Hughes*, 136 S. Ct. 1288. The New Jersey program was also found preempted and invalidated, on substantially similar grounds, by the United States Court of Appeals for the Third Circuit in *PPL EnergyPlus v. Solomon*, 766 F.3d at 246.
111 *Hughes*, 136 S. Ct. at 1297.
112 *Hughes*, 136 S. Ct. at 1297.

is "of no legal consequence," the Court in *Hughes* explained that states "may regulate within the domain Congress assigned to them [under the FPA] even when their laws incidentally affect areas within FERC's domain."[113] But states "may not seek to achieve ends, however legitimate, through regulatory means that intrude on FERC's authority over interstate wholesale rates."[114] In this regard, the "fatal defect that renders Maryland's program unacceptable," the Court explained, was the fact that it "condition[ed] payment of funds on capacity clearing the auction."[115] Nothing in the opinion, the Court emphasized, "should be read to foreclose" states from "encouraging production of new or clean generation through measures 'untethered to a generator's wholesale market participation.'"[116] Thus, the Court noted that it was not addressing "the permissibility of various other measures States may employ to encourage development of new or clean generation, including tax incentives, land grants, direct subsidies, construction of state-owned generation facilities, or re-regulation of the energy sector."[117]

In parallel litigation before FERC, PJM and a group of existing generators, concerned that the potential addition of new generation developed under the Maryland and New Jersey program would cause artificial price suppression in the capacity market, asked FERC to impose additional buyer-side market power mitigation in the form of a minimum offer price rule. In addition, they asked that a previous exemption from buyer-side market power mitigation for "state-mandated resources" be eliminated, such that the new minimum offer price rule would apply to such resources.

FERC approved both requests.[118] Under the minimum offer price rule and without the previous state-mandate exemption, any units developed under the Maryland and New Jersey programs would have been required to offer capacity no lower than a proxy price that represented the "cost of new entry" for a typical gas-fired plant. This rule would likely have had the effect of excluding new resources developed under these programs from the capacity market auction. In approving those requests, FERC was careful to explain that it was not passing judgment on state public policy objectives, but was instead only ensuring that prices in the *wholesale* market continued to be just and reasonable.[119] The United States Court of Appeals for the Third Circuit affirmed FERC's action, concluding that they were "squarely, and indeed exclusively, within [its] jurisdiction."[120]

The parallel tracks on which this litigation proceeded, and FERC's careful determination to "stay in its lane," show how jurisdictional challenges, even when successfully navigated, could have implications for state and federal coordination. Even if both Maryland and FERC had prevailed legally in each separate track, FERC's approval of an expanded Minimum Offer Price Rule would have excluded the plants in question from the PJM capacity market and ultimately frustrated (and perhaps blocked

---

113 *Hughes*, 136 S. Ct. at 1298.
114 *Hughes*, 136 S. Ct. at 1298.
115 *Hughes*, 136 S. Ct. at 1299-1300.
116 *Hughes*, 136 S. Ct. at 1299.
117 *Hughes*, 136 S. Ct. at 1299.
118 *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, *order on reh'g*, 135 FERC ¶ 61,228 (2011).
119 *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, at P 141.
120 *N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d at 97.

entirely) the policy objectives of Maryland and New Jersey to encourage new power plants within their state.

4. FERC Order No. 1000 and the Extent of FERC Jurisdiction Over Transmission Planning

In 2011, FERC issued Order No. 1000, an extensive rulemaking that established new transmission planning and cost allocation requirements applicable to transmission providers subject to FERC's jurisdiction (including both vertically-integrated utilities and RTOs/ISOs).[121] Among other things, the rule required that transmission providers: (1) join and participate in a regional transmission planning process that produces a regional plan; (2) ensure that local and regional transmission planning processes consider transmission needs created by public policy requirements enacted by the federal government or the states; (3) eliminate from their tariffs any "right of first refusal" granting incumbent transmission owners the automatic right to build certain transmission facilities; and (4) ensure that each regional transmission planning process includes an *ex ante* cost allocation methodology that will be applied to new regional and interregional transmission projects.[122]

The extensive nature of the regional transmission planning and cost allocation requirements of the rule, and the potential that it would spread transmission costs more broadly across regions or multiple regions, naturally led to opposition. On appeal to the D.C. Circuit, numerous parties (including state commissions, utilities, and other impacted stakeholders) challenged FERC's authority under the FPA to mandate regional transmission planning. They argued, among other things, that FERC's regional transmission planning requirement "infringe[d] on the States' traditional regulation of transmission planning, siting, and construction, violating" FPA section 201(a)'s limit on FERC's transmission authority to "only those matters which are not subject to regulation by the States."[123]

In *South Carolina Public Service Authority v. FERC*, the D.C. Circuit disagreed, concluding that the regional transmission planning mandate of Order No. 1000 "fits comfortably within Section 201(b)'s grant of jurisdiction over 'the transmission of electric energy in interstate commerce.'"[124] Relying heavily on *New York v. FERC*, the Court noted that section 201(b) of the FPA affords FERC "relatively broader authority" over transmission than electricity sales, and that this authority has "expanded over time because transmissions on the interconnected grids that have now developed 'constitute transmissions in interstate commerce.'"[125] In concluding that FERC's transmission planning mandate fit within this broad authority, the Court explained that "*New York v. FERC* teaches that there is no reason to think that the 'prefatory' state of federalism 'policy' in Section 201(a) poses an obstacle to [FERC's] assertion of authority."[126]

---

121 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Pub. Utils.*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

122 Order No. 1000 at PP 1-2.

123 *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 62 (D.C. Cir. 2014).

124 *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 63 (citing *New York v. FERC*, 535 U.S. at 15).

125 *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 63 (citing *New York v. FERC*, 535 U.S. at 7, 16).

126 *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 64 (citing *New York v. FERC*, 535 U.S. at 17, 22).

While Order No. 1000 was the subject of jurisdictional dispute, it also included notable provisions that sought to account for and reconcile state laws and policies in the transmission planning process. In particular, as noted above and discussed in more detail below, FERC required that the regional and local planning processes of transmission providers subject to its jurisdiction adopt procedures that provide for the "consideration of transmission needs driven by public policy requirements," including those enacted by states.[127]

Additionally, in the course of addressing filings made by transmission providers to comply with the requirements of Order No. 1000, FERC approved additional steps proposed by several transmission planning regions to recognize the interaction of the rule's mandates with state laws and regulations. Specifically, in several orders on rehearing, the Commission allowed these regions to adopt tariff provisions that would maintain an incumbent's rights of first refusal when required by a state law or regulation (such as a state law allowing only incumbent utilities the right to build transmission in the state, or where a project is proposed to be located on an existing utility's state-granted right of way).[128] On appeal, the United States Court of Appeals for the Seventh Circuit upheld FERC's approval of these tariff provisions in Midcontinent Independent System Operator, Inc. ("MISO"), concluding that such approval appropriately recognized FERC's statement in Order No. 1000 that it was not "limit[ing], preempt[ing], or otherwise affect[ing] state or local laws or regulations with respect to construction of transmission facilities," and that it met FERC's "proper goal" of "'avoid[ing] intrusion on the traditional role of the states' in regulating the siting and construction of transmission facilities."[129]

C. Themes from Historic and Current Jurisdiction Challenges That May Impact New and Emerging Technologies

The historic and current jurisdictional challenges reviewed above reveal a few central themes that are relevant to future potential jurisdiction challenges impacting new and emerging technologies and the integration of markets for those technologies. Here, we summarize three themes coming from the historic and recent jurisdiction challenges, and briefly touch on how they may impact new and emerging energy technologies. The Appendix to this paper more fully describes some specific recent technology developments in the electric sector, and the regulatory and jurisdictional challenges these new and emerging technologies have raised already and could raise going forward.

<u>Resolution of jurisdiction disputes is generally accomplished by "picking sides."</u> –The jurisdictional provisions of the FPA draw a line between federal and state regulatory jurisdiction. Court review of jurisdictional questions involves, at bottom, determining where that line in the FPA is drawn in particular factual circumstances. Section 201 of the FPA does not provide a means for federal and state

---

127 Order No. 1000 at PP 2, 203. FERC defined "Public Policy Requirements" as "state or federal laws or regulations", including "enacted statutes . . . and regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level." Order No. 1000 at P 2.

128 *See, e.g.*, *Midwest Indep. Transmission Sys. Operator, Inc.* 147 FERC ¶ 61,127, at PP 147-150 (2014); *PJM Interconnection, LLC*, 147 FERC ¶ 61,128 at PP 130-33 (2014); *S.C. Elec. & Gas Co.*, 147 FERC ¶ 61,126 at PP 125-28 (2014).

129 *MISO Transmission Owners v. FERC*, 819 F.3d 329, 336 (citing Order No. 1000 at P 227; *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 76).

regulators to customize, negotiate, delegate, or share jurisdictional roles in circumstances where such an approach might allow them to find middle ground, "win-win" approaches that encourage coordination across jurisdictions and markets. The litigation over state efforts to support in-state generation development within organized wholesale markets that ultimately led to the *Hughes* decision shows that even where both the federal and state governments have FPA-recognized jurisdictional interests (states in generation; FERC in wholesale electricity markets), the actions of one can frustrate the policy goals of another.

