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Secretary Perry's Grid Resiliency Pricing Rule:
On Market Interventions and Minimizing the Damage

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With his September 29 order to the US Federal Energy Regulatory Commission (FERC) to put in place cost-of-service mechanisms (regulatory arrangements that base revenues on costs rather than market forces) for power plants with 90 days of on-site storage, US Secretary of Energy Rick Perry has put FERC and Independent System Operators (ISOs) in a challenging position. The proposed Grid Resiliency Pricing Rule appears to be intended to prevent market-driven retirements of existing coal and nuclear stations, which have faced challenging economics in the face of cheap natural gas and significant new renewables additions. The order gives FERC 60 days to come up with a mandate to ISOs to institute such mechanisms, and the ISOs in turn would have 15 days to submit a compliance filing.[1]

Pushback to the order was immediate.[2] Litigation is inevitable if FERC does not assert its independence either by ignoring the order or instituting appropriate evidentiary proceedings that would ensure due process. Even if the order were to be accepted, the timelines are absurd for an undertaking of this magnitude. Traditional rate cases require submission of reams of evidence regarding costs, operations, and financing; submissions often run to thousands of pages and involve responses by affected stakeholders. The most recent transmission tariff case before FERC, including determining an appropriate cost of capital, took 12 months.[3] Changes to ISO market rules can take up to two years.[4] The negative consequences of the rule for competitive wholesale electricity markets, in which prices are set based on supply and demand dynamics and the marginal (rather than total) cost of the last unit needed, will be exacerbated if it is implemented in haste, particularly given that upward of 40 percent of capacity in some ISOs may be eligible.

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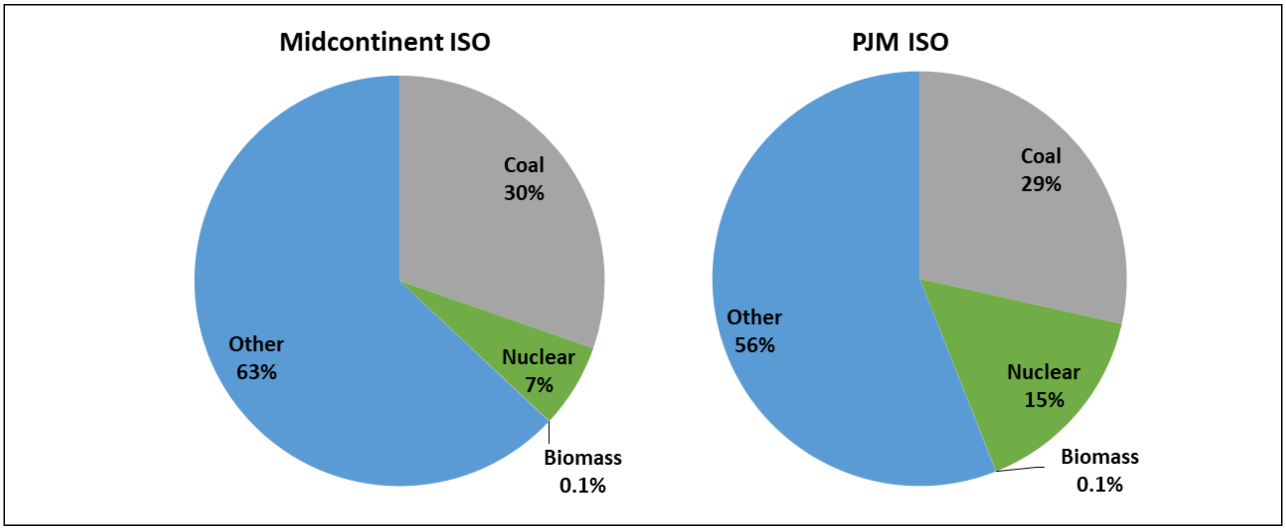
[1] Department of Energy, "Grid Resiliency Pricing Rule," Docket No. RM17-3-000, proposed September 29, 2017 (to be codified at 18 CFR Part 35),
https://energy.gov/downloads/notice-proposed-rulemaking-grid-resiliency-pricing-rule.

[2] Prompt protests were voiced by the American Wind Energy Association, the American Petroleum Institute, and by New York's attorney general, Eric Schneiderman, to name a few. Source: Gardner, Timothy, "U.S. Energy Head Seeks Help for Coal, Nuclear Power Plants," Reuters, September 29, 2017, http://www.reuters.com/article/us-usa-powergrid-perry/u-s-energy-head-seeks-help-for-coal-nuclear-power-plants-idUSKCN1C42G0.

