HARVARD LAW SCHOOL
Environmental & Energy Law Program

REGULATORY PATHS FORWARD FOR A CLEANER GRID

Summary Report of a Workshop Convened by the Harvard Electricity Law Initiative

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The Harvard Electricity Law Initiative convened a group of experts in October 2017 to discuss the future of wholesale electricity markets. Our workshop followed a May 2017 FERC Technical Conference about how state energy policies are affecting FERC-jurisdictional markets and whether markets reforms are necessary. As FERC explained, "[b]ecause the wholesale competitive markets . . . select resources based on principles of operational and economic efficiency without specific regard to resource type, there is an open question of how the competitive wholesale markets . . . can select resources of interest to state policy makers while preserving the benefits of regional markets and economic resource selection."

To frame our workshop, we explored three paths forward for market reform identified by FERC Commissioner Cheryl LaFleur for the Eastern RTOs:

1. maintaining the status quo and resolving state/FERC tensions through litigation;
2. re-regulating resource adequacy to return the responsibility to states; and
3. integrating public policy and RTO markets.

In addition, our initial session focused on the Department of Energy's "Grid Resiliency Pricing" proposal. Each session began with the remarks by as many as four participants followed by an open discussion among all participants.

This summary report highlights major areas of discussion during each session. Discussions were conducted pursuant to the Chatham House Rule, and therefore no statements are attributed to any individual. Participants did not attempt to reach agreement on any policy or legal issues, and this report is not intended to reflect the recommendations of any particular participant or the group.

Session 1: DOE's "Grid Resiliency Pricing" Proposal

Discussant: In recent years, courts have connected FERC's duty to ensure that wholesale rates are "just and reasonable" and not "unduly discriminatory" to electric grid reliability. In 2009, the D.C. Circuit upheld FERC's oversight of capacity market demand, finding that there was a sufficient link between regional resource adequacy and wholesale rates. In 2017, that court concluded that a FERC-jurisdictional capacity market could pay each resource for its ability to contribute to reliability, and deferred to FERC's judgment that improved reliability justified higher consumer costs and did not render rates unjust and unreasonable.

These decisions suggest that FERC has authority to address "resilience" through its oversight of wholesale rates. To the extent that threats to grid resilience or resilience events lead to high wholesale rates, FERC can approve RTO tariff filings or order tariff changes that are designed to mitigate those impacts. DOE's proposal, however, is inconsistent with how FERC has connected wholesale rates to reliability. There, FERC approved a technology-neutral product definition and allowed market participants to compete to provide that product. Here, DOE calls for a specific attribute – fuel assurance – asserts that the attribute enhances grid "resilience," and proposes to provide cost-of-service compensation to resources that can provide it and that are not being paid through state-regulated retail rates. FERC may have authority to do that, but it will have to fill the factual gaps in the proposal, explain why it is not allowing market participants to compete to provide fuel assurance attributes, and explicitly connect resilience to just and reasonable wholesale rates. Even if FERC does that, its approval of DOE's proposal would attacked as "unduly discriminatory" for singling out fuels and plant ownership status.

Discussion

What does resilience mean?

Definition. There have been extensive discussions of how "resilience" relates to the power sector. As examples, NARUC published a study in 2013; DOE has a series of papers from 2016; and the National Academy of Sciences convened experts for two years and published a book on the topic.

Resilience is a characteristic of the grid as a system, not an individual generating unit. It is about being able to recover from extreme or unanticipated events. Resilience attributes include quantifiable attributes such as fuel diversity and ramping capabilities, but resilience is broader than generation.

Resilience Market. If FERC is going to require RTOs to procure resilience through a market, RTOs need to be able to measure resilience and justify how individual attributes contribute to systemwide resilience. Capacity markets were designed to achieve a NERC standard for resource adequacy. What measurement of resilience should markets achieve?

