UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resiliency Pricing	))))	**Docket No. RM18-1-000**

COMMENTS OF PUBLIC INTEREST ORGANIZATIONS, ENVIRONMENTAL DEFENSE FUND, NATURAL RESOURCES DEFENSE COUNCIL, SIERRA CLUB, EARTHJUSTICE, SUSTAINABLE FERC PROJECT, UNION OF CONCERNED SCIENTISTS, THE CENTER FOR BIOLOGICAL DIVERSITY, THE ENVIRONMENTAL LAW & POLICY CENTER, THE SOUTHERN ENVIRONMENTAL LAW CENTER, CONSERVATION LAW FOUNDATION, ENVIRONMENTAL WORKING GROUP, AND FRESH ENERGY

Pursuant to the Federal Energy Regulatory Commission's ("Commission" or "FERC") October 2, 2017 Notice, Environmental Defense Fund ("EDF"), Natural Resources Defense Council ("NRDC"), Sierra Club, Earthjustice, Sustainable FERC Project, Union of Concerned Scientists, The Center For Biological Diversity, The Environmental Law & Policy Center, The Southern Environmental Law Center, Conservation Law Foundation, Environmental Working Group, and Fresh Energy respectfully submit these comments in response to the Commission's request for comments on the Department of Energy ("DOE") September 28, 2017 proposal of a rule for final action by the Commission under Section 403 of the Department of Energy Organization Act[1] ("DOE Proposal" or "Proposal").[2]

[1] 42 U.S.C. § 7173 (2012) ("DOE Organization Act").
[2] Docket No. RM18-1, Department of Energy submits letter proposing a Proposal for final action and providing a copy of the Notice of Proposed rulemaking under RM18-1 (Sept. 29, 2017).

TABLE OF CONTENTS

I. Introduction

On September 28, 2017, the Secretary of Energy signed a notice of proposed rulemaking entitled the Grid Resiliency Pricing Rule, which was published in the Federal Register on October 10, 2017 ("Proposal").[3] The Secretary proposed the rule under Section 403 of the Department of Energy Organization Act of 1977 ("DOE Organization Act"),[4] which allows the Department to propose rules, and reasonable timelines for final action on those rules, for consideration by FERC. These comments take the Proposal at face value and explain why it is unlawful and unwise. But it must be said at the outset that the Proposal is a transparent attempt to reward a political ally through a generous and perpetual bailout.[5] Lacking any semblance of support in record evidence or in any defensible analysis of the energy markets and the law the governs them, the Proposal can only be understood as an effort to prop up the coal industry in service of the Administration's political pledge to revive it. This is obvious not only in light of the flimsiness of the Proposal given the enormous consequences for the energy markets, consumers, and the environment, but also in the absurdly short amount of time in which DOE believes it should be accomplished, and the suggestion that FERC implement it even before engaging with stakeholders and the public on its merits.

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[3] Department of Energy, Grid Resiliency Pricing Rule, 82 Fed. Reg. 46,940 (Oct. 10, 2017)

[4] 42 U.S.C. § 7173 (2012).

[5] Coal company CEO Bob Murray claims that President Trump ordered an aide to ensure that the White House National Economic Council give coal executives "whatever" they want, and ordered Secretary Perry to carry out those wishes. While DOE's action here is different in-kind from the original request, the result – bailing out select companies from bankruptcy – is the same. *See* Letter from Robert Murray, CEO of Murray Energy Corp. to John D. McEntee III, Special Assistant and Personal Aide to the President (Aug. 4, 2017), *available at* https://www.documentcloud.org/documents/3936141-Murray-s-letters-to-Trump-administration.html (describing an in-person exchange between Mr. Murray, the CEO of FirstEnergy, Charles Jones, and President Trump).

DOE goes to some minimal effort to fabricate a problem to which the Proposal responds, claiming that "[t]he resiliency of the nation's electric grid is threatened by the premature retirements of power plants that can withstand major fuel supply disruptions."[6] But it has no facts to back up this claim. The very term "resilience"—upon which the proposal purports to be based, but never actually defines—is clearly a trumped-up effort to fit an attribute to a specific set of preferred energy sources. To address this supposed grid "resiliency" crisis, DOE proposes a special, cost-based rate to facilities that meet particular eligibility requirements specifically tailored to DOE's politically preferred resources.[7]

As we describe below, despite DOE's apparent conviction otherwise, resilience has little to do with having a 90-day supply of fuel on site. The proposal's failure to consider the benefits of other resources capable of providing the same services to the system (including fuel-free resources such as demand response, new energy storage technologies, solar, and wind) provides further evidence that it was proposed for political purposes.

DOE proposes that coal and nuclear resources would receive recovery of all costs and a return on equity that "fully compensate[s] for the benefits and services [the eligible resource] provides to grid operations."[8] The Proposal does not specify how this cost-based compensation is to be reconciled with existing energy, capacity, and ancillary services revenues received by eligible resources in existing wholesale markets, what constitutes a 90-day supply of fuel, and

[6] 82 Fed. Reg. at 46,941, 46,945.
[7] *Id.* at 46,948. We note that the limitation of coverage to markets with energy and capacity markets did not appear in the version of the Proposal first published by DOE and included in Docket No. RM18-1. Rather this limitation is only present in the Federal Register. The reference to capacity markets in that version clearly includes PJM, NYISO and ISO-NE, each of which has a mandatory capacity market, but leaves open the question as to whether MISO's voluntary capacity auction would qualify generation located in that RTO for payments under the proposed regulations. The Proposal appears not to apply to SPP and CAISO.
[8] *Id.*

myriad other implementation issues. It does not appear to require that a resource deemed eligible for cost-based compensation actually perform during an "emergency."[9]

The Proposal is not the first politically motivated effort by DOE to fabricate a resiliency problem in an effort to justify a "solution" that would simply prop up the agency's preferred energy resources. On April 14, 2017, Secretary Perry issued a memorandum calling for his staff to produce a study, within 60 days, detailing the causes of "premature" retirement of so-called "baseload" plants, and asserting that unnamed "analysts" had raised alarm about the reliability of the grid absent these resources.[10] A June 26, 2017 leaked draft of the study contradicted the premise of the Secretary's memorandum, concluding that "many of the retired and retiring plants are unable to provide the services that are needed to maintain reliability" and that "many baseload plant retirements are not premature."[11] The DOE Staff Report, which was issued after some delay on August 23, 2017, notably excised these and other findings.

However, the final report reached conclusions that largely reflected the consensus of experts in the field that while further consideration should be given to understanding the services that make up "resiliency," the nation did not face a crisis even in the face of a rapidly changing grid.[12] The analysis in that DOE Staff Report also concluded that most of the baseload plants that had retired were reaching the end of their expected lifetimes. Much of the summary of findings and many of recommendations in the DOE Staff Report, however, were oddly disconnected from

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[9] *Id.* at 46,941.

[10] Memorandum to the Chief of Staff Re: Study Examining Electricity Markets and Reliability (Apr. 14, 2017).

[11] DOE, Electric Power Systems, Markets, and Reliability Study, Interim Draft Report at 9, 72 (June 26, 2017), *available at* https://info.aee.net/hubfs/docs/DOE%20Draft%20Report.pdf?t=1508459642978.

[12] DOE, Staff Report on Electricity Markets and Reliability (Aug. 2017), at https://energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf [hereinafter DOE Staff Report].

the evidence-based analysis in the body of the report, urging FERC to expedite its efforts to improve energy price formation.[13] The primary author of the technical portions of the report has expressed her view that the summary and recommendations made by Department Staff "missed some important points about reliability and resilience."[14]

Section 403 of the Department of Energy Organization Act grants DOE the authority to propose rules for FERC's consideration and the timeline on which FERC will issue final action on such proposals. Because proposals under 403 relate to FERC's core domain rather than DOE's, DOE should employ its Section 403 power only after careful consideration of a robust evidentiary record and a clear articulation of problem not being addressed through FERC's existing regulations. That clearly has not occurred in this case.

The lack of evidentiary support and blatant political motivation for the DOE Proposal are all the more disturbing given that the Department's precipitous action attempts to commandeer the agenda and energies of FERC, which only recently regained a quorum and faces a substantial backlog of critical matters. The Proposal represents a grave threat to FERC's independence that if adopted, would fundamentally alter both FERC's role in the industry and the power markets it regulates. Acting upon Secretary Perry's politically-driven proposal would severely disrupt energy markets and settled expectations, costing consumers billions of dollars. It would also do serious damage to public health and the environment, accelerating climate change that exacerbates the extreme weather events on which "resilience" appears to be premised. In the

[13] DOE Staff Report at 127.
[14] Alison Silverstein, If I'd written the DOE grid study recommendations (Oct. 2, 2017), UtilityDive, at http://www.utilitydive.com/news/silverstein-if-id-written-the-doe-grid-study-recommendations/506274/.

process, it would also do lasting harm to FERC's reputation as an independent, data-driven regulatory agency. FERC should dismiss this transparent political ploy.

II. Summary of Arguments

The overwhelming evidence—including from DOE's own cited sources—demonstrates that retirements of nuclear and coal-fired units pose no threat to reliability. Given this evidence, the DOE Proposal reaches, as it must, for an alternative theory to justify propping up its preferred energy sources. The DOE Proposal thus purports to address an unmet need for greater system "resilience" in the face of extreme weather events, and identifies on-site fuel storage as essential to ensuring resilience. But the Proposal never defines specifically what resilience entails, and fails to acknowledge its own Staff Report noting that this concept is in need of further study and evaluation rather than precipitous and ill-considered action. Without a clear definition of what grid services constitute resilience, any rule or rate purporting to procure it will be unjust and unreasonable and unduly preferential, in violation of the Federal Power Act ("FPA").

Among the cherry-picked studies and out-of-context statements offered to support its view that coal and nuclear units are indispensable to "resiliency," DOE gives particular importance to the 2014 Polar Vortex. However, contrary to DOE's misrepresentations, the Polar Vortex demonstrated that on-site fuel storage and fuel handling issues specific to coal were vulnerabilities, not assets, as coal piles and coal conveyor belts froze in the extreme cold. By contrast, PJM's post-mortem of the Polar Vortex highlighted better-than-expected performance by wind energy and demand response.

Contrary to DOE's view that fuel insecurity is a critical problem for the grid, the vast majority of outages are caused by transmission and distribution system outages that result from extreme weather. In an analysis attached to these comments, the Rhodium Group found, based on power disruption data from the last five years (a time period that includes the Polar Vortex), that an infinitesimal portion of outages resulted from fuel supply problems. Rhodium Group also examined the frequency and duration of outages experienced in different balancing authorities across the country, assessing whether a relationship exists between outage rates and the portion of coal and nuclear generation within a balancing authority. Rhodium Group concluded that "…increasing amounts of coal and nuclear generation on a utility's system has no relationship with improved reliability metrics."[15]

Likewise, the North American Electric Reliability Corporation ("NERC") does not view a 90-day fuel supply requirement as necessary for reliability, but instead concludes that a wide range of other resources, including renewable energy and storage can provide similar reliability services. Consequently, there would be no basis for FERC to find that the current market rules are unjust and unreasonable, a prerequisite to requiring grid operators to replace those rules with new ones of FERC's choosing.

Were FERC to adopt a final rule in response to DOE's Proposal, it would need to be consistent with the FPA's requirements that rates be both just and reasonable and not preferential or unduly discriminatory. A final rule remotely resembling the DOE Proposal would not meet these standards. First, DOE has not demonstrated that the eligibility criteria it proposes will actually ensure the provision of needed grid services, or that the proposed compensation scheme is a cost-effective way to address any concrete problems. The Proposal does not even require the favored resources to perform during extreme weather events, increasing the likelihood that

[15] Appendix D. Rhodium Group, "Electric System Reliability: No Clear Link to Coal and Nuclear," October 23, 2017.

consumers would pay out billions of dollars annually for no benefit at all. DOE's failure to define any problem or connect payments to specific services makes it impossible to demonstrate that the proposed rates comply with cost causation principles required by the FPA.

We estimate that over 49 GW of coal capacity and over 43 GW of nuclear capacity would be eligible for compensation under this Proposal. The total operating costs of eligible resources are significant and amount to over $14 billion annually. While estimating the cost of a proposal that lacks basic elements such as clear eligibility criteria, a defined compensation mechanism, and rules that clarify interactions with existing market mechanisms is challenging, under any scenario, the costs are massive. Because the DOE Proposal would impose cost-based ratemaking without requiring the crucial determination of whether costs incurred by an eligible generator are prudent, and because the Proposal lacks a sunset provision, there is a significant potential for costs to escalate indefinitely. Paying billions of dollars more per year, with no evidence of value in return, would amount to a textbook violation of the FPA's requirement to demonstrate just and reasonable rates.

DOE's proposed approach provides favorable, cost-based compensation only to so-called "fuel secure" resources, but not to fuel-free resources that are similarly situated in their ability to provide reliability services during extreme weather that might disrupt fuel supplies. Any final rule reflecting a preference for fuel-secure resources would constitute undue discrimination. The discriminatory intent of this proposal is readily apparent. In justifying the Proposal, DOE used its own ostensibly neutral term for the resources it seeks to advantage ("fuel secure resources") interchangeably with reference to coal and nuclear resources. It also expressly states that the Proposal's purpose is to forestall those plants' closure.

DOE's Proposal asks FERC to regulate in ways that would undermine state policies by interfering with states' choices regarding how to ensure resource adequacy, and states' decisions to incentivize the development of cleaner, cheaper, more flexible generation. These rights are reserved to states under the FPA, which explicitly preserves state authority to "ensure the safety, adequacy, and reliability of electric service."

Rather than supporting system reliability, DOE's Proposal is more likely to threaten it. Supporting existing generators that are, in general, very old and inflexible would affirmatively jeopardize system reliability. Propping up these units mutes financial signals that would otherwise incent the entry of new resources that would be better capable of meeting system needs. The Proposal would thus incentivize the category of generators that is among the *least* reliable to remain in operation, while crowding out resources that are less susceptible to outages. Synapse Energy Economics examined the RTOs most affected by the Proposal, and found that over 1.2 GW of coal capacity in MISO and 7.5 GW of coal capacity in PJM is over half a century old.[16] In examining outage rates across these two RTOs, the analysts observe exactly what one would expect: as the coal fleet ages, the outage rates increase significantly. And indeed, as aging coal units retire these outage rates decline, reducing the risk to the grid.

The DOE Proposal does great damage to yet another objective that it purportedly seeks to achieve: accurate price formation. Arbitrarily insulating certain generators from market forces undermines the process by which the competitive markets arrive at prices for non-eligible generators selling those same services.

The DOE Proposal strikes at the core of FERC's statutory mission and mandate by seeking to substantially (if not fatally) impair competitive wholesale markets. For FERC to

[16] Appendix E, Synapse Energy Economics, Inc. at E-22.

accept this proposal would require it to reject decades of work to cultivate market structures as the means to effectuate its mandate to ensure just and reasonable rates, free from undue discrimination or preferential treatment. It would also constitute a reversal of the Commission's preference to use cost-of-service ratemaking only as a last resort. Such a sweeping refutation of the Commission's policy of promoting market competition as the best means to protect the public interest, threatening the significant reliance interests vested in the functioning wholesale markets, without explanation would be both legally flawed and dangerous.

FERC would also need to comply with the National Environmental Policy Act prior to approving any changes to its rules along the lines that DOE proposes. Contrary to DOE's assertion that FERC's action would be categorically exempted from environmental review, that exemption does not apply where, as here, environmental impacts are relevant to the primary basis for the rate proposal. The very climatic events that DOE cites as the cause for urgency—extreme weather events—would be exacerbated by DOE's Proposal to preserve coal-fired power plants.

Finally, FERC must reject the DOE Proposal because the substance and process are both so egregiously inadequate that to approve it in any form would violate Administrative Procedure Act requirements. The public's opportunity to comment on this proposal is rendered meaningless by the lack of essential elements needed to understand it, and no final rule could be deemed a logical outgrowth of DOE's vague and sweeping proposal. The absurdly short period of time allowed for comment is inadequate given the extent of relevant studies and docket materials that could possibly be relevant given the profound changes DOE asks FERC to impose on consumers, states and market participants.

In sum, FERC must reject DOE's proposal, and the inherently flawed premise that on-site fuel supply represents an exclusive and paramount reliability characteristic. Section 403 of the Department of Energy Organizing Act may allow DOE to commandeer FERC's agenda through this Proposal, but it does not and cannot compromise FERC's independence.

III. Background

A. FERC's mandate and typical rulemaking practice.

The Commission is statutorily authorized to ensure adequate service at just and reasonable rates and through means that do not involve unduly discriminatory or preferential treatment. In regions of the United States where the system is operated by Independent System Operators ("ISOs") and Regional Transmission Organizations ("RTOs"),[17] the Commission has foundationally and fundamentally effectuated this mandate through competitive markets. The Commission's longstanding encouragement of wholesale markets is guided by its elemental conviction that wholesale competition is the best mechanism to cost-effectively provide reliable electric service in order to meet its statutory mandate.

When the Commission does take action, it must do so through reasonable determinations based on evidence and fact and through means that do not involve undue discrimination or preferential treatment. Procedurally, the Commission must first identify necessary grid services that are not adequately being provided for or compensated through existing rates, and only then, after extensive evidence and fact-finding, employ any market changes necessary to ensure those

[17] For simplicity's sake, throughout this document we use the term "RTO" to describe both Regional Transmission Organizations and Independent System Operators.

services.[18] Defining the necessary services in a non-discriminatory manner allows competition among resources to provide the necessary services at lowest cost.

Given the complexity of the electricity system, the need for extensive evidence and fact-finding requires processes that provide adequate time for input and examination. Commission rulemakings typically span a year or more, often commencing with technical conferences and stakeholder outreach well in advance of an initial proposal. By the time the Commission issues a final rule, it generally has had the benefit of multiple, highly substantive opportunities for stakeholder input to inform the deliberative process.[19]

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[18] The Commission's approach to ensuring adequate primary frequency response service on the grid illustrates a more measured and tailored approach. First, the nature of the service needed is carefully defined, as well as the amount of that service needed. Then, there is an assessment of whether the amount of that service currently provided by resources on the grid is sufficient, and whether steps are needed to ensure that it remains sufficient. Finally, FERC engages in a rulemaking process designed to seek maximum input from stakeholders on possible solutions, eventually proposing a narrowly tailored solution based on a careful assessment of the evidence. In 2014, FERC approved Reliability Standard BAL-003-1, as submitted by NERC, which describes the amount of frequency response needed in each interconnection. *See* Frequency Response and Frequency Bias Setting Reliability Standard, Order No. 794, 146 FERC ¶ 61,024 (Jan. 16, 2014). That same year NERC initiated the Essential Reliability Services Task Force to better understand how the grid's changing resource mix affects these services. With respect to primary frequency response, the Task Force recommended that all new generators support the capability to manage frequency. In February 2016 the Commission issued a Notice of Inquiry regarding potential requirements for new and existing generators to provide primary frequency response, while acknowledging that all three interconnections were currently comfortably in compliance with BAL-003-1. Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response, 154 FERC ¶ 61,117 (Feb. 18, 2016). In November 2016, FERC issued a proposed rule requiring all new generators to have primary frequency response capability. Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response, 157 FERC ¶ 61,122. That rule has yet to be finalized, as FERC recently sought supplemental comments on several narrow issues.

[19] *See e.g.*, Order 741, Credit Reforms in Organized Wholesale Electric Markets (Issued October 21, 2010) (technical conference in Jan. 2009, following by NOPR in Jan. 2010, final in Oct. 2010); Order 745, Demand Response Compensation in Organized Wholesale Energy Markets (Issued March 15, 2011) (Technical conference and staff reports began in 2006, NOPR issued March 2010, final in March 2011); Order 888, Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities (Issued April 24, 1996) (NOPRs issued in

B. Existing mechanisms to ensure reliability.

"Existing power markets are centrally attuned to ensuring reliable electricity service."[20] Reliability is safeguarded not only by existing FERC requirements and NERC standards, which RTOs rigorously pursue, but by a series of dynamic processes to assess and respond to evolving conditions on the grid. Within the RTO, a series of both market and other mechanisms work together to ensure reliability. The energy, capacity, and ancillary service markets each play an important role in this task, along different timeframes.[21] Individual RTOs have adopted other mechanisms over time to further support their reliability goals, including pay-for-performance, penalty rates for non-performance, reliability-must-run ("RMR") contracts, and dual fuel incentives.[22] Many RTOs have established reliability committees, an entity within the RTO tasked with assessing reliability and resiliency needs as they emerge on the horizon.[23]

At the same time, NERC has a mandate that focuses on upcoming threats to the grid, identifying its goals "to address events and identifiable risk, thereby improving the reliability of the bulk power system."[24] NERC is in a continual process of assessing, developing, monitoring, and enforcing reliability standards, relying on an intensive stakeholder-driven process. Under Order 693, NERC reliability standards are mandatory.[25]

March 1995, with technical conferences following); Order 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities (Issued July 21, 2011) (three technical conferences in Sept. 2009, request for comment Oct. 2009, Proposed Rule June 2010, final July 2011).

[20] Synapse at 3.
[21] *Id*. at 4.
[22] *Id*.
[23] *Id*.
[24] About NERC, NERC, http://www.nerc.com/AboutNERC/Pages/default.aspx
[25] Synapse at 5.

C. Scope of the DOE Proposal

The DOE Proposal appears to target exclusively merchant coal and nuclear generators located within PJM, MISO, ISO-NE, and NYISO.[26] Over 43 GW of nuclear capacity and 49 GW of coal capacity appear to be immediately eligible across these four RTOs. The vast majority of the resources targeted by the DOE Proposal are located within PJM, with only a little more than a quarter of the eligible capacity located across MISO (~17%), ISO NE (~4%) and NYISO (~7%). Within PJM, the more than 66GW of capacity targeted represents more than a quarter of peak load. Only four generation owners[27] (among the more than 50 owners with units affected) own about 50% of the targeted capacity.[28]

IV. DOE provides only vague or flawed bases for its Proposal, plainly failing to meet its burdens under Section 206 of the FPA

DOE bases its "urgent" request to the Commission on the fiction that the grid is under threat due to the retirement of baseload generation.[29] Yet the overwhelming consensus of experts considering the matter, including DOE's own, rejects that false premise. DOE appears to be asserting that the goal of the proposal is to achieve some new measure of grid performance,[30]

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[26] *See* Appendix [2], "xxx" (describing assumptions in estimating the scope of the proposal)
[27] Taking into account the affiliate operator's parent company.
[28] An independent analysis concluded that the 80% of the additional costs of the Proposal to support coal units would go to just 5 companies and, correspondingly, 90% of the costs go to just 5 companies. CPI Report at 2 Available at : http://energyinnovation.org/wp-content/uploads/2017/10/20171021_Resilience-NOPR-Cost-Research-Note-FINAL.pdf
[29] DOE Proposal at 2.
[30] DOE's vague conceptualization of "resiliency" appears to blur into reliability, which is a more clearly defined set of grid performance objectives. While we adopt the term in order to respond to DOE's use of the term, we do not concede that resiliency as DOE uses the term is distinct from reliability or actually defined and articulated. We use the term resiliency loosely throughout the comment to refer to both reliability *and* resiliency (while maintaining that it remains unclear exactly what value is added by the latter). We use the term reliability on its own when discussing FERC rules and practice, where the term stands in for a specific set of grid performance objectives (*e.g.*, adequate reserve margins, essential reliability services, operational reliability). *See infra* Section [IV.B].