The utilization and advancement of new and emerging energy technologies will likely result in more instances where policymakers or courts must analyze particular types of transactions or regulatory programs and engage in jurisdictional line drawing. For example, the increased interest in the development of microgrids may present new questions regarding the jurisdictional status of sales between microgrid operators, utilities, and retail customers.[130] In addition, while the *EPSA* decision may have resolved the threshold question of whether FERC has jurisdiction under the FPA to regulate demand response participation in the wholesale markets, it does not resolve additional jurisdictional questions that may arise as demand response and active demand management are more widely adopted across wholesale and retail markets.[131]

<u>Operational characteristics and attributes can drive jurisdictional issues.</u> – New and emerging technologies have operational attributes that are different from traditionally used technologies. In that traditional system, "power typically flows from central station power plants in one direction to consumers."[132] Increasingly, however, "two-way" flow of power and information will be "common,"[133] as new technologies like distributed generation, storage, and advanced demand management are capable of providing multiple services across the traditional generation, transmission and distribution classifications. These classifications cross the line between federal and state authority. The current jurisdictional boundaries may make little policy sense in any event, because they can result in fragmenting the markets for new technologies and diminishing the value technologies can provide across the system (and jurisdictions).[134]

The recent *EPSA* case provides an example of how operational characteristics of new energy technologies can face jurisdictional controversy. The ability of end use customers to offer demand response commitments in the wholesale market, and to be compensated for those commitments, is made possible by technology changes that allow those customers to be aggregated, monitored, and metered. Thus, end users (sales to which are clearly within state jurisdiction) were participating in wholesale energy markets (which are subject to FERC oversight), presenting a new fact pattern to be analyzed under the FPA jurisdictional provisions. Advancements in new and emerging technologies like behind-the-meter distributed energy resources and energy storage, and proposed new industry

---

[130] Appendix at A-8 to A-12.
[131] Appendix at A-6 to A-8.
[132] QER at 3-4.
[133] QER at 3-4.
[134] *See, e.g.*, Appendix at A-3 to A-6 (describing jurisdictional complications for energy storage systems to provide multiple services across the system).

structures to manage and coordinate the operation of such resources, may present additional situations where end use customers are active participants in the wholesale market, requiring additional FPA jurisdictional determinations.[135]

Competitive interests can drive jurisdictional disputes. – In today's electric sector, the value of very significant investments is determined by market outcomes that are themselves often driven by regulatory decisions about the rules and structure of the market. New entrants – including developers of new generation resources, demand response and energy efficiency developers, non-traditional transmission developers, and new technology developers – are challenging incumbent generators and utilities. The federal-state jurisdictional divide can sometimes be used as a tool in efforts to gain or preserve market share. The recent *EPSA* and *Hughes* cases both illustrate this phenomenon: both pit new entrants (demand response in *EPSA*, new developers of generation resources that may displace existing resources in *Hughes*) against incumbent market participants. As new distributed technologies seek to gain greater market share, jurisdiction is likely to continue to be a point of leverage.

Competitive pressures between different types of incumbent market participants can also lead to jurisdictional disputes or policy conflicts between FERC and state commissions. In both Ohio and New York, for example, state regulators have expressed concern that low wholesale market prices driven by low cost natural gas could force the premature retirement of nuclear and coal generating resources, and have taken actions to provide additional revenues to those resources.[136] In the case of Ohio, the state's regulatory actions led to the filing of two separate complaints at FERC by other incumbent generators concerned about the competitive impacts of those actions in the wholesale markets, one of which effectively halted the state's plans.[137] New York's more recent action has already resulted in the filing of a lawsuit in federal court challenging the state's jurisdictional authority.[138] Similar state efforts to support or otherwise address specific resources or technologies that also compete in the wholesale markets could spawn similar jurisdictional disputes in the future.

V. Potential Tools to Coordinate Across Jurisdictions and Align Regulatory Approaches to Emerging Energy Technologies

A. Proceed Case-by-case under Existing Law

Jurisdictional questions regarding the scope of federal and state authority under the FPA have historically been resolved on a case-by-case, fact-specific basis. The trio of Supreme Court cases decided in the last two terms, while addressing jurisdictional issues in the context of a much different

[135] *See, e.g.*, Appendix at A-1 to A-3 (discussing distributed generation); *id.* at A-12 to A-14 (discussing distribution system operators).
[136] *See* Appendix at A-14 to A-16.
[137] *See* Appendix at A-15.
[138] Appendix at A-15.

industry than the one that existed for most of the FPA's history, are no exception.[139] Each made a fact-bound determination regarding the jurisdictional question presented, and did not attempt to establish a new "bright line" between federal and state authority or establish broader principles for federal-state coordination that might cleanly resolve future disputes. Thus, without further action by Congress to address the issues presented by the current regulatory divide, FERC and the courts will have to try, if they can, to make the existing framework function. Such "muddling through" will entail litigation, uncertainty, and delay.

In theory, courts could, when making future jurisdictional determinations, develop new jurisdictional tests, or consider new factors, that would better coordinate the two jurisdictions and align markets. The structure of the FPA, which speaks in terms of a clear division of authority between FERC and the states, militates against such a result. The jurisdictional provisions of the FPA demarcate exclusive jurisdiction, and leave the courts to interpret where the jurisdictional line resides in a particular factual circumstance. Thus, it would be extremely difficult for courts to create new tests that would establish shared authority or alignment of markets as guiding principles.

Two particular aspects of the Supreme Court's most recent pronouncements in *Oneok*, *EPSA*, and *Hughes* are notable for their potential impact on future efforts to coordinate across jurisdictions and align markets for new and emerging energy technologies. First, in determining whether the federal or state action at issue directly regulates a matter that is subject to the exclusive jurisdiction of the other, and is thus precluded, each of the cases explains that the "aim" or "target" of the particular action is a significant factor.[140] For example, the Court's finding in *EPSA* that FERC's action in establishing the price to be paid to demand response resources in the wholesale energy market was "all about, and only about, improving the wholesale market" weighed heavily in its ultimate decision.[141] Similarly, in *Hughes*, the Court found that the "fatal defect" in the Maryland scheme was the fact that it aimed at wholesale capacity prices, through a requirement that the capacity procured under the program clear the PJM capacity market before receiving compensation.[142] The Court was careful to explain, however, that its decision should not be read to foreclose the states from taking other actions "encouraging production of new or clean generation through measures 'untethered to a generator's wholesale market participation.'"[143]

Thus both FERC and state policymakers must be careful to couch any program or decision that will have an impact on markets outside of its jurisdiction on the benefits it will provide in the markets over which they have exclusive authority. Even where a program or decision will result in beneficial coordination across federal and state jurisdictional markets and improve the integration of wholesale and retail markets, the regulator making it must rely principally on the benefits it will provide within its own jurisdiction to reduce the chances of a successful jurisdictional challenge by unsatisfied parties.

---

[139] *Oneok*, 135 S. Ct. 1591; *EPSA*, 136 S. Ct. 760; *Hughes*, 136 S. Ct. 1288.
[140] Both decisions rely on *Oneok* for this proposition. *See EPSA*, 136 S. Ct. at 764 (citing *Oneok*, 135 S. Ct. at 1599); *Hughes*, 136 S. Ct. at 1298 (same).
[141] *EPSA*, 136 S. Ct. at 776.
[142] *Hughes*, 136 S. Ct. at 1299.
[143] *Hughes*, 136 S. Ct. at 1299.

Second, in upholding FERC's jurisdiction to regulate the price paid to demand response in the wholesale markets, the Court in *EPSA* was influenced by FERC's "notable solicitude toward the States" by allowing them to prohibit their customers from offering demand response into the wholesale market.[144] Despite the fact that the structure of the FPA does not provide for it, the Court went so far as to call it "a program of cooperative federalism, in which the States retain the last word" by allowing states to opt out of allowing retail customers in their state to participate as demand response providers in wholesale markets.[145] This language could provide a basis for future courts to defer to FERC's jurisdictional determinations where they attempt to reconcile the impact they will have on state jurisdictional matters. As discussed next, utilizing judicious interpretations of its own jurisdiction and adopting frameworks to explicitly recognize and reconcile state policy goals and impacts on state jurisdictional matters, then, could be a tool for FERC to align markets while respecting jurisdictional lines.

B. Judicious Assertion or Interpretation of Federal Jurisdiction

FERC has, at least at times, tread softly in areas where it might have a claim of jurisdiction, but where it did not have a policy interest in preempting state regulation. In Order No. 888, for instance, FERC chose not to assert jurisdiction over the transmission component of bundled retail rates, and the majority of the Supreme Court deferred to its choice. Likewise, the FERC has interpreted net metering not to involve a wholesale sale, and thus has avoided triggering federal regulation. These examples, and the Supreme Court's acceptance of FERC's jurisdictional choices in Order No. 888, suggest that FERC interpretations of its jurisdiction that explicitly recognize and accommodate state policy goals and jurisdictional responsibilities could be a tool at FERC's disposal to address jurisdictional uncertainty impacting new and emerging technologies.

