Comments on the United States Department of Energy's Proposed Grid Resiliency Pricing Rule

FERC Docket RM18-1-000

Prepared for Earthjustice

October 23, 2017

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1. CONTEXT AND SUMMARY

The United States electricity system is regulated by a variety of authorities at different jurisdictional levels and of different types. These include state utility commissions, Regional Transmission Operators (RTO) and Independent System Operators (ISO), the Federal Energy Regulatory Commission (FERC) and the United States Department of Energy (DOE). These authorities generally share the mission of ensuring safe and reliable electric service at just and reasonable rates. Indeed, FERC's own mission statement reads, in part:

> FERC's Mission - Reliable, Efficient and Sustainable Energy for Customers…Fulfilling this mission involves [these] goals:
>
> Ensure Just and Reasonable Rates, Terms, and Conditions
>
> Promote Safe, Reliable, Secure, and Efficient Infrastructure[1]

FERC's role, and the role of electric power regulatory authorities generally, shifted after the Northeast Blackout of 2003. In that event, a combination of technical and human errors led to the loss of electric service for approximately 50 million people for up to four days.[2] This event contributed to provisions included in the Energy Policy Act of 2005 and the adoption in 2007 of mandatory reliability standards as governed by the North American Electric Reliability Corporation (NERC).[3]

Over the past decade, regulatory authorities have continued to analyze the primary causes of service interruptions and to propose new regulatory and technology approaches aimed at continuous improvement of the reliability of electric service under both normal and extraordinary conditions. Recent efforts have focused on ensuring reliability as the resources available to generation owners, grid operators, and electricity consumers shift and evolve.

Secretary of Energy Rick Perry raised concerns regarding the resiliency[4] of the electric grid in early 2017.[5] Secretary Perry's letter suggests that recent retirements of conventional, central-station generating units may have threatened the ability of the electric system to deliver safe and reliable service. In particular, Secretary Perry's concerns centered on retirements of "baseload" generating units,

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[1] Federal Energy Regulatory Commission. "Strategic Plan". Available online at: https://www.ferc.gov/about/strat-docs/strat-plan.asp

[2] U.S.-Canada Power System Outage Task Force. "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations". April 2004. p1. Available online at: https://www.energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf

[3] NERC. "History of NERC". August 2013. p5. Available online at: http://www.nerc.com/AboutNERC/Documents/History%20AUG13.pdf.

[4] Synapse recognizes that there is no industry-standard definition of "resiliency." It has most frequently been used in regard to extreme weather-related transmission and distribution outages, and it has more recently been expanded to include cyber security threats.

[5] Secretary Rick Perry, Memorandum to the Chief of Staff re: Study Examining Electricity Markets and Reliability. https://s3.amazonaws.com/dive_static/paychek/energy_memo.pdf

which include those units whose engineering and design optimizes them to run at high annual capacity factors.[6] The majority of units designed for a baseload duty cycle are coal-fired or run on nuclear power.

In response to this concern, the Secretary directed his staff to prepare a report "explor[ing] critical issues central to protecting the long-term reliability of the electric grid" including "the premature retirement of baseload power plants".[7] This report was released in August of 2017. Among its key findings were that "centrally-organized markets have achieved reliable wholesale electricity delivery with economic efficiencies in their short-term operations"[8] despite challenging circumstances and changing market conditions, and that "the biggest contributor to coal and nuclear plant retirements has been the advantaged economics of natural gas-fired generation" in combination with "low growth in electricity demand".[9]

Despite this clear indication that a shifting resource mix presents no immediate threat to the reliability or resiliency of the electric grid, DOE issued a Notice of Proposed Rulemaking (NOPR) letter to FERC in September of 2017. DOE's proposal for a "Grid Resiliency Pricing Rule" instructs FERC to develop rules that would guarantee "full recovery of costs" (including profit) to units with a "90-day fuel supply on site" within 60 days of its issuance.[10]

DOE's proposal leaves open many questions. It is unclear from DOE's NOPR how a "90-day fuel supply on site" would be defined or which set of units, exactly, would qualify for cost-of-service recovery under such a construct.[11] DOE also does not address how its proposed cost-of-service structure would interact with existing wholesale markets. For example, it is impossible to know from the NOPR whether units receiving cost-of-service recovery would be obligated to—or forbidden to—bid into wholesale markets, and if so, at what cost. Nevertheless, Synapse Energy Economics has reviewed DOE's proposal and assessed to the greatest extent possible whether DOE's proposal would improve the reliability or resiliency of the electric grid. Below, we provide a brief survey of some of the many existing reliability-focused regulatory structures pertinent to the wholesale markets. We then discuss the primary causes

[6] Conventionally, units designated as "baseload" would operate differently than "peaking" units that are designed to run at capacity factors of approximately 10 percent as compared to "baseload" capacity factors of 70–80 percent or higher.

[7] Perry Memorandum, p2.

[8] U. S. Department of Energy Staff. "Staff Report to the Secretary on Electricity Markets and Reliability". August 2017. p98. Available online at: https://energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf

[9] Id., p13.

[10] DOE Grid Resiliency Pricing Rule Notice of Proposed Rulemaking. Docket No. RM17-3-000. p11. Available online at: https://www.energy.gov/sites/prod/files/2017/09/f37/Notice%20of%20Proposed%20Rulemaking%20.pdf

[11] For example, DOE's proposal suggests that units must be able to provide operating reserves to qualify, which may exclude most nuclear units. However, other DOE statements indicate the nuclear units are included in the set of "baseload" units of particular interest. As such, the analysis below focuses primarily on coal-fired units with some discussion of nuclear resources as well.

of service interruptions. Finally, we review potential cost and other market impacts from such an extreme change to the current regulatory structure of the nation's wholesale electricity markets.

2. Existing Reliability Mechanisms

In its recent NOPR, DOE contends that the nation's existing wholesale power markets[12] fail to adequately plan for system reliability and resiliency. DOE's assertion in this matter, offered as a primary justification for its proposed rules, is misguided. Substantial attention has been devoted to the question of electric sector resiliency, as detailed in reports from the National Academies of Science[13] and President Obama's administration,[14] the Edison Electric Institute,[15] and GE Energy Consulting.[16] Existing power markets are centrally attuned to ensuring reliable electricity service. For example, PJM's mission statement states that its primary task is "to ensure the safety, reliability and security of the bulk power system."[17]

ISOs and RTOs exist to ensure such reliable service through strict attention to FERC and NERC requirements for resource adequacy and transmission system security, which underlie all of their operational and planning efforts that keep the lights on. ISOs and RTOs use a broad slate of mechanisms to adhere to these standards, resulting in a reliable and resilient grid. Over the past decade, these organizations—often through intensive stakeholder-driven processes—have continued to strengthen their ability to confront threats and avoid outages.

The proposed rule disregards a bevy of successful existing solutions and processes to create new solutions at the level of ISOs, RTOs, and states. Several of these are outlined below.

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[12] DOE clarified in the Federal Register (82 FR 46940) that its proposal applies only to market areas with active energy and capacity markets. Neither the Southwest Power Pool (SPP) nor the California ISO (CAISO) systems have active capacity market constructs. Because the Electric Reliability Organization of Texas (ERCOT) is not subject to FERC regulation, DOE's proposal would not apply to generators located in its territory. As such, DOE's proposal would apply to merchant-owned generation in the ISO New England (ISO-NE), New York ISO (NYISO), PJM, and potentially the Midcontinent ISO (MISO) footprints. It is not certain whether or not MISO's voluntary capacity market would quality under DOE's definition.

[13] The National Academies of Sciences, Engineering, and Medicine. "Enhancing the Resilience of the Nation's Electricity System" 2017. Available online at: https://www.nap.edu/read/24836/chapter/1

[14] Executive Office of the President. "Economic Benefits of Increasing Electric Grid Resilience to Weather Outages". August 2013. Available online at: https://energy.gov/sites/prod/files/2013/08/f2/Grid%20Resiliency%20Report_FINAL.pdf

[15] Edison Electric Institute. "Before and After the Storm". March 2014. Available online at: http://www.eei.org/issuesandpolicy/electricreliability/mutualassistance/Documents/BeforeandAftertheStorm.pdf

[16] GE Energy Consulting. "NJ Storm Hardening" November 2014. Available online at: http://www.nj.gov/bpu/pdf/reports/NJ_Major_Storm_Response-GE_Final_Report-2014.pdf

[17] PJM. "Mission & Vision". Available online at: http://www.pjm.com/about-pjm/who-we-are/mission-vision.aspx

2.1. Many Existing Market and Regulatory Mechanisms are Aimed at Addressing Reliability

ISO/RTOs use a wide array of mechanisms to achieve grid reliability over various time scales, from setting long-term goals to ensuring minute-by-minute electricity flows.