"resiliency."[31] But beyond vague allusions to the concept, DOE never defines precisely what the Proposal aims to achieve. It never discusses specifically what services are purportedly not being compensated and provided for properly under the existing framework of rules, or *how* resiliency is allegedly being compromised. DOE's failure to define the problem is a fatal legal flaw. Under the FPA and Administrative Procedure Act ("APA"), FERC must demonstrate through reasoned decision-making and substantial evidence that existing rates are unjust and unreasonable before proposing a new rate. DOE's false claims and failure to explain do not meet those requirements.

A. FERC cannot propose new rates without demonstrating that existing rates are unjust and unreasonable or unduly discriminatory

To "impose a new rate," FERC must show *both* that newly proposed rates are just and reasonable, and that existing rates are "unjust, unreasonable, unduly discriminatory or preferential."[32] "[C]ourts have repeatedly held that FERC has no power to force public utilities" [such as RTOs] to file particular rates unless it first finds the existing filed rates unlawful."[33] In making these determinations, the Commission must "demonstrate that it has 'made a reasoned

[31] DOE Proposal at 11.
[32] *Maine v. FERC*, 854 F.3d 9, 21, 24-25 (D.C. Cir. 2017). *See also Cities of Bethany v. FERC*, 727 F.2d 1131, 1143 (D.C. Cir. 1984) (for "FERC itself" to "establish the just and reasonable rate," it must "first determine[] that [the] rate set by a public utility is unjust, unreasonable, or unduly discriminatory"). The fact that DOE has made its Proposal under Section 403 of the DOE Organization does not affect any of the requirements that the Proposal would have to meet if adopted by FERC. Such rules must comply with FPA requirements, including those under Section 206. In acting upon past proposals under Section 403, FERC has always complied with the substantive requirements of the statute granting the authority for the final rule. For example, in *Ceiling Prices; Old Gas Pricing Structure*, 51 Fed. Reg. 22,168 (June 18, 1986), FERC acted on a DOE proposal to revise the maximum lawful price for natural gas under Sections 104 and 106 of the Natural Gas Policy Act, which required that such price changes be "just and reasonable." 15 U.S.C. §§ 3314 and 3316 (1982).
[33] *Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 10 (D.C. Cir. 2002).

decision based upon substantial evidence in the record,'" and make "the path of [its] reasoning . . . clear."[34]

Both elements of FERC's dual burden must be met by "principled and reasoned" analysis,[35] and FERC must "explain its reasoning."[36] Moreover, the onus on the agency to explain its reasoning is more substantial "when 'its new policy rests upon factual findings that contradict those which underlay its prior policy; or when its prior policy has engendered serious reliance interests that must be taken into account.'"[37]

The onus to meet the dual burden under Section 206 is no less stringent where the Commission points to non-price factors, such as reliability.[38] This requires FERC to prove the existence of particular circumstances, trends, actions, and/or effects that make current rates unlawful.[39] Absent tangible evidence and sound reasoning indicating a market distortion, FERC would not meet its burden.[40] FERC's burden under Section 206 provides "statutory protection"

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[34] *NSTAR Elec. & Gas Corp. v. FERC.*, 481 F.3d 794, 802 (D.C. Cir. 2007) (quoting *Sithe/Independence Power Partners, L.P. v. FERC,* 165 F.3d 944, 948 (D.C. Cir.1999)).
[35] *Maine v. FERC*, 854 F.3d at 22 (quoting *S. Cal. Edison Co. v. FERC*, 717 F.3d 177, 181 (D.C. Cir. 2013).
[36] *TransCanada Power Mktg. Ltd. v. FERC*, 811 F.3d 1, 12 (D.C. Cir. 2015).
[37] *Perez v. Mortg. Bankers Ass'n,* 135 S. Ct. 1199, 1209 (2015) ("[t]he APA requires an agency to provide more substantial justification [under such circumstances]. It would be arbitrary and capricious to ignore such matters.") (quoting *F.C.C. v. Fox Television Stations, Inc*., 556 U.S. 502, 515 (2009)).
[38] *See TransCanada*, 811 F.3d at 13 (emphasizing FERC's burden to explain how non-price factors, including "reliability benefits," "justify the resulting rates." (internal quotation marks and brackets omitted).
[39] *See, e.g., Pub. Utilities Comm'n of State of Cal. v. FERC,* 462 F.3d 1027, 1051-52 (9th Cir. 2006) (finding rates unjust and unreasonable because purchases were made in an emergency must-buy situation that gave sellers improper market leverage over buyers).
[40] *Id.*

to utilities against the agency's imposition of new rates.[41] As such, Section 206's requirements are "'stricter' than those of Section 205." [42]

B. DOE's claim that the grid is under threat is not backed by evidence

DOE stakes the need and urgency for its Proposal on some unspecified but looming threat to the grid. It states that "chronic distortion of the markets . . . is threatening the resilience of the Nation's electricity system,"[43] and declares that "scheduled retirements of fuel-secure plants could threaten the reliability and resiliency of the electric grid."[44] But DOE's assertions are not supported by any specific explanations or data, and are inadequate to satisfy FERC's burden under Section 206 of the FPA. "Without further explanation, a bare conclusion that an existing rate is 'unjust and unreasonable' is nothing more than 'a talismanic phrase that does not advance reasoned decision making.'"[45]

While it is true that some existing generators (aging, uneconomic ones) are retiring, DOE never links this loss of generation to an undersupply of specific services needed for the system to operate reliably. More importantly, it also entirely fails to look at the bigger picture: that FERC's market mechanisms and regulations designed to ensure reliability naturally facilitate a process whereby new resources provide necessary grid services replacing those previously provided by resources that retire. The capacity markets operated by the RTOs covered by DOE's Proposal, for example, ensure supply is adequate to meet peak demand in a manner that *envisions*

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[41] *City of Winnfield, La. v. FERC.*, 744 F.2d 871, 875 (D.C. Cir. 1984).
[42] *Maine v. FERC*, 854 F.3d at 24 (quoting *City of Anaheim v. FERC*, 558 F.3d 521, 525 (D.C. Cir. 2009).
[43] DOE Proposal at 10.
[44] DOE Proposal at 5.
[45] *Maine v. FERC*, 854 F.3d at 27 (quoting *TransCanada*, 811 F.3d at 12-13).

retirements. These markets send a greater signal to incent the entry of new resources when resource supply is reduced.[46]

Nor does DOE's Proposal point to any evidence that supports its claim that the grid is under threat. At most, it cites evidence that recommends a continued assessment to ensure that reliability services that are *currently being met* will continue to be met going forward. DOE neither identifies any specific grid needs that have arisen as a result of plant retirements, nor provides a reasoned explanation as to how any such needs will arise. The Synopsis of NERC Reliability Assessments it cites, for example, supports continued evaluation to ensure that "sufficient amounts of essential reliability services, such as frequency and voltage support, ramping capability, etc.," are "replaced based on the configuration and needs of the system."[47] NERC explains that "[m]onitoring of the essential reliability services measures, investigation of trends, and use of recommended industry practices will highlight aspects that *could become* reliability concerns if not addressed with suitable planning and engineering practices."[48] In other words, these trends do not currently pose urgent reliability concerns. Likewise, the DOE Staff Report to the Secretary on Electricity Markets and Reliability suggests further inquiry in response to the loss of Essential Reliability Services provided by plants that retire, recommending first *defining* necessary services, and emphasizing the need for "further study."[49]

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[46] *See* Paul Hibbard, Susan Tierney, Katherine Franklin, *Electricity Markets, Reliability and the Evolving U.S. Power System*, Analysis Group, at 63 (June 2017) ("The retirement of aging resources is a natural element of efficient and competitive market forces, and where markets are performing well, these retirements mainly represent the efficient exit of uncompetitive assets, and will lead to lower electricity prices for consumers over time.").

[47] Synopsis of NERC Reliability Assessments at 3 (May 9, 2007).

[48] *Id.* at 7 (emphasis added).

[49] DOE Staff Report at 10.

Overwhelmingly, the evidence—including data from DOE's cited sources—demonstrates that retirements to date do not pose a problem. As DOE's own staff report states, "[Bulk Power System] reliability is adequate today despite the retirement of 11 percent of the generating capacity available in 2002, as significant additions from natural gas, wind, and solar have come online since then. Overall, at the end of 2016, the system had **more** dispatchable capacity capable of operating at high utilization rates than it did in 2002."[50] NERC's 2017 State of Reliability report concluded that "[Bulk Power System] resiliency to severe weather conditions continues to improve."[51] NERC's assessment of a variety of different reliability indicators concluded that nearly all were stable or improving in 2016.[52] Numerous other studies likewise conclude that system reliability remains strong and stable through current and ongoing market-based oversight.[53] DOE's bald assertion of an urgent threat does not withstand even superficial scrutiny.

C. The DOE Proposal does not explain what service it purports to provide the grid

Closely related to its vague claim of threat to the grid, the DOE Proposal purports to address a need for greater system "resilience" or "resiliency." But the Proposal never defines these terms or this supposed problem with any degree of specificity. To satisfy FPA and APA

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[50] *Id.* at 63 (emphasis added) (footnote omitted).

[51] NERC, State of Reliability 2017, at vii, 5 (June 2017), *available at* http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR_2017_MASTER_20170613.pdf.

[52] *Id.* at 27.

[53] 36 recent studies on the reliability of the nation's electricity system are available at http://blogs.edf.org/energyexchange/files/2017/06/DOE-Baseload-Study-Letter-Attachment.pdf and in Appendix A of this document. In addition to undermining DOE's unsupported suggestion that future retirements will cause reliability or resiliency problems, this data demonstrates that there is no reason for FERC to rush this proceeding by imposing a timeline for comments that is inconsistent with the requirements of the APA and FERC's precedent for similarly extensive rulemakings.

requirements, FERC must "cogently explain *why* it has exercised its discretion in a given manner."[54] An agency that fails to explain *what* precisely its action aims to achieve is paradigmatic arbitrary and capricious decisionmaking. This failure renders the Proposal incapable of meeting either element of FERC's dual burden or its procedural requirements under the APA; as such, FERC cannot finalize any rule resembling the Proposal. Indeed, DOE's failure to even attempt the task provides the Commission more than adequate basis to peremptorily reject the Proposal.

By its own admission, the DOE Proposal recognizes that DOE itself does not have "clear definitions of . . . resiliency-enhancing attributes."[55] This is a glaring deficiency in the Proposal because, without a definition, it is impossible to assess whether the undefined attribute is both necessary and not currently being compensated or otherwise provided for adequately under current market rules. FERC staff acknowledge as much in requesting that comments address "[w]hat is resilience, how is it measured, and how is it different from reliability?"[56] The difficulty for the Commission is that there is no industrywide accepted definition of "resilience" and no authoritative description of "resilience" that is independent of characteristics, attributes, and services already defined under reliability.[57]

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[54] *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 48 (1983) (emphasis added).
[55] DOE Proposal at 7 (citing DOE Staff Report at 10). Similarly, the DOE Quadrennial Energy Review cited in the proposal concludes that "there are no commonly used metrics for measuring grid resilience" and "there has been no coordinated industry or government initiative to develop a consensus on or implement standardized resilience metrics." DOE Quadrennial Energy Review at S-13, 4-3.
[56] Request for Information re section 403 of the DOE Proposal by the Federal Energy Regulatory Commission under RM18-1, at 1 (Oct. 4, 2017).
[57] *See, e.g.,* Taft, PNNL, Electric Grid Resilience and Reliability for Grid Architecture, at 1 (June 2017) ("attempts to define and quantify a concept of resilience for electric power grids have mostly relied upon ad hoc definitions that do not have much underlying rigor and are often closely tied to reliability").

Many descriptions of “resilience” from other sources are indistinct from reliability and lack analytic rigor. For example, resilience is often referred to as the ability for the grid to ride through high impact, low frequency events or recover from them quickly.[58] But these characteristics are already inherent in the definitions and metrics assessing the reliability of the system. For example, reliability metrics like Loss of Load Hours (LOLH) limit the frequency and duration (and thus recovery time) of events, and Estimated Unserved Energy (EUE) limit the energy unavailable to serve load.[59]

Others, including PJM and the National Academies, reinforce that “resilience” has no defined or quantified criteria, while metrics and definitions for reliability and reliability services are relatively well developed.[60] As The Brattle Group puts it in a report included with comments filed in Docket RM18-1 today, there is no *operational* definition of resilience that could enable an assessment of it independent from FERC’s existing reliability metrics and form the basis for regulations to improve or maintain resilience.[61] Regulating resilience separately from reliability in any manner (let alone providing compensation on that basis as the Proposal suggests) risks

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[58] While the DOE Staff Report at 63 discusses NERC’s use of the “infrastructure resilience” definition that the National Infrastructure Advisory Council developed, this does not pertain to any resilience attributes of non-infrastructure components such as onsite fuel supply: “Infrastructure resilience is the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event.”
[59] The Brattle Group, “Evaluation of DOE’s Proposed Grid Resiliency Pricing Rule” Attachment to the Comment of NextEra Energy, MR18-1 (Oct. 23, 2017).
[60] National Academies of Sciences, Engineering, and Medicine, *Enhancing the Resilience of the Nation's Electricity System*, at 32 (2017), https://doi.org/10.17226/24836 (NAS) (“Unlike reliability, there are no generally agreed upon resilience metrics that are used widely today.”); PJM Interconnection, L.L.C, “PJM’s Evolving Resource Mix and System Reliability” at 6 (March 30, 2017) (PJM whitepaper), *available at* http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx (“unlike the reliability services used in this analysis, criteria for resilience are not explicitly defined or quantified”).
[61] Brattle Group, supra, note 58 at 7.

redundant and overlapping measures that could create confusion and inefficiency. Any rational approach to investigating any potential areas that may not be fully addressed by the existing framework of regulations must necessarily proceed methodically based on robust evidence to avoid such a result.

But tellingly, DOE's Proposal completely ignores its own internal effort to better define and measure system resilience. DOE is currently in the midst of a 3-year Grid Modernization Initiative to "select, describe and define metrics for the purpose of monitoring and tracking system properties of the electric infrastructure as it evolves over time."[62] One metric this effort is focused on is resiliency. The initiative's latest report agrees with the NAS report and others that "widely-accepted metrics for resiliency do not exist,"[63] and sets forth a plan to pilot a new set of resilience metrics. Unsurprisingly, none of these metrics focus on on-site fuel supplies or so-called "fuel secure" resources.[64] Presumably because this analytical effort does not promise to prop up economically failing coal plants, the DOE Proposal sidesteps it entirely.

In stark contrast to "resilience," various metrics and definitions exist for reliability and reliability services. The DOE Staff Report notes that NERC defines reliability as a function of: "the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components" and "the ability of the electric system to withstand sudden disturbances to system stability or unanticipated loss of system components."[65]

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[62] Grid Modernization Laboratory Consortium, *Grid Modernization: Metrics Analysis*, Reference Document, Version 2.1, at iii (May 2017).
[63] *Id.* at vi.
[64] Indeed, the entire report includes not a single mention of on-site fuel.
[65] DOE Staff Report at 61.

Nothing in the DOE proposal indicates that there is some service needed beyond what already exists for reliability services. The DOE Staff Report acknowledges NERC-defined Essential Reliability Services that help maintain and restore the frequency and voltage on the grid during and after an event, in addition to the various reserves from which grid operators can obtain these services on various timescales.[66] These services and their provision are the subject of recent FERC rulemakings as well as NERC and RTO activity, none of which found any deficiencies requiring urgent action.[67]

Lacking a definition of "resilience" independent of reliability, the Proposal conflates the two throughout. This failure to define "resilience," distinguish it from "reliability," and break it down into measurable components prevents DOE from conducting a robust analysis of what resilience services are not already provided by current NERC and FERC standards and regulations, assessing how much of these services are needed, and determining what they are worth.[68] The Proposal lacks these essential characteristics; foundational evidence, greater specificity, and rigor are conspicuously absent. Furthermore, as explained below, because it is unclear what grid service would be procured through this Proposal, it would be impossible for FERC to demonstrate that the extraordinary cost-based payments proposed by DOE are either just and reasonable or nondiscriminatory, as the FPA requires.

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[66] DOE Staff Report at 68-70.

[67] Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response, 157 FERC ¶ 61,122 (Nov. 17, 2016) (finding current levels of primary frequency response capability adequate to meet NERC standards in all interconnections, but amending interconnection agreements to require new generation to install frequency response capability to ensure continued adequate levels of this service).

[68] As discussed further in Section VI, this failure to define resilience also contributes to the impossibility of accurately calculating the costs of the Proposal.

D. The Polar Vortex demonstrates that on-site fuel storage does not, as DOE suggests, ensure enhanced resiliency

DOE gives singular importance to one recent grid event—the 2014 Polar Vortex—which was a period of extremely cold winter weather throughout much of the country that caused many generators to have operational issues and be unable to perform as required. Despite its centrality to DOE's case for urgency, DOE misrepresents the lessons learned from the Polar Vortex and as a result, concocts a proposal that does nothing to improve reliability. Unlike other aspects of the DOE Proposal, its discussion of the Polar Vortex at least hints at a particular service that may be needed (electricity supply during extreme weather), but because DOE so fundamentally misunderstands the implications of the Polar Vortex, its effort to leverage that event for its objective of propping up uneconomic coal and nuclear plants fails utterly. Neither the Polar Vortex nor any other grid emergency briefly alluded to by DOE adds up to the type of demonstration required to satisfy the Commission's burden to demonstrate that existing rates are unjust and unreasonable under Section 206 of the FPA.

Of the 35,000 MW of generation capacity that failed to respond, nationwide, during the Polar Vortex, 26 percent was coal and 5 percent was nuclear.[69] DOE has not provided any analysis that assesses availability according to whether the plants had 90 days of fuel available on site. While a significant amount of natural gas capacity also experienced outages, the majority of those outages related to frozen equipment, *not* fuel supply issues. As NERC's report reviewing the Polar Vortex explains, "[o]f the approximately 19,500 MW of capacity lost" in the Eastern Interconnection and ERCOT "due to cold weather conditions, over 17,700 MW was due

[69] DOE Staff Report at 98.

to frozen equipment."[70] The DOE Staff Report relates similar problems with coal generation: "many coal plants could not operate due to conveyor belts and coal piles freezing."[71]

In PJM specifically, only a quarter of the record high 22% forced outage rate on January 7, 2014 was the result of fuel supply issues.[72] Far more significant were other causes such as faulty plant maintenance and weather-related damage. *Id.* PJM's own "Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events" highlights better-than-expected performance by wind energy and demand response—two resources that are not reliant on fuel:

> Although operational conditions were tight during the Polar Vortex, some variables exceeded PJM's expectations in real-time: the availability and response of voluntary demand response, the response of the stakeholders to the public appeal for conservation, and the performance of wind-powered generation. Demand response, although not required to respond during the winter this year, did respond and assisted in maintaining the reliability of the system. In fact, the total amount of demand response provided was larger than most generating stations. During the Polar Vortex, PJM called on demand response three times – the morning and evening of January 7 and the morning of January 8 throughout the RTO. Even though demand resources were not obligated to respond during this period, close to 25 percent of the demand response resources registered in PJM did respond and helped PJM manage the grid on the all-time winter peak day. This experience demonstrates the year-round value of demand response. . . . PJM also saw up to 4,000 MW produced by wind power during the peak load periods of January 6-7. Figure 12: shows that wind power produced at a level above the calculated wind capacity, (typically 13 percent of total wind capability). The wind power produced had a positive impact on supply and contributed to PJM's ability to maintain reliability.[73]

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[70] NERC Polar Vortex Review, at 2, 13 (2014), *available at* http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.

[71] DOE Staff Report at 98 (citing PJM Interconnection, Analysis of Operational Events and Market Impacts during the January 2014 Cold Weather Events (May 8, 2014), *available 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).

[72] 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, at Figure 16: Causes of Forced Outages – January 7, 7:00 p.m.

[73] *Id.* at 19-21

Similarly, in ISO-NE and MISO, resources that do not depend on fuel played an important role to ensuring reliability during the Polar Vortex. As explained in a letter to the U.S. House of Representatives Energy and Commerce Committee addressing performance during the Polar Vortex, ISO NE procured over 21 MW of demand response resources to help maintain 30-minute operating reserves.[74] These resources "were a valuable part of maintaining reliability during the winter season." Renewable energy resources "were an important part of the mix" contributing six to seven percent of peak electricity demand, on the day nationwide demand for natural gas hit an all-time peak.[75] In MISO, wind generation provided between 1.2 GW and 9.4 GW during peak load on Polar Vortex days.[76] While certain wind resources became unavailable due to extreme weather, advanced wind-forecasting tools allowed MISO to successfully plan for that variation.[77] Finally, while lack of available fuel was a contributing factor to the unavailability of natural gas-fired capacity in ISO-NE, no analysis supports the conclusion that more generation with on-site fuel storage is the solution to avoiding future performance failures. To the contrary, there is emerging evidence that addressing deep flaws in how pipeline capacity is allocated is perhaps most critical to ensuring gas supply for power generators during times of high demand.[78]

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[74] Letter from ISO-NE to U.S. House of Representatives Committee on Energy & Commerce (April 18, 2014) at 8, available at https://www.iso-ne.com/pubs/pubcomm/corr/2014/2014-04-18-iso-ne-response-to-house-energy-commerce.pdf.

[75] *Id*.

[76] Midcontinent Independent System Operator, Inc., 2013–2014 MISO Cold Weather Operations Report (Nov. 2014) at 11, figure 6. Available at: https://www.misoenergy.org/Library/Repository/Report/Seasonal%20Market%20Assessments/2013-2014%20Cold%20Weather%20Operations%20Report.pdf

[77] *Id*. at 14.

[78] Marks, Mason, Mohlin, Zaragosa-Watkins, *Vertical Market Power in Interconnected Natural Gas and Electricity Markets* (Working Paper: October, 2017). Available at: https://www.edf.org/sites/default/files/vertical-market-power.pdf (with recommendations to

Further, DOE's Proposal would support a fleet of merchant coal units that, in fact, *performed quite poorly* during the Polar Vortex. [79] Analysis by Synergy Energy Economics of hourly generation data reveals that, after initially ramping up to meet growing demand, the coal fleet's performance began to decline even before the peak hour on January 6, 2014.[80] By PJM's winter peak on the evening of the 7th, coal output had fallen by more than 2,500 MW relative to its peak from the prior day.[81] Even among units that remained online, most coal units provided less output at the season peak than they had the previous day.

