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All electrons are not local: A commentary on the interplay of recent U.S. Supreme Court decisions and state efforts to guide local transitions to clean power☆

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ABSTRACT

A consistent assumption is that the market structures approved by FERC as a means of achieving the 'just and reasonable' rates required under the Federal Power Act are the necessary proxy for allocating jurisdiction between FERC and the states in clean energy development. If capacity markets are ultimately determined not to sustain the levels of capacity needed for the electric grid to function reliably and generation capacity declines below the specified levels, the efficacy of this construct will be called into question.

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1. Introduction

Technology advances in the electric utility industry are driving market participants and regulators to grapple with the fact that the prevailing business model upon which regulatory structures are built is changing before our eyes. Many state regulatory authorities and legislatures are addressing the changes wrought and sought by new market participants: distributed generation large and small, the increasing intersection of the effects of climate policy, concerns about water and the need to maintain reliable electric service now and in the future. The states of California, Hawaii, Minnesota, and New York have been particularly active in reviewing old assumptions about their electric regulatory regimes. In 1996, the Federal Energy Regulatory Commission (FERC) established the foundation for separate treatment of the generation, transmission, and distribution segments of the industry through Order No. 888 (which approved regional transmission organizations (RTOs) and independent system operators (ISOs)), based on economic and market structure imperatives for a business model assuming one-way flows of power from central station generation to load. FERC and the states now find themselves trying to incorporate distributed generation, demand response, and other developments that suggest the growth of bi-directional power flows on the grid. To add to the strains faced by traditional electric regulators to accommodate an emerging business model, the federal Environmental Protection Administration (EPA) has entered the fray by proposing that *states* take regulatory action under environmental statutes to reduce the emissions of greenhouse gases from electric generation by changing generator dispatch. Such initiatives, in the form of the Clean Power Plan and related actions, may affect FERC jurisdictional areas. In addition, states are actively investigating how to promote "clean" energy sources within the limits of their own jurisdiction.

Incumbent generation owners, in turn, participate in both legislative and regulatory arenas to protect their existing assets and business models to the extent feasible.[1] Should rooftop solar participate in the wholesale energy markets? Do the states, FERC, both, or neither determine the market pricing signals for the efficient siting of new central station generation, and what pricing guarantees accompany the market structures designed to send such signals? To what extent should end users with their own [distributed] generation be permitted to participate in the local or regional energy markets instead of central station generation, and who controls that participation? These questions and others

☆ All opinions expressed in this article are solely those of the author and do not reflect the views of the firm or its clients.

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[1] *See, e.g.*, Getting Distributed Generation Right: A Response To "Does Disruptive Competition Mean A Death Spiral For Electric Utilities?", David Raskin, 35 Energy L. J. 263 (2014).

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appear to have become most intractable in the context of whether the states or FERC have, or should have, jurisdiction over the measures addressing such issues.[2]

During its 2016 term, the U.S. Supreme Court issued two decisions emphatically establishing that the wholesale markets approved by FERC under the Federal Power Act (FPA) are the guideposts against which state regulatory and business model accommodations to electric industry evolution must be measured. These decisions are *Federal Energy Regulatory Commission v. Electric Power Supply Association,* 136 S. Ct. 760 (2016) (*EPSA*) and *Hughes v. Talen Energy Marketing, LLC*, 136 S. Ct. 1288 (2016) (*MdPSC-Talen*). These decisions, together with the *Oneok, Inc. v. Learjet, Inc.*[3] opinion in the previous term, require all current and potential participants in the electric utility (and natural gas) markets to analyze which transactions and regulatory decisions may affect wholesale electric (and natural gas) market structures as well as wholesale sales of electric energy and sales of transmission service and whether such developments are permissible within the current federal regulatory regime or require FERC's permission.

This article will explain the substance and import of these two decisions. It also will discuss the import of the Court's analytical framework on the evolution of state commission regulatory structures that are more accommodating to greater customer/end user participation in electricity markets.