To facilitate a market-based solution, resilience attributes should be technology-neutral. Resources would then compete to provide those attributes. But a market-based solution may be implausible because improving resilience may require very specific solutions. For example, a Northeastern utility determined a single compressor station was the weak link in its system and that its failure would trigger widespread outages. Its "resilience" solution was to invest in that asset and develop contingencies. Is there a market design that would find that precise solution? Is a region the correct unit of analysis? Or, to be effective, must a regional approach be combined with utility-specific resilience initiatives?

If the RTOs are tasked with addressing resilience, the result is likely to raise consumer costs. When RTOs tackle a new issue, it leads to a new charge.

Regional Differences. Each region faces a distinct set of risks, i.e., the Gulf Coast has a greater risk of severe hurricanes than New England, but New England is at the end of the natural gas pipeline system while the Gulf Coast is an exporting region. It is therefore unlikely that there will be a uniform national approach to enhancing resilience. There may be a single definition of resilience, but each region will need a unique assortment of resilience attributes to achieve the requisite level of systemwide resilience.

Defining resilience is proving to be difficult for am RTO. Participants in PJM's Resilience Roadmap have been struggling with identifying resilience metrics.

Fuel Diversity. Is fuel diversity an attribute that the market should procure, or is it a consequence of other attributes that the system ought to have? Regional grids generally have diverse fuel mixes today. Retiring coal often contributes to diversity, while retiring nukes does not.

What Can FERC Do?

Define It. FERC's first step should be to define what resilience means. NERC definitions are a good model.

Influence. Most power outages are due to the distribution system, but the FPA denies FERC jurisdiction over "facilities used in local distribution." Could FERC nonetheless influence state-level efforts?

Opportunities. FERC has jurisdiction over interstate natural gas pipelines. Given the electric sector's reliance on natural gas, should FERC be more active in requiring coordination between the two industries?

Reliability Authority. In 2005, Congress added section 215 to the FPA, which provides FERC with jurisdiction over NERC reliability standards. Overlap between resilience and reliability could invite debate about whether a particular "resilience" initiative falls under section 215 and must be addressed by NERC. It might be efficient to simply task NERC with addressing resilience to avoid getting bogged down in debates about the line between reliability and resilience.

Do Nothing. Market trends are leading to a more resilient system. We are likely to see increasing penetration of renewable energy generators, distributed energy resources, and demand response – all of which can contribute to resilience. DOE portrays the rising market share of natural gas as a threat, but that's not necessarily the case. Many natural gas generators can ramp quickly, for example, and could be an asset during an emergency.

Thread the Needle. Any final rule that values baseload (as DOE has requested), will need to 1) avoid undermining competitive power markets; 2) be consistent with FERC's authority under the FPA; and 3) include some metric for valuing resilience or fuel diversity. DOE's proposal misses the mark on all three.

Session 2: Maintaining the Status Quo between FERC Regulation of Wholesale Markets and State Clean Energy Programs

Discussant 1: State policies have always affected power prices. Under the vertically integrated model, the utility internalized the costs of relevant state policies and passed them on to consumers. Industry restructuring removed power generation from traditional utility regulation, leading states to enact new policies that affect the generation mix. States will continue to enact such policies. Tensions between FERC-regulated markets and state policies are unavoidable because governors, legislators, and regulators will inevitably focus on their states, and not on regional markets.

Discussant 2: Courts will strike down New York and Illinois Zero Emission Credit (ZEC) policies that benefit in-state nuclear plants. The legal problem is that the states are using FERC-jurisdictional wholesale rates as inputs into the ZEC price formula. A state may not define a policy in terms of outcomes in the wholesale market. States have authority to preserve power plants within their borders and those policies may permissibly affect wholesale rates. But a state may not so directly define outcomes in a FERC-regulated market as New York and Illinois have done here.

Discussion

Jurisdictional Boundaries

Bright or Blurry Line? Reading the Supreme Court's 2016 decision in *Hughes* narrowly leads to a bright line – a state may not condition a state subsidy on a resource's participation in a FERC-regulated auction. If *Hughes* is read more broadly to forbid states from linking subsidies to wholesale rates, the jurisdictional line between states and FERC will be less clear. State renewable energy credit (REC) programs are already linked, explicitly or implicitly, to wholesale rates. Extending *Hughes* to preempt ZECs would create a cloud of uncertainty over state renewable energy programs.