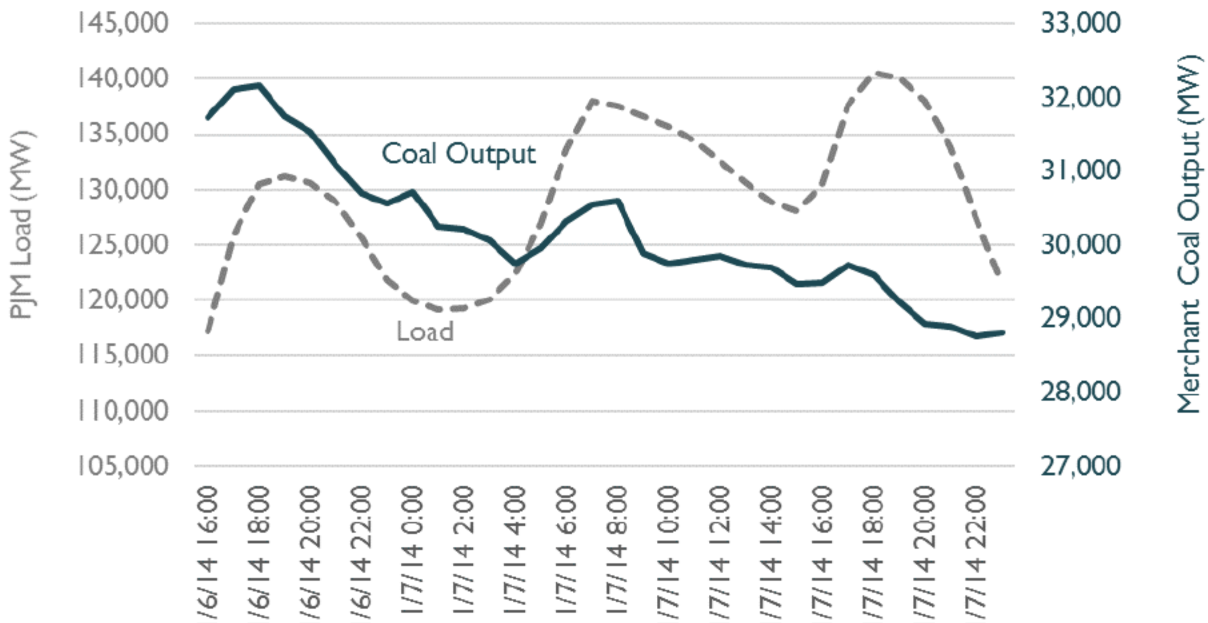
improve market efficiency and gas/electric coordination including "[p]ipeline market reforms that facilitate more flexible contracting mechanisms, more frequent scheduling cycles, and act to prevent capacity withholding, or impose a cost for capacity withholding and create a publicly-available record of capacity withholding; all of which will serve to better align the gas transport and electricity markets, could help to create more liquid markets in which firms find it more difficult to exert market power.").

[79] 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. Appendix E at E-15.

[80] *Id.*

[81] *Id.*

Figure 1: PJM Load and Merchant Coal Output During the 2014 Polar Vortex



DOE's retelling of the Polar Vortex omits all these critical facts that are not consistent with its premise that generation with on-site fuel storage is necessary for reliability. DOE also omits other essential, and rather basic details, of the Polar Vortex story. For example, although fossil-fueled generators failed to perform at an alarming rate during the Polar Vortex, no customer lost power. In the PJM region, which faced the brunt of the plummeting temperatures associated with the Polar Vortex, 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*."[82] This is in large part because each RTO provides for a planning reserve margin precisely to ensure reliability in the event that many supply resources are impacted at the same time, as occurred during the Polar Vortex. "Rather than illustrating a problem, the operational response to the Polar Vortex instead demonstrates both the foresight of

[82] *Id.* at E-14.

RTO/ISO/utility preparedness, and the success of the market, regulatory, and stakeholder-driven solutions to ensure reliability during unprecedented and extreme conditions."[83] Accordingly, DOE's proffered anecdotal evidence of a *near* loss of power, where supplies (with the critical contribution of fuel-less sources) *did* prove adequate, is not on its own evidence of a problem with the existing system of regulation.

Further, DOE does not address at all the reforms carried out after the Polar Vortex, which aimed to address the failings during the event. In response to the Polar Vortex, on April 1, 2014, the Commission held a technical conference focused on the impacts of the Polar Vortex and actions to respond.[84] During the conference, RTOs discussed actions they had already put in place to address winter reliability concerns, and improvements in process for future winter seasons.[85] On November 20, 2014, the Commission issued an Order to initiate a review of how each RTO was addressing "fuel assurances", a "broad concept" intending to encompass "a range of generator-specific and system-wide issues, including the overall ability of an RTO's/ISO's portfolio of resources to access sufficient fuel to meet system needs and maintain reliability." The Order noted that there were a variety of approaches RTOs could consider in addressing market and system performance concerns, ranging from a focus on providing incentives to more administrative approaches.[86]

[83] *Id.*

[84] Notice of Technical Conference, "Winter 2013-2014 Operations and Market Performance in Regional Transmission Organizations and Independent System Operators" AD14-8 (February 21, 2014).

[85] For example, ISO-NE noted in its comment that the Commission's clarification of generator obligations (including strict performance obligations) was a significant step already taken to ensure better winter performance among its oil units, while proposing further performance incentives. Speaker materials of Peter Brandien on behalf of ISO New England, Winter 2013-2014 Operations and Market Performance in RTOs and ISOs Technical Conference, AD14-8 (April 1, 2014).

[86] Order on Technical Conferences, AD13-7 and AD14-8, 149 FERC ¶ 61,145

Each affected RTO responded to this directive, and ultimately adopted a series of reforms intended to address winter performance concerns. For example, PJM implemented a series of common-sense nonmarket reforms to improve generators' preparedness for winter conditions.[87] In the very next winter, despite even higher peak winter loads, PJM saw much lower forced outage rates than during the Polar Vortex, and improved performance among generators that had participated in pre-winter operational testing—one of the reforms PJM put in place following the Polar Vortex.[88] In addition, both PJM and ISO-NE modified their capacity market rules so as to ensure supplier performance during scarcity conditions.[89] MISO, which largely credited proper functioning of its energy market and its load forecast accuracy for maintaining reliability under challenging Polar Vortex conditions,[90] concluded that "lessons learned" from the 2014 winter season "provided valuable experience in managing operations" in subsequent seasons.[91] When MISO saw near record peak loads in the following winter in spite of milder temperatures, its "markets and reliability operations performed well."[92]

(November 20, 2014).

[87] *See* Protest of Public Interest Organizations, FERC Docket No. ER15-623-000, at Appendix B (summarizing PJM's extensive measures to improve generator preparedness), attached hereto as Appendix G.

[88] *See* PJM Interconnection, 2015 Winter Report (May 13, 2015), at http://www.pjm.com/-/media/library/reports-notices/weather-related/20150513-2015-winter-report.ashx?la=en, at 5-6.

[89] *See* Order on Proposed Tariff Revisions, 151 FERC ¶ 61,2018 (2015); Order on Tariff Filing and Instituting Section 206 Proceeding, 147 FERC ¶ 61,172 (2014).

[90] MISO, 2013–2014 MISO Cold Weather Operations Report at 6, 12 (Nov. 2014) Available at: https://www.misoenergy.org/Library/Repository/Report/Seasonal%20Market%20Assessments/2013-2014%20Cold%20Weather%20Operations%20Report.pdf

[91] MISO, 2014-2015 Winter Assessment Report: Information Delivery and Market Analysis, at 4 (May 2015), *available at* https://www.misoenergy.org/Library/Repository/Report/Seasonal%20Market%20Assessments/2015%20Winter%20Assessment%20Report.pdf

[92] *Id*. at 3.

In addition to the Polar Vortex, the Proposal briefly invokes other more recent weather events such as "Superstorm Sandy and Hurricanes Harvey, Irma and Maria," among the reasons for the proposed action, yet it includes no discussion as to whether fuel supply disruptions contributed to system outages during those events, or whether outages that occurred resulted instead from other failures in the electricity system. Superstorm Sandy caused 8.66 million customer outages across 20 states and the District of Colombia, but a separate DOE report attributes these to damage to transmission and distribution networks.[93] DOE concluded in that report that "Sandy did not have a major impact on natural gas infrastructure and supplies in the Northeast," and did not point to *a single case* of electric generator fuel security issues triggered by Sandy in its assessment. But what did fail during Sandy, again according to DOE, were *nuclear plants*. Many shut down 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.[94] Additionally NERC identified over 16.7 GW of fossil fuel capacity (coal-, gas-, or oil-fired steam turbines) that "became unavailable" during the storm.[95] NERC also observed 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." Similarly, DOE's own reporting from Hurricanes Harvey, Irma, and Maria refute

[93] *Id*. at 15 (citing DOE, "Comparing the Impacts of Northeast Hurricanes on Energy Infrastructure" (April 2013), *available at* http://www.oe.netl.doe.gov/docs/Northeast%20Storm%20Comparison_FINAL_041513c.pdf.).
[94] *Id.* (citing DOE " Hurricane Sandy Situation Report # 5" (October 30, 2012), *available at* http://www.oe.netl.doe.gov/docs/2012_SitRep5_Sandy_10302012_300PM_v_1.pdf
[95] Synapse at 15 (citing NERC. "Hurricane Sandy Event Analysis Report". January 2014. p23. Available at: http://www.nerc.com/pa/rrm/ea/Oct2012HurricanSandyEvntAnlyssRprtDL/Hurricane_Sandy_EAR_20140312_Final.pdf)

any linkages between the massive outages related to these events and issues of fuel shortage.[96] Such outages are again attributable to the decimation of transmission and distribution networks during extreme weather.[97]

In sum, DOE utterly fails to explain what its proposal aims to achieve. It fails to meet the requirements of Section 206 of the FPA because it does not identify any concrete problem that renders existing rates unjust and unreasonable or unduly discriminatory. It claims the Proposal is necessary to enhance the "resiliency" of the grid, without every saying what that word means. It alleges it would solve a grid crisis that DOE's own evidence says doesn't exist. And it argues that the Proposal is necessary to prevent the next Polar Vortex crisis even though the evidence is clear that the Proposal wouldn't have prevented the core operational issues of the first Polar Vortex, and other reforms that *do* address those issues are already in place.

E. A detailed examination of outages further demonstrates that on-site fuel supply is not correlated with reliability

Rhodium Group has studied outage data between 2013 and 2016, relying on information submitted by distribution utilities to the DOE Energy Information Administration ("EIA")

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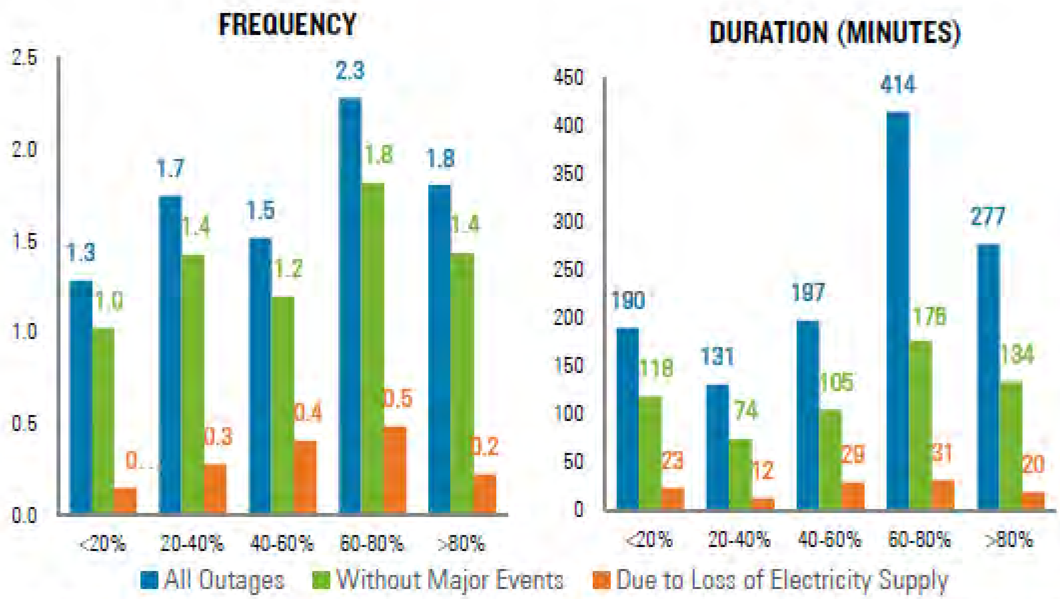
[96] *Id*. (citing .DOE, "Hurricanes Nate, Maria, Irma and Harvey October 13 Event Summary: Report # 64" (October 13, 2017), *available at* https://energy.gov/sites/prod/files/2017/10/f37/Hurricanes%20Nate%2C%20Maria%2C%20Irma%20and%20Harvey%20Event%20Summary%20October%2013%2C%202017.pdf

[97] On October 9, 2017, nearly three weeks after Hurricane Maria made landfall in Puerto Rico, a company spokesman reported that Unit 2 at the AES Puerto Rico coal plant, a so-called "fuel-secure" resource located in Guayama, remains offline. *See* AES Provides an Update on Operations in Puerto Rico and the U.S. Virgin Island, Following Recent Hurricanes (Oct. 9, 2017), *available at* http://aes.com/investors/press-releases/press-release-details/2017/AES-Provides-an-Update-on-Operations-in-Puerto-Rico-and-the-US-Virgin-Islands-Following-Recent-Hurricanes/default.aspx. Meanwhile, AES reported that energy storage it had deployed in the Dominican Republican ""played a key role in maintaining grid stability" during both hurricanes Irma and Maria. *See Dominican Republic energy storage stayed resilient during Hurricanes Irma and Maria, AES claims* (Oct. 18, 2017), *available at* https://www.energy-storage.news/news/dominican-republic-energy-storage-stayed-resilient-during-hurricanes-irma-a.

through Form 861.[98] They cross-referenced this data with generation data submitted through Form 923 to the EIA, in order to assess the generation mix of the Balancing Authority in which each distribution utility is located. These combined data sets allow for an examination of the relationship between the share of coal and nuclear ("fuel secure") generation within a Balancing Authority and the frequency and duration of outages experienced by a distribution utility within that Balancing Authority. Rhodium Group's analysis finds no evidence of any relationship between the generation share of coal and nuclear and the frequency or duration of outages experienced, as evidenced below in the figure below ("average customer electric outages") [99] Rhodium concludes that "increasing amounts of coal and nuclear generation on a utility's system has no clear relationship with higher performance regarding reliability metrics."

[98] Rhodium Group, Electric System Reliability: No clear link to coal and nuclear (Oct. 23, 2017), available at http://rhg.com/notes/doe-nopr-ferc-comments and attached hereto as Appendix D.
[99] Conversely, Rhodium Group also finds that there is no relationship between the share of variable renewable generation and the frequency and/or duration of outages; in other words, there is no evidence to support the claim that renewables growth is eroding overall system reliability. In fact, Rhodium Group notes that utilities in Balancing Authorities with the highest share of RE generation (> 20%) experienced the fewest outages in terms of both frequency and duration.

Average customer electric outages by combined coal and nuclear market share, 2013-2016*



Source: Rhodium Group analysis, EIA. Note: Loss of supply during major events is included in loss of electricity supply.

If coal and nuclear generators made the system more reliable, one would expect that the frequency and duration of outages would be lower in regions with higher shares of these resources. As shown in the figure above, Rhodium Group found no relationship between the frequency and duration of outages and the portion of system supply served by coal and nuclear generators.

The Rhodium Group analysis confirms that there is no evidence that on-site fuel supply improves overall system reliability, and serves to reaffirm that this Proposal would not result in any concrete reliability or resiliency benefits for customers.

V. The DOE Proposal targets resources for preferential rates based on technology type, in violation of the FPA's duties to demonstrate that rates are just and reasonable and not unduly discriminatory

Rather than identifying any specific grid services that are being inadequately compensated under existing rates and developing methods to compensate those specific services, the DOE Proposal simply creates a set of criteria designed to render coal and nuclear resources eligible for preferential compensation while excluding similarly situated resources. Specifically, the DOE Proposal uses criteria not to serve as neutral standards by which resources can be judged but instead as arbitrary tailoring conditions that only coal and nuclear can meet.

This approach violates the FPA in several ways. First, because DOE has not demonstrated that the criteria are connected to the provision of grid services, or that the proposed compensation scheme is a cost-effective way to address any concrete problems, the Proposal fails to meet the requirement that newly proposed rates be just and reasonable. Second, because the approach does not provide the same compensation to similarly situated resources capable of providing the same (undefined) services, it is unduly discriminatory. Finally, DOE's failure to define any problem or connect payments to specific services also makes it impossible to demonstrate that the proposed rates comply with cost causation principles required by the FPA.

Below, we summarize the FPA requirements that FERC must meet in proposing new rates, and explain why DOE's proposed compensation scheme fails to meet these standards.

A. Prior to adopting a new rate, FERC must demonstrate based on substantial evidence and reasoned decision-making that the rate is just and reasonable and not unduly discriminatory

As discussed above, the FPA requires that FERC demonstrate that newly proposed rates are just and reasonable.[100] While FERC is permitted to include non-price factors in its assessment of whether rates are just and reasonable, it must offer a "reasoned explanation of how

[100] Such a demonstration is required under both sections 205 and 206 of the FPA. 16 U.S.C. §§ 824d(a), 824e(a).

the [relevant] factor[s] justif[y] the resulting rates."[101] This is as true for reliability as it is for other non-price factors.[102] Such an explanation must explain "what [FERC's] 'balancing' entail[s], or how it applie[s] the non-cost factors."[103] FERC may not simply "refer[] to 'reliability benefits,' as if to suggest that certain suppliers should be free to command high prices because of their reliability."[104] Rather, it must "demonstrate[] that there would be no excess of profits."[105]

Section 205(b) of the Federal Power Act provides that a utility may not "grant any undue preference or advantage" or "subject any person to any undue prejudice or disadvantage."[106] This prohibits rates and practices that discriminate or confer a preference on one group of market participants over another without an adequate justification.[107] Likewise, Section 206 requires the Commission to replace any proposal, regulation or practice that it finds is "unduly discriminatory or preferential."[108] By corollary, the Commission cannot require the adoption of a regulation, rate, or practice that would be unduly discriminatory or preferential. Compliance with the FPA's prohibition against undue discrimination, like its obligation that rates be just and reasonable, must be demonstrated through reasoned decision-making based on substantial evidence.[109]

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[101] *Farmers Union Cent. Exch., Inc. v. FERC*, 734 F.2d 1486, 1502 (D.C. Cir. 1984).
[102] *See Transcanada*, 811 F.3d at 13.
[103] *Id.*
[104] *Id.*
[105] *Id.*
[106] 16 U.S.C. § 824d(b).
[107] *See, e.g.*, Elec. Consumers Res. Council v. FERC, 747 F.2d 1511, 1515 (D.C. Cir. 1984).
[108] 16 U.S.C. § 824e.
[109] *Maine Pub. Serv. Co. v. FERC,* 964 F.2d 5, 11 (D.C. Cir. 1992) (Court will not take it on faith and rejects evidence that is insubstantial); *Sithe/Independence Power Partners, L.P. v. FERC,* 165 F.3d 944, 951-52 (D.C. Cir. 1999) (remanding where FERC failed to "disclose in any meaningful way the underlying data and assumptions that supported its factual findings" and offered only "cryptic" reasoning).

A rate is "*undu[ly]* preferen[tial]" or discriminatory unless the proposing utility or FERC can "justify[] these different effects."[110] Where FERC approves a rate that treats market participants in a discriminatory manner, it must provide a rational reason for doing so.[111] FERC may provide for "disparate treatment . . . only if [it] offers a valid reason for the disparity." [112] Unless FERC offers such a valid reason, its decision to approve disparate treatment of wholesale ratepayers is "arbitrary and capricious."[113]

B. DOE's proposed criteria seek to support coal and nuclear generators rather than ensure adequate grid services

In order to be eligible for preferential, cost-based compensation under the DOE Proposal, a resource must meet *all* of the following criteria[114]:

> (A) Be "physically located within a Commission-approved independent system operator or regional transmission organization;"

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[110] *Elec. Consumers Res. Council*, 747 F.2d at 1515 (internal quotation marks omitted); *see also Black Oak Energy, LLC v. FERC*, 725 F.3d 230, 239 (D.C. Cir. 2013) (differential treatment is not "undue" if "differences between parties . . . are relevant to the achievement of permissible policy goals").

[111] *Envtl. Action, Inc. v. FERC*, 939 F.2d 1057, 1062 (D.C. Cir. 1991) (finding that FERC approval of tariff that did not provide equal transmission access to qualifying facilities as for utility-owned generation resources was unduly discriminatory).

[112] *Black Oak Energy*, 725 F.3d at 239 (alterations and internal quotation marks omitted).*See also PJM Interconnection, LLC*, 110 FERC ¶ 61,053, 61,245 (Jan. 25, 2005) (if generators are "similarly situated," in the services they provide, but compensated at different rates, such a Proposal "is unduly discriminatory"); *accord Calpine Oneta Power, L.P.*, 116 FERC ¶ 61,282, 62,390 (Sept. 26, 2006) ("Because [other generators] are similarly situated, compensating AEP's generators for their capability of providing reactive power and denying [other generators] for similar capability is unduly discriminatory.").

[113] *See id.* at 237. *Motor Vehicle Mfrs. Ass'n of the U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (holding that in order to survive review under the "arbitrary and capricious" standard, "the agency must examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made" (internal quotation marks omitted)).

[114] 82 Fed. Reg. at 46,948. When the Proposal was published in the Federal Register, an amendment to the "Scope of application" section specified that only resources located within an RTO or ISO with both energy and capacity markets could be eligible for the reliability and resiliency rate.

(B) be “able to provide essential energy and ancillary reliability services, including but not limited to voltage support, frequency services, operating reserves, and reactive power;”

(C) have “a 90-day fuel supply on site enabling it to operate during an emergency, extreme weather conditions, or a natural or man-made disaster;”

(D) be “compliant with all applicable federal, state, and local environmental laws, Proposals, and regulations; and”

(E) not be “subject to cost of service rate regulation by any state or local regulatory authority.”

The DOE Proposal never explains in concrete terms the link between the combination of these criteria and any specific reliability and undefined resiliency benefits (met or unmet by the current system or regulation), or the need to compensate all of these services as a single bundle.[115] The criteria contain no performance requirements, and DOE fails to connect them to specific grid benefits with the degree of specificity that would be needed to render rates based upon those criteria just and reasonable. In fact, the DOE Proposal’s vagueness makes it impossible to carry out such an assessment. The DOE Proposal lacks even the most basic evidence and factual record necessary to evaluate or even identify any non-cost factor benefits. Instead, the eligibility criteria appear primarily to be a thinly veiled tailoring mechanism designed to channel greater compensation to coal and nuclear resources preferred by DOE for political reasons.