2. The analytical framework: FERC-regulated wholesale markets must not be impinged upon by state regulation

2.1. The EPSA *decision*

EPSA addressed the issue whether FERC has jurisdiction to approve the purchase of, and establish a price for, demand response in the organized RTO and ISO markets. Demand response is called upon to reduce peak demands on the generating system. The coordinated and reliable imposition of demand response to avoid peaks is considered a way to reduce the need for construction of new generating facilities, generally fired by fossil fuels, solely to meet peak demand. Demand response reflects an amount of energy that aggregators arrange *not* to be consumed by retail customers during specified hours and which has been bid into the organized wholesale energy markets for such hours by the aggregators in return for a payment. The aggregators, under state authority, entered into contracts with end use electric consumers to reduce or eliminate their electricity demands/consumption during specified hours, in return for a payment for such foregone consumption.[4] The tariffs maintained by the RTOs and ISOs setting forth the structure and operational rules of the energy and related markets specifically addressed the terms and conditions for demand response participation.

The *EPSA* case arose specifically from an appeal of FERC's Order No. 745, the decision requiring the RTOs/ISOs to pay full locational marginal price (LMP) to demand response providers for each megawatt-hour of demand response/energy requirement foregone.[5] EPSA, the trade association of independently owned electric generators, joined by the American Public Power Association, the trade association for municipally and state-owned electric utilities, appealed. It argued that the FERC had no jurisdiction over demand response under the FPA because there was no "sale of electricity for resale" as specified under Sections 201 of the FPA. As an alternative, EPSA argued that if the FERC had jurisdiction, payment of full LMP was inappropriate because the end use customer already realized a savings in the amount of the generation component of the energy charge it did not pay for by reducing its demand.

In a 2-1 decision, the D.C. Circuit reversed FERC by finding that FERC did not have jurisdiction over demand response.[6] The D.C. Circuit took a literal approach in finding that since FPA Section 201 gave jurisdiction to FERC over "the sale of energy for resale" and demand response was the antithesis of the sale of energy, *i.e.* it is the reduction in demand for electric energy during a specific time period, demand response did not constitute the type of transaction delegated to the FERC's jurisdiction. Moreover, since the reduction in electric demand was coordinated between the local service provider and the end user, it was viewed as an inherently retail transaction that was preserved to state jurisdiction under FPA Section 201. The D.C. Circuit also held that FERC had not adequately explained its decision to compensate demand response providers at full LMP.[7] Judge Harry Edwards' dissent found that since solicitation of demand response would reduce the amount of demand that a RTO would be required to meet in any hour under its tariff and reduce the LMP for that hour, demand response was within FERC's jurisdiction under FPA Section 205(c) as a "practice affecting the rates, terms and conditions" of a FERC-regulated service.[8]

The Supreme Court's opinion restated FERC's FPA jurisdiction in terms of the economic function regulated in order to uphold FERC's position and reverse the D.C. Circuit. In her majority opinion, Justice Kagan began by explaining the delegation of jurisdiction between FERC and state authority under FPA Section 201 as well as how demand response works in the organized markets. She then described an evolution of FERC authority in the context of electric markets:

> In this new world, FERC often forgoes the cost-based rate-setting traditionally used to prevent monopolistic pricing. The Commission instead undertakes to ensure "just and reasonable" wholesale rates by enhancing competition—attempting, as we recently explained, "to break down regulatory and economic barriers that hinder a free market in wholesale electricity." *citing Morgan Stanley Capital Group Inc.* v. *Public Util. Dist. No. 1 of Snohomish Cty.*, 554 U. S. 527, 536 (2008). *EPSA*, 136 S. Ct. at 768.

The Opinion describes how the hourly energy market auction operates by taking orders from load-serving entities (LSEs) for electricity needed in a particular hour, the bidding by generators of the price to provide a stated amount of energy in that hour, and the auction operated by the RTO or ISO to match supply with demand at the highest price taken for each hour (that is, the locational marginal price). *Id* at 768-69. The Opinion delineates the negative effect of demand response on energy prices, *i.e.,* that demand response is a negative supply that limits the rate of energy price increase.