Importantly, there are limitations on this approach. First, FERC interpretations of its jurisdiction under the FPA are entitled to deference under *Chevron* principles only if the statute itself is ambiguous, and FERC's interpretation is reasonable.[146] Where the statute is not ambiguous, FERC does not have authority to interpret it in conflict with its plain meaning. Second, while FERC may interpret the scope of its jurisdiction or decline to take action within its jurisdiction, it does not have authority to disclaim jurisdiction that is clearly granted to it.[147] Third, this can be a blunt instrument that may not allow for the fine-tuning of jurisdictional arrangements that would work best for new and emerging technologies. For instance, the finding that net metering does not involve an FPA jurisdictional wholesale sale leaves that area of distributed generation regulation to states, but does not appear to allow FERC forbearance

---

144 *EPSA*, 136 S. Ct. at 779.
145 *EPSA*, 136 S. Ct. at 779.
146 *Chevron U.S.A., Inc. v. Natural Res. Def. Council, Inc.*, 467 U.S. 837, 843-44 (1984).
147 *Compare New York v. FERC*, 535 U.S. at 37-38 (partial dissent of J. Thomas) (arguing that FERC did not have discretion to interpret the FPA to withhold from it authority to regulate the transmission component of bundled retail service because the FPA jurisdictional provisions unambiguously provide FERC with jurisdiction over transmission services in interstate commerce) and *New York v. FERC*, 535 U.S. 25-28 (majority holding that FERC made a permissible decision not to assert jurisdiction over the transmission component of bundled retail service given "the complicated nature of the jurisdictional issues").

if states consider other forms of distributed generation policies that do involve small, but indisputably wholesale, sales.

C. Adoption of FERC Policy Frameworks that Explicitly Recognize State Policy Goals and Priorities

FERC has previously chosen to exercise its jurisdiction in ways that explicitly recognize and accommodate state policy goals. Just one example is FERC's choice in its recent landmark transmission planning and cost allocation rulemaking, Order No. 1000, to establish a framework for recognizing state and local public policy goals.[148] As explained above, FERC required that the regional and local planning processes of transmission providers subject to its jurisdiction adopt procedures "provide for the consideration of transmission needs driven by Public Policy Requirements," including those enacted by states.[149] FERC concluded that such a requirement was necessary to ensure that transmission planning processes would accurately identify transmission needs created by public policies such as state Renewable Portfolio Standards, and noted that adopting the requirement would "complement," rather than conflict with, state integrated resource planning processes.[150]

Additionally, as noted above, FERC made a similar choice in Order No. 719. While FERC required that RTOs/ISOs allow aggregated retail customers to offer their demand response resources directly into their organized wholesale markets, it also allowed states to affirmatively "opt-out" and prohibit their retail customers from participating in the wholesale markets.[151] FERC found that this approach would "properly balance[] the Commission's goal of removing barriers to development of demand response resources in the organized markets that we regulate with the interests and concerns of state and local regulatory authorities."[152] As noted in the previous section, FERC continued to follow this approach in Order No. 745, a fact that the Court in *EPSA* explicitly noted in its decision upholding FERC's jurisdictional determination there.[153]

These examples, and the Court's favorable view of FERC's "notable solicitude toward the States" in *EPSA*, suggest that the creation of frameworks that explicitly recognize and accommodate state policy goals and jurisdictional responsibilities could be a tool at FERC's disposal to address jurisdictional uncertainty and market integration problems impacting new and emerging technologies.

In the case of new and emerging distributed generation technologies, energy storage resources, and other resources that provide value across both FERC and state-regulated categories of service, such frameworks could seek to address the need for such technologies to recover sufficient revenues from providing multiple services to justify investment in them. One way to do that might be to explore the adoption of rate-setting models that allow owners of these resources to "stack" revenues from services

---

148 Order No. 1000 at PP 203-24.
149 Order No. 1000 at P 2.
150 Order No. 1000 at PP 204, 213.
151 Order No. 719 at P 154.
152 Order No. 719 at P 156.
153 *EPSA*, 136 S. Ct. at 779-80.

they provide across the two jurisdictions, while guarding against the potential for over-recovery and unjust and unreasonable rates. This might require the adoption of methods to consider revenues received from other jurisdictions when setting rates.

In addition, to the extent there are barriers to the participation of such new and emerging technologies in the wholesale markets, such as market rules or practices that arbitrarily exclude those resources from eligibility to provide a service or simply fail to account for them, FERC could require that they be addressed. As explained previously, FERC has taken such steps over the past decade with respect to demand response and energy storage resources in particular, and continues to do so today.[154] Those inquiries have generally been focused exclusively on ensuring that such resources have access to the wholesale markets, rather than on how wholesale markets and retail markets might be better aligned to support investments while acknowledging and accommodating jurisdictional lines. Approaching such inquiries with this focus as well might reveal new opportunities for aligning markets and balancing federal and state objectives and jurisdictional responsibilities.

D. Joint Proceedings

Section 209 of the FPA establishes joint hearing and joint board procedures. That section authorizes the FERC (1) to hold joint hearings with state commissioners,[155] and (2) to set up joint boards, consisting of state utility commissioners to consider matters otherwise within the FERC's jurisdiction.[156] The joint hearing provision permits the FERC and states to hear cases together, but provides for no joint decisional procedure. The joint board provision on the other hand, is essentially a limited delegation of FERC decision-making to a board of state commissioners. There is no federal representation on a joint board. Decisions of a joint board have the legal effect specified in FERC regulations and FERC orders establishing the board. A joint board does not exercise any state jurisdiction and the states involved are not necessarily bound by a joint board decision—that is, they appear to be free to litigate the final order in the proceeding.

While rarely used (likely because of the conflicts that may arise in establishing joint hearings/joint boards), these provisions of existing law may provide a potential path to improve federal/state coordination. States and FERC could agree to use a combined joint hearing and joint board procedure: A joint hearing could be held in a particular proceeding before a panel consisting of a FERC commissioner and the state commissioners. Then, the panel acting as a joint board with the FERC commissioner as a non-voting member could decide the federal issues in the case. FERC, after notice and comment, could review and decide whether to affirm the joint board determination (similar to the review of an Administrative Law Judge's ruling), pursuant to a FERC policy statement that gave a rebuttable presumption of validity, if the FERC commissioner concurred.

[154] In Docket No. AD16-20-000, for instance, FERC has an inquiry underway on the participation of energy storage in organized energy markets.
[155] FPA § 209(b), 16 U.S.C. § 824h(b).
[156] FPA § 209(a), 16 U.S.C. § 824h(a).

Joint boards that decide state as well as federal issues are an attractive prospect, and could be used to align decisions at the state and federal level that allow resources to provide services and receive compensation in both retail and wholesale markets. But for such a structure to work, FERC and the states would have to resolve governance issues (e.g., does Rhode Island's vote have the same weight as New York's?) and what law will apply in the board's deliberations (e.g., do we try to apply the FPA and each state's law as is, or do the parties come up with an amalgamation of state and federal laws?). Resolving these issues on a case-by-case basis would be extremely complicated.

E. Regional Regulation

Another possible approach could be legislative changes that redraw the line between federal and state jurisdiction in a fashion that better accommodates today's regulatory needs, particularly to reflect the broader regional nature of electricity markets today and the ability of new and emerging technologies to provide service across both federal and state jurisdictional lines.[157] Assuming that turning over all of utility regulation either to the FERC or to individual states is politically and practically infeasible, policy-makers could look at a number of options to set up regional regulating bodies that would subsume all of FERC's responsibilities in the region and most or all state responsibilities.[158]

Interstate Compacts. The Compact Clause of the Constitution permits states to enter in to compacts inside each other only if authorized by Congress.[159] Congress has authorized states to form compacts on a variety of issues, including compacts on Northwest power planning,[160] low level nuclear waste facilities,[161] and transmission facility siting.[162] Under the Compact Clause, states could negotiate and Congress can approve (or disapprove) regional interstate compacts under which an interstate regulatory entity exercises full electric power regulatory authority in the states that are party to the agreement, displacing both federal and state regulation. For this option to be workable, two features (at least) must be included. First, the regional regulatory entity will need governance provisions that ensure it will be able to make decisions. Unanimous consent or super-majority requirements for decision making could paralyze the agency, rendering the regulatory system even worse than today's. Second, states (and FERC) will have to agree to a common regulatory framework, workable hearing procedures, and provisions for judicial review. Retaining the vestiges of state-by-state regulation will obviate much of the advantage of a regional agency. Such compacts could address jurisdictional hurdles that threaten to undermine efforts to develop new and emerging energy technologies, and could also provide a mechanism for allowing FERC and state regulators to work together to integrate markets for new and emerging energy technologies across their respective jurisdictions.

157 Note that amendments to the Federal Power Act intended to resolve jurisdictional uncertainty with respect to new technologies or circumstances will themselves be subject to interpretation over time, and will have to be applied to ever changing fact patterns.
158 FERC would still need to deal with "seams" issues at the boundaries of the regional regulatory agency, in much the same way it does with inter-RTO seams issues and with interconnections between ERCOT (the portion of the grid that Texas regulates) and the interstate grids that the FERC regulates (the Eastern and Western Interconnections.)
159 U.S. Const. art. I, § 10, cl. 3.
160 Pacific Northwest Electric Power Planning and Conservation Act § 4(a)(2), 16 U.S.C. § 839b(a)(2).
161 42 U.S.C. § 2021d.
162 FPA § 216(i), 16 U.S.C. § 824p.

Federal Regional Regulatory Agency. Using the Commerce Clause rather than the interstate compact mechanism, Congress, on application of states, could establish a multi-state federal regulatory agency consisting of members appointed by the President from FERC and the states involved. The Clean Air Act includes a similar tool.[163] The regional federal agency would exercise plenary utility-regulatory authority,[164] displacing both federal and state regulation. As in the case of the interstate compact option, the regional agency would need workable governance provisions and a unitary regulatory framework, likely embedded in the statute establishing the agency.

F. Jurisdictional Agreements

One final option to consider is the establishment of jurisdictional agreements, which would permit a consensual resolution of potential conflicts between state agencies and FERC. Such agreements would also be a mechanism for cutting short attempts by regulated entities to utilize jurisdictional ambiguities in the FPA as a litigation tool to achieve other market objectives, especially in circumstances like those in *EPSA*, where there was no fundamental dispute between state and federal views regarding the value of demand response resources to both retail and wholesale markets.