To the extent that DOE hints at services that the criteria may be linked to, they are designed in a manner that excludes many resources capable of providing those same services, thereby discriminating between them in an undue manner. Instead, DOE uses a shorthand term

[115] Such a requirement runs contrary to FERC’s existing practices, where resources are compensated according to separate mechanisms for different services. As the Commission has articulated, allowing for the separate provision of services allows the widest possible range of resources to provide each necessary service, enhancing competition and thereby lowering prices.

for its criteria ("fuel secure" resources) interchangeably with "coal and nuclear," and expressly states that the Proposal's purpose is to forestall those plants' closure,[116] evincing a clear intent to favor these resources at the expense of others.

Below, we challenge the two defining features of DOE's criteria: (1) that an eligible resource must provide 90 days of on-site fuel supply; and (2) the criteria focus solely on resource characteristics rather than requiring the delivery of any specific service to the system. DOE's mechanism to channel payments to preferred resources is unduly discriminatory and not just and reasonable in violation of the FPA.

1. DOE's 90-day fuel supply eligibility criterion is not justified

DOE's proposal requires eligible resources to have "a 90-day fuel supply on site." But the vast majority of outages are caused by transmission and distribution system outages that result from extreme weather, not fuel supply failures. Rhodium Group analyzed major power disruptions nation-wide over the past five years (2012 – 2016) using data collected from form OE-417 submissions. It found that "only 0.00007" percent of disturbances "were due to fuel supply problems."[117] The DOE Proposal fails to explain how system reliability and resilience could not be better ensured in a more cost-effective manner through measures targeted at the transmission system.[118]

[116] DOE Proposal at 3.
[117] Houser et al., Note: The Real Electricity Reliability Crisis (Oct. 3, 2017), available at http://rhg.com/notes/the-real-electricity-reliability-crisis. Moreover, the vast majority of this already very small percentage of outage hours due to fuel supply emergencies were related to an outage at a coal-fired power plant. *See id.*
[118] The greater importance of grid infrastructure to reliability has been demonstrated in acute fashion during the ongoing crisis in Puerto Rico, where 95% of the population was been without power at the time the Secretary signed this Proposal. *Id.*

Even during the Polar Vortex (highlighted by DOE as an event singularly exposing fuel supply issues), fuel supply disruption was trumped by other causes of generator outage.[119] This is relatively unsurprising given that generation inadequacy is far more frequently the cause of system outages than fuel supply issues. According to Rhodium's analysis, while generation inadequacy was responsible for only a tiny fraction of outage hours (0.00858%), it still accounted for more than 100 times the number of outage hours than did fuel supply issues.[120] This data suggests that resource adequacy is an inappropriate primary focus in ensuring reliability during extreme weather events, but focusing on fuel supply is even more inappropriate.

None of the evidence cited by the DOE Proposal supports providing cost-based rate recovery to resources (or indeed, any other preferential compensation) based upon a generator's ability to meet a 90-day fuel supply requirement. Nor does the Proposal explain why the eligibility criterion requires 90 days of fuel supply, as opposed to some other amount. It does not point to a single instance of a fuel supply disruption lasting for 90 days, let alone a fuel supply disruption of that duration causing an outage event.

As described above in Section [II.C], a 90-day fuel supply would not have prevented the high rate of outages during the Polar Vortex. DOE offers no rationale for emphasizing Polar Vortex-type events over other grid emergencies such as hurricanes, which may present different system challenges.[121]

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[119] *See supra* at Section II.C.
[120] Houser et al., Note: The Real Electricity Reliability Crisis (Oct. 3, 2017), *available at* http://rhg.com/notes/the-real-electricity-reliability-crisis.
[121] Given the prominence of future extreme weather events in the Proposal's rationale, FERC cannot reasonably approve the Proposal without addressing the effect of climate change on the likelihood and relative incidence of such events. To rationally address any incremental grid reliability needs not addressed by existing mechanisms, DOE and FERC should conduct an

Nor does the IHS Markit report ("IHS report") on which the DOE Proposal relies provide even a shred of evidence supporting the idea that 90-day fuel supply contributes to resiliency. The IHS report claims in conclusory fashion that "[t]he grid-based electricity supply portfolio in the United States is becoming . . . less reliable, and less resilient," but provides zero evidence or analysis to back up this claim. The IHS report makes no attempt to rigorously define resilience or reliability. Instead, the IHS report simply *defines resilience as fuel security*, taking the same tautological approach as the DOE Proposal.[122] Because it defines resilience solely in terms of fuel security, the IHS report reaches the easy conclusion that the scenario with coal and nuclear retirements is the "less resilient" case.[123] This circular reasoning is the only support IHS provides for that conclusion.

The IHS report purports to evaluate two grid mix scenarios, including an entirely unsupported and unrealistically extreme case in which all coal, all nuclear, and 20 percent of hydroelectric resources retire. It uses these scenarios to assess the supposed costs to consumers of moving to the extreme case, claiming a "consumer impact" of $98 billion.[124] But in addition to using a straw man energy scenario to exaggerate the claimed impacts, the report relies on a deeply flawed methodology. To call out just a few of these flaws: it appears to assume, without explanation, that the costs of producing energy from renewable energy are much higher than they

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honest assessment of the likely incidence of extreme weather events going forward, accounting for the effects of climate change, and then move to ensure that the grid attributes and services needed in those kinds of events are available.

[122] Specifically, the IHS Report defines "resilient generation" as "the security of primary energy input supply chain for electric production. For example, fuel inventory at a plant site . . ." IHS Report at 22.

[123] IHS Report at 36.

[124] IHS Markit report at 36.

are in fact today, resulting in much higher retail costs in the heavy-renewable scenario.[125] Second, it calculates the "net benefit" of access to electricity (as consumers reduce consumption due to high costs) as the avoided cost of customers having to resort to emergency backup generators for their energy consumption. This is a ludicrous assumption which cannot be considered a reasonable evaluation of the costs of replacement generation under any scenario.[126] Further, IHS report calculates costs on what it calls an "unsubsidized" basis, which appears to exclude value reflected in some state and federal policies but not others.[127] It is not FERC's role to determine whether the value reflected in such policies for non-electricity products such as emissions reductions credits is accurate. The IHS report is a classic case of "garbage in, garbage out," in which flawed assumptions result in meaningless conclusions.

The IHS report also appears to claim that there is a $75 billion/hour additional cost of shifting to a "less resilient electric supply portfolio."[128] But this conclusion, too, provides no basis for DOE's focus on on-site fuel. The $75 billion/hour figure is simply the estimated value of consumer's willingness to pay to avoid outages, repackaged from another report.[129]

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[125] Appendix E, Synapse at E21-22. The IHS Markit report seems to indicate that it has backed out the Investment Tax Credit and Production Tax Credit, though these credits impact the cost of renewable resources as seen by electricity consumers now and for the entirety of the resources' book lives.

[126] *Id*.

[127] IHS does not list the "subsidies" removed from its calculations. But only forms of generation the IHS report refers to as "subsidized" are wind and solar. So 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 consider tax credits, upstream production subsidies, insurance guarantees, or other policy support for nuclear or coal.

[128] IHS Report specifically asserts that, "Preventing the erosion in reliability associated with a less resilient electric supply portfolio mitigates an additional cost of $75 billion per hour associated with more frequent power supply outages that add to the current US average expected outage rate of 2.33 hours per year." IHS Report at 5.

[129] IHS Report at 20 (citing Michael J. Sullivan, Josh A. Schellenberg, and Marshall Blundell, *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United*

Notwithstanding its misleading phrasing, these are not projected costs of a scenario in which coal and nuclear plants retire, but estimates of the costs of *any* additional outage. If anything, the striking $75 billion/hour figure argues for a strong focus on the transmission and distribution challenges that *do* cause most outages, rather than on the fuel supply issues that account for so few.

The NERC Synopsis cited by DOE directly contradicts the DOE Proposal and reveals that NERC *does not* view a 90-day fuel supply requirement as necessary. Rather, it draws the opposite conclusion, stating that "[n]atural gas-fired units, variable generation, storage, and other resources can provide similar reliability services."[130] NERC explained that "as a practical matter, costs, market Proposals, or regulatory requirements (or lack thereof) can affect whether these resources are equipped and available to provide reliability services."[131] Thus, NERC envisioned that FERC would oversee market structures to ensure that, whatever the mix of supply, the necessary reliability services continue to be met.

2. The DOE Proposal includes no requirement for its preferred resources to actually perform at any time, much less during emergencies.

Another fundamental problem with the criteria is that they appear not to be linked to performance in any way. None of the criteria require delivery of any specific services to the system. Nor does such a requirement appear to be built into the compensation framework set forth by DOE. The Proposal requires RTOs to establish a rate for eligible resources that provides for *both* "(A) purchase of electric energy from an eligible reliability and resiliency resource," *and* "(B) recovery of costs and a return on equity for such resource dispatched during grid

States, Ernest Orlando Lawrence Berkeley National Laboratory, January 2015, retrieved 24 August 2017).

[130] Synopsis of NERC Reliability Assessments, at 2 (May 9, 2017).

[131] *Id*.

operations."[132] The rate includes pricing to *both* "ensure that each eligible resource is fully compensated for the benefits and services it provides to grid operations, including reliability, resiliency, and on-site fuel assurance," *and* allow "each eligible resource recovers its fully allocated costs and a fair return on equity."[133] This language appears to provide for recovery of costs plus a return on equity regardless of whether a resource actually provides any reliability or undefined resiliency services. The lack of performance obligation confirms that the criteria are aimed at choosing preferred resources rather than compensating service. As discussed further in Section VI.D., it also threatens reliability. The coal units targeted by the Proposal are less reliable than replacement resources, and both the eligible coal and nuclear sources frequently fail to perform in extreme weather events.

And as discussed in Sections IV.D.-E., the ability to store on-site fuel bears little relation to performance during extreme weather. Even during the Polar Vortex, cited by DOE as the primary instance in which the targeted generators performed well, coal and nuclear facilities experienced extensive forced outages despite their assumed ability to store fuel on site. Coal resources also failed during other recent extreme cold weather events. In Texas in 2011, for example, ERCOT lost 7,000 MW of generation, 4,800 MW of which was due to poor weatherization at coal plants.[134] Coal and nuclear also have a record of disruptions during hurricanes. Florida's coastal nuclear plants shut down as Hurricane Irma approached the area.[135]

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[132] DOE Proposal at 19.
[133] Id.
[134] https://www.dallasnews.com/news/texas/2011/02/06/freeze-knocked-out-coal-plants-and-natural-gas-supplies-leading-to-blackouts
[135] https://www.fpl.com/clean-energy/nuclear/safety-planning.html ("As a precautionary measure, FPL requires nuclear plants to be shut down in advance of hurricane force winds and remain offline until thorough operational and safety assessments are completed after the storm passes.")

During Hurricane Harvey, the onsite coal pile at a W.A. Parish plant in Texas became so saturated with rainwater that the coal could not be delivered into storage silos, forcing the plant to switch to natural gas for the first time in eight years.[136] Both coal and nuclear plants are also vulnerable to supply disruptions from weather events that may disrupt their cooling systems, such as droughts or extreme heat.[137] For example, in 2012, "Unit 2 of the Millstone nuclear power station in Connecticut had to be shut down because the water from Long Island Sound was too warm to cool the reactor."[138]

The fact that the Proposal hinges not on whether a generator provides necessary services to the system but instead on whether it meets specified criteria clearly designed to carve out a role for only coal and nuclear resources evinces an intent to discriminate between resources according to their type in violation of the FPA. It also renders the rates not just and reasonable because it prevents the Commission from connecting the rates to any particular benefits being provided.

C. DOE's Proposal is unjust and unreasonable, and amounts to undue discrimination, because it ignores other resources that are capable of supplying grid services during extreme weather events

While DOE's proposal fails to account for the record of failure of so-called "fuel secure" resources during extreme weather, its lack of focus on performance simultaneously neglects the potential contributions of other resources and strategies to meet the same system needs.[139]

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[136] *See* Harvey's rain caused coal-to-gas switching: NRG Energy (Sept. 27, 2017), available at https://www.platts.com/latest-news/electric-power/houston/harveys-rain-caused-coal-to-gas-switching-nrg-21081527.

[137] See Synapse Energy Economics, Inc., Water Constraints on Energy Production (Sept. 12, 2013), available at http://www.synapse-energy.com/sites/default/files/SynapseReport.2013-06.CSI_.Water-Constraints.13-010.pdf.

[138] *Id.* at i.

[139] As discussed in Section II, DOE's Proposal does not define any particular system needs served by the Proposal.

DOE's proposal thereby creates an undue preference for generation with fuel storage, and unduly discriminates against other resources that cannot store fuel but nevertheless can perform reliably during grid emergencies. Further, in neglecting other cost effective strategies, the Proposal fails to ensure that rates are just and reasonable.

DOE insinuates, though never clearly states, that the Proposal's objective is to ensure that adequate generation is available during circumstances that might disrupt fuel supply chains. But DOE's Proposal includes no information explaining why this risk is sufficiently consequential as to merit the extraordinary compensation it provides, nor any discussion of how the Proposal is a cost-effective strategy to mitigating fuel supply chain risk.

Moreover, there is simply no rational reason to discriminate against generation resources that do not rely on any fuel at all, such as wind, solar, geothermal and hydroelectric power. Such resources are equally capable of making good on their obligations to provide grid services during fuel supply disruptions or other emergencies. Demand-side resources such as energy efficiency and demand response are also not affected by disruptions in fuel supply; indeed, demand response has proven essential to preserving the reliability of the grid during emergency events, as demonstrated during the Polar Vortex. *See supra*, at Sections IV.D.-E. These resources are invulnerable to fuel supply disruptions; if FERC decides that a new form of compensation is warranted for resources which can provide power during fuel supply disruptions, it must make that compensation available to all such resources; it cannot, consistent with the Federal Power Act, offer that compensation only to generators that decide to stockpile fuel, and not to those that do not rely upon fuel to generate power.

As this Commission has observed, to justify a benefit to (or penalty upon) a particular subset of generators, it must explain why other generators "aren't equally entitled" to that benefit (or penalty); absent such an explanation, it is "unduly discriminatory or preferential to grant the [benefit] to one and not the other—that is, it [is] unduly discriminatory or preferential to help one better compete in the marketplace and not the other." *Bangor Hydro-Elec. Co.,* 95 FERC ¶ 61,149, 61483 (Apr. 27, 2001). If FERC intends to compensate market participants who ensure the provision of "essential energy" even during "supply disruptions caused by emergencies, extreme weather, or natural or man-made disasters," it cannot make such compensation available only to generators with a "90-day fuel supply."[140] Other resources are similarly (and often better) situated in their ability to provide grid services during such disruptions. Importantly, with regard to capacity market obligations, the relevant metric to determine whether the resources are similarly situated is their ability to meet the obligations for which they are compensated. The capacity value of renewable energy resources is already significantly discounted to reflect their variability, meaning that such resources often over-perform during the severe weather events that can shut down other generators, including those with on-site fuel storage. Nor does any particular resource type have an unblemished record of performance during extreme weather events. Thus, fuel-free resources are similarly situated in their ability to provide power as expected, and consistent with their capacity commitments, when compared to so-called "fuel-secure" resources.

The Polar Vortex serves as an example that fuel-free resources like demand response and wind energy were similarly situated, if not better situated, in their ability to support reliability during an extreme weather event, when compared to resources with fuel storage, such as coal and nuclear.[141] Fuel-free resources also performed well during other recent extreme weather events, including cold weather events where coal plants failed. During the 2011 Texas cold

[140] 82 Fed. Reg. at 46,945.
[141] *See supra* Section IV.D.

weather event, ERCOT's President and CEO noted the extremely important role that wind played in supplying power to the grid.[142] Demand response, renewables, and energy storage all contributed to system reliability during record breaking heat waves in California that occurred at the same time as California's Aliso Canyon natural gas storage field experienced a catastrophic leak.[143]

FERC and DOE, as well as RTOs, have found on numerous occasions that fuel-free resources are able to provide services essential to maintaining a reliable grid. For example, the DOE Staff Report found that "[s]torage is . . . expected to play an essential role in helping customers and the [bulk power system] recover from extreme weather events (and should improve resilience and recovery following severe, high-impact events)."[144] FERC recently concluded that non-synchronous resources are fully capable of providing reactive power to the grid, and has required all newly interconnecting non-synchronous generators to provide reactive

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[142] Kate Galbraith, *Trip Doggett: The TT Interview*, THE TEXAS TRIBUNE (Feb. 4, 2011, 2 PM), *available at* https://www.texastribune.org/2011/02/04/an-interview-with-the-ceo-of-the-texas-grid/ ("I'm not aware of any specific issues with wind turbines having to shut down due to icing. I would highlight that we put out a special word of thanks to the wind community because they did contribute significantly through this time frame. Wind was blowing, and we had often 3,500 megawatts of wind generation during that morning peak, which certainly helped us in this situation.").

[143] *See* Herman Trabish, *What California's heat wave revealed about demand response*, UTILITY DIVE (Sept. 20, 2017), available at http://www.utilitydive.com/news/what-californias-heat-wave-revealed-about-demand-response/505186/; Dale Kasler, *Why Californians don't have to worry about their air conditioning conking out*, THE SACRAMENTO BEE (June 22, 2017), *available at* http://www.sacbee.com/news/weather/article157613029.html; Julia Pyper, *Tesla, Greensmith, AES Deploy Aliso Canyon Battery Storage in Record Time*, GREENTECH MEDIA (Jan. 31, 2017), *available at* https://www.greentechmedia.com/articles/read/aliso-canyon-emergency-batteries-officially-up-and-running-from-tesla-green#gs.ZLvZmas; *see* California Public Utilities Commission, *Aliso Canyon Demand-Side Resource Impact Report (May 2017 Update), available at* http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/AlisoDSM_ImpactsReport20170510.pdf.

[144] DOE Staff Report at 73 and footnote aaa.

power.[145] More recently FERC issued a Notice of Proposed Rulemaking that would require all newly interconnecting generators to install and enable primary frequency response capability.[146] Distributed solar resources combined with energy storage are also able to provide reliable power in the aftermath of hurricanes and other extreme weather events that can shutdown central power stations or damage the distribution system.[147] Appendix B includes a list of studies demonstrating the many ways that fuel-less resources can contribute to the provision of grid reliability services.

In sum, DOE's proposal to provide cost-based compensation to a select set of resources, arbitrarily selected on the basis of a characteristic that bears no relationship to DOE's proffered, yet remarkably vague goal, constitutes undue discrimination and preferential treatment. Fuel-free resources are equally if not more capable of providing essential reliability services, and performing during extreme weather conditions, as the resource that DOE has shown it intends to favor. Absent an identified and well-articulated "reliability and resiliency attribute," and a service linked to the benefits of that attribute, FERC cannot rationally identify resources entitled to compensation for possessing that attribute or determine whether resources are similarly situated with regard to its provision. Whatever "resiliency attributes" are, FERC cannot procure them in a discriminatory manner.

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[145] FERC, Reactive Power Requirements for Non-Synchronous Generation, 18 C.F.R. § 35 (2016).

[146] FERC, Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response, 81 Fed. Reg. 85,176 (proposed Nov. 25, 2016).

[147] Pete Kelly-Detwiller, *After Irma: Solar Plus Storage – A Small Beacon of Light In A Sea Of Darkness*, FORBES (Sept. 17, 2017), *available at* https://www.forbes.com/sites/peterdetwiler/2017/09/17/after-irma-solar-plus-storage-a-small-beacon-of-light-in-a-sea-of-darkness/#6ec7c18f340f; Lindsey Gilpin, *After the Hurricane, Solar Kept Florida Homes and a City's Traffic Lights Running*, INSIDE CLIMATE NEWS (Sept. 15, 2017), *available at* https://insideclimatenews.org/news/15092017/after-hurricane-irma-solar-florida-homes-power-gird-out-city-traffic-lights-running.

D. The DOE Proposal does not comply with the cost causation principle

DOE's failure to define a problem or connect its eligibility criteria to any specific grid services also violates the FPA requirement to demonstrate that "approved rates reflect to some degree the costs actually caused by the customer who must pay them."[148] Because the Proposal fails to specify the precise services being rendered, it is impossible to evaluate whether a given customer is in need of those services. Demonstrating that the Proposal is compliant with the cost causation principle as required under the FPA is also impossible because the Proposal fails to explain the mechanics of how payments to eligible generators would work.

This stands in contrast to other mechanisms FERC uses to ensure reliability. For example, because the capacity market construct approved in PJM is designed to ensure that there are enough resources available to meet peak demand, customers are required to pay for their assigned share of capacity according to their contributions to peak demand. If a customer reduces its peak demand, its capacity obligations decline accordingly.[149] Because the DOE Proposal imposes costs for "resiliency" without defining it, no such evaluation can be made to determine a particular customer's resiliency need by which to assign that customer a portion of the increased costs arising through the Proposal's cost-based payments. For example, would a wholesale

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[148] *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C.Cir.2004) (Roberts, J.) (quoting *KN Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C.Cir.1992)) (internal quotation marks omitted). As the court in *KN Energy* explains, this rule "has become known in Commission parlance as the 'cost-causation' principle." 968 F.2d at 1300.

[149] *See* PJM Manual 18: PJM Capacity Market, Revision 38, at 146-47, 199, PJM Capacity Market Operations (Jul. 27, 2017) (requiring each PJM load serving entity to pay a Locational Reliability Charge based on its Obligation Peak Load, which represents the summation of energy use during periods of peak demand for each of the load serving entity's customers).

industrial customer who installed a microgrid and backup generators so as to insulate itself from risks associated with extreme weather events still be required to make payments?[150]

VI. The DOE Proposal would give eligible resources preferential compensation, imposing costs unjustified by any concrete benefits

While DOE has not demonstrated that compensating eligible generators under its proposed rate scheme would offer any concrete benefits, the Proposal *would* cause massive cost increases for customers that would be unconstrained by any prudence review. The Proposal would also cause significant environmental harms that would not otherwise arise, while undermining state public policies. Further, DOE's Proposal threatens to undermine rather than support system reliability.

A. The costs of DOE's Proposal, under any scenario, will cost customers billions more without reducing outages.

The Proposal states that it seeks to ensure that eligible resources are "fully compensated for the benefits and services [they] provide[] to grid operations, including reliability, resiliency and on-site fuel assurance."[151] Compensable costs include operating and fuel expenses (including the additional cost of maintaining a 90 day fuel supply), costs of capital and debt, and fair return on equity and investment.[152]

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[150] Customers increasingly making investments that would insulate them from extreme weather risks. For example, National Grid is partnering with Clarkson University to develop a local microgrid to keep the town's electricity system up and running during extreme weather. The Proposal is silent as to how projects such as these would impact a load serving entity's obligations to pay for the costs of the Proposal.