The opinion traced the unchallenged cohort of statutes and regulations that preceded Order No. 745. These included Section 1252(f) of the Energy Policy Act of 2005[9] that defines and encourages the participation of demand response in energy markets. *EPSA*, 136 S. Ct. at 770 and FERC Order No. 719, issued in 2008, that required wholesale market operators to receive demand response bids from aggregators of electric consumers unless prohibited by state law. *Id.* at 771. The Opinion then noted that Order No. 745 simply was the evolution beyond Order No. 719

[2] *See*, *e.g.*, *The Hazy "Bright Line"; Defining Federal and State Regulation of Today's Electric Grid*, Robert Nordhaus, 36 Energy L. J. 203 (2015); *Federalism and the net metering alternative*, James Rossi, The Electricity Journal, vol. 29, pp. 13–18 (2016) (hereinafter "Rossi Net Metering").

[3] 135 S. Ct. 1591 (2015).

[4] *EPSA*, 136 S. Ct. at 767.

[5] *Id.* at 771-72.

[6] *Elec. Power Supply v. FERC*, 753 F.3d 216 (2014).

[7] *Id.* at 225.

[8] *Id.* at 232.

[9] Pub. L. No. 109-58, § 1252(f), 119 Stat. 966 (2005).

to incent "meaningful demand-side participation" in the wholesale markets as long as the demand response provider has the capability to deliver the service offered and the RTO/ISO's payment for demand response was cost-effective under the net benefits test included in Order No. 745. *Id.* at 771-72. The Opinion noted that demand response providers could not offer the service from areas in which a state law or regulation prohibited such participation. *Id.* at 772.

The Court concluded that while demand response may not specifically be a "sale of electric energy for resale," it certainly fell within the realm of rules or practices "directly affecting" the just and reasonable rate for the sale of electric energy. *Id.* at 774-75. It relied on a prior D.C. Circuit opinion in *California Independent System Operator Corp. v. FERC*, 372 F. 3d 395, 403 (2004) to enunciate the test that such a rule or practice must *directly* affect a wholesale rate to be within the FERC's jurisdiction.[10]

The Opinion then directly addressed the key question (for purposes of this article) about how FERC may exercise authority over a function that is inherently end-user- and retail-market-driven. The Court explained:

> It is a fact of economic life that the wholesale and retail markets in electricity, as in every other known product, are not hermetically sealed from each other. To the contrary, transactions that occur on the wholesale market have natural consequences at the retail level. And so too, of necessity, will FERC's regulation of those wholesale matters. . . . 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 . . . . What is more, the Commission's justifications for regulating demand response are all about, and only about, improving the wholesale market. Cf. *Oneok*, 575 U. S., at ___ (slip op., at 11) (considering "the *target* at which [a] law *aims*" in determining whether a State is properly regulating retail or, instead, improperly regulating wholesale sales). In Order No. 719, FERC explained that demand response participation could help create a "well- functioning competitive wholesale electric energy market" with "reduce[d] wholesale power prices" and "enhance[d] reliability." 73 Fed. Reg. 64103, ¶16. And in the Rule under review, FERC expanded on that theme. It listed the several ways in which "demand response in organized wholesale energy markets can help improve the functioning and competitiveness of those markets": by replacing high-priced, inefficient generation; exerting "downward pressure" on "generator bidding strategies"; and "support[ing] system reliability." 76 *id.*, at 16660, ¶10; see Notice of Proposed Rulemaking for Order No. 745, 75 *id.*, at 15363–15364, ¶4 (2010) (noting similar aims); *supra*, at 769–770. *EPSA*, 136 S. Ct. at 776-77 (internal citation omitted).

The Court goes on to note that Order No. 745 gives the States a veto over the participation of its suppliers and customers from making demand response bids into the wholesale markets. *EPSA*, 136 S. Ct. at 779-80. However, state commissions may not regulate demand response bids; that would constitute an impermissible conflict.