Regional energy markets are designed to ensure real-time system reliability in all hours. ISO/RTOs schedule generation in sufficient advance of the need. Day-ahead markets schedule consumption before operation whereas real-time markets adjust production hour-by-hour. Energy markets send price signals to resource operators, valuing the energy they provide, and scarcity prices signal reserve shortages during unintended events. These price signals are integral to ensuring reliability and demonstrating system value to generators.

Beyond energy markets, most ISO/RTOs run capacity markets. These are primarily concerned with advance procurement of sufficient resource capacity to meet demand (plus a margin for reliability purposes) at peak hours, when the threat of loss of load is most acute. Capacity markets ensure sufficient capacity by compensating resources for guaranteed operational availability (defined as an ability to assist in balancing load and supply) in specific future periods. Importantly, these resources can include both conventional generation units as well as energy storage, demand response, and other new market entrants. Some ISO/RTOs offer pay-for-performance incentives, which reward generators for having successfully provided resource adequacy. The incentives also ensure that generators have the funds necessary to perform in suboptimal conditions on a going-forward basis, such as by securing secondary fuel supplies. In addition, recently instituted pay-for-performance programs often impose penalty rates on operators that fail to provide promised generation.

Ancillary services allow for effective, reliable balancing of supply and demand in real time. These include regulation and frequency response (to maintain second-by-second balance between grid supply and load), operating reserves (spinning, non-spinning, and supplemental, to respond to forecast error and contingency situations), reactive power (to ensure adequate voltage and prevent cascading blackouts), and black start capabilities (to ensure re-start of the grid under extreme outage circumstances). All U.S. ISO/RTOs operate markets to procure ancillary services subject to NERC reliability standards. Despite their name, ancillary services are essential to reliable grid operations. Indeed, vertically integrated utilities in non-RTO areas must self-provide these ancillary services or utilize provisions under the FERC open access transmission requirements to buy them from alternative providers.[18]

Reliability initiatives are not limited to these broad markets. ISO/RTOs utilize a full set of mechanisms to ensure continued generation. These include reliability must-run contracts, which allow ISO/RTOs to compensate generators—that would otherwise retire—for providing reliability assurance. They also

[18] Argonne National Laboratory. "Survey of U.S. Ancillary Services Markets". January 2016. Available online at: http://www.ipd.anl.gov/anlpubs/2016/01/124217.pdf

include dual fuel incentives, which reward generators that diversify their fuel capability.[19] Additionally, most ISO/RTOs host a stakeholder committee dedicated to reliability and resiliency issues, which ensures transparency and stakeholder input as well as encouraging a wide variety of ideas that will lead to the optimal approaches to ensure reliable and resilient service.

The table below outlines market participation in the reliability mechanisms described above for the four markets impacted by DOE's proposed rule.

	PJM	MISO	ISO-NE	NYISO
Energy Market	Yes	Yes	Yes	Yes
Capacity Market	Yes	Yes	Yes	Yes
Ancillary Services	Yes	Yes	Yes	Yes
Pay for Performance	Pending		Pending	
Reliability Must Run	Yes	Yes	Yes	Pending
Dual Fuel Incentives	Yes		Yes	
Reliability Committee	Yes	Yes	Yes	

Finally, all ISO/RTO systems must comply with reliability standards established by NERC.[20] NERC's first pillar of continued success is reliability: "to address events and identifiable risk, thereby improving the reliability of the bulk power system."[21] To ensure reliability, NERC develops, monitors, and enforces Reliability Standards, which are mandatory under FERC Order 693. NERC develops upwards of 100 standards through an intensive stakeholder-driven process which includes a comprehensive drafting process led by multiple committees and a rigorous consensus-building process.[22] The 2016 NERC Compliance Monitoring and Enforcement Program Annual Report notes that since 2010 "serious risk

[19] FERC. "Energy Primer: A Handbook of Energy Market Basics". November 2015. Available online at: https://www.ferc.gov/market-oversight/guide/energy-primer.pdf See, e.g., ISO-NE's "Winter Reliability Program," placed into operation to ensure reliability is assured even under fuel supply uncertainty.

[20] NERC. "About NERC". Available online at: http://www.nerc.com/AboutNERC/Pages/default.aspx

[21] Id.

[22] NERC. "NERC Standards and Compliance 101" April 2014. Available online at: http://www.nerc.com/pa/Stand/Workshops/NERC%20Standards%20and%20Compliance%20101.pdf

violations have declined and continue to account for a small portion of all instances of noncompliance...”, [23] demonstrating the overall success of the NERC standard system.

2.2. Additional Mechanisms Were Added in Response to the Polar Vortex

The DOE NOPR uses the 2014 Polar Vortex, and its potential threat to PJM in particular, to justify shoring up “fuel-secure” generation. However, it ignores both PJM’s tremendous progress on reliability and resiliency since 2014 and, ironically, the evidence of coal-plant failures during extreme weather events. PJM released a paper in March 2017[24] which outlines the steps it has already taken to ensure fuel security and diversity, and highlights areas for growth. The very existence of this report demonstrates a willingness to engage with reliability topics and an attention to the issue.

Following the Polar Vortex, PJM changed its capacity market construct to include a Capacity Performance (CP) product. Since 2015, PJM has transitioned CP into its capacity market, which incentivizes more robust generator performance. In terms of fuel supply, CP requires firm fuel supplies in the form of firm gas supply contracts, more flexible service contracts, or installation of dual-fuel capability.[25]

Beyond PJM, both ISO-NE and MISO also took steps following the Polar Vortex to increase their grid reliability. MISO took a broad set of steps that included improved electric-gas coordination, enhanced resource adequacy monitoring, and market pricing reforms.[26] ISO-NE implemented winter programs while it worked to implement its pay-for-performance initiative, which represents “a comprehensive, long-term, market-based solution to improve resource availability and performance during stressed system conditions.[27]

This history of active response to changing circumstances demonstrates how market constructs adjust and adapt over time. In many cases, evolving market rules allow market participants to provide superior services efficiently and at low costs. We can assume that markets will continue to play this beneficial role as circumstances on the grid evolve.

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[23] NERC. “2016 ERO Enterprise Compliance Monitoring and Enforcement Annual Report”. February 2017. Available online at: http://www.nerc.com/pa/comp/CE/Compliance%20Violation%20Statistics/2016%20Annual%20CMEP%20Report.pdf

[24] PJM Interconnection. “PJM’s Evolving Resource Mix and System Reliability”. March 2017. Available online at: http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx

[25] Id., p36.

[26] MISO. “2013-2014 MISO Cold Weather Operations Report”. November 2014. Available online at: https://www.misoenergy.org/Library/Repository/Report/Seasonal%20Market%20Assessments/2013-2014%20Cold%20Weather%20Operations%20Report.pdf

[27] Gillespie, A. “Winter Reliability Program Updated”. ISO-NE. September 2015. Available online at: https://www.iso-ne.com/static-assets/documents/2015/09/final_gillespie_raab_sept2015.pdf

2.3. State Mechanisms Address Resiliency in the Face of Extreme Weather and Other Threats

States, like ISO/RTOs, have taken steps to guarantee their ability to respond to extreme weather events and other threats to grid resiliency. In particular, state grid modernization proceedings have placed a special emphasis on grid resiliency. In Massachusetts, for example, one of the central tenets of the state's grid modernization plan is "enhancing the reliability and resiliency of electricity service in the face of increasingly extreme weather."[28] Reducing the effect of outages was one of the Massachusetts Department of Public Utilities' four primary goals for grid modernization.[29]

Another notable example is New York's Reforming the Energy Vision (REV) initiative. Following Hurricane Sandy, New York sought to transform its grid from a traditional utility system to a structure built for distributed resources and service providers. One of the primary motivations of the NY REV structure is the observation that "intelligent integration" of distributed resources can "improve the resilience of distribution systems."[30] The NY REV process is particularly focused on countering the growing threat of cyberattacks. As New York Department of Public Service staff stated in a 2014 REV report, "ensuring the cybersecurity of energy delivery systems is absolutely vital."[31]

New Jersey also engaged in an enormous effort to ensure grid reliability following Hurricanes Irene and Sandy. The New Jersey Board of Public Utilities ordered state electric distribution companies to undertake over 100 actions, including infrastructure improvements to avoid substation flooding, better manage vegetation, and prevent circuit outages. Circuit improvement actions focused on smart grid implementation designed specifically to address grid resiliency.[32]

Finally, several states located in wholesale market territories have long-term resource planning processes aimed at ensuring resource adequacy at low cost under a range of risk factors.[33] In some

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[28] Massachusetts Department of Public Utilities. "Grid Modernization" Available online at: http://www.mass.gov/eea/energy-utilities-clean-tech/electric-power/grid-mod/grid-modernization.html

[29] MA DPU. DPU Order 12-76-B. June 2014. Available online at: http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=12-76%2fOrder_1276B.pdf

[30] NYS Department of Public Service Staff. "Reforming the Energy Vision". April 24 2014. p13. Available online at: http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/26be8a93967e604785257cc40066b91a/%24FILE/ATTK0J3L.pdf/Reforming%20The%20Energy%20Vision%20(REV)%20REPORT%204.25.%2014.pdf

[31] Id., p24.