Non-Power Attributes. Does the FPA preempt or place any restrictions on state-created non-power attributes? For example, must the market for non-power attributes be competitive and non-discriminatory? In *Klee*, the Second Circuit found it "significant" for a dormant Commerce Clause claim that Connecticut's regional deliverability requirement for RECs makes geographic distinctions based on FERC-approved regional grids. According to the court, "Congress and FERC are better-situated than the courts to supervise and to determine the economic wisdom and the health and safety effects of these geographic boundaries . . . [and] are best suited to decide which products ought to be treated similarly, and which should not."

Whether RECs are distinguishable from ZECs is a key issue in the current litigation. Pro-ZEC parties argue that the two are legally indistinguishable, and a decision striking down ZECs would threaten RECs. One difference, however, is that RECs are not priced by the state in reference to wholesale rates.

Concurrent Jurisdiction. The Supreme Court has stated explicitly that state policies may affect FERC-regulated markets, and FERC orders may likewise affect state-set retail rates. These interactions lead to tension, particularly where state and federal regulators target the same or related activities. It seems unlikely that courts will be able to discern a bright line between state and FERC authorities; nor perhaps should they. States and FERC may benefit from the flexibility, but inevitably the lack of a bright line will invite more litigation.

As a practical matter, it would be a mistake to prevent states from accounting for wholesale market outcomes. This limit would make it more difficult to craft cost-effective policies. Clean energy policies will then be more expensive and less popular.

Market Risk. Is preemption in *Hughes* tied to Maryland's efforts to subvert PJM's results and ignore FERC's orders? Maryland initially tried to work within PJM and FERC processes to obtain the result that it wanted. When those efforts failed, it ordered utilities to sign contracts that displaced PJM rates and completely insulated the new gas plant from market risk. Was it Maryland's defiance of FERC and its guarantee to the plant that preempted its program?

State Priorities

Political Accountability. If the lights go out, consumer rates go up, or plants close, governors and utilities are going to be held responsible. Citizens are not going to complain to their RTOs. States are rightly focused on themselves, not regional markets. This dynamic makes states particularly susceptible to utilities, independent generators, and other interests lobbying for subsidies that benefit in-state resources. Even if the regional market does not need a local plant, state political actors are motivated by different concerns. Local jobs, consumer impacts, environmental effects, and reliability are all more salient to decisionmakers than wholesale market impacts.

RTO Deference to State Policies. The state/federal jurisdictional line is being policed one way, through preemption lawsuits and complaints at FERC about state policies. To what extent should RTOs defer to state policies that provide cost recovery to certain generators? In the Southwest Power Pool (SPP), vertically integrated utilities self-schedule generation and states true-up any wholesale revenue deficiencies with state-regulated retail rates. This state action has similar economic effects as ZECs. PJM filed a brief in federal district court, asserting that Illinois' policy "substantially harm[s]" PJM markets and should be preempted. SPP has defended utilities' practices in its market.

Spillover Effects. State policies that raise rates in one state may reduce rates in others. As examples, states' energy efficiency and demand response programs are funded through in-state retail rates but may reduce wholesale prices. Neighboring states that do not pay for these programs benefit from them. These benefits are often overlooked in multi-state RTO discussions about state policies, where one state does not want to pay for the costs of other states' programs.

Spillover effects have become a topic of concern in the PJM region as recent RTO rule changes appear to be more focused on preserving the status quo for generation (e.g. proposed subsidies for old units, dis-incentivizing adoption of distributed energy resources, and increasing consumer costs). As a result, some state policymakers see a need for new renewable energy and DER policies.

Capacity Markets

State Frustrations. States in ISO-New England and PJM believe that they are paying twice for capacity. They procure what they need to maintain resource adequacy through the market, and support state-selected clean energy resources through out-of-market procurements. These state policies are in part a reaction to the markets not motivating investment in the types of generation that states want.