2.2. The MdPSC-Talen decision

Several months later, the Supreme Court, in a unanimous decision (with several concurrences) written by Justice Ginsberg, upheld the converse to the *EPSA* decision by finding that the State of Maryland, acting through its Public Service Commission (PSC), had impermissibly impinged on FERC regulatory authority by requiring certain Maryland-based LSEs to enter into a 20-year power purchase agreement with a new-generation developer that, through a "contract for differences" mechanism, ensured that the generation developer received, and the LSEs paid, the contract capacity price regardless of the PJM capacity market price. Maryland's PSC was concerned that PJM RTO's Reliability Pricing Mechanism, the capacity market through which PJM procures the capacity (both actual generation and demand response) needed to produce the energy sold in its organized energy market, had not provided sufficient incentive for construction of new generating capacity within the State of Maryland.[11] The PSC was concerned that since much of Maryland was located within a significant PJM transmission capacity constraint, the failure to build new generating capacity in the state either to serve increased load or to replace retiring generation would threaten reliability of electric service. The PSC issued a request for proposal for construction of new generation based upon a requirement that all Maryland-based LSEs would enter into PSC-approved 20-year purchased power agreements (PPAs) with the winner that would guarantee the generator a fixed capacity payment no matter what price was established in the PJM capacity market. CPV Maryland LLC (CPV) won the bid. The PSC requirements and the PPAs required CPV to bid the capacity of the new generator into the PJM capacity market.

Several owners of existing generation that participate in the PJM auction expressed concern that new, state-encouraged and -subsidized generators such as CPV might depress capacity prices in the PJM capacity market. They challenged Maryland's action as impinging on FERC's regulatory authority under the FPA. A federal district court in Maryland found that Maryland's action indeed was pre-empted by FERC authority to regulate wholesale rates under the FPA.[12] That decision was affirmed by the Fourth Circuit.[13]

As was the case in *EPSA*, the Court's analysis began with the federally approved wholesale market as the initial point of reference for the analysis. In *EPSA*, the Court's opinion examined whether the FERC Order No. 745 could be upheld within the FPA's framework, not whether the inherent features of demand response disqualified the FERC from acting. In *MdPSC-Talen*, the Court began by establishing that the FERC-regulated wholesale capacity market established and operated under the PJM tariff was the standard that Maryland could not violate rather than beginning the analysis with an examination whether there was any way to justify the state program. Early in the decision, the Court stated:

> These cases involve the capacity auction administered by PJM Interconnection (PJM), an RTO that oversees the electricity grid in all or parts of 13 mid-Atlantic and Midwestern States and the District of Columbia. . . . FERC extensively regulates the structure of the PJM capacity auction to ensure that it efficiently balances supply and demand, producing a just and reasonable clearing price. *MdPSC-Talen*, 136 S. Ct. at 1293.

This approach doomed Maryland's program. Under the PSC directives and the PPA, CPV did not sell its capacity to the LSEs for them to bid into the PJM capacity market. Rather, it sold the

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[10] The Court found Order No. 745's directive that demand response be paid the full resulting LMP, rather than a lesser price, not to be arbitrary and capricious. *EPSA*, 136 S. Ct. at 782-84. That decision is not pertinent to the purpose of this article.

[11] *MdPSC-Talen*, 136 S. Ct. at 1294.

[12] *PPL Energyplus, LLC v. Nazarian*, 974 F. Supp. 2d 790 (D. Md. 2013).

[13] *PPL Energyplus, LLC v. Nazarian*, 753 F.3d 467 (4th Cir. 2014). A comparable dispute related to a similar New Jersey local capacity initiative proceeded on a parallel path through a New Jersey federal district court and the Third Circuit. *PPL Energyplus, LLC v. Solomon*, 766 F.3d 241, 246 (3rd Cir. 2014); *PPL EnergyPlus, LLC v. Hanna*, 977 F. Supp. 2d 372 (D. NJ 2013). However, the Maryland case was the lead in terms of timing and depth of analysis and was the case granted certiorari by the U.S. Supreme Court.

project's capacity into the PJM capacity market and received revenues from that market. At the same time, the LSEs purchased their allotted capacity requirement from the PJM capacity market. The PPA required CPV and the LSEs to ensure that CPV received only the capacity price specified in the contract. Thus, if the PJM capacity market price exceeded the PPA price, CPV paid the difference to the LSEs and vice versa.[14] In effect, the PPA constituted a hedge for both CPV and the LSEs *against the contract price, not the PJM capacity market price*. The practical effect was that Maryland "made" a new market for capacity within PJM. As the Court explained:

> A state law is preempted where "Congress has legislated comprehensively to occupy an entire field of regulation, leaving no room for the States to supplement federal law," *Northwest Central Pipeline Corp. v. State Corporation Comm'n of Kan.*, 489 U. S. 493, 509 (1989), as well as "where, under the circumstances of a particular case, the challenged state law stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress," *Crosby v. National Foreign Trade Council*, 530 U. S. 363, 373 (2000). . . . We agree with the Fourth Circuit's judgment that Maryland's program sets an interstate wholesale rate, contravening the FPA's division of authority between state and federal regulators . . . Exercising this authority, FERC has approved the PJM capacity auction as the sole ratesetting mechanism for sales of capacity to PJM, and has deemed the clearing price *per se* just and reasonable. Doubting FERC's judgment, Maryland—through the contract for differences—requires CPV to participate in the PJM capacity auction, but guarantees CPV a rate distinct from the clearing price for its interstate sales of capacity to PJM. By adjusting an interstate wholesale rate, Maryland's program invades FERC's regulatory turf. *MdPSC-Talen*, 136 S. Ct. at 1297.

The Court went out of its way, however, to provide encouragement to the states to experiment. Specifically:

> Our holding is limited: We reject Maryland's program only because it disregards an interstate wholesale rate required by FERC. We therefore need not and do not address the permissibility of various other measures States might 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. Nothing in this opinion should be read to foreclose Maryland and other States from encouraging production of new or clean generation through measures "untethered to a generator's wholesale market participation." (citation omitted). *MdPSC-Talen*, 136 S. Ct. at 1299.

3. What are the explicit red lines of federal jurisdiction that the states may not cross in pursuing clean energy goals?

When read together, the Supreme Court's *EPSA* and *MdPSC-Talen* decisions appear to provide unusually direct guidance to the states: *e.g.* feel free to experiment with initiatives to promote development of clean energy sources and more efficient use of energy as long as such measures do not constitute direct regulation of, or interference with, the two areas of direct FERC regulation under the Federal Power Act. Those areas are the transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce.[15] The Court was mindful that FPA Section 201(b) goes on to state that federal jurisdiction shall not apply to "any other sale of electric energy" and that the

> Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction. . over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce or over facilities for the transmission of electric energy consumed wholly by the transmitter.[16]

This basic statement of jurisdiction, taken together with the Supreme Court's affirmation in *EPSA* and *MdPSC-Talen* that state programs may not directly affect FERC-regulated organized market structures, appears to delineate high-concept red lines for state clean energy and energy usage programs. State efforts to integrate demand response programs, such as that being explored in an ongoing proceeding in California[17] and which do not otherwise affect bidding of demand response resources into the California Independent System Operator energy or ancillary services markets, should be considered well within the state side of the jurisdictional line. Similarly, any program aimed at affecting consumers' behavior, such as encouragement of electric vehicle usage, should not be found to implicate federal jurisdiction.

The most apparent areas of potential tension involve regulation, including price regulation, of the sale of output from distributed generation, potential use of the interstate transmission system to facilitate deliveries by distributed generation to and over the transmission and distribution grids to disparate end use customers, and state efforts to support the development and operation of existing or new generation facilities with low or no greenhouse gas emission profiles that are located in areas served by wholesale capacity markets. While these areas appear to be discrete, the lines between them may become blurred in the context of comprehensive state efforts, such as New York's Reforming the Energy Vision initiative. That proceeding is aimed at, among other things, making the distribution grid available for two-way usage and commerce as well as reducing peak load demands in the state to prevent the need for construction of limited use generation facilities for peak usage only.[18]

3.1. Distributed generation

The allocation of state versus federal jurisdiction over distributed generation appears to be settled law and not subject to great controversy. For purposes of this article, distributed generation is understood to mean any source of electric generation that is owned by an end user and used, at least in part, to satisfy the end user's electric demand. It does not include generation facilities, other than renewables, that are constructed for the sole purpose of making sales of electric energy at wholesale.

At a high level, the issue of price regulation of distributed generation output breaks down into three tranches that are not necessarily mutually exclusive: net metering, generation covered by Section 210 of the Public Utility Regulatory Policies Act (PURPA) and sales of energy (and capacity, outside capacity market states) from generation that do not fall into the first two categories. Net

[14] *MdPSC-Talen*, 136 S. Ct. at 1295.