[32] New Jersey Board of Public Utilities, Docket NO. EO11090543, Order Accepting Consultant's Report and Additional Staff Recommendations and Requiring Electric Utilities to Implement Recommendations. January 2013. Available online at: http://www.nj.gov/bpu/pdf/boardorders/2013/20130123/1-23-13-6B.pdf

[33] Wilson, R. and B. Biewald. "Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans." Prepared for the Regulatory Assistance Project. June 2013. Figure 2, p5. Available online at: http://www.raponline.org/wp-content/uploads/2016/05/rapsynapse-wilsonbiewald-bestpracticesinirp-2013-jun-21.pdf.

states, such as Connecticut,[34] this planning process is conducted by the state itself. In other states, like Virginia,[35] utilities with service territory in that state are required to file an Integrated Resource Plan detailing how they plan to serve load reliably over the near-, mid-, and long-terms.

These are just several examples of the many actions taken and policies implemented by states to confront grid reliability. States and ISO/RTOs have proven their ability to respond to stakeholder feedback and changing market conditions, over time leading to the adaptation of market rules to fairly, transparently, and efficiently address major questions surrounding reliability. As several former FERC commissioners noted in their comments on DOE's proposal, ISO/RTOs have "done a superb job operating the transmission networks and managing markets reliably, safely and efficiently for all wholesale power customers."[36] The proposed rule would obstruct the extensive checks and balances already in place to ensure successful market operation.

3. Fuel Insecurity Is a Negligible Source of Electric Service Disruption in the United States

DOE's NOPR relies on the premise that new rules are required "to protect the American people from energy outages expected to result from the loss of…fuel-secure generation capacity."[37] However, the NOPR provides no evidence to support this statement. Data collected by DOE indicates that fuel supply issues are responsible for a vanishingly small number of electricity outages in the United States.

The DOE requires electric utilities to fill out an electric emergency incident and disturbance report (Form OE-417) following any major disturbance to electric service.[38] This form provides a list of possible incident causes to select from, one of which is labeled "Fuel Supply Deficiency."[39] The individual incident reports are subsequently aggregated in a spreadsheet that is updated and published each month.[40]

[34] Comprehensive Energy Strategy, Connecticut Department of Energy and Environmental Protection. Available online at: http://www.ct.gov/deep/cwp/view.asp?a=4405&q=500752&deepNav_GID=2121

[35] Code of Virginia, Title 56, Chapter 24, § 56-599. Integrated resource plan required. Available online at: https://law.lis.virginia.gov/vacode/title56/chapter24/section56-599/

[36] Comments of the Bipartisan Former FERC Commissioners, Docket RM18-1-000, p6.

[37] DOE NOPR, p3.

[38] U.S. Department of Energy. Electricity Delivery and Energy Availability Form OE-417. Available online at: https://www.oe.netl.doe.gov/docs/OE417_Form_03312018.pdf

[39] *Id.,* p. 2.

[40] U.S. Energy Information Administration. Electric Power Monthly, Tables B1 and B2. Available online at: https://www.eia.gov/electricity/monthly/

Synapse analyzed all incident report records filed since 2011[41] to assess the degree to which the "loss of fuel-secure generation capacity" is harming Americans.

Figure 1 displays the affected customer-hours of service by year and cause for all reported incidents in years 2011 through 2016.[42] Only data reported in the RFC, MRO, NPPC, and SPPC NERC regions are included. These regions include the ISO-NE, NYISO, PJM, and MISO footprints as well as some vertically-integrated areas (primarily in the Southeast). As is clearly apparent from this figure, fuel supply and generation inadequacy issues cause a vanishingly small percentage of actual customer impacts. During the period shown in this chart, approximately one in 1.8 million customer-hour outages were identified as related to fuel supply issues. Across the entire period, less than 0.07 percent of customer-hour impacts in these regions were caused primarily by other generation-related challenges. In contrast, more than 94 percent of service disruptions resulted from weather-related impacts other than fuel supply constraints.

Importantly, submitters of form OE-417 are directed to indicate *all* contributing factors to each disturbance, rather than selecting a single primary cause. It is therefore reasonable to surmise that interruptions due to weather-related impacts that have no mention of fuel supply constraints are, in fact, completely unrelated to fuel supply constraints. Instead, weather-related outages most commonly result from damages to the nation's transmission and distribution systems rather than impacts to the generation resources. This aligns with the Executive Branch's decision to "focus on the status and outlook of the grid's transmission, distribution and management/control systems" rather than generating assets in its 2013 analysis of methods to "increase electric grid resilience to weather outages."[43]

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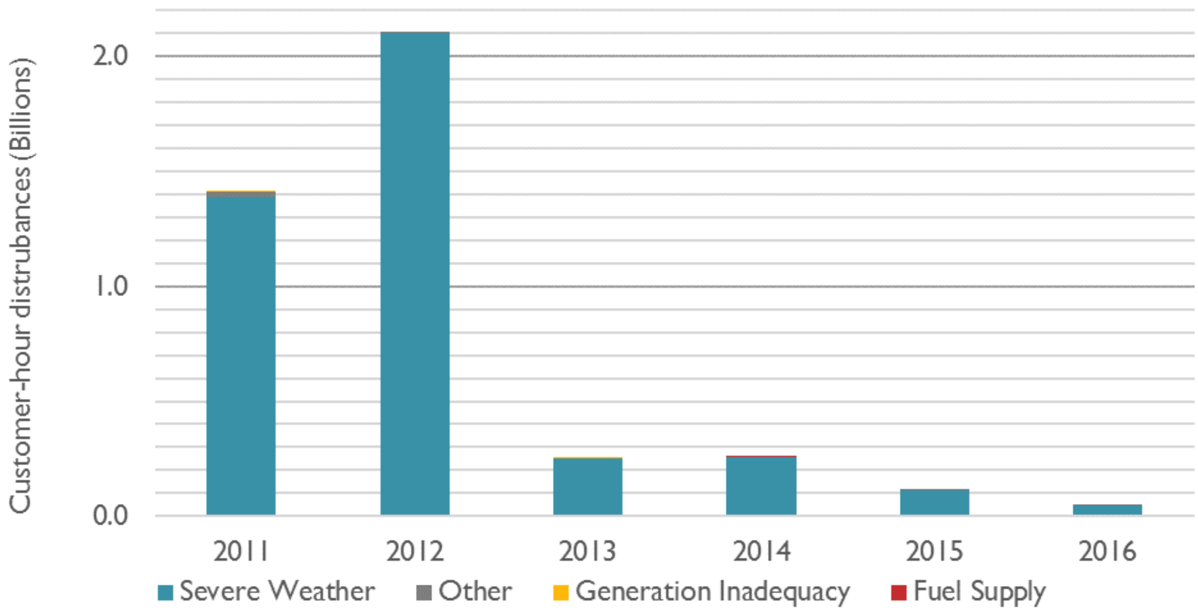
[41] This analysis owes its primary structure to a similar review published by the Rhodium Group on October 3, 2017. *See* http://rhg.com/notes/the-real-electricity-reliability-crisis

[42] Incidents with no reported customer impacts, including those listed as "unknown" for either the number of customers impacted or the duration of the interruption. There were a total of 20 events reported in the NPPC, RFC, MRO, and SERC regions caused by fuel supply issues without a reported value for customers impacted, duration, or both. Of these, 13 events (65 percent) were described as being related to a deficiency of coal.