[3] FERC, Docket No. ER16-2320-001, September 20, 2017, https://www.ferc.gov/whats-new/comm-meet/2017/092017/E-23.pdf.

[4] PJM released a proposal for a capacity payment change to FERC on August 20, 2014. The proposal was approved on June 9, 2015, effectively taking more than 10 months for FERC approval. This does not include the lengthy stakeholders process conducted by PJM prior to proposing the rule change. "FERC Approves PJM Capacity Market Reforms over Chairman's Objection." ReedSmith. June 17, 2015.
https://www.reedsmith.com/en/perspectives/2015/06/ferc-approves-pjm-capacity-market-reforms-over-cha.

Figure 1. Installed capacity of coal, nuclear, and biomass plants with no proposed retirement date



Source: Energy Velocity.

The order is a solution in search of a problem, if the identified issue is one of reliability.[5] ISOs already have procedures in place to keep plants that are needed in service. There are "reliability-must run contracts" that allow ISOs to compensate plants to continue operating in the face of insufficient market revenues until such time as the plant is no longer needed to maintain reliability. ISO-New England established procedures to allow plants to stockpile backup fuel and be reimbursed for it to avoid winter outages. More generally, those ISOs with capacity markets have been continually tweaking their market rules to strike the appropriate balance between economic retirement and reliability. The challenge facing competitive power markets today is not the retirement of inflexible baseload plants. Instead, it is determining how to retain and encourage flexible quick-start generation that can serve as backup to intermittent generation.

It is unclear what reliability challenge is met with Secretary Perry's rule focused on 90 days of fuel storage.[6] Recent natural disasters suggest that both nuclear and coal plants are ill suited to provide system resiliency. Nuclear plant protocols require them to begin shutdown procedures as soon as significant storm activity is imminent. During Hurricane Harvey coal stockpiles became sodden and useless; those power plants so affected that could switch from coal to natural gas did so.[7]

Transmission and grid resilience are another critical issue when assessing how quickly power can be restored after disruptions. Large central power stations require transmission to reach customers. Maintaining an

[5] Even if the ostensible claim that the rule is targeted at reliability issues is cover for retaining employment in coal mining, implementation of the order would likely result in little additional production using coal; the eligible stations would be dispatched at approximately the same levels, and owners would simply receive additional payments to cover fixed costs. Little additional coal is likely to be burned.

[6] For example, Singapore, an island nation with limited interconnections (and thus in greater need of backup), requires only 30 days of on-site fuel reserves, with access to an additional 30 days off-site. Energy Market Authority, "Review of the Long Run Marginal Cost Parameters for Setting the Vesting Contract Price for 2017 and 2018," September 28, 2016, https://www.ema.gov.sg/cmsmedia/Consultations/Electricity/Review%20of%20LRMC%20parameters%20for%20Vesting%20Contract%20Price%202017%20-%202018/Final%20Determination/Final%20Determination%20Paper%20-%20Review%20of%20Vesting%20Parameters%20for%202017-2018.pdf.

[7] Mark Watson, "Harvey's Rain Caused Coal-to-Gas Switching: NRG Energy," S&P Global Platts, September 27, 2017, https://www.platts.com/latest-news/electric-power/houston/harveys-rain-caused-coal-to-gas-switching-nrg-21081527. Some coal stations faced similar challenges during the Polar Vortex, when coal piles were frozen.

otherwise uneconomic power plant in service, as required by Grid Resiliency Pricing Rule, when customers cannot receive power due to downed transmission lines defeats the purpose.[8] The move toward distributed solutions means that Secretary Perry's order would require customers to subsidize unneeded plants with little to no impact on reliability or resiliency.