[15] Federal Power Act § 201 (b), 16 U.S.C. § 824(b).

[16] *Id.*

[17] *See* Order Initiating Rulemaking to Create a Consistent Regulatory Framework For the Guidance, Planning and Evaluation of Integrated Demand-Side Resources, Rulemaking 14-10-003, 2014 WL 5284549 (Cal. Pub. Utils. Comm'n Oct. 2, 2014).

[18] Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan, Case 14-M-0101, 2015 WL 862119, *14 (N.Y. Pub. Serv. Comm'n Feb. 26, 2015) (noting that flattening the 100 h of greatest peak demand could avoid capacity and energy costs of $1.2–$1.7 billion per year and that distributed generation could avoid line losses which range between $200 and 400 million per year).

metering involves the sale by an end user of excess energy generated by that user into the grid. It is a program initially authorized by states.[19] From a federal jurisdictional perspective, the FERC has found that deliveries of excess energy to the grid under a state-sponsored net metering program are not subject to FERC regulation under the FPA.[20] Many state programs establish very low limits on the capacity of the generation that qualifies for net metering such that any individual unit will often be less than 1 MW.[21] Notwithstanding the increasingly pointed controversy in several states about the price to be paid by utilities for excess energy, the basic jurisdictional line appears to be settled.

Jurisdiction over cogeneration and renewable energy generation facilities owned by end users (or others) that meet the definitional, size, and technical requirements of Section 210 of PURPA[22] and the FERC regulations at 18C.F.R. Part 292 is covered in those statutes and regulations. Federal law requires electric utilities to interconnect with and purchase the output from such facilities and to pay the utility's avoided cost for such purchase. Federal law also explicitly delegates to the states the authority to determine each utility's avoided cost as well as the terms and conditions of interconnection and purchase contracts. When the State of California attempted to assert jurisdiction to determine the rate to be paid by utilities for the output of combined heat and power facilities that otherwise had not been qualified under Section 210 of PURPA, the FERC made it clear either that California could establish prices within the PURPA Section 210 ratemaking context for those facilities meeting the cogeneration qualifications or the facilities would be required to become subject to FERC's plenary rate and related regulation under the FPA.[23]

As noted above, there is little mystery about the applicability of federal regulation to the sale of electric energy from renewable energy or other "clean energy" facilities[24] that do not otherwise meet the qualifications of Section 210 of PURPA. Such facilities are "public utilities" within the meaning of FPA Section 201 and are subject to the full panoply of FERC regulation under applicable provision of the FPA.[25]

3.2. Potential use of the interstate transmission system to deliver output from distributed generation or other designated clean energy generators

In the wake of FERC's adoption of Order No. 888, and subsequent restructuring of the electric utility industry to the extent of separating wholesale power sales and transmission functions, much focus was directed at the demarcation of federal and state jurisdiction for the unbundled delivery of electric energy over the transmission and distribution systems. The Supreme Court confirmed the principal line of demarcation in *New York v. United States*, 525 U.S. 1 (2001) in which it upheld that portion of Order No. 888 exerting FERC jurisdiction over transmission service provided for the unbundled delivery of electric energy over distribution systems to end users in the states that permit retail choice. Order No. 888 acknowledged and preserved state jurisdiction over the provision of traditional bundled retail electric services over distribution facilities. Thus, the owner of a combined transmission and distribution system may have a tariff on file with the FERC for provision of transmission service to end users for retail access energy while maintaining tariffs with the applicable state regulatory authorities for the simultaneous delivery of bundled retail energy services to other customers.

The specter of a red line arises, however, if a state proposes to change its regulation to promote the development of bidirectional uses of the distribution system that could result in substantial outflow from distributed generation to the transmission system.[26] The New York Public Service Commission's Reforming the Energy Vision proceeding raises this question most directly. As stated in its most recent order,[27] the NYPSC's focus "is to create a modern regulatory model that challenges utilities to take actions" that better align "utility shareholder financial interest with consumer interest".[28] More directly, "the unidirectional grid must evolve into a more diversified and resilient distributed model engaging customers and third parties".[29] Distribution utilities will no longer rely exclusively on revenues collected from end use customers based on cost-of-service rates; they will be required to develop sources of "platform service revenues" derived from the sale of products and services that may be provided by third parties instead of the utility.