[151] DOE Proposal at 19.

[152] The Proposal's language redundantly mentions both "the cost of capital" and a "fair return on equity and investment." The cost of capital is the weighted cost of both debt and equity. The cost of equity capital is the return that equity investors must be able to expect before they make equity investments in the enterprise. That, for many decades, has been the accepted definition of a "fair return." Any further return would be a windfall at the expense of consumers.

The costs of this Proposal to customers will easily reach into the billions of dollars every year. Estimating the cost of a proposal that lacks such basic elements as a description of the service being provided, a defined compensation mechanism, and rules that clarify interactions with existing market mechanisms, is challenging. But under any scenario, the costs are massive.

Based upon our best interpretation of the vague eligibility criteria, we estimate that over 49 GW of coal capacity and over 43 GW of nuclear capacity would be eligible for compensation under this Proposal. As an important point of context, the total operating costs (fixed and variable O&M, as well as fuel) of these eligible resources amounted to over $14 billion in 2016.[153] Moreover, this figure is likely an underestimate of the total costs that may be eligible for recovery under this Proposal.[154] We did not account for any remaining debt that may be on the books of eligible resources, nor does it include a "fair return on equity and investment." The total costs eligible for recovery also may increase because eligible resources in a position to do so (coal units in particular) are likely to dispatch more frequently as a result of the compensation provided in this Proposal.[155] Similarly, the recoverable costs under this Proposal may increase due to the possibility that resources may take steps to become eligible for compensation (e.g. dual-fuel units may install more fuel storage capacity).

DOE's Proposal does not specify how costs would be recovered, making it difficult to estimate net costs. Nonetheless, several analysis firms have attempted to estimate the potential

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[153] The methodology used to arrive at this estimate is detailed in Appendix C.
[154] Because the Proposal is so vague, it is impossible to tell whether covered resources would continue to participate in and receive revenue from RTO markets for energy, capacity and ancillary services. This estimate is of gross costs, not netting out any revenues from those markets.
[155] Coal units are often dispatched significantly below their maximum potential output, whereas nuclear units are not, given their engineering constraints that prevent them from running at less than maximum output.

incremental costs of the Proposal (i.e. the costs customers would bear as a direct result of this rulemaking). For example, the Brattle Group analyzed the total costs that units are eligible to recover net of potential market revenues, including estimates of the annualized cost of capital investments made over the past decade.[156] Brattle projects the extent to which eligible units may recover some of their costs through existing energy and capacity markets.[157] After accounting for projected market revenues, Brattle then calculates the additional amount that these resources would need to be compensated under this Proposal. Net of potential market revenue, Brattle estimates that the DOE Proposal would result in customer costs of between $3.7 and $11.2 billion per year.[158]

Energy Innovation and Climate Policy Initiative examined several interpretations in order to project the potential costs of implementing DOE's Proposal. In its "most conservative" scenario, eligible units are limited to only generators that are cash flow negative, and these resources recover only costs which are not currently received through market payments, in the form of uplift payments. Even under this constrained interpretation (which seems at odds with DOE's lack of limitation of the Proposal's coverage to units that are cash flow negative), the

[156] The capital costs of pollution controls adopted since units first came online are quite significant, and in many cases not likely to be fully paid off. Brattle estimates these undepreciated capital costs to be in the order of $10 billion for the affected units, and the return on equity on these retrofits alone is likely to be in the order of $2-2.6 billion. *See* Comments of Next Era Energy, RM18-1 (Oct. 23, 2017).

[157] In order to estimate this market revenue, Brattle assumes that the DOE Proposal does not result in any changes in bidding behavior by the eligible resources (i.e., that these units do not bid as price-takers and thereby change the extent to which their offers clear in the energy markets). While this simplifying assumption is useful to calculate a set of costs that serves as a useful anchor point for the potential impacts of the Proposal, we note that the DOE Proposal does not incorporate any limitations on eligible resources' bidding behavior. *Id*.

[158] *Id*.

total cost of the Proposal exceeds $2 billion per year.[159] Under their worst-case cost interpretation, in which all eligible units are assumed to be compensated for their full costs through a mechanism outside the market, and these units operate up to their maximum potential output, the costs of the proposal reach $10.6 billion annually.

These estimates, taken together, provide a sense of the potential costs of DOE's proposal, across a broad range of interpretations of the vague directives provided. The weight of evidence could not be more stark: paying billions of dollars more per year, with no evidence of value in return, is a far cry from the just and reasonable rates afforded by the FPA.

In addition to the high economic costs, the Proposal would also have significant environmental and public health impacts, as described in Appendix C.

B. The DOE Proposal's costs would be unconstrained by any prudence review

DOE's Proposal calls for "full recovery of costs of certain eligible units,"[160] which "shall include, but not be limited to, operating and fuel expenses, costs of capital and debt, and a fair return on equity and investment."[161] The implication of DOE's proposal is that if a unit is eligible according to the criteria DOE has set out, full recovery of costs shall be ensured. Thus, DOE's proposal seeks to short-circuit the careful process for cost-of-service ratemaking that FERC has established.

Where FERC conducts cost-of-service ratemaking, it may not simply rely on the "end result," but rather has an obligation to explain a clear, developed standard for determining which

[159] Energy Innovation and Climate Policy Initiative, "The Department of Enegy's Grid Resilience Pricing Proposal: A Cost Analysis" at 3 Available at : http://energyinnovation.org/wp-content/uploads/2017/10/20171021_Resilience-NOPR-Cost-Research-Note-FINAL.pdf
[160] 82 Fed. Reg. at 46,945.
[161] *Id.* at 46,948 (proposed 10 C.F.R § 35.28(g)(10)(iv).

costs are reasonably recovered such that the rates arrived at will be just and reasonable.[162] In the context of "cost-of-service ratemaking" FERC "[t]ypically" meets this obligation by applying a "prudence test" that disallows costs where they are "examined and found to be excessive or improper." *Id.* at 1117.

The DOE Proposal seeks to bypass the key question in prudence review of whether an asset generally, or a particular investment, is needed in the first place. Indeed, given the Proposal's stated goal to prevent the retirement of eligible resources that would otherwise occur through the operation of competitive markets, and the lack of specific evidence that any of those resources are needed for system reliability (as would be the case through an RMR contract, for example), the Proposal seems aimed to specifically compensate costs that are *not* prudent.

Prudence review cannot simply be implied by the Proposal, both because of the inherent contradiction that it targets imprudent costs, and also because FERC carries the obligation to explain its precise methodology for applying prudence review in a given case.[163] The Commission's prudence review "is regulation's substitute for competitive forces,"[164] "to prevent regulated companies from becoming 'high cost-plus compan[ies] and to secure efficiency in the allocation of resources."[165] Where, as here, cost-based ratemaking is being employed as backstop

[162] *See Pac. Gas & Elec. Co. v. FERC*, 306 F.3d 1112, 1118 (D.C. Cir. 2002) (striking down an application of cost-of-service ratemaking where "FERC never clarified and developed either the approach or the standard that it applied").
[163] *See* Pac. Gas & Elec. Co. v. F.E.R.C., 306 F.3d 1112, 1118 (D.C. Cir. 2002) (striking down an application of cost-of-service ratemaking where "FERC never clarified and developed either the approach or the standard that it applied").
[164] Scott Hempling, REGULATING PUBLIC UTILITY PERFORMANCE, THE LAW OF MARKET STRUCTURE, PRICING AND JURISDICTION (2013), at 235.
[165] *Democratic Cent. Comm. of the D.C. v. Wash. Metro. Area Transit Comm'n*, 485 F.2d 886, 907 (D.C. Cir. 1973).

measure to prevent the retirement of resources unable to compete in competitive markets, the burden for finding that recovery of costs for such units is prudent should be especially high.

The Proposal also lacks a sunset provision. According to the Proposal's terms, cost-based ratemaking for eligible units, many of which are already multiple decades old, would appear to continue indefinitely.[166] With time, maintenance costs for such plants would increase dramatically, just as the efficiency of those plants is declining, further skyrocketing the costs of the Proposal. The lack of a sunset provision also means that this supposedly urgent measure is in fact intended to permanently displace market-based mechanisms for ensuring reliability.

DOE's Proposal also places no apparent constraint on what costs for particular investments related to any given unit would be deemed prudently incurred, dramatically amplifying the risk to customers. The purpose of prudence review is to impose discipline on the owners of generating facilities that would otherwise be provided by the marketplace. Without that discipline, coal and nuclear plant operators would essentially have a blank check for expenditures at their facilities. Coal and nuclear plants require frequent costly investments for compliance with environmental and public safety regulations, as well as to replace aging components. In addition, the carte blanche granted to facility owners by DOE's Proposal would incentivize imprudent investments to add dual fuel capacity or extraordinary measures to store fuel on-site, in order to qualify for cost-based ratemaking under this Proposal.

FERC must not allow its carefully developed cost-of-service ratemaking process to be bypassed in the manner that DOE proposes. The Commission should hew closely to its long-standing commitments to substitute market-based rates for cost-based rates. Nor is this defect curable. Without any defined service or clear demonstration that the eligible units are necessary

[166] The average age of eligible resources is 40 years. *See* Appendix C.

to maintain reliability, the costs incurred under the Proposal would by definition be imprudent.[167] Further, applying prudence review in practice would result in hundreds of extremely complex cases before RTOs. Ultimately, the Proposal's failure to constrain cost-based compensation with prudence review is a fatal flaw that renders the Proposal incurably unlawful under the FPA.

C. The Proposal undermines and fails to consider state public policies in violation of the APA and FPA

The Proposal also undermines state public policies in a manner that disregards FERC's responsibilities under the APA and FPA to consider state policies and regulate in a manner that accounts for them. The Supreme Court has held that the FPA "[was] drawn with meticulous regard for the continued exercise of state power, not to handicap or dilute it in any way."[168] Careful respect for overlapping jurisdiction and interest between state and federal entities is therefore a foundational tenant undergirding the regulation and operation of the electric sector.

The Commission has long voiced its intent not to "interfere with state programs that further specific legitimate policy goals,"[169] and has affirmatively pursued strategies to harmonize market rules with state policies. In Order No. 1000, for example, the Commission mandated transmission owners to "explicitly provide for consideration of transmission needs driven by Public Policy Requirements," defined as encompassing "state or federal laws or regulations."[170]

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[167] It is possible that pursuant to existing RMR processes, specific evidence could be developed to show that a specific resource eligible for payments under the Proposal is needed for reliability purposes and that cost-based compensation is prudent with respect to that unit. But to the extent that this is the case and payments under the Proposal do not exceed RMR payments, the Proposal is duplicative of the RMR mechanism.

[168] *Oneok v. Learjet*, 135 S.Ct. 1591, 1599 (2015). While *Oneok* considered the scope of FERC's authority under the Natural Gas Act Supreme Court has noted that "the relevant provisions of the two statutes are analgous." *Hughes v. Talen Energy, LCC*, 136 S.Ct. 1288, 1298 n.10 (2016).

[169] *See New York Indep. Sys. Operator, Inc.*, 131 FERC ¶61,170 (May 20, 2010) at ¶137.

[170] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 136 FERC ¶ 61,051, at PP 2, 82 (2011).

FERC has framed its responsibility to facilitate rather than impede state policies as commensurate with its other duties to "promote economically efficient markets and efficient prices."[171] This makes sense because FERC ensures just and reasonable wholesale prices against the backdrop of state policy choices. Its duty is to provide for efficient markets after taking those choices into account.[172] Under the APA, as with any agency action, FERC must consider the evidence and use reasoned decision-making to explain how it has achieved this mandate.

The DOE Proposal undermines state policies in multiple ways. First, it interferes with choices states have made regarding how to ensure resource adequacy. Consistent with the rights reserved to them under Section 201(a) of the FPA[173] and the FPA's explicit preservation of state authority to "ensure the safety, adequacy, and reliability of electric service,"[174] states have chosen different resource procurement mechanisms. Some have elected to continue to engage in integrated resource planning, while others have decided to rely on RTO markets to procure resources and have based their framework of resource adequacy regulations around that decision. The DOE Proposal undermines the deliberate resources adequacy decisions by states in RTO regions by imposing a new system that upsets the existing careful balance of regulatory mechanisms with absolutely no discussion or evidence as to its impact in this area. Those states located within RTOs that have chosen to restructure their utility sectors have done so in reliance on FERC's oft-expressed intention to promote competition as a means to ensure cost-effective and reliable electric service. Meanwhile, states that use integrated resource planning in those

[171] *ISO New England Inc. & New England Power Pool Participants Comm.*, 155 FERC ¶ 61,023 at P 23 (2016).
[172] *See Federal Power Commission v. Conway Corp.*, 426 U.S. 271, 280 (1976) (explaining that it is "necessary" for FERC to account for state retail rate regulation choices when regulating wholesale rates).
[173] 16 U.S.C. § 824(a).
[174] 16 U.S.C. § 824o(i)(3).

regions will be forced to make additional payments to support the Proposal's preferred resources despite designing their own portfolios with reliability in mind. In sum, DOE's Proposal would harm states who have designed their own regulation in reliance upon FERC's established practice of incenting competition. Such a fundamental change in policy in the face of reliance faces a heightened burden in terms of reasoned decision-making.[175]

DOE's Proposal also undermines state public policy decisions to influence their generation mix.[176] The DOE Proposal overrides these policy choices by designing a policy specifically to ensure the continued operation of coal and nuclear resources that would otherwise retire, essentially selecting the mix of generation. Indeed, Secretary Perry has insinuated that DOE Proposal explicitly aims to counter policies that promote renewables and rebalance the scales in favor of so-called "baseload" resources.[177] But this fundamentally misunderstands FERC's constrained statutory role. FERC, unlike states, is mandated by statute to ensure with singular focus reliable and adequate service at just and reasonable rates through non-unduly discriminatory or preferential means.[178] By contrast, FERC has repeatedly acknowledged and

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[175] *See Encino Motorcars v. Navarro*, 136 S.Ct. 2117 (2016) (striking down Department of Labor regulation for failing to adequately explain its change of position and acknowledge the serious reliance interests at stake).

[176] States exercise their traditional powers to influence generation mix reserved under the FPA through integrated resource planning, and through the adoption of policies such as Renewable Portfolio Standards. At least twenty-nine states and the District of Columbia have adopted Renewable Portfolio Standards to achieve state public health and environmental goals. Galen Barbose, *U.S. Renewables Portfolio Standards: 2016 Annual Status Report* 5 (Apr. 2016), https://emp.lbl.gov/sites/all/files/documents/lbnl-1005057.pdf.

[177] *See* Timothy Cama, "Perry: 'There is no free market in the energy industry,'" (Oct. 6, 2017) (quoting Secretary Perry stating, in defense of the DOE Proposal, that the former administration "had their thumb on the scale" to help out renewables, to the "detriment … of reliable, baseload industries that are really important for the future security of this country").

[178] While the federal government may promote various resource types over others using other means, such as the tax code or through programs funded by DOE, FERC's role is to implement policies set by these other actors, not make them.

affirmed that states are drivers of policy objectives.[179] Venturing into the political realm of supporting particular resource types as the Proposal does would fundamentally overstep FERC's statutory authority .[180] Moreover, it would place the Commission in constant conflict with the states whose policies it is tasked with respecting.

D. Adopting the Proposal threatens system reliability

In addition to imposing significant monetary and environmental costs on customers without any demonstrated benefits, DOE's Proposal threatens to affirmatively jeopardize system reliability. By design, the Proposal supports existing generators that are, in general, very old and inflexible. Propping up these units mutes financial signals that would otherwise incent the entry of new resources that would be better capable of meeting system needs. The Proposal would thus incentivize the category of generators that is among the *least* reliable to remain in operation, while crowding out resources that are less susceptible to outages. The perverse effects of the Proposal are equally striking with respect to the ability to quickly recover from loss of load. By supporting units that are often very slow to come back online after a major disturbance, the Proposal undermines the speed at which the grid can resume normal operation.[181]

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[179] *See ISO New England Inc. & New England Power Pool Participants Comm.*, 155 FERC 61,023 at P 23 (2016) (stating that the Commission sought to accommodate the ability of states to pursue their policy goals in ensuring that capacity prices are at a just and reasonable level); *Order No. 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Pub. Utils.*, 136 F.E.R.C. ¶ 61,051, 76 Fed. Reg. 49,842 (2011) (codified at 18 C.F.R pt. 35) (recognizing the need for bulk transmission planning rules to account for state public policies).

[180] As dicussed *supra* Section V, preferring certain resource types would also violate the Commission's mandate against undue discrimination.

[181] For example, "in the Northeast blackout of Aug. 14, 2003, nine U.S. nuclear plants SCRAMmed from 100% to 0% as designed, but took two weeks to restore due to fuel supply issues such as exon and samarium poisoning and core-flux inhomogeneities." Lovins, Amory B. "Do coal and nuclear generation deserve above-market prices?" *The Electricity Journal*, 30.6 (2017): 22-30, at 27.

Synapse Energy Economics conducted an independent assessment of the DOE Proposal to evaluate how it could impact the characteristics of the supply mix in the impacted wholesale markets. Synapse concluded that DOE's Proposal targets about 55,000 MW of merchant coal generators throughout MISO, PJM, ISO NE, and NY ISO, with the vast majority (~41,000 MW) in PJM.[182] Close to 90 percent of these plants are older than 30 years old, and nearly two-thirds are older than 40 years old.[183] More than 15 percent are over 50 years of age.[184] Indeed, over 1.2 GW of coal capacity in MISO and 7.5 GW of coal capacity in PJM is over half a century old.[185] The consequences of plant aging are well documented: after a "mature phase" in which forced outage rates are low, availability is high, and operation and maintenance costs are low, the dependability of the plant declines:

> This mature phase normally lasts 25 to 30 years, depending on the design and use of the unit. The power plant is usually operated near rated capacity during this period. Following this phase, the aging process becomes noticeable. Forced outages and maintenance costs increase and availability declines. Component end of life usually causes the higher forced outage rate. Occasional operational error and the degradation of boiler components due to erosion, corrosion, creep and fatigue lead to localized failures. The forced outage rate steadily increases during this phase unless major overhauls or component replacements are instituted.[186]

Moreover, unless DOE would have FERC fundamentally abandon the principle that the most efficient, cost-effective units are dispatched first, these aged units will continue to cycle in

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[182] Synapse's independent assessment of the DOE Proposal results in impacts that are in the same order of magnitude, but slightly different in total MW capacity than the approach described in Appendix C. Such minor variations are to be expected in projecting the impacts of a proposal that is as vague as the DOE proposal. *See* Appendix E at E22-23.

[183] *Id*. Based on 2015 data on nameplate capacity and unit age, 88% of the affected capacity, and 90% of affected capacity in PJM, is over 30. Sixty percent (60%) of capacity, and 63% in PJM, is over 40.

[184] *Id*. Seventeen percent (17%) of capacity, and 15% in PJM, is over 50 years of age.

[185] *Id*.

[186] Babcock & Wilcox, STEAM, ITS GENERATION AND USE, 40th Ed., (1992), Chapter 46, at pages 46-1 *et seq*; *see also* Direct Testimony of David A. Schlissel, Public Version. WVA Public Services Commission, Case No. 17-0296-E-PC at 49-50.

a manner that results in a *more than doubling* of their forced outage rates.[187] Indeed, DOE-supported research concludes that "[c]ycling units more frequently increases the probability of catastrophic failures."[188]

The poor performance of aging coal units is well demonstrated by Equivalent Demand Forced Outage Rate (EFORd) [189] and the Equivalent Forced Outage Rate During Peak Hours (EFORp), [190] performance measures which reflect the reliability of different classes of generators. In PJM, where the vast majority of affected units are located, the average EFORd rate for steam generators (comprising primarily coal units) is almost three-times higher than a natural gas-fired combined cycle unit.[191] Steam generators are, by far, the *least reliable* generator by PJM by this measure. These units perform no better during peak hours and are also, on average, the least reliable source of power during peak periods. A coal-fired generator is more than 3.5

[187] The DOE National Energy Technology Laboratory (NETL) calculated that forced outage rates go up to 7%, compared to a baseline of 3%, when units are cycled. *See* Meeting Minutes of the EIA Working Group on the Aging Coal Fleet (Aug. 17, 2016) available at: https://www.eia.gov/outlooks/aeo/workinggroup/coal/pdf/Final_Coal_Fleet_Aging_Meeting_Notes_081716.pdf

[188] *Id.* ("NETL identified a lot of little problems that add up to bigger issues including boiler tube corrosion, waterwall web cracking, casing failures, and creep.") *See also* DOE Staff Report at 154-55 (describing how turning a plant on and off causes stress and damage, results in critical component failure, and higher plant equivalent forced outage rates).

[189] Equivalent Forced Outage measures exclude planned outages and reflect the fact that a plant might be forced to partially or completely reduce its output due to an unplanned (or forced) event or problem. A plant's EFORd is a measure of the probability that a generating plant will fail, either partially or totally, to provide power when it is needed to operate at any time throughout the year.

[190] A plant's EFORp is a measure of the probability that the unit will fail, either partially or totally, to produce power when it is needed to operate during the peak hours of the day in the peak months of January, February, June, July and August. Like EFORd, EFORp does not include planned outages and also measures whether the unit would have operated if it had not been forced out of service during the peak hours of the year.

[191] In PJM, the average EFORd for steam generators from 2010 to 2016 was 10.79%, compared to 3.57% for gas-fired combined cycle units.