[43] Executive Office of the President. "Economic Benefits of Increasing Electric Grid Resilience to Weather Outages". p5.

Figure 1. Major electricity disturbances by source in the NPPC, RFC, MRO, and SPPC NERC regions, 2011–2016



Sources: U.S. Energy Information Administration (EIA), Synapse

3.1. Coal Plants Have Been Largely Responsible for the Few Recent Generation-Related Reliability Incidents

In the few incidents in which fuel supply or generation inadequacy led to customer outages, the coal resources identified in the NOPR as providing reliability advantages were almost universally those at primary fault for causing the outages. Of all affected customer-hours nationwide driven by fuel supply constraints, about *98 percent* occurred because of a 2014 fuel shortage at Minnesota coal plants. According to media reports from the time, delays in rail shipments of coal from Montana and Wyoming compelled Minnesota Power to idle four of its coal units.[44]

Similarly, a single incident featuring under-performing coal plants dominated the recent customer service impacts resulting from generation inadequacy. In February of 2011, millions of customers in the Southwest lost power due to a series of generating unit failures. The generation outages included seven ERCOT coal units, amounting to around 4,800 MW of capacity, that shut down in the face of a range of weather-related equipment failures.[45] The outages resulting from this confluence of generation failures

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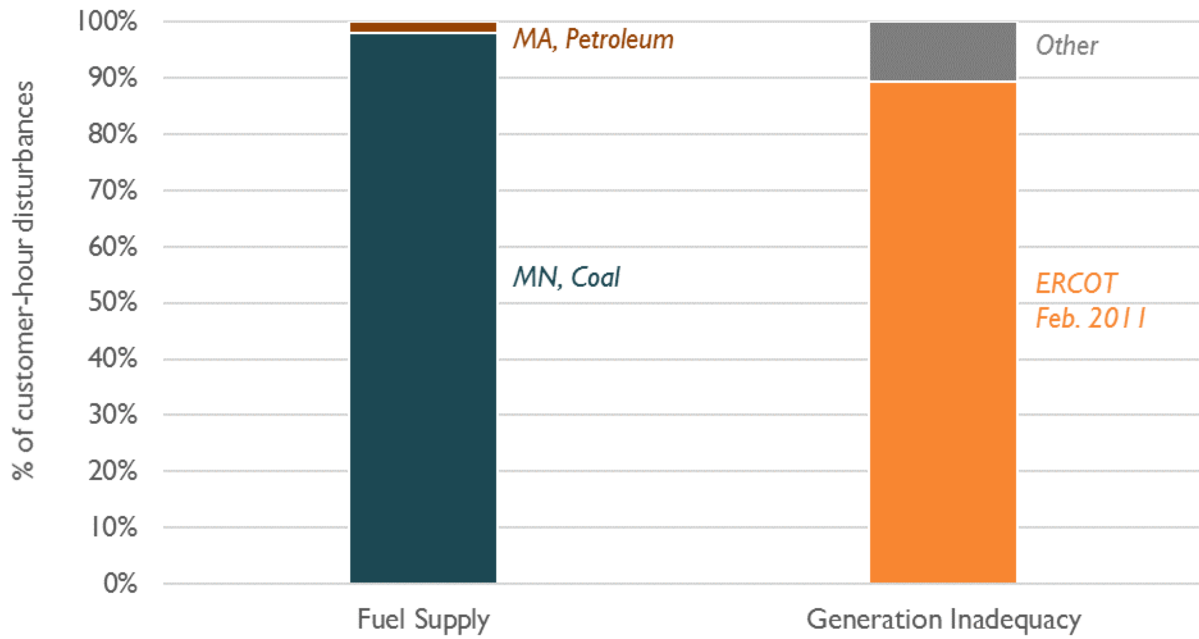
[44] Duluth News Tribune & Wisconsin Public Radio. "Minnesota Power to Idle Four Coal-Fired Electrical Generation Units". September 11 2014. Available online at http://www.duluthnewstribune.com/content/minnesota-power-idle-four-coal-fired-electrical-generation-units

[45] Souder, Elizabeth, S.C. Gwynn and Gary Jacobson. "Freeze knocked out coal plants and natural gas supplies, leading to blackouts." Dallas News. February 2011.Available online at https://www.dallasnews.com/news/texas/2011/02/06/freeze-knocked-out-coal-plants-and-natural-gas-supplies-leading-to-blackouts; Federal Energy Regulatory Commission and North

account for about 89 percent of all affected customer-hours nationwide resulting from generation inadequacy between 2011 and 2016 (see Figure 2). These examples contradict the NOPR's assumption that coal plants' onsite fuel storage capacity enables them to prevent fuel- and generation-related outages. On the contrary, coal plants have been a primary cause of such outages in the past, thanks in part to their susceptibility to equipment failures and transportation delays.

Figure 2. Sources of major generation- and fuel-related electricity disturbances in United States, 2011–2016



Sources: EIA, Synapse

3.2. The 2014 Polar Vortex Does Not Justify the NOPR

The NOPR largely relies on the Polar Vortex of 2014 to justify the proposed actions. A full section of the NOPR is devoted to discussing how "The 2014 Polar Vortex Exposed Problems With the Resiliency of the Electric Grid."[46] As recognized by at least two *current* FERC commissioners,[47] the Polar Vortex provides poor justification for the unprecedented actions recommended in the NOPR, for at least four reasons. First, though the Polar Vortex posed a challenge to some grid operators, *it did not result in any customer outages*. Second, most of the generator outages caused by the Polar Vortex were unrelated to fuel supply constraints. Third, much of the coal fleet which the NOPR proposes to subsidize performed quite

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American Electric Reliability Corporation. "Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011". August 2011. Available online at: https://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf

[46] DOE NOPR, p4.

[47] Bade, G. "LaFleur: DOE NOPR likely not detailed enough to form final rule." UtilityDive. October 17, 2017. Available online at: http://www.utilitydive.com/news/lafleur-doe-nopr-likely-not-detailed-enough-to-form-final-rule/507488/

poorly during the Polar Vortex. Finally, as discussed previously, RTOs and ISOs across the country have already implemented rules to address issues raised by the Polar Vortex.

The Polar Vortex Did Not Result in Electricity Interruptions

From the way in which the NOPR highlights the grid impacts of the Polar Vortex, one might think that millions of customers experienced significant outages. That is simply not the case. In the PJM region, which faced the highest number of record-low temperatures due to the extreme cold associated with the Polar Vortex,[48] the grid operator successfully managed the threat without having to resort to blackouts. A post-mortem report found that "even on the day with the tightest power supplies—January 7—*several steps remained before electricity interruptions might have been necessary*."[49] Similarly, neighboring MISO reported that it "only had to utilize the first few steps of its progressively escalating emergency operations process to maintain grid reliability" during the Polar Vortex, and never had to shed firm load.[50] Rather than illustrating a problem, the operational response to the Polar Vortex instead demonstrated both the foresight of RTO/ISO/utility preparedness, and the success of the market, regulatory, and stakeholder-driven solutions to ensure reliability during unprecedented and extreme conditions. All of this occurred without falling back on non-market subsidies to relatively inflexible coal and nuclear power plants, as warranted by the precepts of the NOPR.

The NOPR itself implicitly recognizes that the Polar Vortex did not result in any material reliability impacts. The NOPR states that PJM "struggled to meet demand for electricity," and suggests that "sixty-five million people within the PJM footprint *could have been affected*" under different operating conditions.[51] In other words, demand was met, and nobody's service was affected. The fact that the NOPR has to resort to speculation on what "could have" happened during an event that was successfully managed three years ago—and that has been further addressed during the past three years – highlights the flimsiness of DOE's proffered justification for the NOPR.

Most Forced Outages During the Polar Vortex Were Unrelated to Fuel Supply

While the Polar Vortex did not result in any actual customer outages, it did result in substantial generation forced outages that caused spikes in the price of electricity and drove grid operators to emergency actions. However, these outages were not primarily a result of the type of problem that the

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[48] 24 out of 49 record cold temperatures set on January 7, 2014 occurred in the states of Delaware, Maryland, Ohio, Pennsylvania, Virginia, and West Virginia. Rice, D. "List of record low temperatures set Tuesday." USA Today. 7 January 2014. Available online at: https://www.usatoday.com/story/weather/2014/01/07/weather-polar-vortex-cold/4354945/

[49] PJM Interconnection. "Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events". May 8, 2014. p4. Emphasis added. Available online at: http://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx

[50] MISO. "2013-2014 MISO Cold Weather Operations Report". November 2014. pp. 5-6. Available online at: https://www.misoenergy.org/Library/Repository/Report/Seasonal%20Market%20Assessments/2013-2014%20Cold%20Weather%20Operations%20Report.pdf

[51] DOE NOPR, pp4-5. Emphasis added.

