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Issues on the Horizon at the Federal Energy Regulatory Commission

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Review
This policy brief has not undergone a formal review process, but has been reviewed by some experts in the field. It is intended to stimulate discussion and inform debate on emerging issues.

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Summary

Congress created the Federal Energy Regulatory Commission (FERC) as an independent agency to oversee the cross-state transmission of electricity, natural gas, and oil. As innovations and changing consumer preferences shape the energy industry, FERC must grapple with a number of key issues:

- The Trump administration has advocated for payments to coal and nuclear resources that are struggling financially, arguing that resources with “onsite fuel” increase grid resilience. Opponents cite projected costs to customers and potential to crowd out newer technologies that would improve grid flexibility and resilience. FERC is deciding what, if anything, it should do.
- FERC will review rules that could determine the ability for newer technologies and non-emitting resources to compete in the markets. Reforms could reduce oversupply of generation. This could result in higher prices for generators but lower total costs for consumers.
- FERC will decide whether to finalize a proposal to enable Distributed Energy Resources to compete in the wholesale electricity markets.
- FERC is considering changes to the Public Utility Regulatory Policies Act, which could help or hinder renewable energy growth in certain regions.
- FERC is revisiting its pipeline approval policy, after increased opposition to pipeline development. Of nearly 400 pipeline applications filed since FERC’s 1999 policy was enacted, FERC has rejected two.

RESILIENCE AND COAL AND NUCLEAR BAILOUTS

At a Glance:

- The Trump administration has advocated for payments to coal and nuclear resources, many of which are struggling financially, arguing that plants should be compensated for keeping 90 days' worth of fuel onsite.
- FERC denied a Department of Energy proposal for such bailouts but opened a proceeding to evaluate the resilience of the grid.
- Two grid operators have expressed concern about future resilience in the face of increasing reliance on natural gas. Other grid operators and stakeholders oppose compensation for fuel security, and stress the importance of fuel and technology neutrality in determining the resilience and reliability of the grid.
- Bailout advocates argue that onsite fuel security is key to grid resilience. Opponents cite a Brattle Group report suggesting payments to coal and nuclear plants could cost customers tens of billions of dollars a year, and argue the payments may disincentivize new technologies that improve the flexibility and reliability of the grid in the long term.

FERC is actively considering whether it needs to take action to improve the resilience of the bulk power system (and better coordinate with regulators responsible for the resilience of the distribution system). In 2017, the Department of Energy (DOE) conducted a study to address concerns that the rise of natural gas and renewables threatened the resilience of the grid. The report did not find that the changing fuel mix threatens grid resilience or reliability, nor did it recommend fuel security measures for the grid. Nevertheless, DOE took the unprecedented step of submitting a proposal to FERC to compensate otherwise uneconomic coal and nuclear plants for being "fuel secure," defined as keeping 90 days' of fuel onsite.

Trump's nominee to fill the empty FERC seat, Bernard McNamee, was key in formulating the proposal while he was at DOE. Although FERC unanimously rejected the proposal, FERC initiated a new proceeding to evaluate the resilience of the bulk power system. FERC asked for input from grid operators and other stakeholders on the concept of "resilience" and whether FERC action is needed.

In their March 2018 responsive filings, regional grid operators concluded that reliability is not currently at risk from retirement of coal and nuclear plants. However, the Mid-Atlantic (PJM) and New England (ISO-NE) grid operators expressed concern about future resilience in the face of increasing reliance on natural gas plants.

These grid operators are conducting fuel security studies to evaluate these future resilience issues. PJM's fuel security study determined its grid is robust against extremely unlikely contingencies but nevertheless recommended initiating a process to develop market-based compensation for fuel-secure resources. ISO-NE has examined fuel security as well. FERC will decide whether ISO-NE can give Exelon's fossil-fired Mystic Generating Station a cost of service contract for reliability purposes by January 2019, providing a set amount of revenues for Exelon. ISO-NE is proposing to price Mystic into its capacity auction at zero, which some contend would suppress prices.

Other grid operators and stakeholders have opposed compensation for fuel security, stressing the importance of fuel and technology neutrality in determining grid resilience and reliability. Although FERC has not yet taken action on the issue, a leaked memo suggested that DOE might invoke a 1950s wartime law to favor coal and nuclear plants, which McNamee has publicly championed. This plan has been shelved for the time being, but fuel security likely will come up again soon at FERC.

The Brattle Group estimates that forcing utilities to buy power from uneconomic plants would cost U.S. consumers tens of billions of dollars per year. Supporters argue that these bailouts are needed to keep fuel-secure baseload power plants online. Others argue that bailouts would crowd out investments in new technologies that could improve the flexibility and reliability of the grid.

The focus on fuel also ignores problems with transmission and infrastructure, the most common causes of power outages. Additionally, coal and nuclear plants have often failed to perform during natural disasters like hurricanes and the 2014 Polar Vortex. Although they are often able to stay running for long periods, coal and nuclear plants are unable to "black start" or begin running after a complete blackout, unlike flexible sources like renewables and natural gas. In emergency situations, more flexible technologies like microgrids can also isolate grid threats to keep them from affecting other parts of the system. There are concerns that new technologies like energy storage, fast-ramping natural gas plants, micro-grids, new grid-edge technologies, or improved transmission and distribution systems might be underprioritized in approaches too focused on fuel security.