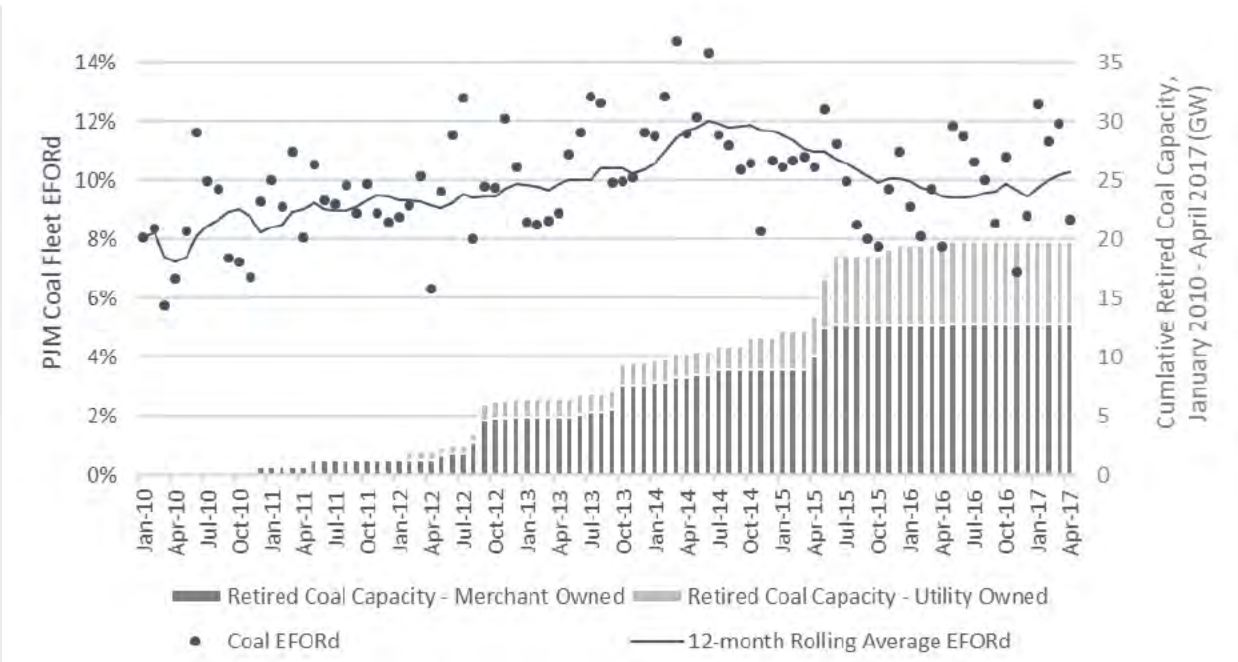
times less likely to produce power during the peak hours in peak months of January, February, June, July and August than a gas-fired combined cycle unit.[192]

Analysis of the trends in EFORd rates over time show that higher outage rates have clear linkages to the age of the coal units.[193] While still high compared to other technologies, coal units in MISO, which are on average about 10 years younger than those in PJM, have lower EFORd rates. The trend in EFORd rates in PJM also tracks tightly to age of the fleet of coal generators. Outage rates among coal units in PJM increased generally as the average age of these generators increased. Then, in 2014-2016, as a significant amount of aging coal capacity retired, the trend reversed and average outage rates for this class of generators declined. The DOE Proposal would undo the positive effect on outage rates that results from the retirement of aging units, resulting in greater risks of plant failure over time.[194] Far from increasing "resiliency", the DOE Proposal would reward the lowest performing units, increase outage risks, and pose a threat to the continued reliable operation of the grid.

[192] In PJM, the average EFORd for steam generators from 2010 to 2016 was 7.54%, compared to 2% for gas-fired combined cycle units.
[193] *See* Appendix E, Synapse at E-24.
[194] Avoiding the increased risk of outages would require substantial capital cost investments into aging plants. Babcock & Wilcox, *supra* note 187. ("major overhauls" or "component replacements").

Further, it would reward the system's least flexible units at a time when experts across the industry are concluding that resource flexibility should be more highly valued. As experts from The Brattle Group stated, "it is becoming increasingly clear" that "operational flexibility" is one of the services "most under-recognized by today's markets."[195] For example, a recent study of California's system found that as flexibility increases, reliability improves and both production costs and emissions decrease.[196] These needs are increasing. The California

Figure 2 PJM coal fleet monthly EFORd and cumulative retired coal capacity, January 2010–April 2017



Independent System Operator ("CAISO") found that the need for 3- hour ramping capacity

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195 Chang et al., Advancing Past "Baseload' to a Flexible Grid: How Grid Planners and Power Markets Are Better Defining System Needs to Achieve a Cost-Effective and Reliable Supply Mix, at iii (2017), available at http://www.brattle.com/system/publications/pdfs/000/005/456/original/Advancing_Past_Baseload_to_a_Flexible_Grid.pdf?1498482432.

196 Astrape, Flexibility Metrics and Standards Project—a California Energy Systems for the 21st Century (CES-21) Project, January 6, 2016, available at http://www.astrape.com/?ddownload=6826.

increased significantly between 2015 and 2017.[197] Likewise, analysis of New Mexico grid operations found that over time, operational flexibility will be increasingly important in avoiding future blackouts.[198] Fortunately, needs are being met by new technologies. Enhanced resource flexibility is one of the reasons that new "technologies being added to the system have, in combination," enhanced "most if not all of the reliability attributes provided by resources exiting the system."[199] By propping up the system's oldest and least flexible resources, the Proposal would undermine price signals for newer more flexible resources, thereby compromising these reliability gains.

By supporting the retention of coal-fired generators that are one of the primary contributors of climate change, the Proposal would contribute to increased frequency and greater magnitude of extreme weather events that cause outage events. Given the prominence of future extreme weather events in the Proposal's rationale, FERC cannot reasonably approve the Proposal without addressing the effect of climate change on the likelihood and relative incidence of such events. To rationally address any incremental grid reliability needs not addressed by existing mechanisms, DOE and FERC should conduct an honest assessment of the likely incidence of extreme weather events going forward, accounting for the effects of climate change,

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[197] See California Energy Commission—Tracking Progress, Resource Flexibility, December 15, 2016, p. 5, available at http://www.energy.ca.gov/renewables/tracking_progress/documents/resource_flexibility.pdf.

[198] Astrape, PNM Preliminary Reliability Analysis, April 18, 2017, available at https://www.pnm.com/documents/396023/3306887/04182017-irp-mtg-reliability/66b6bdc0-d9d4- 4f72-b1dc-076d8c5c74c2.

[199] Hibbard, P., Tierney, S., & Franklin, K., Electricity Markets, Reliability and the Evolving U.S. Power System, at (2017, June), at 55, https://info.aee.net/electricity-markets-reliability-and-the-evolving-us-power-system-report

and then move to ensure that the grid attributes and services needed in those kinds of events are available.[200]

E. The DOE Proposal would have unintended consequences that would further increase its costs

Because the DOE Proposal is so vague, it is difficult to assess what its consequences will be. But the apparent structure of the Proposal suggests several avenues through which the Proposal could create unintended costs and undermine system reliability.

At the most basic level, the Proposal creates incentives for generators (1) to take steps to render themselves eligible for compensation under the proposed 'resiliency' rates, and (2) to maximize profits under those rates. Many such actions could unnecessarily raise costs and compromise system reliability. The precise actions that market participants would engage in would vary based on how the Proposal is interpreted and implemented.

Most obviously, the Proposal would encourage plant operators to stockpile fuel to meet the Proposal's requirement to store "a 90-day fuel supply on site." For natural gas burning facilities with dual-fuel capability, this could encourage the construction of massive, expensive oil tanks. If payments under the Proposal are lucrative enough, it could even incent costly and counterproductive gas-to-coal fuel switching at some facilities.[201] Many coal facilities would need to stockpile more fuel to meet the 90-day requirement,[202] offering no measurable

[200] As set forth in Section [VIII], such an assessment is required in order to comply with NEPA.
[201] Such retrofits would likely *decrease* generator performance and reliability rather than enhance it, although the full consequences of any such actions are difficult to predict.
[202] According to the EIA, between January and August 2014, 60-80% of coal plants had 60 days or fewer of fuel stored on site. *See Coal stockpiles at coal-fired power plants smaller than in recent years: EIA* (Nov. 6, 2014), available at https://www.eia.gov/todayinenergy/detail.php?id=18711#. *See also* Alison Silverstein, *Alternate conclusions & recommendations for the DOE Staff Report to the Secretary on Electricity Markets & Reliability*, at 7 (Oct. 17, 2017) (stating that average coal on-site inventories today are

improvements to their grid services but significantly increasing dangerous and costly environmental pollution. Compensation for such costs through the Proposal's cost-based rates for eligible generators would further drive up costs for customers.

Fuel stockpiling would also have negative environmental consequences. A working paper from the National Bureau of Economic Research (NBER) found that a 10 percent increase in coal stockpiles results in an increase of fine particulate matter ("PM") for locations up to 25 miles away from and downwind from plants. The estimated increase in "mortality rates implies local environmental costs of [roughly $203] per ton of coal stockpiled" and "to put this in perspective, the average power plant paid roughly $48 per ton of coal."[203]

Secondly, a generator would have an incentive to run at their maximum output (and absent any prudence review, expand capacity over time), even where the market price is lower than its marginal cost. An operator that is guaranteed its full costs maximizes its profits by running as much as possible, while also looking for any justification for additional capital expenditures and their corresponding rate of return. These perverse incentives would not only result in some of the least efficient, most expensive plants setting energy prices, with big impact to customers, but would also mean some of the dirtiest (coal) plants would greatly increase their operations.

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only 45-70 days, not 90 days), *available at* http://westernenergyboard.org/wp-content/uploads/2017/10/10-17-17-crepc-wirab-silverstein-future-baseload-in-west.pdf.

[203] Jha and Muller, Handle with Care: The Local Air Pollution Costs of Coal Storage. No. w23417. National Bureau of Economic Research, 2017, *available at* http://www.nber.org/papers/w23417. The report finds that costs would be roughly $183 from PM 2.5 alone, and roughly $203 per ton when accounting for other local air pollution. NBER found that "localized environmental costs of coal transportation and storage disproportionately impact the economically disadvantaged communities living near coal-fired power plants."

The Proposal also threatens to increase costs by undermining efficient bilateral contracting by wholesale market participants. Were the Proposal adopted, buyers would likely fear entering into power purchase agreements with any eligible units lest they be required to pay again for the output of those units through the Proposal's cost-based rates.[204]

F. The DOE Proposal would destroy rather than encourage proper price formation

While the DOE Proposal vaguely suggests that better "price formation" is necessary, it would undermine rather than support this goal, potentially entirely destroying the practice of price formation through competition in wholesale markets.[205] Price formation, in the context of FERC's regulation, refers to the process by which market inputs shape the prices for grid services over time. The goal in price formation is to ensure that services are accurately and transparently valued, such that market participants understand price inputs and have an incentive to operate efficiently. Far from allowing price formation to more accurately define grid values, the DOE Proposal completely undermines this process by arbitrarily insulating certain generators from market forces. The DOE Proposal does so because (1) it compensates eligible generators for an undefined product with absolutely no analytical basis that connects the compensation of that product to the value being provided, and (2) cost-based rates under the DOE Proposal

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[204] The Proposal is silent as to how obligations under bilateral contracts would be treated.

[205] Morgan Stanley analysts stated their view that the Proposal is not workable because it ". . . would bring an end to competitive power markets, is not clearly needed to ensure grid reliability & resiliency, and would be very expensive." SNL Energy, "Wall Street views DOE grid proposal as anti-competitive," Oct 2 2017, https://www.snl.com/web/client?auth=inherit#news/article?id=42144491&KPLT=6&s_data=si%3D5%26kpa%3D4ff9c982-6b41-4717-903b-72ee3affbfad%26sa%3D. Similarly, J.P. Morgan Securities Analysts wrote that: "Effectively re-regulating a major portion of the currently de-regulated organized markets via a cost-of-service system would presumably render any existing discernable market pricing mechanisms irrelevant." *Id.*

include compensation for products that are already compensated in RTO markets.[206] By compensating generators for offering the *same* services as those currently being provided through RTO markets, the DOE Proposal undermines the process by which the competitive markets arrive at prices for non-eligible generators selling those same services. And because there is no analytical basis for the payments, the DOE Proposal skews the bidding behavior of eligible generators rather than making it more accurate. Far from enhancing transparency in the markets, the DOE Proposal completely obscures what services resources are being paid for. The vagueness of the Proposal and lack of clarity surrounding how payment mechanics would work and how offer incentives would be modified further compound these problems and enhance the uncertainty that the Proposal causes for market prices for these services.[207]

This stands in stark contrast to state policies designed to address value *not* being captured in FERC-regulated competitive markets, such as policies to require polluters to pay the true societal cost of emissions, or to credit generators who facilitate the avoidance of costly emissions or other pollution. Policies compensating values not being captured by FERC's markets can help

[206] Overlapping products include the "purchase of electric energy," contributions to "reliability" (which are covered by a number of different products in RTOs including perhaps most prominently capacity, but also in ancillary services markets and cost-based tariffs). DOE Proposal at 19.

[207] While DOE cites an IHS Markit study to suggest that current wholesale market rules provide for inaccurate price formation in a manner that does not truly value resiliency, IHS Markit's report provides no support for the suggestion that the DOE Proposal enhances price formation. The DOE Proposal's approach of providing cost-based regulation for services that *are* provided in FERC-regulated markets rather than compensating specific grid services that are not, would undermine rather than enhance proper price formation even if IHS Markit's conclusions were true. Nor does the DOE Proposal provide any basis for developing a "resiliency" product. It does not state *which* wholesale price formation proposals are inadequate, detail which services they do not compensate, or explain how much compensation is warranted. *See* DOE Proposal at 5 (citing IHS Markit, "Ensuring Resilient and Efficient Electricity Generation: The Value of the current diverse US power supply portfolio" at 8).

achieve price formation goals by ensuring that the services generators do sell in FERC markets are priced according to accurate market inputs.[208]

VII. The DOE Proposal departs from FERC's existing market-based mechanisms without explanation

A. Failure to adequately explain a change in policy violates the APA.

Though an agency may reasonably change a prior position, it must provide a more substantial explanation of such a departure where "its new policy rests upon factual findings that contradict those which underlay its prior policy."[209] Such a heightened standard also applies where the prior position has "engendered serious reliance interests."[210] In such cases, in order to offer "a satisfactory explanation" for its action, "including a rational connection between the facts found and the choice made," the agency must give "a reasoned explanation . . . for disregarding facts and circumstances that underlay or were engendered by the prior policy"[211]

[208] This is particularly true for state policies such as Renewable Portfolio Standards that create a competitive market to deliver clean energy attributes not addressed by FERC's markets, and for programs that use rigorous analytical methods to determine the value of services not captured by FERC's markets and price those services at or below that true value. At least twenty-nine states and the District of Columbia have adopted Renewable Portfolio Standards to achieve state public health and environmental goals, and these programs have long worked in harmony with FERC's competitive markets. Similarly, programs that require polluters to pay for the cost of their emissions such as the Regional Greenhouse Gas Initiative promote accurate pricing by requiring polluting facilities to account for the cost of their emissions as a market input related to the production of electricity. Further, as discussed in Section VI.C., it is not FERC's role to determine the value of emissions and other questions related to public policy, so the value for these attributes are "accurate" for FERC's purposes because they do not price FERC-jurisdictional products such as energy, capacity, and ancillary services.

[209] *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009).

[210] *Mexichem Fluor, Inc. v. EPA*, 866 F.3d 451, 462 (D.C. Cir. 2017).

[211] *Mingo Logan Coal Co. v. EPA*, 829 F.3d 710, 718–19 (D.C. Cir. 2016) (internal citations omitted).

B. DOE's Proposal is inconsistent with FERC's policy of compensating generators based on market prices

In RTO-administered wholesale markets, FERC has been unequivocal in its long-standing and foundational support for market structures as the means to effectuate its mandate to ensure just and reasonable rates, free from undue discrimination or preferential treatment. As the Commission stated in Order 2000, "[c]ompetition in wholesale electricity markets is the best way to protect the public interest and ensure that electricity ratepayers pay the lowest price possible for reliable service."[212] The Commission has consistently encouraged the formation of competitive markets for grid services, with the elemental belief, "that appropriate RTOs could successfully address the existing impediments to efficient grid operation and competition and could consequently benefit consumers through lower electricity rates resulting from a wider choice of services and service providers. In addition, substantial cost savings are likely to result from the formation of RTOs."[213]

The Commission has repeatedly reaffirmed its support for market-driven competition to meet its statutory mandate:

> National policy for many years has been, and continues to be, to foster competition in wholesale power markets. As the third major federal law enacted in the last 30 years to embrace wholesale competition, the Energy Policy Act of 2005 (EPAct 2005) strengthened the legal framework for continuing wholesale competition as federal policy for this country.[214]

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[212] Regional Transmission Organizations FERC Order 2000, 89 FERC ¶ 61,285, at 3 (1999).
[213] Regional Transmission Orgs. (FERC Order 2000), 89 FERC ¶ 61,285, at 2-4 (1999).
[214] Wholesale Competition in Regions with Organized Elec. Markets, 119 FERC ¶ 61,306, at 2 (June 22, 2007). Similarly, FERC Order 745 specified that, "effective wholesale competition protects customers by, among other things, providing more supply options, encouraging new entry and innovation, and spurring deployment of new technologies. Improving the competitiveness of organized wholesale energy markets is therefore integral to the Commission fulfilling its statutory mandate under the FPA to ensure supplies of electric energy at just, reasonable, and not unduly discriminatory or preferential rates."

Effective wholesale competition protects consumers by providing more supply options, encouraging new entry and innovation, spurring deployment of new promoting demand response and energy efficiency, improving operating performance, exerting downward pressure on costs, and shifting risk away from consumers.[215]

Case law likewise recognizes and affirms the Commission's policy that competition is the primary and preferred means to ensure just and reasonable and not unduly discriminatory rates. "In this new world, FERC often forgoes the cost-based rate-setting traditionally used to prevent monopolistic pricing. The Commission instead undertakes to ensure 'just and reasonable' wholesale rates by enhancing competition— attempting, as we recently explained, 'to break down regulatory and economic barriers that hinder a free market in wholesale electricity.'"[216]

RTO-administered wholesale markets operationalize the Commission's just and reasonable mandate by "align[ing] revenue with the instantaneous supply and demand for electricity; generators and load change output and consumption in response to prices."[217] These

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[215] *See Wis. Pub. Power Inc. v. FERC*, 493 F.3d 239, 246 (2007) ("In the mid-1990s, FERC determined that longstanding structural barriers to competition in the wholesale power market constituted undue discrimination. Since then, it has been the Commission's policy to eliminate those barriers and promote competition.")

[216] *FERC v. EPSA*, 136 S. Ct. 760, 768 (2016) (quoting *Morgan Stanley Capital Group Inc. v. Pub. Util. Dist. No. 1 of Snohomish Cty.*, 554 U. S. 527, 536 (2008)). *See also N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74, 81 *(*"FERC now seeks to ensure that market-based rates are "just and reasonable" largely by overseeing the integrity of the interstate energy markets."); *Pub. Util. Dist. No. 1 of Snohomish Cty. Wash. v. FERC*, 471 F.3d 1053, 1064 (9th Cir. 2006) (The "move toward energy regulation reform was premised on a new set of widely-shared assumptions [including that]. . . . newly feasible market competition could drive down wholesale prices and measure the cost of service, including the cost of long-term investments, more accurately than did the previous regulatory regime."); *Interstate Nat. Gas Ass'n of Am. v. FERC*, 285 F.3d 18, 31 (D.C. Cir.2002) (Competition "at least over the long pull," will lead to prices that "approximate [marginal] cost").

[217] Eric Gimon & Robbie Orvis, *The state of US wholesale power markets; Principles for managing an evolving power mix*, Utility Dive (July 25, 2017), *available at* http://www.utilitydive.com/news/the-state-of-wholesale-power-markets-principles-for-managing-an-evolving-p/447839/.

markets efficiently promote a least-cost resource mix, "allowing the lowest-cost technologies to generate electricity first" because these markets can generally be operated with little regulatory or administrative intervention and are based upon resource owner bid decisions which in turn incorporate their costs and expected profits."[218]

The Commission has likewise stated repeatedly not only its preference for market mechanisms, but also its aversion to cost of service ratemaking as an alternative:

> We disagree with [arguments that] in essence seek[] a return to cost-based ratemaking under which the price each resource receives is solely a function of its costs. In a competitive market, prices do not differ for new and old plants or for efficient and inefficient plants; commodity markets clear at prices based on location and timing of delivery, not the vintage of the production plants used to produce the commodity. Such competitive market mechanisms provide important economic advantages to electricity customers in comparison with cost of service regulation. For example, a competitive market with a single, market-clearing price creates incentives for sellers to minimize their costs, because cost-reductions increase a seller's profits. And when many sellers work to minimize their costs, competition among them keeps prices as low as possible. While an efficient seller may, at times, receive revenues that are above its average total costs, the revenues to an inefficient seller may be below its average total costs and it may be driven out of business. This market result benefits customers, because over time it results in an industry with more efficient sellers and lower prices. By contrast, sellers have far weaker incentives to minimize costs under cost-of-service, because regulation forces a seller to reduce its prices when the seller reduces its cost.[219]

Extensive analysis and narrow tailoring has accompanied those rare instances where out-of-market regulatory or administrative intervention has occurred in the RTO context. "[T]he

[218] *Id.*

[219] *PJM Interconnection, LLC*, 117 FERC ¶ 61,331, at P 141 (Dec. 22, 2006); *see also* Am. Elec. Power Co., 103 FERC ¶ 61,089, at P 11 (April 30, 2003) ("the Commission's vision has been to ensure the delivery of dependable, affordable energy through reliance on sustained competitive markets rather than through a rigid adherence to strict-cost-of service principles."); *FERC v. EPSA*, 136 S. Ct. at 768 ("In this new world, FERC often forgoes the cost-based rate-setting traditionally used to prevent monopolistic pricing. The Commission instead undertakes to ensure 'just and reasonable' wholesale rates by enhancing competition — attempting, as we recently explained, 'to break down regulatory and economic barriers that hinder a free market in wholesale electricity.'" (quoting *Morgan Stanley Capital Grp.*, 554 U.S. at 536); *Pa. Water & Power Co. v. Fed. Power Comm'n*, 343 U.S. 414, 418 (1952).

Commission has emphasized that RMR agreements should be of a limited duration so as to not perpetuate out-of-market solutions that have the potential, if not undertaken in an open and transparent manner, to undermine price formation."[220]

The DOE Proposal strikes at the core of FERC's statutory mission and mandate by insulating a significant fraction of total capacity in several RTOs from competitive wholesale market incentives. Despite the Commission's repeated finding that "competition in wholesale electricity markets is the best way to protect the public interest and ensure that electricity ratepayers pay the lowest price possible for reliable service," the DOE Proposal instead seeks without justification to provide for "recovery of costs and a return on equity" for eligible resources. The Proposal thus creates a cost of service regime for a specific set of resources, despite the Commission's view that "competitive market mechanisms provide important economic advantages to electricity customers in comparison with cost of service regulation."[221]

DOE also says nothing about the tremendous reliance interests (amounting to trillions of dollars in investment) built upon the foundation of competitive markets. DOE is silent on its reasoning for establishing a parallel cost of service regime for approximately one fifth of the generating capacity in the targeted wholesale markets, rather than relying on market competition to provide the allegedly missing resiliency services. And it offers no justification for gutting the competitive wholesale markets, and the critical role these markets play in ensuring reliability, by instituting this parallel preferential and anticompetitive regime. Such a sweeping refutation of the Commission's policy of promoting market competition as the best means to protect the

[220] *N.Y. Indep. Sys. Operator*, 150 FERC ¶ 61,116, at P 2 (2015). The narrow instances for which the Commission tolerates cost-based ratemaking as the primary compensation mechanism for a given resource located in an RTO are discussed in greater detail in Section VII.C..

[221] *PJM Interconnection, LLC*, 117 FERC ¶ 61,331, at P 141 (Dec. 22, 2006).

public interest, threatening the significant reliance interests vested in the functioning wholesale markets, without explanation is both legally flawed and dangerous.