Vertically Integrated States. PJM is particularly complicated because its members include vertically integrated utilities. To the extent a state with vertically integrated utilities wants certain generation attributes, it can pay its utilities through the state-regulated ratemaking process for those attributes and not run afoul of any jurisdictional lines. In some restructured states, distribution companies and generation are owned by the same utility holding company. States may be able to use distribution rates to subsidize wholesale generation. Ohio tried this but it failed for reasons unrelated to state/FERC jurisdiction.

Session 3: "Re-Regulating" by Returning Resource Adequacy to the States

Discussant 1: There is no political appetite for "re-regulation." States are not going to abandon capacity markets and require utilities to meet resource adequacy obligations. Maine did explore leaving ISO-NE about a decade ago due to high transmission rates. Ultimately, however, it decided to stay in the ISO. Dealing with resource adequacy at the state level would be enormously challenging for state regulators. Even if a state wanted to withdraw, what is the legal mechanism to order a utility to leave the market and pursue resource adequacy by other means?

Discussant 2: Prior to the formation of the ISO-NE capacity market, New England utilities demonstrated resource adequacy by holding "tickets" that represented a quantity of capacity. If a utility held an insufficient amount, it had to pay a deficiency charge. Tickets were worth pennies per kW, but prices spiked when there was a shortage. This construct did not motivate investment in new generation. Ultimately, FERC ordered ISO-NE to develop a capacity market.

If the region were to eliminate the capacity market, it would have to use other means to ensure resource adequacy. Whatever the solution might be, it should not encourage actors to create scarcity crises that provide opportunities for windfalls. Contracting for capacity is a relatively straightforward solution, but who bears the risks? How would utilities prevent the sort of major cost overruns that plagued nuclear projects in the 1970s and 80s? Would consumers be on the hook again? What role does state planning play in this construct, and should RTOs be involved in generation planning?

Discussant 3: California has ambitious clean energy goals and does not have a capacity market. Instead, the California PUC administers utility procurements based on CAISO studies about total capacity, including capacity at particular locations, and flexible capacity needs. This construct does not eliminate jurisdictional tensions. The energy market must account for FERC-jurisdictional power and state-jurisdictional renewable energy credits and carbon allowances. Tracking RECs and allowances products across state lines has already proved legally challenging, and regional expansion of the ISO (if it happens) may exacerbate the difficulties.

Discussion

Death to Capacity Markets. Restructuring happened at a particular moment when there was a reasonable case for RTO-administered capacity constructs. Today, these so-called markets are subsidizing old units, dis-incentivizing adoption of distributed energy resources, and increasing consumer costs. It is time for them to go. Instead, utilities should be responsible for their own resource adequacy. If they fail to plan, energy prices will reflect scarcity and increase. The potential for that outcome should motivate utilities to manage demand and incentivize consumers to invest in efficiency and DERs. In this model, states regulate competitive utility procurements and demand-side management while RTOs perform true monopoly functions, including real-time grid operations and transmission planning.

Does Demand Response Needs Markets? Capacity markets are the best mechanism for developing demand response. State and utility control over resource adequacy does not lead to investment in demand response. In MISO, for example, there is little demand response because the utilities and PUCs have resource adequacy responsibility and are not recognizing its value. Leaving demand response on the supply side of the capacity market is essential for its development. Reforming the capacity market so it is truly a residual market or eliminating it entirely will harm demand response.

Re-Regulation Would Harm Competition. Utilities zealously guard their territories and fiercely oppose new market entrants. The only way to enter the market is to provide the utilities a share of the revenue. Returning resource adequacy responsibility to the states will provide utilities with another source of leverage and control and will stifle competition.

State Regulation Affects Capacity Markets

Re-Regulate Retail? Where there is retail competition, utilities are particularly leery about entering into long-term contracts for supply. Retail marketers profit from volatility and so are also disinclined to enter into long-term contracts. Generation companies claim that long-term contracts are vital for project development, particularly for clean energy resources. Would ending retail competition enable an environment more conducive to long-term contracts, providing an alternative development model to capacity markets?