CAPACITY MARKETS

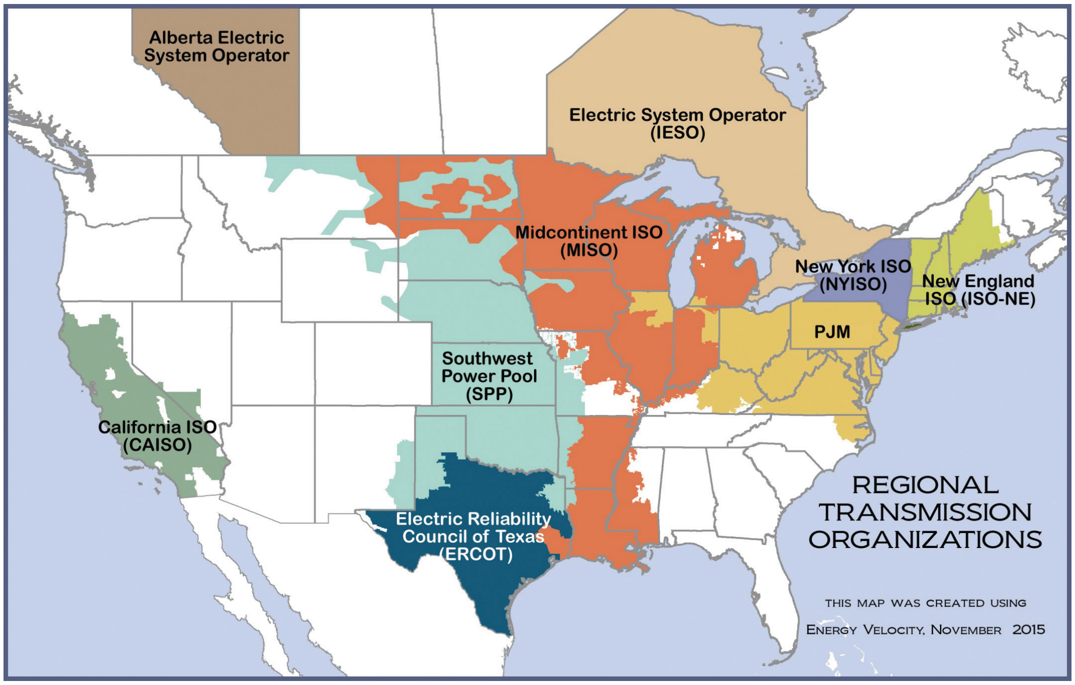
At a Glance:

- In 2019, FERC will review capacity market rules in at least three proceedings. Capacity markets provide for the sale of commitments to supply electric power at a future time. Potential actions could determine the ability for newer technologies and non-emitting resources to compete in the markets. Reforms in these three proceedings could reduce oversupply of generation resources compared to demand in the markets, a key trend underlying "low" market prices. Doing so could result in higher prices for generators but lower total costs for consumers.
- FERC could address structural barriers to market competition, particularly from newer technologies and wind and solar resources. This would make the market more efficient in matching seasonal supply with seasonal demand.
- FERC will approve or request modifications to PJM's proposed changes to its demand curve (predetermined pricing structure) for its capacity market, which is determined by PJM. This would impact how much capacity utilities are required to purchase and would also address the oversupply of capacity that is depressing energy market prices.
- FERC will review PJM's proposed changes to its capacity market treatment of resources that are "subsidized" by public policies (which will be determined by the final rule, and will likely include nuclear and renewables policies).

Background

Issues with mandatory capacity markets continue to be contentious at FERC. Capacity markets are designed to ensure sufficient generation will be available to meet future electricity demand. Where capacity markets are mandatory, utilities and other suppliers serving end-use customers are required to obtain resource commitments to meet their forecasted demand plus a reserve margin. Resource commitments to provide electricity can be purchased in capacity auctions. Seven Independent System Operators (ISOs) or Regional Transmission Organizations (RTOs) operate competitive power markets in the United States; three have mandatory capacity markets: New York-ISO (NYISO), ISO-New England (ISO-NE), and PJM Interconnection (PJM).

Capacity markets should send efficient signals to market participants and investors about what resources will be needed in the months and years ahead to meet electricity demand. However, eligibility rules that favor traditional resources (see, e.g., "Eligibility Requirements" section) can impede market participation of newer technologies. Minimum offer price rules can increase the costs of implementing state policies, such as those supporting zero-emission resources. If state-sponsored renewable and nuclear resources do not clear, or get chosen in the capacity market, utilities in those states will have to procure capacity in the market *and* duplicative state-sponsored capacity unless they are otherwise allowed to count the capacity of these sponsored resources. Both overly restrictive eligibility rules and minimum offer rules can lead to capacity over-procurement, which depressed energy market prices for generators and causes consumers to pay for too much capacity. (Overly conservative requirements for capacity contributes to this; see "Capacity Market Demand Curve Revision" section.)



NYISO, ISO-NE, and PJM cover a large demand footprint, covering roughly 210,667 megawatts (sum of peak demand in each region) (FERC, 2015).

Issues

Eligibility Requirements for Capacity Auctions

Following the 2014 Polar Vortex, which forced a large part of the coal and natural gas fleet offline, PJM imposed harsher penalties for capacity resources failing to perform as committed during emergencies. But PJM also required that all capacity be procured in year-long commitments, which discourages fuel-free, seasonal resources from participating in the capacity market.