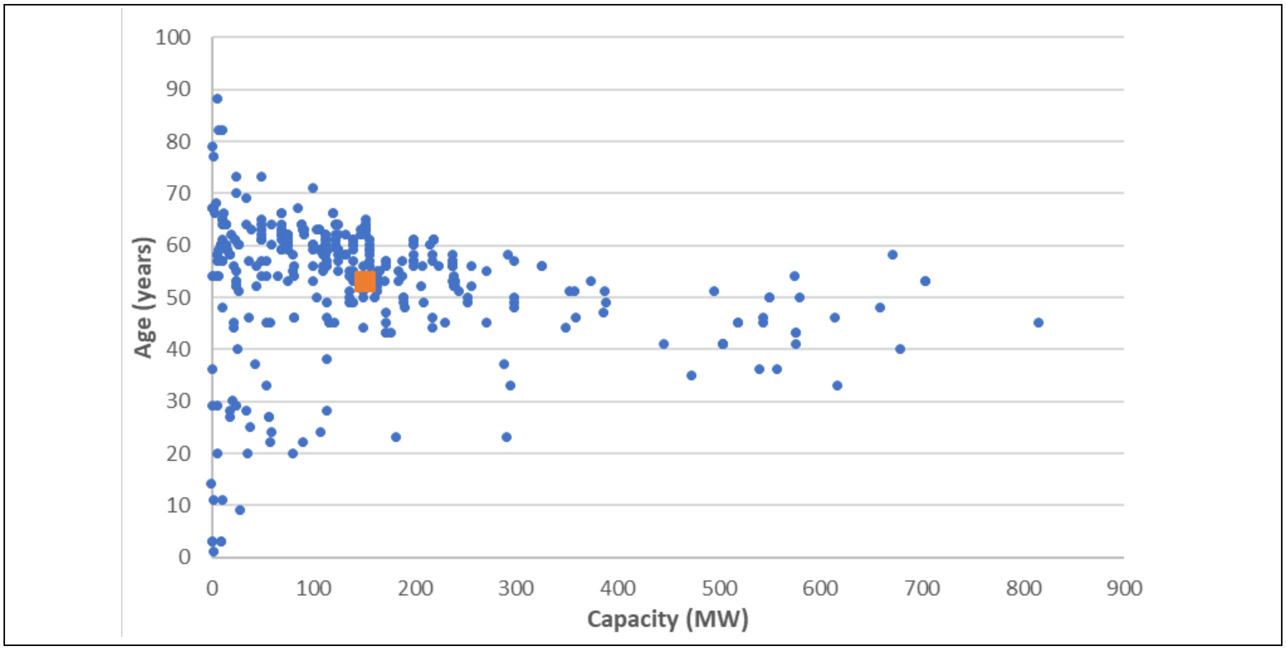
PICKING WINNERS, STATES RIGHTS, AND HIGHER COSTS

The order runs contrary to several cherished Republican ideals. It adds regulation to a functioning competitive market and effectively picks winners in the power sector rather than relying on market forces. (One attribute of a functioning market is that obsolete technologies are replaced by new ones, as has been the case in the United States, with natural gas displacing coal.) The order also interferes with states' rights, especially as many states are actively seeking to move away from coal and nuclear. Finally, it will unarguably increase costs to consumers. Retirements to date have largely been older, smaller coal plants and single unit nuclear stations—the least efficient of the fleet. As Figure 2 shows, the average age of the retired coal plants during the period from 2012 to 2017 was over 50 years, and the average size was approximately 150 megawatts (MW). By definition, those plants seeking aid will be those that are receiving insufficient revenues from a combination of energy, capacity, ancillary services, and state support mechanisms.[9] The additional costs of the support contracts will be passed on to consumers. Ironically, because ERCOT, the ISO that serves part of Texas, is not FERC jurisdictional, the order would not apply in Secretary Perry's home state.

[8] Puerto Rico's electricity system, built around central power stations, proved particularly vulnerable to Hurricane Maria.

[9] New York and Illinois have established state-level programs to provide incremental support to existing nuclear stations. Specifically, New York's Clean Energy Standard was adopted on August 1, 2016, taking a total of seven months for the order to be considered. Michael Kuser, "New York ZEC Suit Dismissed," RTO Insider, July 25, 2017. https://www.rtoinsider.com/new-york-zero-emission-credit-zec-46648/; Reuters Staff, "NY Regulators Approve Clean Energy Standard with Nuclear Subsidies," Reuters, August 1, 2016, https://www.reuters.com/article/us-new-york-nuclear/n-y-regulators-approve-clean-energy-standard-with-nuclear-subsidies-idUSKCN10C2Z6.

Figure 2. Coal plant retirements from 2012–2017



Note: 359 coal plants retired from 2012–2017. The average age of these plants was 53.1 years, and their average capacity was 150.8 MW, as shown with the orange marker. Source: London Economics International LLC, using data sourced from Energy Velocity.