Utility Incentives. Capacity market requirements in New England are based on peak demand over a twelve-month period. Industrial and other large consumers actively manage their demand to reduce their capacity charges. Utilities have little to no incentive to similarly reduce peak demand and are actually rewarded for building transmission and distribution infrastructure that enables continued growth in peak consumption. When demand response or other distributed energy resources are a more cost-effective solution, utilities will not advocate for it because they can't capture the benefits. Changing utility incentives at the state level could improve the effectiveness of FERC-regulated capacity markets.

There are examples of vertically integrated utilities seriously pursuing demand response. The key is to provide the utility with the correct incentives through the state-regulated ratemaking process.

Integrated Resource Planning. Restructuring did not eliminate planning. To the contrary, restructuring made it worse. Rather than being administered by PUCs, planning is now conducted by lobbyists at the legislature.

Session 4: Integrating Public Policy and Markets

Discussant 1: Several proposals under discussion in the PJM stakeholder process would result in higher capacity market payments to "non-subsidized" resources. A proposed bifurcated capacity market would separately determine the total quantity of cleared resources and price, with the price set based only on resources that do not receive out-of-market subsidies.

Generators complain that low capacity market prices are threatening their viability, and market reforms are necessary to ensure that non-subsidized resources stay online. But the market has far more capacity than it needs, and low prices are not motivating retirements. Does transferring capacity market revenue from "subsidized" resources to non-subsidized resources result in just and reasonable rates? And how should PJM define subsidized resources?

Discussant 2: The Brattle Group recently released a study on a NYISO carbon price that included a cover letter from the state and ISO, demonstrating that there is some political support for an ISO-administered carbon price. The study finds that the consumer impact would be relatively small. While that conclusion may make a carbon price more palatable for stakeholders, there are still implementation challenges. Critically, who sets the carbon price? Because the price will directly affect the state's clean energy policies, New York does not want to cede control of the carbon price to the ISO. There are legal questions about how to achieve this result. Other challenges include addressing leakage and allocating carbon price revenue.

Discussant 3: New England states have various carbon and renewable energy goals or policies, but with the exception of RGGI, they are not reflected in the ISO-NE market. Massachusetts' 2016 energy bill, for example, calls for technology-specific utility procurements of 2,800 MW of capacity, which is sufficient to meet approximately forty percent d of the state's demand. Once implemented, these out-of-market procurements will reduce demand in the ISO-NE markets and might correspondingly reduce prices below a financially sustainable level for resources that rely on market revenues. In 2016, regional stakeholders initiated a dialogue to explore market-based mechanisms to achieve state policies. Although discussions included a carbon price, some states were concerned that a carbon price would not lead to the construction of the resources that states want and would necessarily result in consumers in some states paying for other states' policies.

The Carbon-Linked Incentives to Policy Resources (CLIPR) proposals aims to capture the benefits of carbon pricing while allowing states to participate at whatever level they choose. CLIPR pays low-carbon resources based actual carbon abatement at their specific location on the grid. The location-specific payment should induce development of clean energy resources where they will displace emitting generation. Each state can set utility demand for these clean energy attributes, just as it does for a renewable portfolio standard.

Discussant 4: We should be skeptical of an RTO's ability to implement state clean energy policies. Today's discussions in PJM and ISO-NE about market reforms are primarily aimed at raising revenue for existing, emitting resources. It appears that the RTOs themselves support keeping these old resources online, despite the higher than necessary reserve margins. Why should we have faith in their ability to promote technology-neutral program that are explicitly designed to displace traditional resources?

Discussion

Carbon Price Jurisdiction. How can New York set a carbon price that is implemented by the FERC-jurisdictional ISO? One option is for the PSC to issue an order unifying its state policies around its desired carbon price. To account for the uniform carbon price, the order would modify the state's REC procurements, the ZEC program, and the PSC's valuation of distributed energy resources. The NYISO would then implement that carbon price in its wholesale markets. This structure would allow the state to modify the carbon price in the future, although it might not obligate the NYISO to follow that price.