The requirement favors annual resources that can burn fuel at all times of the year, such as nuclear, coal, and gas power plants. Renewable resources such as wind and solar energy and demand response (e.g., customer curtailment of air conditioning for compensation) are allowed to aggregate and offer as a single annual resource into the auction. However, this adds transaction costs to capacity bids for these resources. In addition, solar power and cycling of air conditioning for demand response tend to be stronger in the summer when overall demand is higher. Thus, procuring only annual capacity leads to over-procurement in non-summer months.

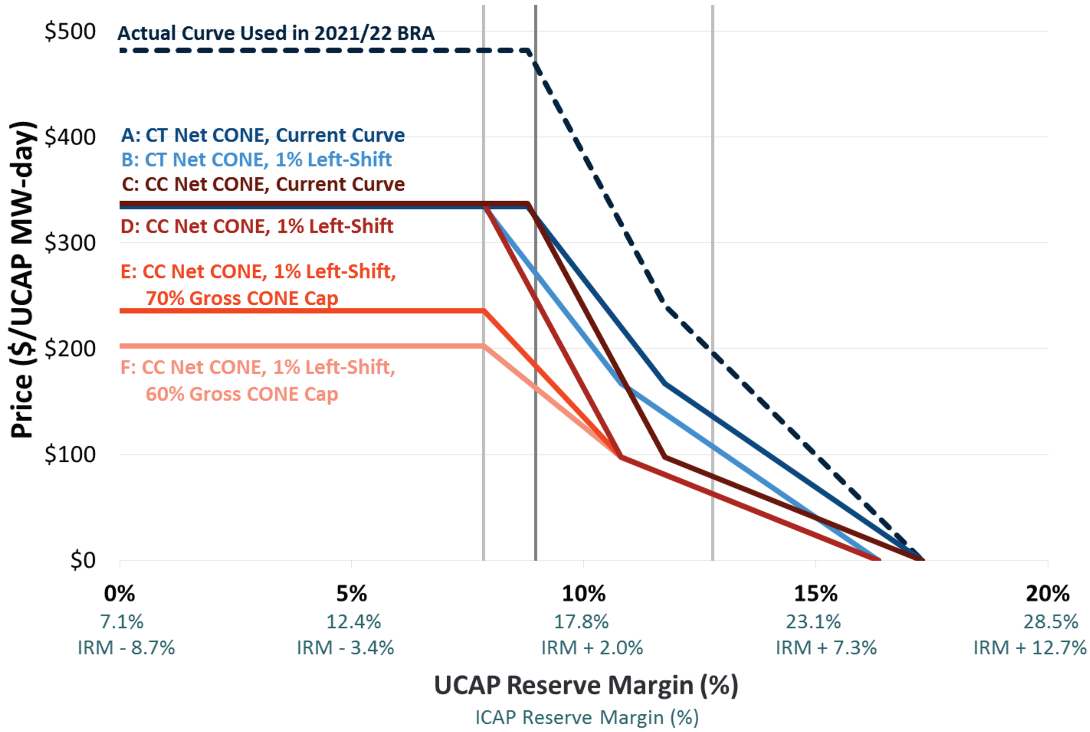
These barriers for fuel- and emissions-free resources can be alleviated by procuring capacity with commitment periods that match the seasonal demand and supply, through seasonal capacity auctions. For example, a two-season auction would take into account different demand and supply needs for the winter and summer and allows generators to bid into the summer, winter or annual auction depending on their resources' production profile. A seasonal auction can ensure reliability through penalties for non-performance, while opening up the market to competition from resources that could satisfy seasonal demand more cost-effectively than annual-only resources. In this way, a seasonal auction would save money for consumers by cutting costly seasonal over-procurement, and allowing more low-cost resources to compete.

Whether PJM should reform its capacity market to allow seasonal auctions is currently pending as a complaint before FERC.

Capacity Market Demand Curve Revision

Most markets have a demand curve that is based on how much a consumer wants to buy at each price point; however, mandatory capacity markets, such as PJM's, have *administratively set* curves. These curves are designed to procure at least a certain amount of capacity under a range of offers from suppliers. Setting the curve too high in terms of prices or volume causes consumers to pay too much and distorts the energy market with too much supply.

PJM's existing demand curve builds in a number of conservative assumptions, resulting in an over-procurement of capacity at consumer expense. PJM filed a revised version of its demand curve currently pending for FERC approval, but it did not adopt some of its expert consultant's key recommendations and the proposed curve will continue to significantly over-procure capacity.



The dotted line represents PJM's existing administratively set demand curve (known as the "VRR Curve"), while the solid lines show its expert consultant's modeled demand curves, all of which would satisfy, and in fact on average surpass, PJM's target reserve margin. Brattle conservatively recommended Curve E. (Brattle, 2018)

Reconciling Markets with Public Policies

In 2019, FERC will decide how certain policy-sponsored resources, such as renewable and nuclear energy, can participate in PJM's capacity market.

Some FERC commissioners are concerned that PJM's current market design unfairly advantages certain resources supported through subsidies. Other Commissioners and commenters argue that essentially all resources benefit from some form of subsidy or preferential treatment and that these subsidies actually pay for attributes, like carbon-free generation, not capacity.