Under this option, the FPA would be amended to include provisions, similar to those in a number of other federal statutes,[165] that would authorize the FERC and state commissions to enter into jurisdictional agreements that depart (in either direction) from the current "bright line" of the FPA in order to rationalize their respective state, multi-state, and/or federal regulatory jurisdiction. For example, states might agree to the FERC's exercise of authority over demand response bids into wholesale markets, in return for allowing states greater latitude to make generation choices without being preempted under the FPA or hampered by FERC-approved buyer-side mitigation rules. This option would require Congressional authorization for the FERC to enter into such agreements, but would not require Congressional approval of each agreement. State legislative authorization would probably also be required.

---

163 *See, e.g.,* Clean Air Act § 176A, 42 U.S.C. § 7506a, under which EPA establishes interstate transport commissions consisting of members from each state and EPA representatives.

164 In *FERC v. Mississippi*, 456 U.S. 742, *reh'g denied*, 458 U.S. 1131 (1982), the Supreme Court recognized that Congress, if it chose to, could regulate virtually all aspects of the electric power system, including retail sales, under the Commerce Clause. *FERC v. Mississippi*, 456 U.S. at 764.

165 *See, e.g.*, National Labor Relations Act of 1935, Pub. L. No. 74-198, §§ 10(a), 14(c), 49 Stat. 449, 453, 457 (codified as amended at 29 U.S.C. §§160(a), 164(c)); Atomic Energy Act of 1954, Pub. L. No. 83-703, § 244, 68 Stat. 919, 958-59 (codified as amended at 42 U.S.C. § 2021 (2005)); Clean Air Act § 111(c), Pub. L. No. 91-604, § 111(c), 84 Stat. 1676, 1684 (1970) (codified as amended at 42 U.S.C. § 7411(c) (1977)).

Appendix

Potential Jurisdictional Issues Impacting New and Emerging Energy Technologies and Related Markets

This Appendix briefly describes some recent technology developments in the electric sector, and regulatory and jurisdictional issues these technologies have raised already and could raise going forward. The particular technologies were chosen based on the vision of the future grid described in Chapter Three of the QER.

A. Distributed Generation

Distributed generation has seen a significant increase over the past few years driven largely by substantial cost declines of solar photovoltaic (PV) technology and by supportive state policies.[166] While there is no universally agreed upon definition, distributed generation is generally considered to be any electric generation capacity that is:

- located close to consumer load and often behind a consumer's electric consumption meter;
- connected to the electric *distribution* system (rather than the electric transmission system); and
- designed to serve on-site load as well as to supply excess generation to the power distribution system.[167]

Distributed generation may be renewable energy-powered or fired by natural gas and other fuels.

States have adopted a number of policies that have accelerated the pace of distributed generation deployment. In many cases, these state policies were designed to increase renewable generation and decrease greenhouse gas emissions. These policies are varied and include direct cash incentives, tax credits, property tax incentives, sales tax incentives, loan programs, permitting relief, renewable portfolio standards, and net-metering.[168] The most important such policy is net metering. Net metering is a retail electricity tariff that permits electricity customers that generate their own electricity (through ownership of on-site generation or other financial arrangements such as leases or power purchase agreements) and credit this generation as an offset to their on-site electricity consumption.[169]

---

[166] "EIA Electricity Data Now Include Estimated Small-Scale Solar PV Capacity and Generation," U.S. Energy Information Administration (Dec. 2, 2015), http://www.eia.gov/todayinenergy/detail.cfm?id=23972.
[167] *See, e.g.*, "Glossary," U.S. Energy Information Administration, accessed Aug. 18, 2016, http://www.eia.gov/tools/glossary/index.cfm?id=D (defining distributed generator to be "A generator that is located close to the particular load that it is intended to serve. General, but non-exclusive, characteristics of these generators include: an operating strategy that supports the served load; and interconnection to a distribution or sub-transmission system (138 kV or less)").
[168] *See* North Carolina Solar Center, Database of State Incentives for Renewables & Efficiency, Solar Policy Guide: A Resource for State Policymakers (September 2012), *available at* http://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2015/09/Solar-Policy-Guide.pdf ("Solar Policy Guide").
[169] Solar Policy Guide at 69.

Net metering is a state policy (or a voluntary contractual agreement between a utility and its customers), rather than a federal policy. Net metering encourages distributed generation because it typically compensates distributed generation at the full retail rate of electricity rather than at a lower rate such as the wholesale market rate or the utility's avoided cost rate.
Net metering of distributed generation presents potentially thorny questions of state and federal regulatory jurisdiction. A distributed generator participating in a net metering program provides excess electricity to a distribution utility that will resell the power to another consumer in exchange for a bill credit at the retail electric rate–that is, it arguably makes wholesale sales (at least for periods when on-site generation exceeds on-site load). Such sales could, in theory, subject on-site generators to the Federal Energy Regulatory Commission's ("FERC") jurisdiction under the Federal Power Act ("FPA") over wholesale sales.[170]

FERC has largely disclaimed jurisdiction over net metering arrangements to date,[171] concluding that net metering does not constitute a wholesale sale subject to its jurisdiction "when the owner of the generator receives a credit against its retail power purchases from the selling utility" and remain a net buyer over the relevant utility billing period.[172] FERC has made a series of interpretations of its jurisdiction that allow state net metering programs to continue without federal regulatory interference. This approach makes sense if one concludes that asserting jurisdiction over a large number of very small entities selling relatively little electricity to the electric system in direct response to supportive state policy would be administratively complicated and would likely provide little public benefit.

As noted above, however, FERC's decisions rest on a common regulatory construct–that consumers with on-site generation are merely "offsetting" consumption and not selling at wholesale. This logic is increasingly under strain. States are revising policies away from traditional net metering and towards more complex regulatory and pricing systems aimed at more directly compensating distributed generation for the variety of services that such generation provides.[173] The overall system impact of distributed generation is also increasing as the deployment of such generation expands.[174] Community solar programs may be the next focus of debate on the bounds of state jurisdiction over net metering and related policies.[175]

Finally, and importantly for purposes of other new and emerging technologies discussed here, distributed generation is being combined with other new technologies (such as small-scale on-site

---

170 16 U.S.C. § 824(b)(1), (d).

171 *See* Jeffery S. Dennis, Suedeen G. Kelly, Robert R. Nordhaus, and Douglas W. Smith, "Federal/State Jurisdictional Split: Implications for Emerging Electricity Technologies" ("Main Paper"), at section IV.B.1.

172 Order No. 2003-A at P 747; *MidAmerican Energy Co.*, 94 FERC ¶ 61,340; *Sun Edison LLC*, 129 FERC ¶ 61,146, at P 18*.*

173 *See, e.g.*, National Renewable Energy Laboratory. Value of Solar: Program Design and Implementation Considerations. Mike Taylor et al. (March 2015), *available at* http://www.nrel.gov/docs/fy15osti/62361.pdf.

174 *See, e.g.*, David B. Raskin, "The Regulatory Challenge of Distributed Generation," Harvard Business Law Review Online 4 (2013), 38, http://www.hblr.org/?p=3673; David B. Raskin, "Getting Distributed Generation Right: A Response to 'Does Disruptive Competition Mean a Death Spiral for Electric Utilities?'", Energy Law Journal 35 (2014), 274-78.

175 *See Southern Maryland Cooperative, Inc. and Choptank Electric Cooperative, Inc.*, FERC Docket No. EL16-107-000 (Petition for Declaratory Order filed Aug. 23, 2016), *pending.*

electric storage and demand response, and enhanced technical controls) that can provide additional services traditionally provided only by large-scale generators. As a result, distributed generation may increasingly be utilized to provide wholesale capacity, energy, and ancillary services markets. As discussed in Section B of this Appendix, FERC recently noted this potential in a proposed rulemaking addressing the participation of electric storage and distributed energy resource aggregators in organized wholesale electricity markets. If distributed generators providing such resources are still connected close to load and within the distribution system subject to state regulation, then additional coordination between the wholesale and retail markets, and federal and state regulators, may be required. These developments could further blur the line between state and federal jurisdiction (as discussed in more detail below).

B. Energy Storage

Energy storage, which FERC has functionally defined as any "facility that can receive electric energy from the grid and store it for later injection of electricity back to the grid,"[176] presents a unique set of jurisdictional challenges. Energy storage encompasses a wide range of technologies, including pumped hydroelectric, compressed air, batteries, flywheels, and thermal storage, each of which has different attributes in terms of the amount of energy it can store, the duration and power with which it can release that energy, the speed and accuracy with which it can respond to dispatch directions, and the efficiency of its performance. Even electric vehicles can be used as storage assets that inject electricity back into the grid or provide other services.[177] Storage can be interconnected directly with a transmission system, distribution system, or behind customer meters, each of which has different regulatory implications under the division of labor between federal and state regulators. Given these technical characteristics, "[s]torage is unique because it can take energy or power from the grid, add energy or power to the grid, and supply a wide range of grid services on short (sub-second) and longer (hours) timescales."[178] Finally, in certain cases a single storage device (or an aggregation of storage devices) can provide multiple services simultaneously, such as frequency response or other ancillary services, dispatchable output akin to generation, or dispatchable charging (somewhat like demand response).