LIMITING THE DISTORTIONS

If, notwithstanding these flaws, the order proposed by Secretary Perry is put into effect, there are several steps ISOs can take to reduce its distortionary impact:

Ensure technology neutrality. The resulting arrangements should be open to all resource types that can demonstrate ability to operate reliably for 90 days. Biomass is an obvious additional resource that could qualify, and natural gas plants with oil backup would likely be the most cost effective. It is possible that intermittent resources could be paired with various storage and fossil backup systems on-site to meet the requirements of the order, as that statistical methods can be used to demonstrate capabilities as well as using statistical methods to demonstrate reliability, for example for run of river hydro stations in rivers which have sufficient year-around flow..

Require the applicant to demonstrate financial hardship. Applicants will need to be prepared to open their books and justify their need for supplemental payments. This will mean providing market revenue projections, any contracted revenues, cost studies, and justifications for any planned capital expenditures. While some aspects of the process could be simplified—for example, ISOs could establish a benchmark expected set of expected future electricity price outcomes that would be uniformly used across all applicants, adjusted for locational differences—it would not be a trivial undertaking. Issues of confidentiality will need to be addressed, as will the need for stakeholder intervention and comment periods. However, in the absence of clear financial need, supplemental revenue contracts should not be awarded.

Utilize a contracts-for-differences (CfD) structure. A CfD structure forces eligible plants to continue to be active participants in ISO markets by requiring eligible plants to first attain what revenue they can from organized markets, with any supplemental payment under the contract only making up the shortfall. The target revenue would be based on the approved total costs for the plant. At the end of each year, the plant would add up its revenues from energy, capacity, and ancillary services. If revenues were below the revenue requirement, the plant would receive a payment from the ISO, while if revenues exceeded the revenue requirement, the plant would pay the surplus back to the ISO. ISOs would recover the supplemental payments through surcharges on load, which would also be entitled to refunds in the event of a surplus.

Use recent transmission cases to establish cost of capital. Setting the cost of capital is normally among the most hotly contested elements of any rate case. Requiring ISOs to establish the cost of capital on a plant by plant basis as the plants apply is administratively burdensome and ultimately impractical. A pragmatic approach would be to take the most recently established transmission capital structure and cost of equity in each ISO and apply that to calculating generation revenue requirements. While a classic academic approach to establishing the cost of capital would normally result in a higher target return for generation than for transmission, in this case the increased perceived risk of generation would be offset by the existence of the contracts themselves. Generators could be directed to file revenue requirements with the established cost of capital, streamlining the process.

Limit arrangements to relatively short durations. The term of the arrangements should be relatively short in term. This would allow at risk plants sufficient time for life extension planning purposes but would not lock in the current supply mix should technologies continue to advance and national policy priorities evolve again.

It is important to note that while the above measures would reduce the negative impact of Secretary Perry's proposed rule, it would still be extremely disruptive and add significant unnecessary cost.