After rejecting proposals from PJM and a group of generators in a June 2018 order, FERC offered a framework for PJM and its stakeholders to develop into a new proposal for its capacity market. The framework, which would carve out subsidized resources from PJM's capacity auctions, includes two basic components: a Minimum Offer Price Rule (MOPR) and a Resource Specific Fixed-Resource Requirement (FRR-RS). Under the MOPR, subsidized resources, such as renewable or nuclear energy would have their bids increased to a "fair" price—making it more difficult for these resources to clear the market and win capacity commitments. This would drive some of these resources out of the market, where state public policies might require their purchase anyway. Because procuring a certain amount of capacity from the market is mandatory, customers would be forced to buy duplicate capacity.

To avoid distorting the market with over-procurement and charging customers twice, the second piece of FERC's proposed framework suggests subsidized resources subject to the MOPR could opt out of the market through the FRR-RS mechanism. This means resources like renewable and nuclear energy could sell directly to load-serving entities, electric utilities that serve retail consumers, rather than participating in the market. The FRR-RS gives buyers of subsidized resources, such as electric utilities, a reduced obligation to purchase the corresponding megawatts of capacity from the market.

In October 2018, PJM submitted its initial testimony to FERC in response to the FERC order. The new proposal expands on the MOPR and adopts what it calls a resource carve-out (RCO), which is essentially another name for FRR-RS. But PJM's latest proposal also introduces a mechanism to inflate the capacity prices after MOPR and RCO have been applied. PJM's rationale is that removing subsidized supply and their corresponding customer demand from the market "suppresses" prices, even though that is the price determined from the intersection of the supply and demand curves. Thus, PJM suggests keeping the amount of customer demand no longer purchased from the market in the auction for the sole purpose of setting the auction price (which will result in a higher price).

Additionally, PJM proposes to have consumers pay resources that didn't earn a capacity commitment because they were out-competed by the other "unsubsidized" resources. This "crowd-out" effect occurs when the customers buying subsidized resources are taken out of the market and demand is reduced. Because PJM's newest proposed adjustments produce prices that are higher than what basic economic principles would yield and pay resources that are not committed in the capacity market, this design may undermine market efficiency. Paying too high a price for capacity would attract unneeded supply, and that would continue the cycle of capacity oversupply that brings prices back down.

ROLE OF INDEPENDENT MARKET MONITOR

At a Glance:

- RTO and ISO Independent Market Monitors (IMMs) seek to ensure all market actors are operating fairly, analyzes market performance, and identifies market distortions and opportunities for market improvement.
- IMMs have disagreed with grid operators in FERC proceedings, and grid operators have contested IMM ability to participate in FERC and court proceedings. The participation role of IMMs is unsettled.

Grid operators have challenged the role of or taken actions that compromise the independence of market monitors. In May 2017, PJM asked FERC to dismiss a complaint filed by the Midcontinent ISO's IMM, Potomac Economics (Potomac is also the IMM for ISO-NE, NYISO, and ERCOT). PJM argued that an IMM cannot file a Section 206 complaint at FERC—a provision of the Federal Power Act which allows certain entities to file concerns regarding rates, terms, and conditions. In June 2018, PJM attempted to extend a recent court decision finding that an IMM did not have standing to intervene in a federal appeals court proceeding as evidence that IMMs cannot file complaints at FERC. PJM's motion to dismiss is still pending. Most recently, PJM's IMM (Monitoring Analytics) sought to intervene in a rate case before a FERC administrative law judge. After some debate, FERC determined that an Article III court's denial of standing for the IMM did not mandate the same result in FERC's administrative proceedings.

To ensure effective markets and protect consumers, market monitors must maintain their ability to engage in administrative proceedings and independence from any potential political or business influence. FERC in its ongoing decisions will either ensure or erode the role of independent market monitors.

DEMAND-SIDE AND DISTRIBUTED ENERGY RESOURCES, STORAGE, AND NON-TRANSMISSION ALTERNATIVES

At a Glance:

- In 2018, FERC finalized a major rule enabling electricity storage to more robustly participate in wholesale electricity markets. However, implementation of the rule will depend on FERC approval of RTO/ISO compliance filings.
- FERC has not yet finalized its proposal to enable Distributed Energy Resources (DERs) to compete in the wholesale electricity markets. A similar rule already exists for demand response to participate in FERC-regulated markets.
- DERs like small-scale solar, batteries, back-up generators, and electric vehicles (EVs) are small, dispersed, and regulated by states and local authorities. FERC will have to strike a balance in reducing wholesale market barriers to these resources while ensuring that state regulators can exercise their traditional power over resource choice and distribution system safety issues.
- DER resources are rapidly expanding around the country; greater visibility of DERs for wholesale grid operators gives them an important tool for maintaining reliability and there are other opportunities to leverage these resources in aggregate for wholesale grid services.
- FERC's policy statement on energy storage receiving cost recovery as transmission services has yet to be tested. Proceedings at two grid operators may lead to filings that FERC will have to approve.

Enabling distributed energy resources (DERs), such as small-scale solar and batteries to participate in wholesale electricity markets is another issue on FERC's near-term agenda. These resources are small, dispersed, connected to the distribution system and typically regulated by state utility commissions. DERs' potential role on the wholesale FERC-jurisdiction market is still unknown. However, DER penetration has increased extensively in many regions of the US, due to new technology advances, state policies, and consumer interest. Allowing these resources to trade on the wholesale market could provide consumer savings through more robust market competition, grid flexibility benefits, as well as revenue streams for residential and commercial owners of solar systems, batteries, and electric vehicles.