Using existing regulatory structures, many storage systems already provide a specific grid service. Pumped hydroelectric storage (in which water is pumped uphill at off-peak times, and spilled downhill when dispatched) has been used for decades in many parts of the country as dispatchable generation. At the wholesale level, FERC has issued orders facilitating the participation of storage resources in

---

[176] *See* FERC, Letter requesting comments by 5/23/2016 regarding the Electric Storage Participation in Regions with Organized Wholesale Electric Markets at 1 n.1, FERC Docket No. AD16-20-000 (issued Apr. 11, 2016).

[177] *See, e.g.,* Andrew Meintz *et al.*, Presentation, "Integrating PEVs with Renewables and the Grid" at p. 5 (June 29, 2016), *available at* http://www.nrel.gov/docs/fy16osti/66638.pdf (summarizing grid services that may be provided by plug-in electric vehicles).

[178] U.S. Department of Energy, Quadrennial Energy Review: Energy Transmission, Storage, and Distribution Infrastructure (April 2015), 3-10, *available at* http://energy.gov/sites/prod/files/2015/07/f24/QER%20Full%20Report_TS%26D%20April%202015_0.pdf ("QER")..

ancillary services markets.[179] For instance, Order No. 755 required all regional transmission organizations ("RTO") and independent system operators ("ISO") to adopt pay-for-performance measures in their frequency regulation market, which are intended to reward units capable of quickly and accurately responding to signals to maintain steady transmission frequency.[180] Battery and flywheel systems, for instance, perform well using this metric compared to gas-fired peaking plants, an alternative source of frequency regulation. As a result of these changes, PJM has added over 100 megawatts ("MW") of utility-scale, transmission-connected storage since 2013.[181]

Despite this growth in storage resources participating in wholesale ancillary services markets, few storage resources other than pumped hydroelectric resources are used in wholesale energy markets as the equivalent of dispatchable generation. In addition, while FERC has indicated that storage resources may be classified as transmission assets in limited circumstances and receive a cost-based transmission rate,[182] to date few storage resources are operating as transmission.

State regulatory policies have also driven the adoption of storage in certain regions. For example, state-jurisdictional retail rates for some utilities include demand charges for peak hours of the day (most commonly for industrial and commercial, rather than residential, customers), and a 2015 study from the National Renewable Energy Laboratory found that battery storage will become an economical means to reduce demand charges if battery system prices drop (or if demand charges rise).[183] Additionally, the California Public Utility Commission ("CPUC") has imposed an energy storage procurement requirement for its investor-owned utilities, which will result in 1,325 MW of storage deployment – using a variety of technologies in a variety of applications – by 2024.[184] In its order, the CPUC identified numerous regulatory "use cases," or services, that storage can provide based upon the point of interconnection.

However, deploying storage resources solely using the existing regulatory classifications (wholesale energy and ancillary services markets, transmission, distribution) can limit the available "use cases" and artificially constrain the services that a particular storage device can provide, and thus the revenue sources which its owner or operator can effectively obtain. A 2015 report from the Rocky Mountain Institute found that in many cases, limiting storage resources to providing a single primary service

---

179 *Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies*, Order No. 784, FERC Stats. & Regs. ¶ 31,349 (2013), *order on clarification*, Order No. 784-A, 146 FERC ¶ 61,114 (2014); *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Order No. 755, FERC Stats. & Regs. ¶ 31,324 (2011), *reh'g denied*, Order No. 755-A, 138 FERC ¶ 61,123 (2012).

180 *See generally* Order No. 755.

181 GTM Research, U.S. Energy Storage Monitor (2015), 6, http://energystorage.org/system/files/attachments/us-energy-storage-monitor-q2-2015-es-final.pdf.

182 *See W. Grid Dev., LLC*, 130 FERC ¶ 61,056 (2010).

183 National Renewable Energy Laboratory. Deployment of Behind-the-Meter Energy Storage for Demand Charge Reduction. J. Neubauer & M. Simpson (2015), *available at* http://www.nrel.gov/docs/fy15osti/63162.pdf.

184 *Order Instituting Rulemaking Pursuant to Assembly bill 2514 to Consider the Adoption of Procurement Targets for Viable and Cost-Effective Energy Storage Systems*, Decision Adopting Energy Storage Procurement Framework and Design Programs, Rulemaking 10-12-007 (Cal. Pub. Util. Comm'n Dec. 16, 2010), *available at* http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M078/K912/78912194.PDF.

would result in the resource not being economical, but that allowing for a "stack" of services would significantly improve a project's commercial viability.[185] For instance, a battery storage system's primary service might be to defer distribution upgrades by reducing system wear and tear, but that same system might be able to provide ancillary services; similarly, a behind-the-meter solar-plus-storage system could also provide regulation services in some circumstances. Importantly, the Rocky Mountain Institute report noted that not all of these value streams would necessarily be useful to the same stakeholder groups, and that typical market structures do not allow for multiple sources of revenue for the owner or operator of the storage resource. One particular regulatory complication is that storage may be selling multiple services, some of which are subject to market-based prices and others of which are sold at cost based rates. And of course, the ability to "stack" these services to achieve sufficient revenues may require action from both FERC and state regulators, requiring coordination across the jurisdictional line.

Both state regulators and FERC have recognized that these existing regulatory constructs, and especially the existing functional classifications to which system resources are typically assigned for jurisdictional purposes, can prevent the integration of markets for storage resources. For instance, New York has begun a process entitled Reforming the Energy Vision ("REV"), which, as discussed below may culminate by creating a new distribution entity (initially by changing the role of existing utilities) to focus on providing a platform for distributed resources, including storage, to be optimized to provide multiple services and values to the distribution grid. Among the wholesale markets, FERC recently approved market changes proposed by the California Independent System Operator, Inc. ("CASIO") to allow aggregations of distributed energy resources connected to the distribution system – including storage resources – to fully participate in its energy and ancillary services markets.[186] CASIO has also indicated that it will examine the ability of distributed energy resources (including storage) to provide multiple value streams in future proceedings.

Additionally, FERC is conducting an ongoing inquiry into barriers to full participation of storage in organized wholesale markets, which may further address these issues.[187] Based on the information gathered there, on November 17, 2016, FERC issued a new Notice of Proposed Rulemaking that, if finalized, would require RTOs/ISOs to revise their tariffs and market rules to remove barriers to the participation of electric storage resources and distributed energy resource aggregations in the capacity, energy, and ancillary services markets they operate.[188] Specifically, FERC proposed to require the RTOs/ISOs to (1) establish a "participation model"[189] that recognizes the physical and operational

---

185 Rocky Mountain Institute, The Economics of Battery Energy Storage (2015), *available at* http://www.rmi.org/Content/Files/RMI-TheEconomicsOfBatteryEnergyStorage-FullReport-FINAL.pdf.
186 *California Independent System Operator Corp.*, 155 FERC ¶ 61,229 (2016).
187 *See* FERC Docket No. AD16-20-000.
188 *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Notice of Proposed Rulemaking, 157 FERC ¶ 61,121 (2016) ("Storage NOPR").
189 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." Storage NOPR, 157 FERC ¶ 61,121 at P 2 n.5. For example, RTO/ISO tariffs define participation models for traditional generation resources, demand response, and certain other kinds of resources.

characteristics of electric storage resources to accommodate their participation in organized wholesale markets, and (2) define distributed energy resource aggregators as a category of market participant and allow them to participate in the organized wholesale markets under the existing participation model that best accommodates their particular physical and operational characteristics.

C. Demand Response and Active Demand Management Facilitated by New Technologies

"Demand response" refers generally to "the ability of customers to participate in load control" by reducing their consumption, based either on an upfront commitment to do so when called upon by the system operator or in response to price signals.[190] While the use of customer load reductions as a tool to moderate demand and prices is nothing new, emerging grid and information technology applications are allowing more customers to participate in new and different ways. Automated load control technologies, "smart devices," advanced metering, building management systems, and real-time and time of use tariffs, among other new tools, are allowing traditional demand response to become more dynamic and "active."[191] These technologies are deployed by building owners (e.g., smart thermostats), by energy service companies (e.g., through energy savings performance contracts), by aggregators (e.g., by combining the demand response of smaller end-users), and by utility programs that sign up individual retail customers.

These new technologies can facilitate the creation of a network of individual demand response sites that are directly controlled by a grid operator from a network operations center. This kind of "active demand management" can be dispatched in much the same way as a generation facility, rather than relying on individual customers to take actions, allowing grid operators to use demand response to provide a multitude of services. Peak shaving, grid management, energy balancing, and other ancillary services, and integration of renewable and distributed resources are some of the services active demand management can facilitate. Deploying such resources in strategic locations may also allow utilities to defer more expensive infrastructure additions.

Thus, demand response and active demand management, like distributed generation and energy storage resources, can provide services that span the traditional generation, transmission, and distribution functions. These operational characteristics of demand response and active demand management, combined with the fact that end-use customers are involved, can drive jurisdictional uncertainty, especially in today's more competitive electricity markets. While the recent *EPSA* case resolved the threshold question of whether FERC can exercise any jurisdiction over demand response participation in wholesale markets under the FPA, it does not resolve other jurisdictional uncertainties or market integration challenges that could arise as demand response and active demand management resources become more of a presence on the grid.

---

[190] QER at 3-10.
[191] QER at 3-10.