NOPR purports to fix. The NOPR is focused on "fuel supply disruptions" and "fuel-secure generation capacity."[52] But during the peak of the Polar Vortex, gas interruptions and other fuel supply issues accounted for only about 26 percent of PJM-wide forced outages. [53] This means that at least 74 percent of the forced outages that were concurrent with the Polar Vortex would have happened even if all generation units had an infinite on-site fuel supply.

Merchant Coal Plants Performed Poorly During the Polar Vortex

The NOPR's proposed solution to the issues raised by the Polar Vortex is also flawed in that it would support a fleet of merchant coal plants that performed quite poorly during the most critical moments of that event. Synapse used hourly, unit-specific generation data from the U.S. Environmental Protection Agency's Air Markets Program Data database to evaluate the performance of PJM generating units during the Polar Vortex event.[54] Figure 3 displays the aggregate performance of PJM merchant coal units during the Polar Vortex.[55] After initially ramping up to meet growing demand, a variety of plant failures caused the coal fleet's performance to start declining even before the peak hour on January 6. By the time of the record PJM winter peak on the evening of January 7, coal output had fallen by more than 2,500 MW relative to its peak output from the prior day. Three units that were online on January 6 were offline during the January 7 peak, and most units that remained online provided less output at the season peak than they had the previous day.

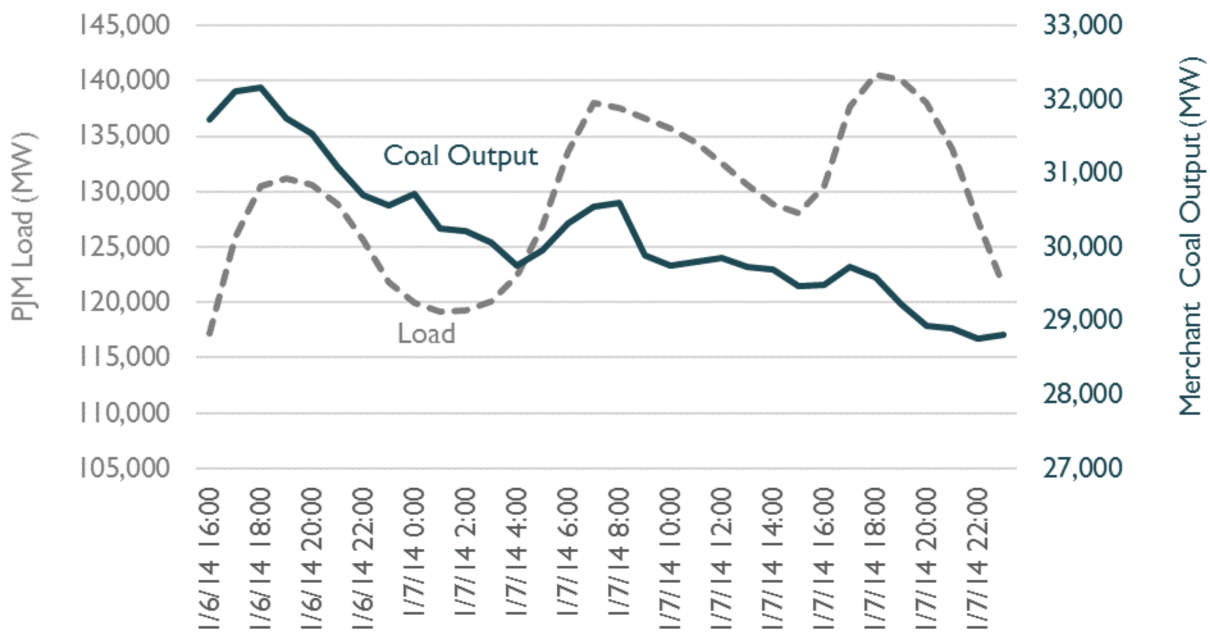
[52] DOE NOPR, pp2-3.

[53] PJM Interconnection. "Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events". pp24-25.

[54] U.S. Environmental Protection Agency. Air Markets Program Data. Available online at: https://ampd.epa.gov/ampd/

[55] This chart compares coal output as measured on the right vertical axis to load as measured on the left vertical axis.

Figure 3. PJM load and merchant coal output during the 2014 Polar Vortex



Sources: EPA; PJM; Synapse

Altogether, PJM estimated that coal units accounted for about 34 percent of unavailable capacity during the peak of the Polar Vortex.[56] There were a variety of reasons why these units failed to perform. Most suffered from equipment issues, many of them associated with cold weather.[57] The DOE Staff Report heavily cited in the NOPR points out that many coal plants "could not operate due to conveyor belts and coal piles freezing," providing a reminder that gas units were not the only generators facing fuel supply challenges during the Polar Vortex.[58] The various problems that prevented coal units from operating during the Polar Vortex all share at least one characteristic: they would not be addressed by the NOPR.

3.3. Recent Storm Events Provide No Support for the NOPR

In addition to discussing the Polar Vortex at length, the NOPR states that "the devastation from Superstorm Sandy and Hurricanes Harvey, Irma, and Maria, reinforce the urgency that the Commission must act now."[59] However, the storms referenced in the NOPR provide even less support for the DOE's proposal than the Polar Vortex does. Neither DOE's own reports on these storms, nor the NOPR itself,

[56] PJM Interconnection. "Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events". pp25-26.

[57] Id., pp24-25.

[58] DOE Staff Report, p98..

[59] DOE NOPR, p11.

provide evidence that fuel insecurity had anything to do with the extensive electric service disruptions caused by Sandy, Harvey, Irma, or Maria.

Superstorm Sandy

Superstorm Sandy wrought havoc on the electric system of the northeastern United States, ultimately causing 8.66 million customer outages across 20 states and the District of Columbia.[60] However, those outages were due to damage to *transmission and distribution networks*, not because of any impacts on fuel security. DOE's summary of the harm caused by Sandy included tallies of over 100 damaged substations, thousands of damaged transformers and poles, and hundreds of miles of damaged transmission lines and wires.[61] In contrast, DOE did not identify a single case of electric generator fuel security issues triggered by Sandy. In fact, DOE explicitly concluded that "Sandy did not have a major impact on natural gas infrastructure and supplies in the Northeast."[62]

NERC and DOE both identified generation-related impacts from Sandy but noted that these impacts were not a primary cause of customer outages. DOE described over 2.8 GW of nuclear capacity that shut down and a further 5.3 GW that reduced output either to protect equipment from the storm, to reduce output in response to reduced demand, or to address damage to plant facilities or related transmission infrastructure.[63] Ironically, nuclear plants are identified in the NOPR as having resiliency attributes that deserve special compensation. NERC additionally identified over *16.7 GW* of combined cycle, combustion turbine, and "fossil" (implying coal-, gas-, or oil-fired steam units) capacity that "became unavailable" during the storm—although NERC continued on to note that even this level of generator unavailability "did not result in any capacity issues."[64] NERC described recovery efforts as centering on restoration of the transmission system and of substations powering important customer distribution networks.[65] NERC also went on to observe that "curtailments due to wet coal" were one potential risk to the operability of the generation fleet during the storm, describing such curtailments as "normal with *any* significant precipitation".[66]

DOE and NERC's post-event identification of Sandy's impacts on the electric grid as being rooted in the transmission and distribution system rather than in fuel constraints is confirmed by status reports issued while Sandy remained a threat. A DOE Situation Report published just a day after Sandy made landfall in New Jersey detailed excessive flooding at New Jersey substations, widespread damage to transmission

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[60] U.S. Department of Energy. "Comparing the Impacts of Northeast Hurricanes on Energy Infrastructure." April 2013. p7. Available online at: http://www.oe.netl.doe.gov/docs/Northeast%20Storm%20Comparison_FINAL_041513c.pdf

[61] Id., pp9-10.

[62] Id., p25.

[63] Id., p13.

[64] NERC. "Hurricane Sandy Event Analysis Report". January 2014. p23. Available online at: http://www.nerc.com/pa/rrm/ea/Oct2012HurricanSandyEvntAnlyssRprtDL/Hurricane_Sandy_EAR_20140312_Final.pdf

[65] Id., p5.