FERC finalized Order No. 841 in February 2018, which would require grid operators to eliminate market barriers for energy storage participation by revising market participation rules to account for the physical and operational characteristics of storage resources. That is, storage resources can function like generators by *releasing* electricity as well as like a consumer by *absorbing* electricity. The effectiveness of this rule will depend on the grid operators' compliance filings, which FERC will have to approve. FERC's recent Order No. 845, which reforms the generator interconnection process may also provide opportunities for storage resources. As with Order No. 841, FERC actions on requests for rehearing and compliance filings will shape the ability for storage to interconnect and participate.

FERC proposed a set of market reforms related to DERs at the same time it proposed reforms for storage. However, it has not finalized a proposal enabling DER participation in the markets. That proposed rule would have addressed whether DERs can aggregate to participate in wholesale markets, and would have given regional grid operators a structure for developing rules for DERs in their regions. To gather more information on the issue, FERC called a technical conference in April 2018 on specific challenges to DER participation in wholesale markets raised in stakeholder comments. Although FERC announced that the conference generated sufficient information on DERs, FERC has yet to take further action on the topic.

Also, in February 2018, FERC staff released a report weighing the benefits and challenges of integrating DERs onto the bulk power system. DERs provide power close to the consumer, and therefore reduce grid losses and system peak load. They make the grid more resilient because they can maintain or quickly restore power in emergency situations. However, the report noted some complications of integrating DERs that would occur at higher penetration levels. For example, the integration process requires additional coordination between grid operators and utilities. It also reopens a debate on where to draw the line between what FERC and states should regulate.

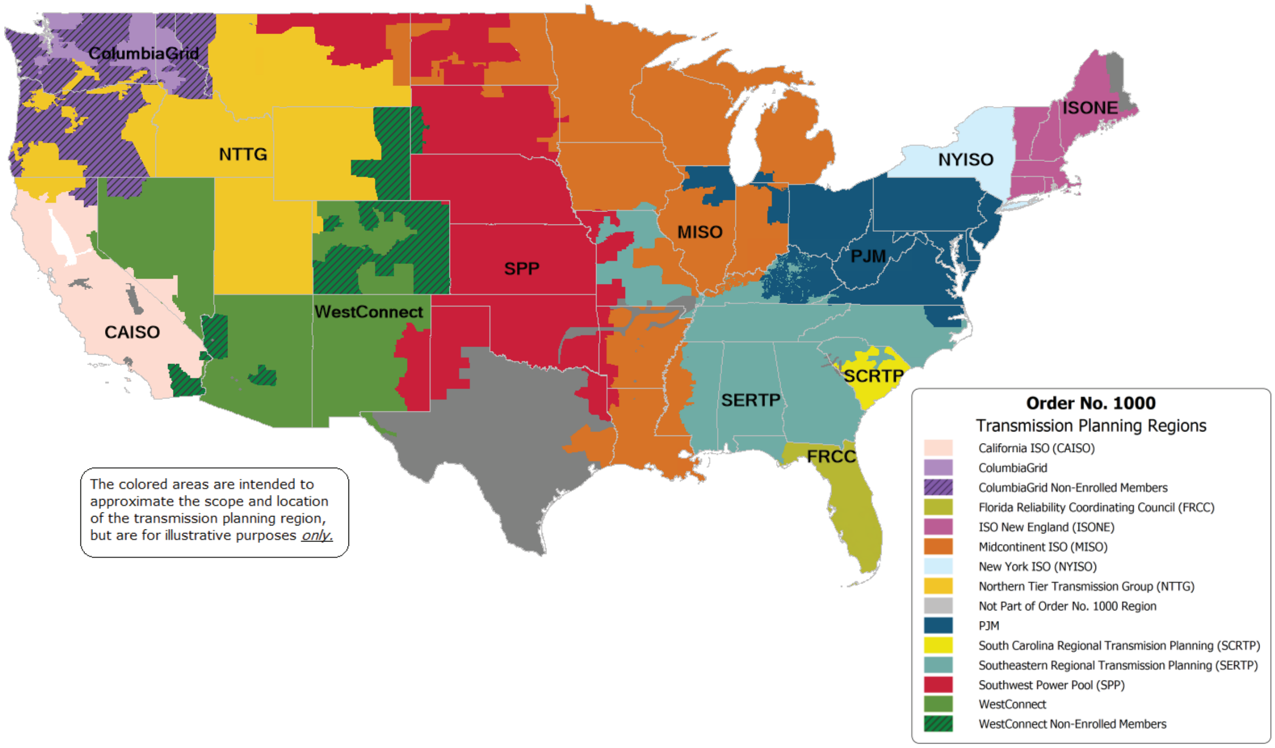
As FERC mulls over these issues, rapid growth of these technologies continues. Between 2018 and 2020, U.S. distributed solar installations are expected to grow from 2 million to almost 3.8 million. The residential storage market has reached record highs, and is expected to grow from 74 MWh in 2018 to 11,700 MWh in 2023. EVs, which can act like DERs, are predicted to grow from 1% of car sales to over 50% by 2035. States like California and New York already have pilot projects in place that allow DERs to participate in the wholesale market. A FERC DER ruling would provide guidance for regions seeing rapidly increasing penetration of solar, electric vehicles, and other DERs.