First, as the *EPSA* proceeding clearly demonstrated, both state and federal policy makers are interested in utilizing these resources to achieve their respective policy goals at the retail and wholesale level. There could be situations where those policy goals diverge, or where committing those resources to service in one market would make them unavailable to provide services in the other. For example, in FERC's Order No. 719 proceedings, many states and other entities raised concerns that allowing third parties to aggregate the demand response of individual retail customers and offer that demand response into the wholesale market would effectively allow them to "cherry-pick" the most valuable demand response resources and commit them to the wholesale market.[192] These states and others were concerned that these valuable resources would then be unavailable for use in retail demand response programs, hurting the cost-effectiveness of those programs.[193] While FERC ultimately resolved such concerns by allowing states to affirmatively "opt-out" their retail customers from aggregation in the wholesale market, such concerns could resurface in the future.[194]

Second, and related, like many other new technologies, the ability of demand response and active demand management resources to provide services across the wholesale and retail markets and transmission and distribution systems may require coordination among jurisdictions to ensure that such resources are appropriately compensated for the full range of services they provide. Measures like the "opt-out" provision of Order No. 719, while deferential to traditional jurisdictional limits, may limit the ability of investors to capture revenue for all of the value and efficiencies that demand response and active demand management resources can provide across jurisdictions.

In fact, a lack of coordination among the wholesale and retail jurisdictions may not just result in inefficiency; it may limit available revenues to the point that new and emerging demand response and active demand management resources will not earn sufficient revenues to justify their investment. For example, consider the case of an active demand management project that would combine technologies such as smart meters and building management devices with energy storage to provide both dynamic demand reductions to the retail distribution system and also provide capacity in the wholesale market. That developer may need to combine revenues from providing the retail service (perhaps through participation in a retail load response program) with revenues from providing the wholesale service (capacity) to recover its costs and earn a sufficient return for its investors. If either jurisdiction has rules or practices in place that prevent or inhibit participation in both the retail program and the wholesale market, the developer may not be able to go forward. Additionally, the interactions between retail and wholesale programs must be clear to enable full participation; for instance, if a participant has dropped load under a retail program, it cannot count the same reduction again in the wholesale capacity market. Concerns about this potential to inhibit retail demand response projects and programs drove some

192 *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 125 FERC ¶ 61,071 at P 141 (2008), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).
193 Order No. 719 at P 141.
194 Order No. 719 at P 155.

states to affirmatively support FERC and its assertion of jurisdiction over demand response resources in the proceedings leading to the *EPSA* decision.[195]

Efforts by either FERC or state regulators to facilitate the participation of demand response and active demand management resources across the wholesale and retail markets, or even to provide greater coordination between these markets, could nonetheless face jurisdictional challenges. The circumstances of the *EPSA* case are a prime example. There, FERC's approach to compensating demand resources in the wholesale markets led to fierce objections from competing generators, as well as states and others concerned that the pricing scheme would result in discriminatory treatment among resources or give federal regulators too much authority in retail service matters. While the jurisdictional question raised in the course of the generators' challenge to FERC's compensation approach was ultimately resolved, several years of jurisdictional uncertainty resulted during the litigation. *EPSA* resolved the specific question before it – whether FERC has authority to regulate compensation of demand response resources in wholesale markets. New or different efforts by FERC or states to regulate demand response and active demand management resources could result in additional jurisdictional disputes to the extent the facts are different than those underlying the *EPSA* decision.

D. Microgrids

Microgrids are small- to medium-scale, low voltage controllable electrical distribution systems that connect loads in a relatively limited geographical area to nearby generation –generally including associated small-scale distributed energy resources (including those powered by renewable resources or more traditional fuels like natural gas) located close to those loads – in a way that allows them to operate independently of the broader electric distribution and transmission system (termed "islanding").[196] While they can function as an electrical island, they can also connect to the traditional electric grid (often with power flowing in either direction).

Microgrids are at this time mostly a niche application, having been most widely deployed by discrete institutions such as university campuses and military facilities. However, local communities and business have also increased microgrid deployment.[197]

---

[195] *See, e.g.,* Letter from Sarah Hofmann, Exec. Dir., New Eng. Conf. of Pub. Util. Comm'rs, to Cheryl A. LaFleur, FERC Acting Chairman, FERC Docket No. RM10-17-000 (July 1, 2014); Letter from the Maryland Public Service Commission to Cheryl A. LaFleur, FERC Acting Chairman, FERC Docket No. RM10-17-000 (June 25, 2014).

[196] *See* Berkeley Lab, "About Microgrids," accessed August 18, 2016, https://building-microgrid.lbl.gov/about-microgrids.

[197] *See* Berkeley Lab, "Examples of Microgrids," accessed August 18, 2016, https://building-microgrid.lbl.gov/examples-microgrids; Peter Asmus et al., Pike Research, Microgrid Deployment Tracker 4Q12 (2012), *available at* http://www.navigantresearch.com/wp-content/uploads/2012/11/MGDT-4Q12-Executive-Summary.pdf.

Microgrids can be attractive to policymakers (and electricity customers) for a number of reasons.[198] Primarily, microgrids can provide redundancy and, therefore, more reliable and resilient electric service. Microgrids allow customers to rely on traditional grid services but can also be islanded when circumstances change on the wider electric system, such as during planned and unplanned outages (such as natural disasters or other grid disruptions). This can be more cost-effective than the installation of redundant backup generation systems by individual electric consumers, and can also provide many of the same grid services as the centralized grid when islanded (such as centralized monitoring and load balancing). Because microgrids are generally paired with more sophisticated systems to control local electric demand, they can often provide demand response services to the wider bulk wholesale electric grid (including capacity, energy and ancillary services). They are also seen as an effective way of increasing the penetration of distributed renewable energy resources, because their control systems can be used to maximize the use and value of such resources.

1. Microgrids under Cost-of-Service Utility Regulation

The traditional electric utility regulatory model is cost-of-service regulation of a vertically integrated power supplier who has a local retail monopoly. This model is still the norm in about half of the U.S.[199] A microgrid system that (i) is end-user-owned, (ii) is behind-the meter, and (iii) supplies no output back to the grid, does not present any obvious federal-state jurisdictional issues or market integration challenges under this traditional cost-of-service model. However, if any of the three conditions are not met, then, absent regulatory accommodation to this new technology, jurisdictional issues and potential regulatory barriers may arise that can present obstacles to deployment of these systems, as described below.

<u>Third-party Systems Issues</u>. One attractive model for large-scale microgrids is a system which is owned by a third party (rather than the utility or the end-user). The third party purchases power from the utility (perhaps in combination with generating power on its own) and resells that power to individual users as well as selling or distributing its customer's on-site distributed generation. This configuration raises two important questions under conventional utility regulation. First, is the utility sale to the microgrid operator a wholesale sale regulated by FERC under the FPA, rather than a retail sale regulated by a state utility commission under state law? Second, is the sale by the microgrid owner to the end-user a retail sale that contravenes the utility's retail monopoly? No clear answer exists to either

---

198 *See generally* Lawrence Berkeley National Laboratory. Value Streams in Microgrids: A literature Review. Michael Stadler et al. LBNL-1003608 (October 2015), *available at* http://eetd.lbl.gov/sites/all/files/value_streams_in_microgrids_a_literature.pdf; *see also* New York State Energy Research & Development Authority, Microgrids: An Assessment of the Value, Opportunities and Barriers to Deployment in New York State (2010), 69-98, http://www.nyserda.ny.gov/-/media/Files/Publications/Research/Electic-Power-Delivery/microgrids-value-opportunities-barriers.pdf.

199 *See*, *e.g.*, U.S. Energy Information Administration, "Status of Electricity Restructuring By State," accessed August 18, 2016, http://www.eia.gov/electricity/policies/restructuring/restructure_elect.html.

question because the answer relies on inconsistent FERC precedent relating to "sub-metering,"[200] and vagaries of state law on exclusive retail service areas.

Sales Back to Wholesale Market. Another key benefit of a microgrid is the ability to collect distributed renewable generation (or other on-site generation) and to sell any surplus energy to the local utility or in the wholesale market. The wholesale sale will ordinarily be subject to wholesale rate regulation under the FPA (but qualifying facilities ("QFs") under 20 MW are exempt from FPA rate regulation under the Public Utility Regulatory Policies Act of 1978 ("PURPA"),[201] and sales from government-owned and certain cooperatively-owned microgrids are excluded from wholesale rate regulation under the FPA section 201(f)).

PURPA also requires utilities to purchase the output of QFs. However, significant limitations exist both on the utility's federal law obligation to purchase from these facilities and on a state's ability to require purchase at rates above avoided cost. In major competitive wholesale markets (such as PJM, New York Independent System Operator, Inc., ISO New England), FERC rules have largely relieved utilities of their purchase obligations.[202] In addition, the PURPA purchase obligation, where it exists, is limited to "avoided cost"[203] – which is, the cost the utility would have incurred if it had generated the power itself or purchased it elsewhere, as determined by the state utility regulatory commission. In most states, avoided cost is well below retail rates and may be less effective than net metering in promoting deployment of renewable generation.

Whether states have authority to require utilities to pay higher-than-avoided-cost rates is uncertain. FERC precedent from 1995 purports to preempt certain state rules requiring utilities to pay qualifying

---

[200] *El Paso Elec. Co.*, 114 FERC ¶ 61,175 (2006) (FERC has no jurisdiction over a customer that traditionally purchased its power under a state-regulated retail tariff, and has provided primarily a sub-metering function, because the customer is not reselling that power and thus no sale for resale exists); *see also Ala. Power Co.*, 95 FERC ¶ 61,002 (2001) (disclaiming jurisdiction); *Cf. Oakland Bd. of Port Comm'rs v. FERC*, 754 F.2d 1378 (9th Cir. 1985) (holding that municipal agency operating an airport that purchases electricity and resells it through an electricity distribution system to tenants at the airport is a wholesale customer).

[201] 18 C.F.R. § 292.601(c) (2016). A microgrid's resale of QF power purchased from its customers may not qualify as an exempt QF sale under PURPA.