C. The DOE Proposal is inconsistent with precedent that provides for non-competitive cost-based actions to be temporary, tailored choices of last resort

FERC allows certain tailored, non-competitive cost-based interventions, but only rarely and as a choice of last resort. These heavy-handed interventions into the wholesale market provide a short-term backstop for particular reliability needs. DOE's Proposal neither acknowledges the existence of these backstop measures, nor addresses its potential conflicts or redundancies with such measures.

Each region covered by the DOE Proposal already has a system "used strictly as a last resort" to address any anticipated supply shortfall through temporary institution of contracts to compensate resources for continued operation.[222] While the procedures related to the institution of such contracts varies by region, all are designed to foresee and prevent the rare event of a generator retirement decision impacting specific reliability concerns.

RMR contracts exemplify the Commission's foundational preference for competitive market mechanisms in effectuating its statutory responsibility in ensuring just and reasonable rates. FERC's relevant decisions on RMRs identify that this "last resort" contract should be targeted and specific, locationally tailored, and time limited.[223]

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[222] Such contracts are known by different terminology across the RTOs. PJM calls these agreements "Reliability Must Run" contracts, for example, while MISO calls them "System Support Resources" agreements. *See Devon Power LLC*, 103 FERC ¶ 61,082, at P 31. *See* PJM Open Access Transmission Tariff, Part V (2017), *available at* https://www.pjm.com/directory/merged-tariffs/oatt.pdf; *Midcontinent Indep. Sys. Operator, Inc.*, 156 FERC ¶ 61,116 (2016) (accepting in part tariff revisions related to MISO's treatment of System Support Resources); *Midcontinent Indep. Sys. Operator, Inc.*, 160 FERC ¶ 61,014 (2017) (approving an SSR Agreement pursuant to MISO's tariff).

[223] *See Millford Power Company, LLC*, 119 FERC ¶ 61,167 n.51 (2007) ("The Commission has repeatedly expressed dissatisfaction with these 'non-market' mechanisms and has adopted a 'last

The DOE Proposal flies in the face of the Commission's measured approach, requiring no identified reliability concern, no extensive evidence or study, locational detail, or time limitation before offering an expansive cost of service guarantee for preferred resources in perpetuity.

VIII. The Proposal violates NEPA

The DOE Proposal suggests that the Commission may forego the environmental analysis required by the National Environmental Policy Act, 42 U.S.C. § 4321, *et seq.* (NEPA).[224] NEPA "is our basic national charter for protection of the environment,"[225] and "requires a federal agency 'to the fullest extent possible,' to prepare 'a detailed statement on . . . the environmental impact' of 'major Federal actions significantly affecting the quality of the human environment.'"[226] NEPA's procedural requirements ensure that federal agencies will carefully consider the environmental effects of their proposals, and that the public will have access to the agency's information.[227] The DOE Proposal dispenses with any type of NEPA report, because

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resort' policy when considering RMR agreements."); *see La Paloma Generating Co., LLC v. Cal. Indep. Sys. Operator Corp.*, 157 FERC ¶ 61,002, at P 30 (2016) (where FERC denied the relief requested by the generator because CAISO's local reliability study did not show a reliability need for the units); *See York Indep. Sys. Operator*, 150 FERC ¶ 61,116, at P 13 (2015) ("NYISO should describe the process for conducting the reliability analyses necessary to determine that there is a reliability need for the unit . . . We believe it is appropriate to require the NYISO Tariff to provide transparency with respect to such timelines, processes, and schedules, not just for the practical administration of the NYISO Tariff, but also to help ensure that there is no undue discrimination or preference in the handling of RMR service and agreements pursuant to the NYISO Tariff."); *see Devon Power LLC*, 107 FERC ¶ 61,240, at P 35 (2004) ("In NEMA/Boston these reliability concerns have been limited to the need for RMR contracts for a limited number of specific units that are needed to satisfy reliability because of the location of these units. The RMR contracts were filed because specific units were needed, not because there were inadequate resources within NEMA/Boston in general. As such, reliability compensation appears to be more of a short-term issue in NEMA/Boston").

224 DOE Proposal at 16.

225 40 C.F.R. § 1500.1(a).

226 *Ctr. for Biological Diversity v. Nat'l Highway Traffic Safety Admin.*, 538 F.3d 1172, 1185 (9th Cir. 2008) (quoting 42 U.S.C. § 4332(2)(C)(i) (2007)).

227 *See Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 349 (1989).

"the Commission has previously concluded that neither an Environmental Assessment nor an Environmental Impact Statement is required for a [Notice of Proposed rulemaking] under section 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the [Act]."[228] But that categorical exclusion does not apply here. It exists to further the Commission's limited authority in garden-variety ratemaking proceedings, and does not justify a decision to ignore the environmental effects of a rule that provides profit guarantees to certain types of energy generation.

The exclusion codified in 18 C.F.R. § 380.4(a)(15) is based on the Commission's understanding of its statutory authority to set just and reasonable rates under sections 205 and 206. Specifically, it flows from the Commission's interpretation that those sections "deliberately" withhold from the Commission any "jurisdiction over the capacity planning, determination of power needs, plant siting, licensing, construction, and the operations of coal-fired power plants."[229]

The DOE proposal, which is designed to ensure the continued operation of so-called "fuel secure generation,"[230] does not fit under this categorical exception because it does not merely "take[] [power] plants as it finds them."[231] Rather, the explicit purpose of the Proposal is to bail out non-competitive coal-fired and nuclear power plants which would be shuttered due to the

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[228] DOE Proposal at 16 (citing 18 C.F.R. § 380.4(a)(15))
[229] *See Monongahela Power Co.*, 40 FERC ¶ 61,256, 61,861 (Sept. 7, 1987); 52 Fed. Reg. 47,897, 47,900 (Dec. 17, 1987) (40 C.F.R. § 380.4(a)(15) "merely codifies the *Monongahela* decision"); *see also Monongahela Power Co.*, 39 FERC ¶ 61,350, 62,097 (June 25, 1987) ("Given this jurisdictional constraint on its ability to oversee the siting and construction of . . . power plants, the Commission has no means by which to assure that their location and technical features pose the least risk of adverse environmental impact.").
[230] DOE Proposal at 3.
[231] *Monongahela Power Co.*, 39 FERC ¶ 61,350, 62,097.

operation of market forces.[232] The Commission has previously recognized that an environmental assessment is warranted when action by the Commission would affect the operation of particular power plants in such a direct way. For example, FERC determined that an Environmental Assessment was warranted where an action held the potential to result in utility "operat[ing] its power plants … more intensely," and "reactivate currently unused plants," so as to "significantly increase emissions" of pollutants, an assessment is "warranted")[233] In short, this is not a case where the Commission's "limited statutory authority" means that the Commission need not consider the environmental effects of those power plants' continued operations.[234] The DOE Proposal would require that the Commission adopt pricing rules to guarantee the economic viability of particular power plants, making those power plants the subject of "federal control and responsibility."[235]

Further, reasoned decision-making requires the Commission to consider whether the DOE Proposal *itself* will exacerbate the "natural [] disasters" that prompted DOE's call for special rates to "fuel-secure" facilities, something the Commission can accomplish only through an environmental assessment.[236] The Proposal cites the need to respond to "extreme weather" events such as "[t]he recent Polar Vortex, as well as the devastation from Superstorm Sandy and

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[232] *See* DOE Proposal at 3, 7 (lamenting that "power plant retirements were dominated by coal plants" and that "[t]he next largest set of planned retirements are nuclear plants," highlighting that "nuclear are coal plants typically have advantages associated with onsite fuel storage," and declaring that "these facts" warrant "prompt action," and demonstrating that the Proposal seeks to forestall future "fuel-secure" plant retirements) (internal citations omitted).
[233] *See S. Cal. Edison Co. & San Diego Gas & Elec. Co.*, 49 FERC ¶ 61,091, 61,357 (Oct. 27, 1989); *see also Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Utilities Recovery of Stranded Costs by Pub. Utilities & Transmitting Utilities*, 72 FERC ¶ 61022, 61061 (July 12, 1995) (ordering FERC staff to conduct an environmental impact statement in a ratemaking proceeding)
[234] *See Dep't of Transp. v. Pub. Citizen*, 541 U.S. 752, 770 (2004).
[235] 40 C.F.R. § 1508.18 (definition of "Major Federal action" under NEPA).
[236] DOE Proposal at 2-3.

Hurricanes Harvey, Irma, and Maria."[237] Climate change strongly influences the frequency and severity of such events.[238] By prolonging the life of coal-fired power plants, the DOE Proposal would also prolong the greenhouse gas emissions that accompany those plants, and which are the prime contributor to climate change.[239]

The climate-related impacts of FERC's actions are thus definitively "useful[]" to FERC's "decision-making process."[240] The FPA may not always require FERC to consider environmental effects when setting rates under sections 205 and 206; but where environmental impacts are relevant to the primary basis for the rate proposal, FERC cannot ignore them. The climate-related impacts of the DOE Proposal are central to the rationale for the Proposal, and the Proposal's utility. Because of this, the Commission is required to assess those impacts under NEPA.[241]

IX. The proposal is so egregiously inadequate that FERC's only legally viable path is to reject it

[237] *Id.* at 11.

[238] CLIMATE CHANGE IMPACTS IN THE UNITED STATES: THE THIRD NATIONAL CLIMATE ASSESSMENT 115 (*See* Jerry M. Melillo et al., eds., 2014), *available at* http://www.globalchange.gov/browse/reports/climate-change-impacts-united-states-third-national-climate-assessment-0 (noting that "Climate change has begun to affect the frequency, intensity, and length of certain types of extreme weather events" including "extreme precipitation events, sustained summer heat, and in some regions, droughts and winter storms").

[239] *See* Coal, Center for Climate and Energy Solutions, *available at* https://www.c2es.org/energy/source/coal ("Carbon dioxide emissions from coal combustion for electric power and industry were responsible for 24.5 percent of total U.S. greenhouse gas emissions in 2012."); *see also* 52 Fed. Reg. at 47,900 (recognizing that actions that are likely "to result in fuel switching" may "have a long-term or widespread impact on air quality").

[240] *Pub. Citizen*, 541 U.S. at 768.

[241] *See* 18 C.F.R. § 380.4(b) (requiring preparation of environmental assessment where evidence demonstrates significant, relevant environmental impacts).

A. The proposal violates APA requirements

In addition to violating the Commission's core statutory mandate under the Federal Power Act, the substance of the DOE Proposal, and the timeline for public consideration of the Proposal and its finalization fail to meet even the most basic procedural and substantive obligations under the APA. The APA's required "opportunity for comment must be a meaningful opportunity," and "[t]hat means enough time with enough information to comment and for the agency to consider and respond to the comments."[242] The Proposal lacks essential elements needed to understand it, rendering the opportunity for comment meaningless. Similarly, the cursory reasoning offered in support of the Proposal prevents stakeholders from engaging with the Commission on its rationale for the proposed action or offering contrary evidence. The Commission's approval of this Proposal, or some variation thereof, would contravene the APA's paramount directive to engage in meaningful public comment and reasoned decisionmaking. It would represent a dramatic departure from prior Commission policy without basis, and undercut the important benefits of public notice and comment.

Equally problematic is the breakneck speed of the Commission proceeding. The DOE Proposal is sweeping in its impact, potentially affecting over one fifth of the generating capacity in the targeted wholesale markets with cost implications reaching into the hundreds of billions of dollars and significant environment impact. With so much at stake, the dramatic curtailment of the normal period for public input on the proposal is alarming, and runs afoul of APA requirements.

[242] *Prometheus Radio Project v. FCC*, 652 F.3d 431, 450 (3d Cir. 2011) (citations omitted). *See also Am. Hosp. Ass'n v. Bowen*, 834 F.2d 1037, 1044-45 (D.C. Cir. 1987) (noting the "obvious importance of the [APA's] policy goals of maximum participation and full information.")

Finally, neither DOE nor the Commission have provided any basis whatsoever to warrant the gross inadequacies of the Proposal and the process to consider it. With such a deeply deficient basis for action, the Commission's only legally viable course is to reject the Proposal.

1. The Proposal is too vague for meaningful comment

Section 553 of the APA[243] requires that an agency proposing rulemaking "provide sufficient factual detail and rationale for the proposal to permit interested parties to comment meaningfully."[244] These core requirements are "designed (1) to ensure that agency regulations are tested via exposure to diverse public comment, (2) to ensure fairness to affected parties, and (3) to give affected parties an opportunity to develop evidence in the record to support their objections to the proposal and thereby enhance the quality of judicial review."[245] In addition, "a chance to comment … [enables] the agency [to] maintain[] a flexible and open-minded attitude towards its own rules,"[246] and "avoid[s] the inherently arbitrary nature of unpublished ad hoc determinations."[247] An agency may not circumvent these APA obligations by issuing a very broad 'notice' and then "whimsically picking and choosing" from among a lengthy set of issues raised in the four corners of the proposed rulemaking.[248] To the contrary, "the notice required by the APA . . . must disclose in detail the thinking that has animated the form of a proposed rule and the data upon which that rule is based . . . . [A]n agency proposing informal rulemaking has

[243] 5 U.S.C. § 553(b)(3).
[244] *United States Telecom Assn. v. FCC*, 825 F.3d 674, 700 (D.C. Cir. 2016) (quoting *Honeywell Intl., Inc. v. EPA*, 372 F.3d 441, 445 (D.C. Cir. 2004) (internal quotation marks omitted)).
[245] *Int'l Union, United Mine Workers of Am. v. Mine Safety and Health Admin.*, 407 F.3d 1250, 1259 (D.C. Cir. 2005)
[246] *McLouth Steel Prods. Corp. v. Thomas*, 838 F.2d 1317, 1325 (D.C. Cir. 1988).
[247] *United States v. Reynolds*, 710 F.3d 498, 520 (3d Cir. 2013).
[248] *CSX Transp., Inc. v. Surface Transp. Bd.*, 584 F.3d 1076, 1082 (D.C. Cir. 2009) (quoting *Etvtl. Integrity Project v. EPA*, 425 F.3d 992 (D.C. Cir. 2005)).

an obligation to make its views known to the public in a concrete and focused form so as to make criticism or formulation of alternatives possible."[249]

The DOE Proposal fails to provide the requisite notice to allow meaningful comment. It lacks the most essential elements needed for adequate notice and opportunity for comment: *what* the Commission proposes to do, and *how* that action will be implemented. At best, it provides a vague sketch of a direction of travel. The list of questions left unanswered by the Proposal is a long one. The Proposal does not include the requisite finding that current rates are not just and reasonable,[250] depriving commenting parties from an opportunity to comment on its basis. As discussed in Section V, the Proposal does not identify precisely what the targeted generation sources would be compensated for and, on the other side of the coin, what attributes are purportedly under-compensated under existing market-based rates. While it requires "full compensation" for this enigmatic missing service, it provides no indication of the benchmarks to determine whether that requirement has been met. DOE also never defines some of the criteria determining eligibility for rates under the Proposal, leaving suppliers to guess whether they may qualify.[251] Even if the Proposal had clearly articulated what it aims to achieve, it also fails to identify the most basic mechanism of how such "full compensation" will be attained, whether

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[249] *Home Box Office, Inc. v. FCC*, 567 F.2d 9, 35-36 (D.C. Cir. 1977); *see also Horsehead Res. Dev. Co., Inc. v. Browner*, 16 F.3d 1246, 1268 (D.C. Cir. 1994) ("[Agencies] must describe the range of alternatives being considered with reasonable specificity. Otherwise, interested parties will not know what to comment on, and notice will not lead to better-informed agency decision-making." (internal citations and quotation marks omitted)).
[250] A notice of proposed rulemaking must "provide sufficient factual detail <u>and rationale</u> for the rule to permit interested parties to comment meaningfully." *Honeywell Int'l., Inc.*, 372 F.3d at 445 (emphasis added).
[251] *See supra*, III.B. Notably, to be eligible a resource must be "able to provide essential energy and ancillary reliability services." DOE does not explain what such services are.

that be through RTO markets, separate cost-based mechanisms (as the proposal seems to suggest), or some mix of the two.

Indeed, the Commission staff's lengthy request for information drives home the utter inadequacy of the DOE Proposal. It asks for input on a range of foundational issues, asking over 30 questions on such critical details as "[w]hat is resilience" and "[h]ow would eligible resources receiving compensation under the proposed rule be committed and dispatched in the energy market?"[252] Without clarity on its fundamental components, interested parties cannot meaningfully engage with the Proposal. Market participants and consumers cannot understand whether they will be affected, much less the degree of those impacts.[253] The public cannot weigh in on the pros and cons of a proposal when one cannot say for sure *what it does*.[254]

Nor does the Commission's staff request for more specific comment cure the inadequacy of the DOE Proposal. The Commission's broad solicitation of input is analogous to the "request[] [for] information and data from interested parties" found in an Advanced Notice of Proposed Rulemaking, which the Commission may use to "determine . . . whether to take any further action."[255] A belated request for public input regarding the elemental concepts underlying the Proposal does not help interested parties better understand what the Proposal would achieve, how it would do so, and whether it might impact them. It therefore does not enable the opportunity for meaningful comment required by the APA.

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[252] Request for Information Regarding: Grid Reliability and Resilience Pricing Model, FERC Docket No. RM18-1-000 (Oct. 4, 2017), *available at* https://www.ferc.gov/media/headlines/2017/2017-3/10-04-17.pdf.

[253] Indeed, the range of estimates of potential costs of this proposal to consumers is symptomatic of the uncertainty surrounding what the proposal is.

[254] *See Kooritzky v. Reich*, 17 F.3d 1509, 1513 (D.C. Cir. 1994) ("Something is not a logical outgrowth of nothing.").

[255] *P & V Enterprises v. U.S. Army Corps of Engineers*, 516 F.3d 1021, 1024 (D.C. Cir. 2008).

Finally, DOE is wrong to point to prior dockets as though they provide information or deliberation that helps to inform what the Proposal aims to achieve.[256] DOE cannot bootstrap its poorly reasoned Proposal into a more-considered one by pointing to unrelated Commission actions. None of the dockets that DOE cites in its Proposal provide any forewarning of a Proposal such as DOE's, or the alleged "resiliency crisis" it claims to address.[257]

2. The timeline for consideration of the Proposal is unreasonable

The APA requires the Commission to "give interested persons an opportunity to participate in the Proposal making through submission of written data, views, or arguments.[258] While the APA does not define an adequate period of time for comment, Executive Order 12,866 provides that "in most cases" the agency "should include a comment period of not less than 60 days" in order to "afford the public a meaningful opportunity to comment on any proposed regulation."[259]

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[256] DOE Proposal at 8 ("FERC is cognizant of the problem and has the necessary information on which to act expeditiously.").

[257] These dockets vary. Some are very general, and thus related in a peripheral way to any topic that has to do with making prices more transparent or the grid more reliable. Others are very specific and entirely unrelated to the DOE proposal in any way. *See*, *e.g.*, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators (Docket No. AD13-7-000) (June 17, 2013) (a technical conference to "provide an opportunity to review at a high level the centralized capacity market rules and structures."); *PJM Interconnection*,, 151 FERC ¶ 61208, 62,297-98 (June 9, 2015) (accepting PJM's Capacity Performance Filing); *Advanced Energy Mgmt. All. v. FERC*, 860 F.3d 656, 660 (D.C. Cir. 2017) (upholding PJM's Capacity Performance filing); Price Formation in Energy and Ancillary Services Markets Operated by RTO/ISOs (Docket No. AD14-14-000) (June 19, 2014) (opening a general discussion of "whether the energy and ancillary services markets are being operated in a way that produces accurate price signals"); Staff Analysis of Operator-Initiated Commitments in RTO and ISO Markets (Docket No. AD14-14-000) (December 2014) (raising questions on price formation, including "how to ensure that fast-start resources are considered when setting price."); Settlement Intervals and Shortage Pricing in Markets Operated by RTO/ISOs, Docket No. RM15-24-000, ORDER NO. 825 (June 16, 2016) (issuing an Order "to align settlement and dispatch intervals").

[258] 5 U.S.C. § 553(c).

[259] Exec. Order No. 12,866, 58 Fed. Reg. 51,735 (Sept. 30, 1993).

Moreover, in practice the Commission affords extensive opportunity for comment on proposals of significance that change fundamental market rules with widespread impact across the RTOs. Prior FERC rulemakings of this magnitude were preceded by months or years of deliberation and consultation with affected parties. For example, before amending transmission planning and cost allocation requirements via Order No. 1000 in 2011, FERC convened three technical conferences in September 2009, issued a Notice of Request for Comments in October, 2009, and issued an NOPR on June 17, 2010.[260] The Commission received roughly 5,700 pages of initial and reply comments in response following the NOPR, and over a year elapsed before it issued Order No. 1000 on July 21, 2011. Similarly, almost an entire year elapsed between the Commission's issuance of an NOPR on March 18, 2010 and its final Proposal via Order No. 745 on March 15, 2011 addressing compensation for demand response in RTOs.[261]

The Commission's compressed timeframe, affording a mere thirteen days from the Proposal's publication in the Federal Register on October 10 to the close of initial comments on October 23rd, is manifestly unreasonable.[262] The DOE Proposal points generally to Commission dockets containing thousands of pages of filings and to reports and letters that, in turn, synthesize thousands of pages of studies. Locating relevant information in those sources that could possibly pertain to the DOE Proposal is a time-consuming task. The time constraints also limit an analyst's ability to develop more detailed assessments of the potential costs and impacts of the DOE Proposal. Further, Commission staff's voluminous set of questions could be better

[260] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 136 FERC ¶ 61,051 (July 21, 2011).
[261] *Demand Response Compensation in Organized Wholesale Energy Markets*, 134 FERC ¶ 61,187 (Mar. 15, 2011).
[262] The Federal Register notice was issued after the Commission issued a notice requesting comments in this docket, leaving members of the public who do not avidly track FERC dockets even less time to comment.

answered with careful consideration of existing research or additional analysis, all of which takes time. The Commission's incredibly compressed timeframe for input violates the APA because it limits the quality and depth of commenters' participation in the rulemaking process in a manner that does not match the complex, technical, and extremely consequential Proposal.[263]

Ultimately, cutting off public comment in this manner is harmful to the Commission's own deliberation and the quality of any final action. Stakeholder engagement is vital to "test" a proposed policy, by identifying potential flaws and improvements to a proposal. A proposal that introduces new and undefined concept and that would throw away years of a market-based approach to reliability and stand in the way of market-based outcomes is precisely the type of proposal that stands to benefit from more thorough vetting.

3. There is no basis for an exception to APA requirements

DOE suggests directly issuing its egregiously flawed and environmentally and economically disastrous Proposal as an interim final rule as an alternative to the rushed comment period. This is, quite simply, a suggestion to circumvent APA requirements without cause. It should be roundly rejected.