Lastly, FERC's policy statement on how storage resources can recover costs for providing both transmission services and market-based generation-related services remains untested. The issue is that storage resources can provide multiple services at once, and there's currently no market-based way to compensate them for providing transmission services. Enabling compensation for transmission services in this way opens the door for other non-transmission alternatives, such as generation and demand response. Initiatives at the California Independent System Operator and the Midcontinent Independent System Operator may lead to filings that FERC will have to approve.

TRANSMISSION PLANNING AND ORDER NO. 1000

At a Glance:

- Among other things, FERC Order No. 1000 requires regional planners to consider transmission needs resulting from public policies, such as transporting state-supported renewable energy generation to population centers, and neighboring regions must coordinate on potential interregional transmission projects.
- FERC may revisit this and other parts of FERC Order No. 1000, as planners have failed to produce plans for high voltage interregional transmission under the order.
- FERC will also likely consider return on equity and transmission incentives.



The above map shows the transmission planning regions created by Order No. 1000 (FERC, 2018).

In 2019, FERC may also take up or rule on transmission planning and incentives reforms, which can impact incentives for infrastructure build and upgrades, customer rates, renewable integration, and grid resilience.

FERC's Order No. 1000 requires transparent regional transmission planning and interregional coordination.

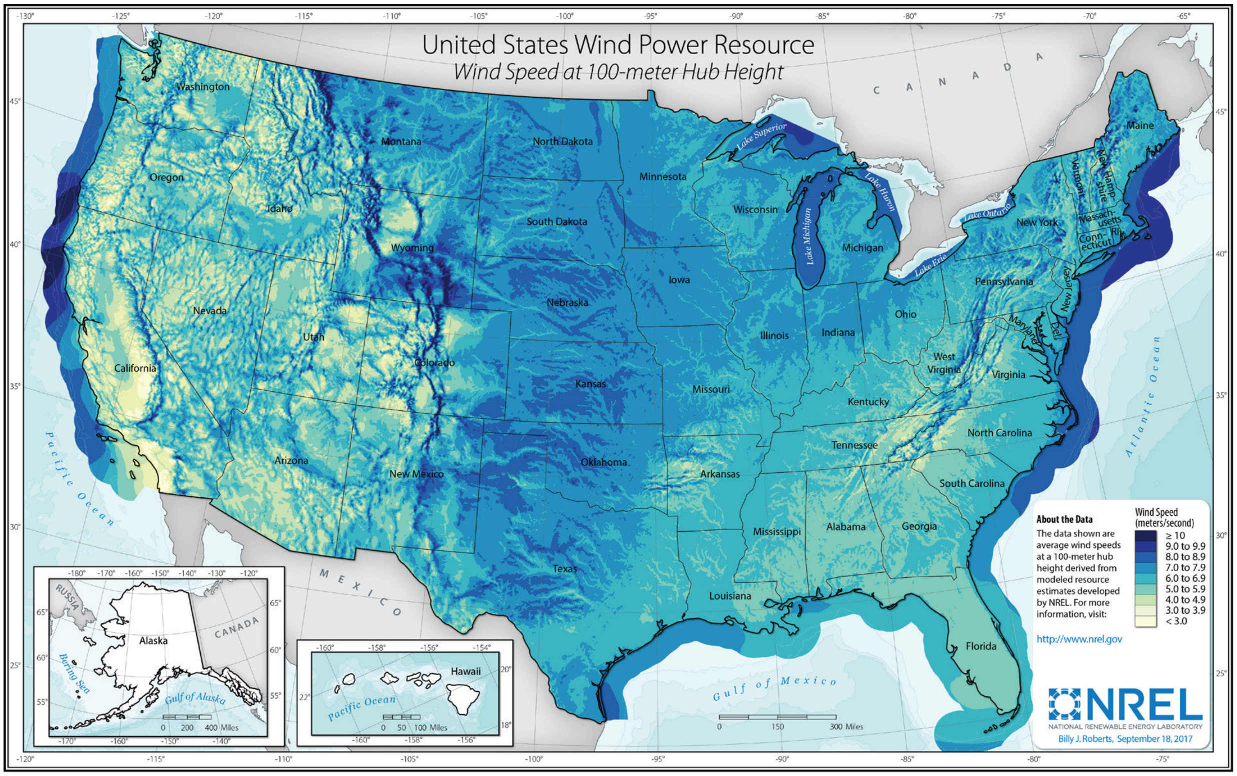
The 2011 order allows independent transmission developers to compete with traditional utilities, with the goal of promoting cost-effective projects. It also requires regional planners to consider transmission needs arising from federal and state public policies. For example, wind energy generation in the Midwest and Great Plains needs sufficient transmission infrastructure to transport that power to populated areas. Similar outlets would also facilitate utility-scale solar in the South.

Transmission needs driven by public policies seeking to further develop such resources, for example, would be considered under Order 1000 planning.