[202] *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities*, Order No. 688, 71 Fed. Reg. 64,342 (Oct. 20, 2006), FERC Stats. & Regs. ¶ 31,233 (2006) (implementing PURPA section 210(m), 16 U.S.C. § 824a-3(m)). Order No. 688 also created a rebuttable presumption that qualifying facilities larger than 20 MW have non-discriminatory access to at least one of these competitive markets. Order No. 688 at P 9.

[203] 16 U.S.C. § 824a-3(b) (explaining that no rule prescribed in PURPA Section 210(a) shall provide for a rate which exceeds the "incremental cost" to the electric utility of alternative electric energy). In the context of electric energy purchased from a qualifying cogenerator or qualifying small power producer, PURPA Section 210(d) defines incremental cost as the "cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source." 16 U.S.C. § 824a-3(d).

facilities rates in excess of avoided cost.[204] However, FERC more recently offered guidance that would allow for exceptions to this general rule where a state has a policy of encouraging development of a particularly technology; in that case, FERC indicated that the state can set an avoided cost rate specific to that technology.[205] Calculating an avoided coast rate specific to microgrids could be extremely challenging. To the extent these rules raise a problem for microgrids, they could be dealt with, at least in part, by changes to PURPA that (1) permit these systems to sell output at avoided cost rates without regard to size, and (2) give states clear authority to require above avoided-cost rates.

Utility Ownership of Microgrids. An alternative to third-party ownership of large scale microgrids is utility ownership of the microgrid. This model could be an effective means of deploying systems that sell power from a multi-building network to multiple end-users, particularly in states that have exclusive retail service territory laws. If the incumbent utility is the retail seller, then no retail service exclusivity issue arises; however, the microgrid service must still be authorized either under the general terms of the state's utility laws or by action of the state regulator. A more important issue is whether the utility will in fact provide a useful and cost-effective microgrid service to end-users and whether the public is better served by having competitive offerings from a number of prospective microgrid operators.

2. Microgrids in Restructured Retail Electric Power Markets

In much of the U.S., electric power regulation has been restructured to allow retail competition. Microgrids face fewer issues in these markets than in cost-of-service areas. While their sale of power to a utility or other wholesale purchaser may still be subject to FERC regulation, the resale of power to end-users will not raise questions under exclusive services area laws (which do not apply in these markets). However, sales back to the grid in restructured markets raise similar issues to those discussed in retail cost-of-service markets. In addition, nearly every state with retail competition is also in an RTO/ISO organized wholesale market. If the RTO/ISO's market rules and operational practices do not appropriately account for microgrids, it could present barriers to full utilization of the microgrid across the retail and wholesale markets. For example, an RTO/ISO could have tariff provisions or market rules that effectively prevent a microgrid from participating in the wholesale market, denying it the opportunity to sell the collected services of its customers in that market and thus denying it the opportunity to earn additional revenues and maximize the value of its services.

Thus far, states have promoted microgrids in several ways, typically without changing franchise rules or otherwise encouraging third-party ownership of microgrids. One approach is customer-driven, in which

---

[204] *Cf. Conn. Light & Power*, 70 FERC ¶ 61,012, *reconsideration denied*, 71 FERC ¶ 61,035 (1995), *appeal dismissed*, 117 F.3d 1485 (D.C. Cir. 1997) (finding that the FPA preempted the Connecticut Department of Public Utility's ability to order a utility to enter into a contract at a state-set price because otherwise it would be impossible for the utility to simultaneously comply with the state mandate and the FERC mandate); *So. Cal. Edison Co.*, 70 FERC ¶ 61,215, *reconsideration denied*, 71 FERC ¶ 61,269 (1995). *See also Midwest Power Sys.*, 78 FERC ¶ 61,097 (1997) (finding that the FPA did not preempt a state law requiring utilities to purchase from state-designated facilities, but the FPA did preempt any order by the Iowa Utilities Board which set rates for wholesale transactions); *see also* National Renewable Energy Laboratory. Renewable Energy Prices in State-Level Feed-In Tariffs. Scott Hempling et al. (Jan. 2010), *available at* http://www.nrel.gov/docs/fy10osti/47408.pdf.

[205] *Cal. Pub Utils. Comm'n*, 133 FERC ¶ 61, 059 (2010), *reh'g denied*, 134 FERC ¶ 61,044 (2011).

the state provides support to potential microgrid customers (most commonly distribution utility customers with multiple facilities, such as municipalities and college campuses).[206] Other states have focused on the utility role, and have pushed jurisdictional utilities to deploy microgrids where appropriate.[207]

E. Independent Distribution System Operators

As distributed energy resources (such as rooftop solar PV), behind-the-meter energy storage resources, demand response and active demand management, and other new technologies achieve greater levels of adoption by customers, policymakers in several states have begun considering new industry structures for managing and coordinating their operations.[208] These new structures are intended to achieve multiple policy goals, including the encouragement of additional investment in distributed resources, the achievement of greater value from those resources, fuel and resource diversity, greater reliability and resiliency against human and natural threats, and emissions reductions, among others.

One concept under discussion in several states is the creation of a distribution system operator ("DSO") or similar entity charged with optimizing all of these resources and managing the multiple-directional flows of information and electricity they inherently create. A significantly more active version of the

---

206 Many of the states using this method of microgrid development financially suffered from significant reliability issues in 2011's Hurricane Irene and/or 2012's Hurricane Sandy. Most prominently, in 2012 Connecticut's legislature and governor passed into law a measure requiring the state to establish a microgrid loan and grant program for critical facilities, with $18 million in support of these facilities announced in the pilot round of funding. S.B. 23, 2012 Sess. (Conn. 2012), *available at* https://www.cga.ct.gov/2012/ACT/Pa/pdf/2012PA-00148-R00SB-00023-PA.pdf; Connecticut Department of Energy & Environmental Protection, "Microgrid Program," accessed August 17, 2016, http://www.ct.gov/deep/cwp/view.asp?a=4405&Q=508780. In 2013, the program was expanded by statute to include a further $30 million. S.B. 6360, 2013 Session (Conn. 2013), *available at* https://www.cga.ct.gov/2013/act/pa/pdf/2013PA-00298-R00HB-06360-PA.pdf. The bulk of Connecticut's awards have gone to municipalities and college campuses. New York has implemented a state competition for $40 million in funding to help communities create microgrids, largely by facilitating the detailed planning and engineering processes to lower barriers to development. NYSERDA, "Powering a new Generation of Community Energy," accessed August 18, 2016, http://www.nyserda.ny.gov/All-Programs/Programs/NY-Prize. Finally, New Jersey in 2014 launched a state Energy Resilience Bank, focusing disaster relief funds on developing distributed resources at critical facilities to prevent future reliability problems. New Jersey Board of Public Utilities, NJ Energy Resilience Bank Now Accepting Applications (October 20, 2014), *available at* http://www.state.nj.us/bpu/newsroom/announcements/pdf/20141020_erb_press.pdf.

207 For instance, Maryland law allows for utility ownership of "public purpose microgrids," serving critical assets spanning multiple properties, and utilities such as Baltimore Gas & Electric have begun to propose microgrid projects. Maryland Energy Administration, Resiliency Through Microgrid Task Force Report, *available at* http://energy.maryland.gov/documents/marylandresiliencythroughmicrogridstaskforcereport_000.pdf; Letter from David J. Collins, Executive Secretary, State of Maryland Public Service Commission, to Daniel W. Hurson, Assistant General Counsel, Baltimore Gas and Electric Co. (January 15, 2016), *available at* http://www.psc.state.md.us/wp-content/uploads/BGE-letter-on-Microgrid.pdf. California's PUC has required jurisdictional utilities to conduct distributed resource planning – including microgrids – as part of regular integrated resource plans. California law now requires utilities to consider the physical and electrical locations of distributed technologies, including generation, storage, demand response, and electric vehicles, and must demonstrate reliability, safety, and other ratepayer benefits in the plan. Cal. Pub. Util. Code § 769 (2016).

208 *See* Gavin Bade, "Beyond the substation: How 5 proactive states are transforming the grid edge," Utility Drive (March 2, 2015), http://www.utilitydive.com/news/beyond-the-substation-how-5-proactive-states-are-transforming-the-grid-edg/369810/.

microgrid concept discussed above, the DSO – which could be a utility or an independent entity – might perform functions similar to an RTO/ISO, such as least-cost dispatch of available resources to meet retail customer needs, load forecasting, distribution system planning, etc. Some DSO proposals envision such organizations also operating independent markets to facilitate competition for distributed generation and other energy services at the retail level. All of these proposals are still in the very early stages of consideration and exploration, although New York's REV proceeding appears furthest along in shifting the role of distribution utilities to one of supporting a diversified platform of utility- and third-party-owned distributed resources.[209]

A number of the potential roles and responsibilities of DSOs could raise jurisdictional or market integration concerns. At a high level, a DSO would naturally need to interact with the wholesale electricity market to ensure reliable operations. How that interaction occurs could have implications for the coordination of wholesale and retail markets and the integration of those markets. While identifying specific implications requires the analysis of a specific DSO construct, at a minimum, if an RTO/ISO or other bulk transmission system operator does not appropriately account for the operations of a DSO, it could present barriers to the achievement of the policy goals that led to the creation of the DSO. For example, an RTO/ISO could have tariff provisions or market rules that prevent the DSO from participating in the wholesale market or from effectively coordinating its operations with those of the wholesale market. FERC has addressed similar concerns in the past in the context of integrating demand response and energy storage into RTO/ISO markets, accepting market rule and tariff changes to ensure that such resources can participate in the wholesale market.[210]

A DSO might take on certain specific roles, as directed by a state regulatory authority that could have jurisdictional implications. For example, as part of its role in optimizing the use of demand response, active demand management, distributed resources and energy storage assets within the distribution system, the DSO might purchase products from these individual resources and resell them to utilities, or aggregate them and offer the combined resources into the wholesale market. This role would be similar to a potential role of a microgrid, as discussed in the previous section, and thus could have similar jurisdictional implications. Depending on how they are structured, these transactions might be characterized as "sales for resale in interstate commerce", triggering FERC's jurisdiction, and could also have similar PURPA implications. Triggering FERC jurisdiction would likely result in fragmented or overlapping oversight by both state and federal regulators. In the course of its REV proceeding, the New York Public Service Commission considered these issues and determined that "[t]o avoid

---

[209] Key regulatory developments actions in the New York REV proceedings are available at: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/C12C0A18F55877E785257E6F005D533E?OpenDocument.