[66] Id., emphasis added.

and distribution systems, and intentional shutdowns of New York underground distribution systems to protect them from floodwaters.[67] No mention was made of any impacts to generation units or their fuel supplies.

Hurricanes Harvey, Irma, and Maria

The claim that the impacts of Hurricanes Maria and Irma help justify the NOPR is refuted by the storm status reports that DOE continues to publish on a daily basis. These reports make plain that the massive outages caused by Maria and Irma have nothing to do with fuel assurance, and everything to do with decimated transmission and distribution systems. For example, the report issued on October 13 stated that, as of the latest information available, about 91 percent of Puerto Rico electric customers, 88 percent of St. Croix customers, and 100 percent of St. John customers remained without power.[68] Emergency repair crews working in Puerto Rico had only managed to re-energize 20.2 percent of transmission lines and 31.6 percent of distribution lines.[69] The same report affirmed that oil and gas "fuel stocks are adequate across the region," and that the major Puerto Rico and U.S. Virgin Island ports had been re-opened and were receiving fuel imports.[70] The evidence could not be clearer: fuel security is unrelated to the ongoing electric reliability challenges faced by the survivors of Maria and Irma.

The same story holds true for Hurricane Harvey. DOE status reports published shortly after the storm struck Texas indicated that Harvey had damaged or destroyed thousands of distribution poles and hundreds of transmission structures and distribution circuits.[71] DOE also noted that electric service could not be restored in some areas that remained inundated by flood waters.[72] No mention was made of any electric service disruptions caused by shortages of generation fuel.

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[67] U.S. Department of Energy. "Hurricane Sandy Situation Report # 5". October 30, 2012. pp5-6. Available online at http://www.oe.netl.doe.gov/docs/2012_SitRep5_Sandy_10302012_300PM_v_1.pdf

[68] U.S. Department of Energy. "Hurricanes Nate, Maria, Irma and Harvey October 13 Event Summary (Report # 64)". October 13, 2017. p2. Available online at https://energy.gov/sites/prod/files/2017/10/f37/Hurricanes%20Nate%2C%20Maria%2C%20Irma%20and%20Harvey%20Event%20Summary%20October%2013%2C%202017.pdf

[69] Id., p2.

[70] Id., pp1,3.

[71] See., e.g., U.S. Department of Energy. "Tropical Depression Harvey Event Report (Update # 13)". September 1, 2017. Available at https://energy.gov/sites/prod/files/2017/10/f37/Hurricane%20Harvey%20Event%20Summary%20%2313.pdf

[72] *Id.,* p4.

4. DOE's Proposal Will Increase Costs, Will Stifle Innovation, and May Lead to a Less Reliable Fleet

Although it is unlikely to achieve the stated goal of increasing the resiliency of the electric grid, DOE's proposal may nonetheless have substantial impacts on the grid's costs and operations. Perhaps most importantly, DOE's proposal will lead without doubt to increased electric system costs. The proposal also runs the risk of leading to preservation of a less-reliable, less-flexible generating fleet, and threatens ongoing efforts to innovate and invest in new solutions to improve grid resiliency.

4.1. DOE's Proposal Will Increase Costs for Consumers without Providing Additional Resiliency Benefits

That DOE's proposal will increase the cost of energy seen by consumers is a certainty. After all, the fundamental premise behind DOE's NOPR is that certain units are currently providing a reliability- or resiliency-related value to the grid, and that this purported value is not being adequately compensated by the revenues they are receiving in the energy, capacity, ancillary service, reserve, and other markets. DOE's proposal aims to ensure that these units receive "cost-of-service"-based compensation, meaning that they earn back all of their incurred costs plus a return on equity. [73] The implication is that the compensation earned by these units for providing services on the current wholesale markets does not allow these units to earn back all of their costs—or, potentially, provide a level of profit that the owners would consider to be fair—at current prices.

To be clear, DOE's proposal inherently assumes what energy system analysts (including DOE's own staff) have repeatedly demonstrated for several years: the energy sources with increasing market share are those which can provide grid services at the lowest cost. Independent analysts at Lazard[74] and Bloomberg New Energy Finance[75] have found that energy from renewable technologies such as wind and solar generation is now cheaper than coal, and in some cases gas, even on an unsubsidized basis (Figure 4). These comparisons relate primarily to construction of new capacity rather than the ongoing costs of existing resources. But even the existing resources targeted by DOE's proposal, which have already depreciated all or some of their initial capital outlays, (which would suggest that the all-in cost of energy from these resources should generally be lower than that of new construction), are

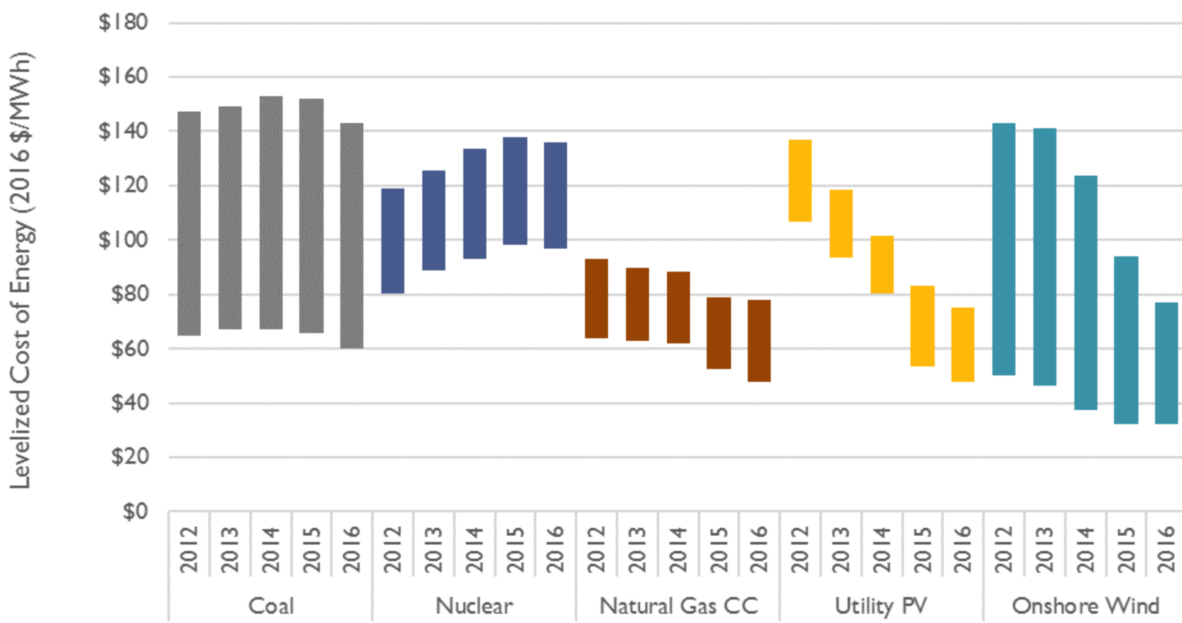
[73] In traditional cost-of-service regulation, incurred costs are subject to a "prudence review" by a regulatory commission or other entity to ensure that expenditures were reasonable and in accordance with the public interest. DOE's proposal makes no mention of such a review. Therefore, it is not clear who—if anyone—would have the power to conduct a prudence review of the spending of "fuel-secure" merchant resources in market regions under DOE's proposal.

[74] Lazard. "Levelized Cost of Energy Analysis". Editions 6.0 through 10.0 (2012-2016). Edition 10 available online at: https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-100/

[75] Bloomberg New Energy Finance. "New Energy Outlook 2017". Available online at: https://about.bnef.com/new-energy-outlook/

increasingly not cost-competitive with renewable energy technologies. A review of FERC Form 1 data estimated the LCOE of *existing* coal units at approximately $40.14/MWh.[76] As such, even these resources are now approximately as expensive as new construction of wind and solar energy even on without taking the ITC and PTC into account.

Figure 4. Lazard unsubsidized levelized costs of energy, 2012–2016



Sources: Lazard LCOE Report v6.0 – v10.0, Synapse

DOE recently published a comparison of the approximate profitability of coal- and gas-fired resources (referred to as the "dark" and "spark" spreads, respectively), which demonstrated that coal in PJM is simply less profitable than gas in that region.[77] This reality is echoed in the low valuations of coal and nuclear resources operating in market regions in recent years. For example, Eversource recently agreed to sell its two coal-fired plants in the ISO New England Territory for a total value of only $175 million, down from a book value in 2013 of nearly $600 million.[78] An independent analysis conducted in 2013

[76] Stacy, T. F. and G. S. Taylor. "The Levelized Cost of Electricity from Existing Generation Resources", p5. Institute for Energy Resource. June 2015. Available online at: http://instituteforenergyresearch.org/wp-content/uploads/2015/06/ier_lcoe_2015.pdf.