Notwithstanding the concepts described in the REV Ratemaking Order, the types of third-party services that may pop up and provide distribution owners with an opportunity to collect revenues cannot be detailed at this time. The obvious assumption underlying much of the REV proceeding, however, is that the types of third-party actions that take place on the distribution system will have no effect on the transmission system. If the New York Independent System Operator detects such effects, however, one may assume that it will revert to the FERC to determine whether a red line has been crossed and whether to try to stop such actions or attempt to incorporate them into a shared federal-state regulatory regime.

3.3. State generation/integrated resource/clean energy planning in capacity market states

The EPA's Clean Power Plan has brought into focus for many states the need to inventory generation sources within each state and encourage the development of those resources emitting zero or minimal greenhouse gases. Several states have directed their regulated utilities to focus on promoting energy efficiency, demand

[19] For a more comprehensive description of net metering programs in the states, *see Rossi Net Metering*, *supra* note 2, and the authorities cited therein.

[20] *MidAmerican Energy Co.*, 94 FERC ¶ 61, 340 (2001).

[21] Jocelyn Durkay, *Net Metering: Policy Overview and State Legislative Updates*, National Conference of State Legislatures, (Dec. 18, 2104) (*available at* http://www.ncsl.org/research/energy/net-metering-policy-overview-and-state-legislative-updates.aspx) (noting that nearly half of states with net metering policies impose a cap of 1 MW).

[22] 16 U.S.C. § 824a-3 (2012).

[23] *Cal. Pub. Utils. Comm'n*, 132 FERC ¶ 61,047 (2010), *order granting clarification and dismissing reh'g*, 133 FERC ¶ 61,059 (2010), *reh'g denied* 134 FERC ¶ 61,044 (2011).

[24] As yet, there is no standard industry definition of a "clean energy facility." Consistent with the exclusion of FERC jurisdiction over generation facilities under Section 201 of the FPA, states either have adopted or are considering individual definitions of clean energy. A comprehensive discussion of the nuances of this topic is beyond the scope of this article.

[25] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services 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 (March 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[26] The discussion in this article does not depend on establishing a technical explanation of the difference between the transmission and distribution systems and will use those terms generically to distinguish between high-voltage facilities used to deliver electric power in bulk (transmission) and lower-voltage facilities used primarily to deliver electric energy to individual end users (distribution).

[27] Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework*, Case 14-M-0101, 2016 WL 2962732 (N.Y. Pub. Serv. Comm'n May 19, 2016). (REV Ratemaking Order).

[28] *Id.* at *1.

[29] *Id.*

response, and reductions in GHG emissions in their integrated resource plans. However, those states located in the footprints of RTOs and ISOs dictating that LSE/distribution utilities may only meet their installed capacity obligations through the organized capacity markets, such as Maryland, may have found their ability to influence the siting of clean energy facilities somewhat diminished by the *EPSA* and, more importantly, the *MdPSC-Talen* decisions.

The capacity markets allocate qualifying generating capacity based on price, i.e. the price derived from the capacity auctions. The FERC tariffs provide that the capacity markets officially constitute the principal means through which owners of generating capacity receive compensation for their fixed costs. The primary qualification for capacity eligible to bid into the capacity market is the ability to dispatch energy at virtually any time upon demand, i.e. the capacity rating.[30] At the time this article is written, the combination of auction-driven price setting for capacity and application of capacity ratings has resulted in obstacles to state-guided resource planning to enhance the development or operation of clean energy generation. On one hand, owners of several nuclear plants, particularly Entergy and Exelon, have complained that the capacity markets result in inadequate recovery of nuclear plant fixed costs and some have shut down older nuclear plants.[31] On the other hand, the capacity ratings of wind and solar facilities often do not reach the level required to participate in the capacity auctions. That, in turn, has raised a question whether the amount of capacity that LSEs must obtain through the capacity auctions should be reduced by an amount representing the capacity value of the renewable generation they have purchased through other means.[32]