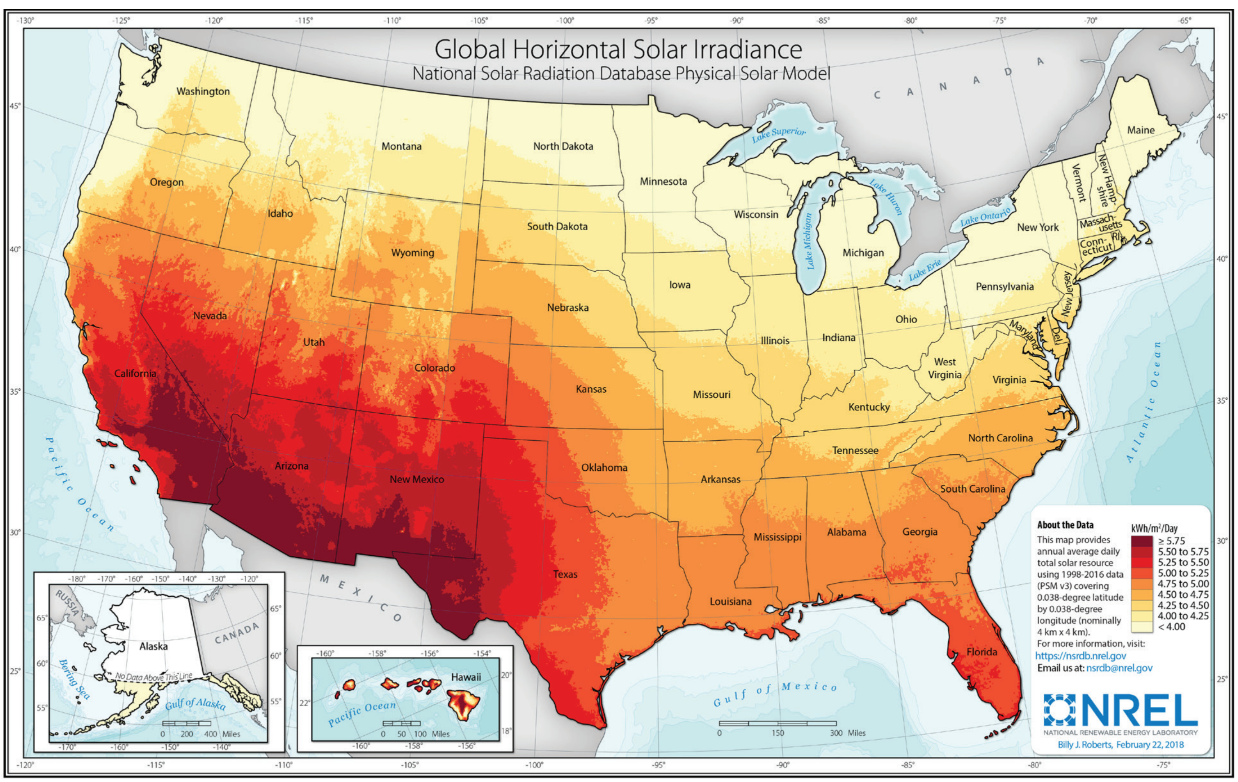
FERC has been pressed to revisit the order, on a number of grounds. The Order 1000 process has not yet produced plans for high voltage interregional transmission projects. Other competitive transmission projects getting through the regional process have been somewhat limited, while consumer costs from projects that don't require Order 1000 review have ballooned. Critics point to contention over how costs are allocated and the resulting litigation, incomplete and regionally disparate accounting of transmission benefits that undervalue project proposals, and the lack of interregional *planning* requirements (the order requires only interregional *coordination*). All together, these failures can result in underinvestment of transmission while diverting customer funding to other types of projects that do not require as much process and transparency.

Return on equity and transmission incentives are also live issues at FERC. FERC recently made changes to the methodology for determining transmission owners' return on equity (ROE) rates that could give FERC more discretion to dismiss complaints that ROEs are not "just and reasonable," potentially resulting in higher electric rates.

Transmission owners may also receive ROE adders to incentivize certain types of investments. Incentives, properly designed, can help alleviate congestion, improve access to renewables, and improve the efficiency of the system. ROE adders are traditionally available only to companies that exclusively operate transmission as they can more nimbly respond to market signals than combined utility-transmission companies. FERC will continue to evaluate approval of ROE adders for independent transmission companies and those affiliated with traditional utilities.



NREL's map indicates available wind resource at a height of 100 meters across the country. Wind resources tend to be concentrated in the Great Plains, on mountain peaks, and offshore (NREL, 2017).



NREL's map of solar irradiance averages the daily solar resource from 1998-2016 in the United States. Solar resources tend to be concentrated in the Southwest (NREL, 2016).

PURPA REFORM

At a Glance:

- FERC is considering changes to the 1978 Public Utility Regulatory Policies Act. The law requires utilities to buy from qualifying facilities, which include cogeneration and certain renewable facilities, if the price is at or below the utilities' cost of generating their own power.
- In many states, rapid renewables growth can be attributed to the law. However, some utilities have lobbied to weaken the law's effects.
- Renewable energy advocates say PURPA remains critical to renewable energy growth in some regions, but that many states have not implemented PURPA properly.
- FERC's ruling on this issue may provide clarity on a contentious issue.

FERC is considering changes to its regulations under the Public Utility Regulatory Policies Act (PURPA), a 1978 law responsible for the rapid deployment of solar and other renewable technologies in many states. PURPA requires utilities to buy power from cogeneration facilities or small renewable generators if the cost is below what the utility would pay to generate its own power. Renewable qualifying facilities (QFs) include hydro, wind, solar, biomass, waste, and geothermal sources. As the cost of renewable resources has fallen rapidly, the law has enabled smaller renewable facilities to provide significant amounts of power in many states, including those that do not have renewable portfolio standards like Georgia, Idaho, and South Carolina.