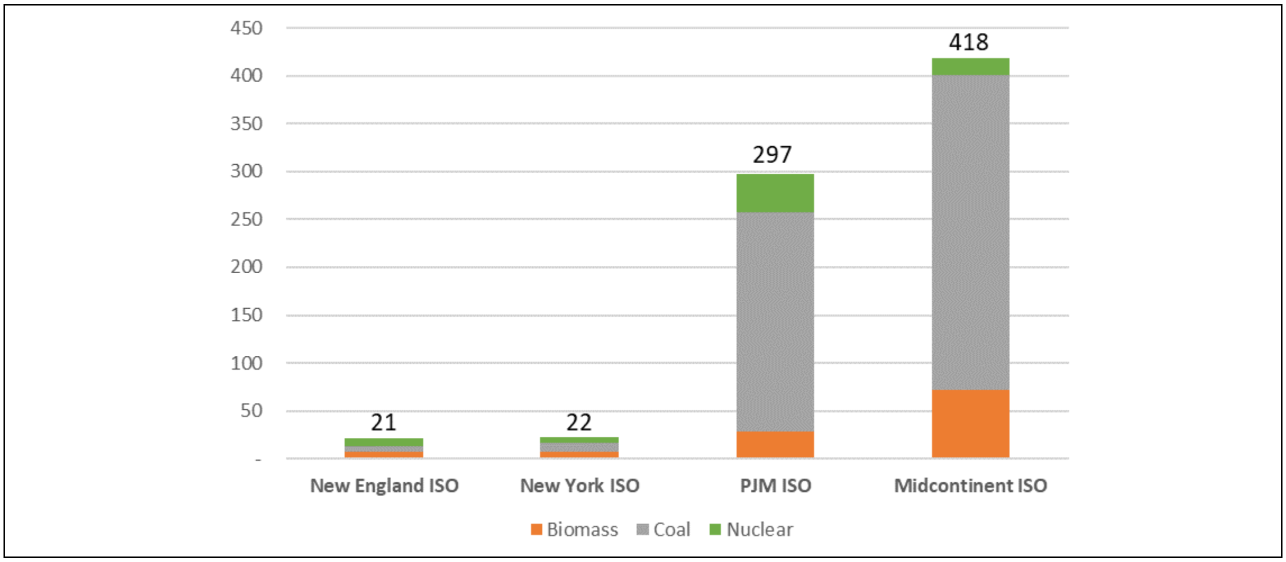
CONCLUSION

Existing competitive wholesale markets are not perfect. Continued growth in renewables in response to state-led initiatives in the face of stagnant US power demand growth raises a number of challenges related to balancing of intermittent resources. However, competitive wholesale markets have delivered substantial benefits to consumers, allowing for a transition to more cost-effective fuel sources (natural gas) more rapidly than would likely have been the case had the entire country remained under cost-of-service regimes, which is effectively what the Grid Resiliency Rule attempts to return baseload generation to in competitive markets. The challenges of cost-of-service regimes have been amply demonstrated by the Kemper and Edwardsport clean coal projects and attempts to build new nuclear stations in South Carolina and Georgia.[10]

[10] The Kemper and Edwardsport clean coal projects had significant cost overruns; the Kemper project had an estimated construction cost of $2.4 billion but ended up costing more than $7 billion to date. The Edwardsport project took $3.55 billion and five years to construct, which was in

If the order is instituted, it will represent a significant institutional challenge to ISOs. Some ISOs, such as PJM and MISO (both part of the Eastern Interconnection), could face hundreds of applications, as Figure 3 shows. None are equipped to conduct cost-of-service assessments on the magnitude that would be required. ISOs have never had to grapple with concepts like prudency, used and useful, or other philosophical cornerstones of regulatory proceedings.[11] Staff would need to be hired, models developed, processes created, and settlement systems adjusted. This suggests that it could take upward of a year before ISOs would be in a position to accept applications for support under the new program. The costs of creating this administrative infrastructure will also need to be passed on to consumers. ISO management would also need to take care not to allow the policy to distract them from the myriad other issues that they are already grappling with in order to maintain reliability.

Figure 3. Total biomass, coal, and nuclear units in ISO-NE, NYISO, PJM, and MISO



Note: Biomass, coal, and nuclear units with proposed retirement dates have been excluded. Source: Energy Velocity.

In lieu of an order focusing on fuel storage, Secretary Perry could have focused on creating a nationwide carbon trading system, with proceeds used to provide retraining and severance to those in the fossil fuel industry displaced by the shift to clean energy. Such a program would likely be less costly to implement (New York is already exploring using a carbon adder in its market dispatch) and would have provided a more economically efficient means to compensate nuclear stations for their zero-emitting characteristics. Depending on the carbon price parameters, some existing coal stations may be retained under such a system in some jurisdictions and may even benefit from greater certainty about environmental regulation.

There are legitimate questions as to whether there is tension between policies promoting renewables and market constructs underpinning reliability. But the markets themselves are equipped to address this issue, particularly if one looks beyond ISOs to the developing market for distributed energy resources (DERs).

excess of their original $1.985 billion budget. "IEEFA Update: Kemper, Edwardsport, and 'Clean Coal,'" IEEFA, February 28, 2017, http://ieefa.org/ieefa-update-kemper-edwardsport-clean-coal-myth/.

[11] Strikingly, the proposed rule refers to "full recovery of costs" with no direct link to prudency tests, though presumably recovery of imprudent costs would not be just and reasonable.

Indeed, if the additional cost burden of supplemental payments to aging coal and nuclear stations is too high, grid defection to DERs may trigger the very retirements of grid-connected baseload stations that the order is intended to prevent.

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