The analytical framework adopted in the *EPSA* and *MdPSC-Talen* appear to constitute the type of red line regarding state involvement in determining the type of generating capacity to be developed in those states within the boundaries of the organized capacity markets. This red line affects only the market/pricing mechanisms that a state may prescribe as part of such integrated resource planning. However, market structure and pricing are among the most important features that will determine the viability of privately developed generation. Whether EPA's Clean Power Plan survives the outstanding litigation in its current form, many states (and other industry participants) will continue to plan to meet its GHG reduction goals. That progress may well be hindered by this red line as development of large amounts of clean generation capacity will be needed to reach those goals and fixed cost coverage ultimately will determine which projects proceed and which existing clean generation survives.

4. Does the Supreme Court' analytical framework for allocating federal and state jurisdiction contain a tripwire that ultimately may benefit the states?

The Court explained in *EPSA* that it uses the FERC-regulated market framework as the guidepost for its analysis because the Commission instead undertakes to ensure "'just and reasonable' wholesale rates by enhancing competition" in a free market in wholesale electricity.[33] Similarly in *MdPSC-Talen*, the Court explained that, "FERC extensively regulates the structure of the PJM capacity auction to ensure that it efficiently balances supply and demand, producing a just and reasonable clearing price.[34] The consistent assumption is that the market structures approved by FERC as a means of achieving the "just and reasonable" rates required under FPA Sections 205 and 206 are the necessary proxy for allocating jurisdiction between FERC and the states in clean energy development.

If capacity markets are ultimately determined not to sustain the levels of capacity needed for the electric grid to function reliably and generation capacity declines below the specified levels, the efficacy of this construct will be called into question. A survey of the relationship between participation in capacity markets, generation retirements due to inadequate fixed cost recovery and capacity market pricing is both beyond the scope of this article and possibly premature at the time of this writing. In the event that capacity markets are determined to have failed, however, the analytical framework assumed by the Court in *EPSA* and *MdPSC-Talen,* (but not necessarily the holdings) may become antiquated and future state initiatives to promote clean energy may be reviewed under more conventional statutory interpretation analyses.

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[30] The capacity rating is a traditional reliability criterion of long standing that is used to determine whether LSEs have secured sufficient generating capacity to meet their anticipated peak loads plus a margin. In PJM, the capacity rating is augmented by the new "Capacity Performance" criterion that provides additional compensation for a selected generator's performance at critical times as well as monetary penalties for failure to do so. PJM Open Access Transmission Tariff, Attachment DD.5.5A(a), version 0.1.0 (effective Apr. 1, 2015).

[31] Press Release, Entergy, Entergy to Close, Decommission Vermont Yankee (Aug. 27, 2013), *available at* http://www.entergy.com/news_room/newsrelease.aspx?NR_ID=2769; Press Release, Entergy Newsroom, Entergy to Close James A. FitzPatrick Nuclear Power Plant in Central New York (Nov. 2, 2015), *available at* http://www.entergynewsroom.com/latest-news/entergy-close-jamesfitzpatrick-nuclear-power-plant-central-new-york/; Petition Requesting Initiation of a Proceeding to Examine a Proposal for Continued Operation of the R.E. Ginna Nuclear Plant, LLC, Order Adopting the Terms of a Joint Proposal, Case No. 14-E-0270, 2016 WL 791806 (N.Y. Pub. Serv. Comm'n Feb. 24, 2016), *clarified by*, 2016 WL 1569417 (Apr. 13, 2016).

[32] *ISO New England Inc.*, 147 FERC ¶ 61,173, at P 83 (2014), *order on reh'g and clarification*, 150 FERC ¶ 61,065, at PP 21–22 (2015); *N.Y. Pub. Serv. Comm'n v. N.Y. Indep. Sys. Operator*, 153 FERC ¶ 61,022 (2015), *order denying reh'g*, 154 FERC ¶ 61,088 (2016), appeal docketed No. 16-1107 (D.C. Cir. Apr. 5, 2016).

[33] *EPSA*, 136 S. Ct. 760, 768 (2016).

[34] *MdPSC-Talen*, 136 S. Ct. 1288, 1293-94 (2016).