[77] EIA. "Today in Energy: Spark and dark spreads indicate profitability of natural gas, coal power plants". October 13, 2017. Available online at: https://www.eia.gov/todayinenergy/detail.php?id=33312

[78] Staff of the New Hampshire Public Utilities Commission and The Liberty Consulting Group. "Repot on Investigation into Market Conditions, Default Service Rate, Generation Ownership and Impacts on the Competitive Electricity Market". June 7, 2013. p33. Available online at: https://www.puc.nh.gov/Electric/IR%2013-020%20PSNH%20Report%20-%20Final.pdf..

found that these plants likely had a negative valuation even in that year.[79] Similarly, FirstEnergy's own analysis of its proposed transaction to guarantee recovery all costs, including profit, associated with several coal and nuclear assets in Ohio showed customers losing hundreds of millions of dollars per year in the near term on the transaction.[80] Quite simply, many of the assets most targeted by DOE's proposal have costs that far outweigh their current market values.

In its NOPR letter, DOE cites[81] a report from IHS Markit[82] that claims consumers would lose $98 billion per year of value[83] given a "less diverse" grid that was reliant primarily on wind, solar, hydro, and natural gas-fired resources. The analysis underlying this value has substantial flaws, of which two stand out: first, it is based on an unrealistic "net benefits of electricity" calculation. IHS's definition of the net benefits of grid-based electric service appears to be based on a subtraction of the costs of grid energy from the costs of providing the same level of service using backup generation.[84] IHS's calculation makes the assumption that consumers would resort en masse to backup generators designed for emergency use only in the absence of an electrical grid. This cannot be considered a reasonable evaluation of the costs of replacement generation in any remotely realistic alternative scenario to the current grid system.

Second, IHS's "low-diversity" grid scenario purports to calculate the costs of providing service from a grid mix with "no nuclear, coal, or oil" resources, "20% less hydro capacity," and the remainder "wind and solar resources integrated with natural gas-fired" generation "in proportions reflecting the current mix of these technologies." Importantly, gas-fired capacity totals approximately 4.5 times the total capacity of *all* non-hydro renewables (including geothermal and other resources not mentioned by IHS),[85] meaning that the "low-diversity" case is primarily an examination of a gas-heavy grid mix. Furthermore, IHS claims to be comparing the real and "low-diversity" cases using resource costs on an "unsubsidized" basis.[86] IHS does not list the subsidies contemplated for removal in this calculation.

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[79] Id., p36.

[80] Direct Testimony of Tyler Comings in the Matter of the Application of the Ohio Edison Company, the Cleveland Electric Illuminating Company and the Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 In the Form of an Electric Security Plan (Case No. 14-1297-EL-SSO), at p7, lines 3-7. December 22, 2014. While the company claimed that customers would benefit from such a deal in later years, independent analyses using more reasonable market forecasts showed that customers would lose significant amounts of money over the full fifteen-year term of the proposal.

[81] DOE NOPR, p5.

[82] Makovich, L. and J. Richards. "Ensuring Resilient and Efficient Electricity Generation: the value of the current diverse US power supply portfolio." IHS Markit, September 2017. Available online at: https://cdn.ihs.com/www/pdf/Value-of-the-Current-Diverse-US-Power-Supply-Portfolio.pdf.

[83] While the IHS report does mention additional costs related to "preventing the erosion in reliability associated with a less resilient electric supply portfolio", these costs are not included in the $98 billion/year value cited by DOE. The IHS report does not provide the analysis used to support its conclusion that a "less diverse" resource fleet would lead to "more frequent power supply outages". See IHS, p5.

[84] Id., p19.

[85] EIA Form 860 data for year 2015 (the last year for which complete data is available).

[86] IHS Markit, p37

However, because wind and solar resources are the only forms of generation referred to as "subsidized" in the report, it is reasonable to surmise that this calculation removes federal tax credits (such as the Investment Tax Credit or ITC and Production Tax Credit or PTC) from wind and solar generation but does not remove subsidies for other resources. For instance, it neglects tax credits or other subsidies for nuclear generation[87] or upstream subsidies for coal production (such as discounts on royalties for coal mined on federal lands[88]). These apparent omissions would be unjustified and distortionary—but, worse, they also mean that IHS's analysis is simply irrelevant when considering forward-going costs of the electric system. IHS's calculation fundamentally cannot be applied when considering the costs to electric consumers associated with a shifting grid mix for the simple reason that the ITC and the PTC actually exist today. These tax credits impact the cost of renewable resources as seen by electricity consumers now and for the entirety of the resources' book lives (normally 20 years). IHS's analysis cannot reasonably be considered indicative of the costs and benefits of DOE's proposal because it does not take real resource costs seen by the electric system into account.

Ultimately, therefore, the only reasonable conclusion is that adding additional compensation for "fuel secure" units to meet their costs-of-service must lead to higher energy system costs even if all else were to be held equal. Groups including both ICF[89] and the Sierra Club[90] have assessed costs associated with the proposal at values in the billions of dollars per year. Moreover, because DOE's proposal is unlikely to increase grid resiliency, the increased costs associated with the proposal would likely not reduce or replace any effective costs they currently pay that are associated with grid outages. In other words, DOE's proposal is all but certain to increase costs without providing electric ratepayers with value in return.

4.2. DOE's Proposal May Lead to Preservation of Some of the Grid's Least-Reliable, Least-Resilient Units

There is a real risk that implementation of DOE's proposal would lead to a *less* reliable and resilient grid. The merchant coal fleet in the nation's wholesale market is aging. On a capacity-weighted basis, merchant coal-fired units in MISO are over 30 years old on average, and those in PJM are over 40 years old on average.[91] Over 1.2 GW of coal capacity in MISO and over 7.5 GW of coal capacity in PJM was

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[87] Which totaled approximately $1 billion/year in FYs 2010 and 2013. See: EIA. "Direct Federal Financial Interventions and Subsidies in Energy in Fiscal Year 2013". March 2015. Table 7. Available online at: https://www.eia.gov/analysis/requests/subsidy/pdf/subsidy.pdf

[88] Government Accountability Office. "Coal Leasing: BLM Could Enhance Appraisal process, More Explicitly Consider Coal Exports, and Provide More Public Information." December 2013. pp24-25. Available online at: http://www.gao.gov/assets/660/659801.pdf.

[89] ICF. "DOE Acts to Transform the Energy Landscape". October 4, 2017. Available online at: https://www.icf.com/resources/webinars/2017/doe-nopr

[90] Sierra Club. "New Analysis Finds Dramatic Costs of Perry's Directive to FERC". October 16, 2017. Available online at: https://sierraclub.org/press-releases/2017/10/new-analysis-finds-dramatic-costs-perrys-directive-ferc

[91] EIA Form 860 data for 2015 (the last year for which complete data is available).

installed over half a century ago.[92] Due to changes in market conditions (including both load patterns and relative prices), many of these units are now operating in a frequent-cycling mode for which they were not designed. For example, the average capacity factor of all coal units in the states wholly within PJM territory was approximately 53 percent in 2010 but fell to only 41 percent by 2015.[93] An analysis by DOE's National Energy Technology Laboratory found that the forced outage rate for coal units more than doubles when those units are cycled frequently as compared to when they are operating at a steady output.[94]

In accordance with these operational changes, the Equivalent Forced Outage Rate (EFORd) of coal-fired units in both PJM and MISO has increased over the past decade. EFORd measures how likely it is that a unit will not be able to provide full output when needed and is therefore a key measure of unit reliability. A grid riddled with high-EFORd units cannot be considered "resilient" as there is a high chance that those units will not be able to respond to emergency conditions. Coal-fired units in MISO with capacities between 200 and 400 MW experienced an increase in EFORd from approximately 8.1 percent for the 2011–2012 planning year to 9.8 percent for the 2018–2019 planning year—a jump of over 20 percent. A similar increase was seen for units with capacities of between 600 and 800 MW. In PJM, the coal fleet's average EFORd nearly doubled from 6–8 percent in 2010 to 12–14 percent in 2014, recovering slightly only after retirement of 9.5 GW of some of the region's least cost-effective and reliable coal-fired units (Figure 5). This observation echoes that made by the Bipartisan Former FERC Commissioners that "wholesale competition, indeed, has forced existing resources to become more reliable or to exit the market."[95] Notably, these statistics cover both utility- and merchant-owned units. As such, it is unlikely that a cost-of-service compensation structure would lead to substantial improvements in coal fleet EFORd in the absence of a pointed regulatory directive to address unit reliability issues.