Utilities have pushed against PURPA requirements, and many have lobbied state utility commissions to loosen requirements. Utility commissions have done so primarily by reducing the minimum size limit and length of standard contracts and by making it more difficult for a QF to obtain a legally enforceable obligation against the utility. Opponents of PURPA point to the utility's lack of control in the planning process and an inability to effectively control the dispatch of these resources. PURPA requirements have recently been weakened in Montana and Idaho, despite strong renewable resource potential in those states. North Carolina reduced PURPA requirements and effectively replaced the law with a new competitive procurement process for renewable energy that allows the monopoly utility to compete with independent renewable energy companies to provide that renewable energy.

Michigan recently strengthened PURPA regulations, setting new "avoided capacity rates" for renewable plants. Renewable energy advocates say PURPA remains critical to the growth of these resources in a few regions, but that many states have not implemented PURPA in accordance with the law, hobbling project development. They would like FERC to focus its review on states with little PURPA development to ensure they are implementing the law properly.

In May 2018, FERC reopened its review of PURPA after a lull following a 2016 technical conference on the matter. The National Association of Regulatory Utility Commissioners submitted a white paper arguing that utilities should be allowed to exempt themselves from PURPA requirements. However, proponents of the law argue that PURPA is necessary for the continued growth of renewables, particularly in states without renewable energy policies in place. Changes to the law could influence the rapid rate of solar and wind adoption in states across the country.

Questions have also been raised about whether energy storage co-located with renewable energy should be considered a single, integrated QF for purposes of calculating total megawatt size under PURPA. Montana-based utility Northwestern Energy has petitioned FERC to revoke QF status for four 80 megawatt (MW) wind facilities, each paired with batteries of significant size. Because renewable QFs are capped at 80 MW, how FERC responds may impact the eligibility of similar technologies deployed in the future. Some have opined that such a critical issue may be more appropriate for the general PURPA rulemaking underway.

GAS PIPELINE POLICY

At a Glance:

- FERC is revisiting its pipeline approval policy, after increased opposition to pipeline development from landowners, local governments, and environmental groups.
- Under its current policy statement, FERC has full jurisdiction to review and approve proposed gas interstate pipelines.
- FERC has come under fire for over-approving pipelines. Of the nearly 400 pipeline applications filed since the 1999 policy was enacted, FERC has rejected two.

Under the Natural Gas Act, FERC reviews the need for and location of the pipeline, the level of investment recovery, and the environmental impacts of the proposed project. Once FERC approves the pipeline project, the developer can acquire land through eminent domain to construct and operate the facility. FERC adopted its current policy statement spelling out how it uses its Natural Gas Act authority to approve natural gas pipelines in 1999. Since then, the natural gas industry has expanded rapidly, and natural gas has become one of the country's primary energy sources for electricity.

As the industry has expanded, landowners, local governments, and environmental groups have increasingly opposed pipeline development. In May 2018, the Department of Energy's Inspector General released a report directing FERC to be more transparent in its pipeline approval process, and reporting substantial problems with the process including lack of controls for tracking and addressing the comments of stakeholders.

To address concerns about the relevance of the 1999 policy in a changing energy sector, FERC announced in April 2018 that it would review it. This review is still under consideration.

FERC has been criticized by landowners, industry, and environmental groups for over-approving pipelines. Of the nearly 400 pipeline applications filed since the 1999 policy was enacted, FERC has rejected two. In particular, the 1999 policy, as implemented by FERC, assumes there is a "public need" for the pipeline if the pipeline developer has a contract from a company wishing to ship gas over the proposed pipeline. The contracting company can be (and is often) an affiliate of the pipeline owning company applying for FERC approval.

The Analysis Group reports that the total amount of pipeline capacity approved since 1999 is 180 billion cubic feet per day. This is twice as much as the amount Americans consume in winter months (about 90 billion cubic feet per day), and much more than the all-time peak of 137 billion cubic feet per day consumed during the 2014 polar vortex.

The costs of building new pipelines are passed onto the consumer, even when they are in fact, unnecessary. Cost competitive renewable energy alternatives have increasingly become part of this discussion. According to a report from the Rocky Mountain Institute, there is a significant risk that natural gas pipelines could become stranded assets due to drops in demand resulting from cost-viable alternatives. Many stakeholders will look to FERC to develop a policy that aligns with new market realities.

CONCLUSION

There are significant questions in need of answers from FERC, which will shape how we update the transmission grid to reflect a changing resource mix and consumer demand. FERC has historically operated in a bipartisan manner, aiming to ensure fair and open markets, resource-neutral rules, and an appropriate level of infrastructure investment. A new commissioner at FERC could have an important impact on a number of issues and the ability to find common ground with the other commissioners will be key.

Acknowledgments

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Nicholas Institute for Environmental Policy Solutions

The Nicholas Institute for Environmental Policy Solutions at Duke University is a nonpartisan institute founded in 2005 to help decision makers in government, the private sector, and the nonprofit community address critical environmental challenges. The Nicholas Institute responds to the demand for high-quality and timely data and acts as an "honest broker" in policy debates by convening and fostering open, ongoing dialogue between stakeholders on all sides of the issues and providing policy-relevant analysis based on academic research. The Nicholas Institute's leadership and staff leverage the broad expertise of Duke University as well as public and private partners worldwide. Since its inception, the Nicholas Institute has earned a distinguished reputation for its innovative approach to developing multilateral, nonpartisan, and economically viable solutions to pressing environmental challenges.

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