Clean Energy Attribute Jurisdiction. Would states or FERC have jurisdiction over CLIPR attributes? The proposal, sponsored by a coalition of market participants and the Conservation Law Foundation, envisions that the ISO will play some role in implementing it. This is a pragmatic choice – the ISO has the data needed to compute payments and has the systems in place for creating the market and paying resources. The ISO will need FERC's approval of conforming tariff amendments, but the program itself might be administered by a separate entity with the assistance of the ISO. The governance of this separate entity would need to be hashed out by the participating states. RGGI provides one plausible model.

The attribute itself is similar to a state-jurisdictional REC – it represents environmental benefits and is sold separately from power or capacity. Yet, unlike a REC, the attribute's price is directly tied to wholesale market outcomes. Does that "tether" render it FERC-jurisdictional? Perhaps FERC could assert jurisdiction because the attribute directly affects energy prices, but it may not be obligated to do so. The jurisdictional question might also turn on the precise role played by the ISO.

Endnotes

[1] Notice of Technical Conference, FERC Docket No. AD17-11-000 (Mar. 3, 2017).

[2] Transcript of May 1 Technical Conference, FERC Docket No. AD17-11-000, at 10:24–11:2.

[3] Conn. Dep't of Pub. Util. Control v. FERC, 569 F.3d 477 (D.C. Cir. 2010).

[4] Advanced Energy Mgmt. Alliance v. FERC, 860 F.3d 656 (D.C. Cir. 2017).

[5] On January 8, 2018, FERC rejected DOE's proposal. Order Terminating Rulemaking, 162 FERC ¶ 61,012 (2018).

[6] *See, e.g.*, National Academy of Sciences, Enhancing the Resilience of the Nation's Electricity System (2017); Dep't of Energy, Office of Energy Policy and Systems Analysis, Resilience of the U.S. Electricity System: A Multi-Hazard Perspective (Aug. 2016), https://energy.gov/sites/prod/files/2017/01/f34/Resilience%20of%20the%20U.S.%20Electricity%20System%20A%20Multi-Hazard%20Perspective.pdf; Kristina LaCommare, et al,, Evaluating Proposed Investments in Power System Reliability and Resilience: Preliminary Results from Interviews with Public Utility Commission Staff (Berkeley, CA: Lawrence Berkeley National Laboratory, 2016), https://energy.gov/epsa/downloads/evaluating-proposedinvestments-power-system-reliability-and-resilience-preliminary; M. Finster, et al., Front-Line Resilience Perspectives: The Electric Grid (Lemont, IL: Argonne National Laboratory, November 2016), https://energy.gov/epsa/downloads/front-line-resilienceperspectives-electric-grid; J. Phillips, et al., State Energy Resilience Framework (Lemont, IL: Argonne National Laboratory, Dec. 2016), https://energy.gov/epsa/downloads/state-energy-resilienceframework; Miles Keogh and Christina Cody, NARUC, Resilience in Regulated Utilities (Nov. 2013), https://pubs.naruc.org/pub/536F07E4-2354-D714-5153-7A80198A436D.

[7] Allco Finance Ltd. v. Klee, 861 F.3d 82, 107 (2nd Cir. 2017).

[8] Joe Daniel, Sierra Club, Backdoor Subsidies for Coal in the Southwest Power Pool, https://www.sierraclub.org/sites/www.sierraclub.org/files/Backdoor-Coal-Subsidies.pdf.

[9] Tom Kleckner, RTO Insider, "Report: Costly Coal Undermining SPP Market, Bilking Consumers," (Dec. 12, 2017).

[10] *See* Order Granting Complaint, 155 FERC ¶ 61,101 (2016) (rescinding FirstEnergy's waiver of its affiliate power sales restrictions because non-bypassable charges approved by Ohio regulators to supported the utility's affiliated generation assets "present the 'potential for the inappropriate transfer of benefits from [captive] customers to the shareholders of the franchised public utility.'"