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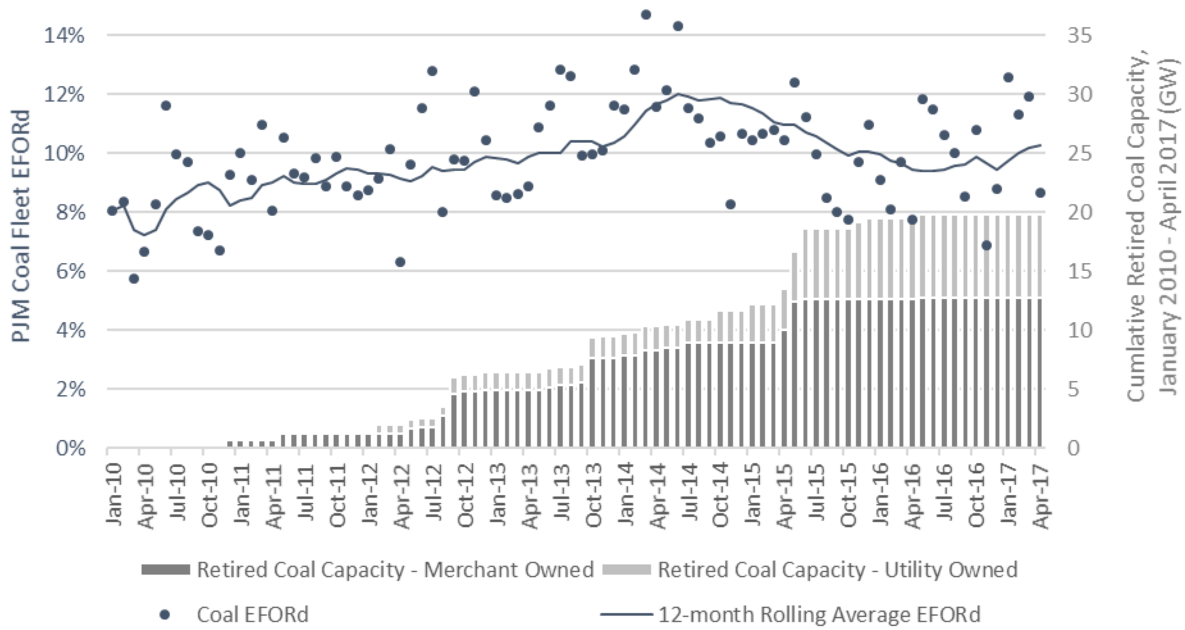
[92] Id.

[93] Based on data in EIA forms 860 and 923.

[94] Nichols, C. "Characterizing and Modeling Cycling Operations in Coal-fired Units". EIA Modeling Meeting. June 2016. Available online at: https://www.eia.gov/outlooks/aeo/workinggroup/coal/pdf/EIA%20coal-fired%20unit%20workshop-NETL.pdf

[95] Comments of the Bipartisan Former FERC Commissioners, p5.

Figure 5. PJM coal fleet monthly EFORd and cumulative retired coal capacity, January 2010–April 2017



Sources: PJM, EIA, Synapse

EFORd measures the reliability of units under general operating conditions and does not address the likelihood that units will fail specifically under critical grid conditions. However, recent events have shown that many "baseload" units are unable to perform during exactly the sorts of severe weather conditions cited by DOE as grid resiliency concerns. For example, Georgia experienced unusually low temperatures in the winter of 2015. These low temperatures induced such a high rate of outages and failures in Georgia Power's (utility-owned, cost-of-service based) coal fleet that it requested permission to increase its planning reserve margin[96] (or, in other words, to maintain a larger generation fleet than previously thought necessary given the same level of demand). Similarly, DOE's Hurricane Irene and Superstorm Sandy after-action report demonstrated that many nuclear units in the Mid-Atlantic region had to be taken offline during the storm due to concerns related to their ability to continue operating safely.[97] When these units are taken offline, they often take two weeks or more to ramp back online,[98] even though the vast majority of grid emergencies and disturbances are resolved in a far shorter timeframe.[99]

[96] Georgia Power 2016 IRP Reserve Margin Study, submitted as part of Georgia Public Service Commission Docket 40161.

[97] U.S. Department of Energy. "Comparing the Impacts of Northeast Hurricanes on Energy Infrastructure." p13.

[98] Id.

[99] U.S. Energy Information Administration. Electric Power Monthly, Tables B1 and B2.

As above, it is not clear from DOE's proposed language how the NOPR would impact the generating fleet in the wholesale markets. Providing cost-of-service recovery for non-economic central-station generators, however, may very well crowd out additions of newer, more flexible, and more reliable and resilient units. As such, preservation of "fuel-secure" units beyond the point where they are economic may result in a less reliable grid overall, in addition to increasing costs.

4.3. DOE's Proposal May Stifle the Innovation Needed for Continued Improvement of Grid Resiliency

Ironically, DOE's proposal works counter to its own leadership in innovative initiatives to improve grid resiliency. Historically, DOE has been an important source of thought leadership. It has provided technical assistance, expertise, and funding for research programs and pilot projects related to grid resiliency. Many of these initiatives have been successful. For example, DOE's American Recovery and Reinvestment Act funding of energy storage projects led to the installation of over 500 MW of storage capacity[100]—and it fostered the growth of a rapidly expanding industry now worth hundreds of millions of dollars a year.[101]

DOE has several current initiatives aimed exactly at increasing grid resiliency. Most recently, Secretary Perry announced in September 2017 that DOE would provide $50 million in funding for research into distributed resources and cybersecurity, aimed at "improv[ing] the resilience and security of the nation's critical energy infrastructure."[102] These projects bring together national labs, universities, and private industry to develop the next generation of technologies that will enable the U.S. grid to respond to the threats of the future. Microgrids and related distribution system-focused technologies for resilience have been of particular interest. While microgrid technology remains in the initial stages of implementation and commercialization, there is growing evidence to support increasing investment in such installations. DOE itself has conducted or funded multiple pilot projects and studies that have demonstrated the ability of microgrids to reduce the impact of outages and decrease costs. One demonstration project was found to result in a 25x improvement in reliability while lowering utility

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[100] U. S. DOE. "ARRA Funds Support Almost 538 MW In New Energy Storage". Available online at: http://www.sandia.gov/ess/projects/arra-funding/

[101] Munsell, M. "US Energy Storage Market Experiences Largest Quarter Ever". GTM Research. June 6, 2017. Available online at: https://www.greentechmedia.com/articles/read/us-energy-storage-market-experiences-largest-quarter-ever

[102] U. S. DOE. "Energy Department Invests Up to $50 Million to Improve the Resilience and Security of the Nation's Critical Energy Infrastructure " September 12, 2017. Available online at: https://www.energy.gov/articles/energy-department-invests-50-million-improve-resilience-and-security-nation-s-critical

costs;[103] another resulted in a 7 percent improvement in SAIDI and an 8 percent reduction in outage-related costs.[104]

As discussed above, states are also experimenting and investing in new technologies. For example, the next decade may see several gigawatts of new offshore wind on the Eastern Seaboard (approximately 4 GW in Massachusetts[105] and New York,[106] with additional capacity in Maryland[107] and Delaware[108]). New York,[109] Massachusetts,[110] and other states are also installing microgrids, batteries, and other distributed resources for resiliency and grid modernization purposes.

These initiatives are both informed by and drivers of an experienced-based planning system. This model is most successful when local, state, and federal authorities collaborate to provide targeted funding and other interventions promoting those technologies and practices that have the greatest potential to increase grid resiliency at a reasonable cost. DOE's broad-brush proposal may undermine this important progress. A costlier energy market with a less-flexible, less-reliable fleet provides few opportunities and fewer incentives for continued innovation and investment—potentially undermining ongoing resiliency efforts by DOE and others.

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[103] Roley, R. "SPIDERS: Smart Power Infrastructure Demonstration for Energy Reliability and Security". DOE Energy Exchange. August 2016, p25. Available online at: http://www.2017energyexchange.com/wp-content/tracks/track4/T4S7_Roley.pdf.

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