[210] *See, e.g., California Independent System Operator Corp.*, 116 FERC ¶ 61,274 (2006) (encouraging further incorporation of demand response into the redesign of the CAISO markets); *Midwest Independent Transmission System Operator, Inc.*, 116 FERC ¶ 61,124 (2006) (directing a technical conference to consider, *inter alia*, the integration of demand response in MISO's procedures for addressing shortage and emergency conditions occurring in the real-time energy market.; *see also, e.g.*, *New York Independent System Operator, Inc.*, 127 FERC ¶ 61,135 (2009); *Midwest Independent Transmission System Operator, Inc.*, 129 FERC ¶ 61,303 (2009) (both addressing market rule changes to incorporate energy storage resources into the markets).

overlapping jurisdiction," its utilities (who will serve as the DSOs) "will not purchase power that would constitute a sale for resale under the FPA, except for purchases that are otherwise required by law."[211]

In addition, some DSO concepts envision that this entity will serve as a "platform" for the purchase and sale of energy services between customers entirely "behind the meter" and within the distribution system. Again depending on how such transactions are structured, it is possible that they could be considered "sales for resale" subject to FERC jurisdiction under the FPA, or retail sales subject to state laws and regulations. To the extent such transactions are structured in a way that makes them similar to sales by retail customers back to their host utility under a net-metering arrangement, then FERC's net metering precedent (which, as noted above, finds that such sales are not subject to FERC jurisdiction where the customer is a net buyer of electricity over the relevant billing period) might resolve this jurisdictional uncertainty.[212] However, to the extent such sales became subject to FERC jurisdiction, then it is possible that the distribution facilities over which those sales are made could also become subject to FERC regulation, and the seller would be treated as a public utility.[213]

F. Efforts of States to Prevent Shut Down of Baseload Nuclear Generation Before the End of Its Useful Life

In regions with RTO/ISO-operated organized wholesale markets (which now serve approximately two-thirds of all customers), independent merchant generators (i.e., generators that do not receive guaranteed cost recovery from bundled retail rates) sell a significant portion (if not all) of their power in the FERC-regulated markets. In some cases, wholesale market revenues for these and other generators have been insufficient to keep plants economically viable (particularly in a period of historically low natural gas prices and increased participation by renewable resources with low marginal costs), threatening their premature retirement;[214] in other instances, environmental regulations are a significant driver of potential retirements.[215] Premature economic retirements have been a particular concern.[216]

States have, and may continue to have, significant concerns with these retirements. States may wish to keep existing plants in operation for several reasons. Reliability concerns may necessitate operation of facilities to maintain adequate supply. Employment at the plants or other local economic interests understandably leads to concern about a potential closing. And in the case of a nuclear generator, a

---

211 Order Adopting Regulatory Policy Framework and Implementation Plan, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision at 43, No. 14-M-0101 (N.Y. Pub. Serv. Comm'n Feb. 26, 2015).

212 *See SunEdison LLC*, 129 FERC ¶ 61,146, at P 18 (2009), *order on reh'g*, 131 FERC ¶ 61,213 (2010).

213 *See NARUC v. FERC*, 475 F.3d 177 (upholding FERC's exercise of jurisdiction over interconnections to the distribution system where those interconnections are for the purpose of making wholesale sales).

214 Nuclear Energy Institute, "Nuclear Plant Shutdowns Reveal Market Problems," accessed August 18, 2016, http://www.nei.org/News-Media/News/News-Archives/Nuclear-Plant-Shutdowns-Reveal-Market-Problems.

215 U.S. Energy Information Administration, "Analysis of the Impacts of the Clean Power Plan" (May 22, 2015), http://www.eia.gov/analysis/requests/powerplants/cleanplan/.

216 *See, e.g.*, Nuclear Energy Institute, "Exelon on the 2014 PJM Capacity Market Auction" (June 12, 2014), http://www.nei.org/News-Media/News/News-Archives/Exelon-on-the-2014-PJM-Capacity-Market-Auction.

shutdown prior to the end of its useful life removes a large quantity of zero-carbon electricity, requiring the state to address environmental or resource mix policies through alternative means.

To address these concerns, some states have recently attempted to develop regulatory policies which would allow existing baseload coal or nuclear power plants that might otherwise retire based on market outcomes to remain in operation. These state interests in preserving existing generation resources, and the interests of FERC in ensuring wholesale market operation (and particularly capacity market operation), may create tension.

For example, the New York Public Service Commission has adopted requirements obligating the state's utilities to purchase "Zero Emissions Credits" ("ZECs") (similar to Renewable Energy Credits) from nuclear facilities. This program creates a separate market for the environmental attributes from nuclear facilities, providing an additional revenue stream for those plants at a time when low natural gas prices are undercutting market viability. Governor Andrew Cuomo has stated that shutting down nuclear facilities with a valid license "would eviscerate the emission reductions achieved through the state's renewable energy programs, diminish fuel diversity, increase price volatility, and financially harm[] host communities."[217] On October 19, 2016, a lawsuit was filed in federal court by a coalition of generators that compete with nuclear facilities in New York's FERC-regulated wholesale market, asserting that the ZEC program will artificially suppress wholesale prices and unlawfully intrudes on FERC's jurisdiction.[218]

In contrast, in March 2016 the Public Utilities Commission of Ohio ("PUCO") approved proposals by two Ohio utilities to adopt retail rate provisions that would allow them to recover the costs of power purchase agreements ("PPAs") with coal plants and one nuclear plant owned by their own affiliates. Merchant generators – which have no retail customers – objected, alleging that the PPAs discriminated in favor of utility-owned plants and would have the effect of depressing wholesale market prices. In its order approving the retail rate provisions underlying the PPAs, the PUCO emphasized that these arrangements would protect consumers by minimizing long-term rate volatility caused by uncertain future wholesale market prices, and that retail consumers would further benefit from the concessions made by the utilities to deploy advanced technology promote retail competition.[219]

Merchant generators and others opposed to the Ohio utilities' proposals and the PUCO's approval of them also filed three complaints with FERC. In the first two, they asked FERC to rescind a previously-granted waiver of certain affiliate restrictions that allowed the Ohio utilities to enter into the PPAs without up-front FERC approval. In the third, they sought an expansion of the Minimum Offer Price

[217] Letter from Andrew M. Cuomo, Governor, New York, to Audrey Zibelman, CEO, New York State Department of Public Service (December 2, 2015), *available at* https://www.governor.ny.gov/sites/governor.ny.gov/files/atoms/files/Renewable_Energy_Letter.pdf.

[218] *Coalition for Competitive Electricity et al. v. Zibelman et al.*, No. 1:16-cv-08164 (S.D.N.Y., Oct. 19, 2016).

[219] *In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Power Purchase Agreement Rider*, Opinion and Order at 77, Nos. 14-1693-EL-RDR et al. (Ohio Pub. Serv. Comm'n Mar. 31, 2016), *available at* https://dis.puc.state.oh.us/TiffToPDf/A1001001A16C31B40932C01840.pdf.

Rule in PJM's capacity market to apply it to the units involved in the proposed arrangements. FERC granted the first two complaints, determining that the PPAs in question might lead to cross-subsidization that would need to be subject to heightened scrutiny from FERC, rather than approved as submitted.[220] The third complaint remains pending.

FERC's decision regarding the Ohio PPAs, in conjunction with the Supreme Court's 2016 determination in *Hughes* that states could not set compensation for new generators based upon the prices those units received in capacity markets, demonstrates the jurisdictional implications of these state efforts with regard to generation operating in competitive wholesale electric markets, and the limits states face when they want to support development of, or continued operation of, electricity generation within their state. New York's approach requires acquisition of environmental attributes through the purchase of ZECs, with the price of those ZECs based in part on projections of future wholesale capacity prices. Unlike the program struck down in *Hughes*, the ZEC prices are not based on actual wholesale capacity prices received by a generator, which could arguably place New York's program in a better position. To the extent states adopt additional policies like those explored in Ohio and New York - whether to support the continued operation of existing power plants or to encourage the development of new or emerging energy technologies – and they are found to impact the FERC-regulated wholesale markets, similar issues could arise.

[220] *Elec. Power Supply Ass'n v. AEP Generation Res., Inc.*, 155 FERC ¶ 61,102 (2016); *Elec. Power Supply Ass'n v. FirstEnergy Sols. Corp.*, 155 FERC ¶ 61,101 (2016). Although concerns with distortions of PJM's capacity markets were raised in the proceeding, FERC found that it did not need to address these in finding that the PPAs in question should be subject to heightened scrutiny.