While the APA excuses compliance with notice-and-comment requirements under certain narrow circumstances[264], use of the exception "should be limited to emergency situations,"[265] or

[263] Nor should the Commission mistakenly assume that because the Public Interest Organizations worked to develop a long and substantive comment in this docket, that the timeframe for comment was reasonable. A standard for reasonableness should not demand that members of the public work burn midnight oil or work ceaselessly to vindicate the opportunity for comment.

[264] The "good cause" exception excuses compliance with the APA's notice-and-comment requirements "when the agency for cause finds (and incorporates the finding and a brief statement of reasons therefor in the Proposals issues) that notice and public procedure thereon are impracticable, unnecessary, or contrary to the public interest." 5 U.S.C. § 553(b)(B).

[265] *Am. Fed'n of Gov't Emps. ALF-CIO v. Block*, 655 F.2d 1153, 1156 (D.C. Cir. 1981)

where serious harm could result if delayed.[266] Neither the DOE Proposal, nor the Commission in issuing its notice inviting comment, offered any basis for exempting the proposed action from APA requirements. The DOE Proposal's vague allusions to urgency are an inadequate basis for an exception that is to be "narrowly construed and only reluctantly countenanced."[267] Claims of urgency are unsupported in the record, with NERC, DOE, and numerous RTO analyses all rejecting the notion that the grid faces any imminent reliability threat.[268]

4. The flaws in the Proposal are too egregious to resolve through this proceeding

DOE "directs" the Commission to take final action on the proposal within 60 days of its issuance in the federal register, indicating that any actions required by law should be taken with sufficient time to allow that timeframe to be met. The flaws of the DOE Proposal are deep-seated, and cannot be remedied on this timeframe. The Proposal is procedurally and substantive inadequate, and finalizing it would run afoul of both APA and FPA requirements. Indeed, nothing resembling it could ever pass muster under the FPA or the APA. To comply with even the APA's basic procedural requirements for notice-and-comment rulemaking, the modifications necessary to actually apprise the public of the specific rationale for the rule and alternatives under consideration would be so substantial as to essentially render DOE's current Proposal

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[266] *See Jifry v. FAA*, 370 F.3d 1174, 1179 (D.C. Cir. 2004) (applying good cause exception where delay resulting from notice and comment could prevent agency from taking effective action relative to known terrorism threat).

[267] *See Tenn. Gas Pipeline Co. v. FERC*, 969 F.2d 1141, 1144 (D.C. Cir. 1992); *see also Bowen*, 834 F.2d at 1044-45.

[268] DOE Staff Report at 63; NERC, State of Reliability 2017, at vii, 5, 27, available at http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR_2017_MASTER_20170613.pdf; *see also* Appendix B.

unrecognizable. New comment period would be required to provide a meaningful opportunity for engagement.[269]

More fundamentally, any sound pathway forward must reject the inherently flawed DOE focus on on-site fuel supply as the exclusive and paramount reliability characteristic.[270] The assertion that certain technology is necessary to reliability or "resiliency" of the grid because it relies on on-site fuel, rather than fuel delivery or no fuel at all, is not only inadequately demonstrated on this record, it is factually incorrect. While there will always be a role of FERC, NERC, and the RTOs to examine whether market operation will continue to deliver the essential reliability services needed to ensure a reliable grid, the Commission is doomed to failure in this critical task if it assumes, as the DOE proposal does, that past is prologue, and that which served the grid in the past is, of necessity, the only way to serve the grid in the future. Just because so-called "baseload" resources have provided essential reliability services historically does not mean these are the only resources that can provide those services today. FERC should instead start its inquiry from a rational (and technology neutral) framework that recognizes the contributions of all technology types to grid reliability.

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[269] "Given the strictures of notice-and-comment rulemaking, an agency's proposed rule and its final rule may differ only insofar as the latter is a 'logical outgrowth' of the former." *Envtl. Integrity Project v. EPA*, 425 F.3d 992, 996 (D.C. Cir. 2005) (citing *Shell Oil Co. v. EPA*, 950 F.2d 741, 750–51 (D.C. Cir. 1991); *Ne. Md. Waste Disposal Auth. v. EPA*, 358 F.3d 936, 952 (D.C. Cir. 2004)). A final rule amounts to a "logical outgrowth" of its noticed counterpart only if interested parties "'should have anticipated' that the change was possible, and thus reasonably should have filed their comments on the subject during the notice-and-comment period." *Ne. Md. Waste Disposal Auth.*, 358 F.3d at 952 (citation omitted).

[270] As described above, Section IV.C., the Commission should start by considering whether there is a problem at all, and, if so, carefully defining the service that finds lacking. Such an approach would have avoided the baseless and unworkable Proposal here.

B. Section 403 of the DOE Organization Act reinforces the Commission's obligation to reject the procedurally and substantively flawed DOE proposal

The DOE Organization Act neither requires the Commission to ignore its statutory mandate under the FPA, nor skirt the substantive and procedural requirements of the APA. To the contrary, the DOE Organization Act presents a clear mandate to the Commission to independently consider a Section 403 proposal and to act on it consistent with its statutory duties. In the face of such a clearly deficient proposal, the DOE Organization Act demands but one result: rejection of the DOE proposal.

1. The Commission has an independent duty to evaluate section 403 proposals

The Commission has exclusive jurisdiction over rules proposed pursuant to Section 403 of the DOE Organization Act, which provides that the Commission "shall consider and take final action on any proposal made by the Secretary under such subsection in an expeditious manner in accordance with such reasonable time limits as may be set by the Secretary for the completion of action by the Commission on any such proposal."[271] The Act states that "[t]he decision of the Commission involving any function within its jurisdiction . . . shall not be subject to further review by the Secretary [.]"[272] The Commission is thus duty-bound to independently evaluate DOE's proposal, and to reject it if it is not supported by the record, or is otherwise inconsistent with law, or the dictates of the FPA in particular.

DOE has proposed rules under Section 403 infrequently, and the Commission has always exercised its independent judgment in acting upon such proposals. For example, in 1979, DOE issued a proposal under Section 403 relating to the "transportation of natural gas . . . to displace

[271] 42 U.S.C. § 7173(b).
[272] *Id.* § 7172(g).

certain foreign fuel oil supplies."[273] Following a hearing and public comment period,[274] FERC promulgated a final rule via Order No. 30.[275] Order No. 30 independently analyzed the policy rationale and implications of DOE's proposal, concluding that unacceptably high fuel oil prices, and the Commission's "responsibility" to certain "high priority customers" compelled it to adopt the proposal.[276] However, the final rule significantly modifies the language of DOE's proposed rule, and the Commission explicitly declined to adopt several provisions contained in the proposal.[277]

Order No. 451[278] provides another example of the Commission exercising its independent judgment to modify and reject aspects of a DOE proposal under Section 403. In issuing a final rule, the Commission rendered "an endorsement of the objectives set forth in the DOE proposal, modified to recognize the current needs of the natural gas market for regulatory change and the most practical means of meeting those needs."[279] The final rule substantially amended DOE's proposal in reflection of FERC's independent analysis, such as through its modification of a good faith negotiating rule contained in the proposal.[280]

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[273] Transportation Certificates for Natural Gas, Displacement of Fuel Oil, 44 Fed. Reg. 17,644 (Mar. 22, 1979).
[274] Docket No. RM 79-34, Hearing Tr. dated April 30, 1979, at 17-53.
[275] Transportation Certificates for Natural Gas, Displacement of Fuel Oil, 44 Fed. Reg. 30,323 (May 25, 1979).
[276] *Id.* at 30,324-25.
[277] *Id.* at 30,327-31 ("Section 284.205(c)(2) differs from the one-year renewal period proposed by [DOE], by prohibiting extensions beyond the termination of the fuel shortage emergency period."; "The [DOE] proposed rule included an automatic 90 day extension for eligible users purchasing gas under a take-or pay contract. Although the Commission has provided such extensions in its direct sales programs for high-priority users, the nature of this program, insofar as it makes direct sale gas available to low priority users, and the size each sophistication of such users makes any automatic extensions inappropriate.").
[278] Ceiling Prices; Old Gas Pricing Structure, 51 Fed. Reg. 22,168 (June 18, 1986).
[279] *Id.* at 22,177.
[280] *Id.* at 22,204 ("The Commission generally adopts the good faith negotiation rule proposed by DOE in its NOPR. However, in order to provide more balanced negotiating rights among the

The Commission's obligation to independently assess a section 403 proposal must be taken even more seriously where, as here, the proposal is facially discriminatory to the benefit of a small subset of market participants, is being rushed on a wholly unsubstantiated claim of an urgent threat, and the record raises the specter of political motivations for the action, rather than legitimate statutory aims. By design, the DOE Proposal targets only some generation resources, within only some regional markets under FERC jurisdiction, for preferential cost treatment. One of the biggest beneficiaries of the Proposal happens to be the same entity[281] that, according to a letter from the CEO of Murray Energy Corp to the Administration, was promised "whatever [it] want[s]" from President Trump.[282] Whatever the truth of Mr. Murray's allegations about a deal with the Trump Administration, the prospect of politically-motivated manipulation of market rules can best be laid to rest by a clear exercise of the Commission's authority to independently to review the proposal. Even perceptions of unfair advantage can be damaging to market operation and grid reliability, threaten to compromise the Commission's reputation of independence, and warrant a serious response.[283]

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parties, the Commission modifies DOE's proposed rule so that when a producer seeks a higher price for old gas in one contract the purchaser may seek a lower price for all gas (both old and new) in any contract between the parties containing any old gas.).

[281] FirstEnergy has at least 40 units that have the potential to benefit from the DOE proposal, more than almost any another market participant. [CITE]

[282] Letter from Robert Murray, CEO, Murray Energy Corp. to John D. McEntee III, Special Assistant and Personal Aide to the President (Aug. 4, 2017), *available at* https://www.documentcloud.org/documents/3936141-Murray-s-letters-to-Trump-administration.html (describing an in-person exchange between Mr. Murray, the CEO of FirstEnergy, Charles Jones, and President Trump).

[283] *Reg'l Transmission Organizations*, 89 FERC ¶ 61285 (Dec. 20, 1999) ("If market participants perceive that other participants have an unfair advantage . . . it can inhibit their willingness to participate in the market, thus thwarting the development of robust competition . . . . [S]uch mistrust can also harm reliability").

2. Section 403 may not be used to circumvent APA requirements

The DOE Organization Act grants the Secretary a role in proposing rules with respect to any function within the jurisdiction of the Commission under Section 402 of the Act. This agenda setting authority, however, does not supersede other applicable federal law, and must be read in a manner that is consistent with other statutory mandates. Section 403(b)'s directive to take final action on a proposal "in an expeditious manner in accordance with such *reasonable* time limits as may be set by the Secretary" can only sensibly be interpreted to allow for the opportunity for notice and comment required by the APA.[284] In other words, if DOE imposes a timeline that prevents adequate APA notice and comment, the timeframe is unreasonable under section 403. The tight timeline DOE set for action in its proposal likewise provides no excuse for failing to meet other substantive or procedural requirements under the APA, such as clear notice, the need for a reasoned explanation for the proposal's departure from prior FERC policy, and to present a rational basis for the action selection.

X. Conclusion

For the foregoing reasons, the undersigned organizations respectfully request that the Commission deny the DOE Proposal.

Dated: October 23, 2017

/s/ Kim Smaczniak
Kim Smaczniak
Clean Energy Staff Attorney
Earthjustice
1625 Massachusetts Avenue, N.W., Suite 702
Washington, DC 20036-2243
T: 202.797.5247 or 202.667.4500 Ext. 5247
F: 202.667.2356

[284] *See* 42 U.S.C. § 7173(b).

earthjustice.org

/s/ Michael Panfil
Michael Panfil
Senior Attorney and Director of Federal Energy Policy
Environmental Defense Fund
1875 Connecticut Ave., NW
Washington, DC 20009
T 202 572 3280
mpanfil@edf.org

/s/ Miles Farmer
Clean Energy Attorney
Natural Resources Defense Council
40 W. 20th St.
New York, NY 10011
T: 212-727-4634
mfarmer@nrdc.org

/s/ Casey Roberts
Senior Staff Attorney
Sierra Club
1536 Wynkoop St., Suite 312
Denver, CO 80209
T: 303-454-3355
Casey.roberts@sierraclub.org

/s/ Allen Gleckner
Allen Gleckner
Director, Energy Markets
Fresh Energy
Phone 651 726 7570
gleckner@fresh-energy.org

/s Michael B Jacobs
Senior Energy Analyst
Union of Concerned Scientists
2 Brattle Square
Cambridge, MA 02138-3780
T: 617-301-8025
mjacobs@ucsusa.org

/s/ Grant Smith
Grant Smith
Senior Energy Policy Advisor
Environmental Working Group
317-442-8802 (cell)
grant.smith@ewg.org

/s/ Howard M. Crystal
Howard M. Crystal
Senior Attorney
Center for Biological Diversity
1411 K Street, N.W. Suite 1300
Washington, DC 20005
hcrystal@biologicaldiversity.org
(202) 809-6926

/s/ Frank Rambo
Senior Attorney
Southern Environmental Law Center
201 West Main St., Suite 14
Charlottesville VA 22902
T: 434-977-4090
frambo@selcva.org

/s/ Gregory M. Cunningham

Gregory M. Cunningham
Vice President and Program Director
Clean Energy and Climate Change
Conservation Law Foundation
53 Exchange Street, Suite 200
Portland, ME 04101
P: 207-210-6439

/s/JOHN MOORE
JOHN MOORE
Director, Sustainable FERC Project
NATURAL RESOURCES
DEFENSE COUNCIL
20 N. WACKER DRIVE, SUITE 1600
CHICAGO, IL 60606
T 312.651.7927
M 312.339.0926
JMOORE@NRDC.ORG
MOORE.FERCPROJECT@GMAIL.COM

/s/ Justin Vickers
Staff Attorney
Environmental Law & Policy Center
35 East Wacker Drive, Suite 1600
Chicago, IL 60601
T: 312-795-3736
jvickers@elpc.org

Appendix A: Description of the Signatories

The undersigned organizations include:

EDF is a national nonprofit membership organization engaged in linking science, economics, and law to create innovative, equitable, and cost-effective solutions to society's most urgent environmental problems. EDF is committed to fostering efficient market designs as a pathway for clean energy resources and cost-effective outcomes. With over 2 million members and engaged participants nationwide, EDF has been an active environmental and energy advocate since 1967. EDF has been a regular participant in energy matters, including before and involving the Commission and RTOs. Before this Commission, EDF has long recognized the intrinsic connection between fostering efficient market outcomes as a primary implement to safeguard energy customers, foster economic energy infrastructure investment and facilitate beneficial environmental outcomes, optimized within the rubric of fair market competition.

Natural Resources Defense Council ("NRDC") is a national non-profit membership organization with more than 3 million members and engaged community participants. NRDC is committed to the preservation and protection of the environment, public health, and natural resources. To this end, NRDC is actively involved in advancing policies that reduce greenhouse gas emissions and other dangerous forms of air pollution and that accelerate the deployment of energy efficiency and renewable energy. Further, since its inception in 1970, NRDC has sought to improve the environmental, health, and safety conditions at the nuclear facilities operated by DOE and the civil nuclear facilities licensed by the Nuclear Regulatory Commission and their predecessor agencies. NRDC has for many years advocated before and engaged on issues relating to reliability, resiliency, and markets for electric energy, capacity, and ancillary services. This has included proceedings and other stakeholder processes before FERC, NERC, DOE, RTOs and other transmission planning entities, and state regulatory authorities. One of NRDC's top federal electric regulatory priorities is ensuring a system that provides robust reliability and resiliency in a manner that facilitates the integration of clean energy and is affordable to customers.

Sierra Club is a national organization with more than 60 chapters and over 740,000 members. The Sierra Club's purpose is to explore, enjoy, and protect the wild places of the earth; to practice and promote the responsible use of the earth's ecosystems and resources; and to educate and enlist humanity to protect and restore the quality of the natural and human environments. An important part of the Sierra Club's work at both the national and chapter level is to reduce environmental and public health problems associated with energy generation, and to advocate for a transition to clean energy sources in a way that is affordable for and benefits all communities. Sierra Club frequently engages at state public utility commissions, regional transmission organization proceedings, and other forums to advance these goals.

Earthjustice is the premier nonprofit environmental law organization. We wield the power of law and the strength of partnership to protect people's health; to preserve magnificent places and wildlife; to advance clean energy; and to combat climate change. We are here because the earth needs a good lawyer.

The Sustainable FERC Project (the "Project") is an education and advocacy initiative that represents a consortium of national and regional environmental, consumer, and energy policy non-governmental organizations with members throughout the United States. The Project focuses on accelerating the deployment of renewable energy and demand-side resources by advocating electric regulatory policies that remove barriers for these resources and ensure more just and reasonable rates. The Project is engaged in stakeholder discussions and proceedings at

FERC, PJM, ISO-New England, and NYISO involving price formation, reliability, market design, and related issues.

The Union of Concerned Scientists is a national organization that puts science into action to build a healthier planet and a safer world. UCS conducts rigorous technical analysis and uses it to advocate for change: informing decision makers, shaping public opinion, and creating policies to help solve some of today's most pressing problems. UCS is backed by more than a half-million supporters, including some of the nation's top scientists.

Environmental Working Group is a non-profit, non-partisan research and advocacy organization, founded in 1992, with offices in Washington, D.C., San Francisco and Ames, Iowa. Our energy program focuses on educating our members and the American public on the environmental, economic and health benefits of renewable energy and advocating at the national and state levels for policies to advance the nation's transition to a clean, safe and sound energy future.

The Center for Biological Diversity is a national non-profit organization dedicated to the preservation, protection and restoration of biodiversity, native species, ecosystems, public lands and waters and public health. On behalf of more than 1.5 million members and online activists throughout the United States, the Center's Climate Law Institute seeks to reduce U.S. greenhouse gas emissions and other air pollution to protect biological diversity, the environment, and human health and welfare. The Center has engaged in numerous projects aimed at reducing the Nation's reliance on coal and other dirty energy sources.

Environmental Law & Policy Center ("ELPC") is a public interest environmental and sustainable energy business advocacy organization based in Chicago, Illinois with members, contributors, staff and offices throughout the Midwestern states. Among other things, ELPC advocates before the Department of Energy ("DOE"), the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, Regional Transmission Organizations, and state regulatory authorities for the reliable integration of renewable resources and demand-side resources into regional energy grids. ELPC is committed to ensuring a resilient grid that integrates clean energy at least cost to consumers.

The Southern Environmental Law Center ("SELC") is a regional nonprofit organization dedicated to protecting the health and environment of the Southeast, including one state almost entirely covered by PJM, Virginia, and two others with portions falling within the PJM footprint, North Carolina and Tennessee. To fulfill its mission, SELC works extensively on issues concerning energy resources and their impact on the people, culture, environment and economy in the region. This works includes participation in numerous proceedings before state utility commissions and utility company stakeholder processes, as well as advocacy before PJM and FERC, on a range of matters raised by the on-going transformation of the electricity system. SELC advocates for resolving these matters based on thorough assessments that incorporate up-to-date analyses of the economics, market drivers, job creation and grid benefits of clean energy.

Founded in 1966, CLF is a regional non-profit advocacy organization working to promote thriving, resilient communities. With offices in Massachusetts, New Hampshire, Maine, Vermont, and Rhode Island, CLF has several thousand members across New England. CLF uses law, economics and science to design and advance solutions that strengthen New England's environmental and economic vitality. CLF maintains extensive interests and expertise concerning energy projects and markets. As an active member of NEPOOL and an active participant in the NEPOOL stakeholder process, CLF has participated in the formation and refinement of New England's energy markets and planning of the region's electric transmission grid. CLF's interests and expertise in the energy arena extends to natural gas and electricity coordination, natural gas energy efficiency and conservation, natural gas supplies, natural gas distribution infrastructure, greenhouse gas emissions reduction requirements, and the economic and environmental impacts of energy generation and infrastructure. CLF and its members are concerned with the environmental and health impacts of meeting the region's current and future energy needs. CLF strives to enhance the clean energy public policies of the New England states to facilitate the development of clean energy sources. For decades, CLF has been active at state utility commissions, ISO-New England, and before this Commission advocating for policies that advance clean energy, reduce energy sector pollution and decarbonize our electric grid.

Fresh Energy is a 25-year-old energy policy non-profit based in St. Paul, Minnesota. Fresh Energy's mission is to shape and drive realistic, visionary energy policies that benefit all. With our partners and members, we are working toward a vision for an economy we thrive in and energy that ensures our well-being. Fresh Energy is speeding Minnesota's, and the Midwest's, transition to a clean energy economy, which will ensure that our region enjoys good health, a vibrant economy, and thriving communities today and for generations to come. From putting Minnesota on the pathway to being a national renewable energy leader to promoting clean transportation options for our growing economy, Fresh Energy has been an essential partner in helping the region develop efficient, cost-effective, and inclusive energy programming. Working purely in the public interest, Fresh Energy's team of scientists, economists, policy analysts, and educators develops and advances solutions that secure a clean energy future where all can thrive. Fresh Energy is an active participant in the MISO stakeholder process and Minnesota energy policy and energy resource procurement.

Appendix B: Reliability Studies

This document provides a bibliography of 36 recent studies on the impacts of increased deployment of clean energy resources on the reliability of the nation's power grid. This nonexhaustive review includes analyses from a variety of authoritative sources, including grid operators, national labs, academic institutions and government entities. The studies consistently find that current levels of clean energy penetration pose no threat to reliability, that clean energy resources can contribute to the provision of grid reliability services, and that increasing levels of clean energy generation to as high as 80% (and at minimum 25%) would present no threat to reliability. In addition, reports indicate that present day operation of the power system is reliable with wind and solar, at times meeting as much as 40, 50, even 67% of demand with wind and solar in different parts of the U.S.

Grid operator findings included:

• SPP's 2016 Wind Integration Study, which found that the SPP system could operate reliably with wind generation comprising 60% of its generating capacity;

• CAISO's Using Renewables to Operate Low Carbon Grid study, which found that the ability of renewables to provide a range of grid reliability services was "comparable to, or better than, conventional resources;" and

• PJM's Renewable Integration Study, which found that the PJM system could incorporate 30% variable generation with no loss of reliability.

• NYISO's 2016 Comprehensive Reliability Plan found that New York State Bulk Power Transmission Facilities will meet all applicable Reliability Criteria over the 2017 through 2026 Study Period.

• ERCOT's 2016 Reliability Risks Due to Coal Retirement Report found that coal plant retirement is unlikely to undermine reliability.

• The portion of load served by wind in Texas has reached 48.28%, set on March 23, 2016.1 In Colorado Wind has met 50% of load for an entire day. And in California, nonhydropower renewable facilities served a record 67.2% of the CAISO's electricity needs.

National lab, governmental, and academic institution findings included:

• NREL's Renewables Future Study reported no concerns on "any reliability metric" with renewable energy resources providing at least 25-50% of electricity, and found that renewable generation levels as high as 80% could be achieved with technologies commercially available today without compromising reliability.

• NREL's Eastern Renewable Generation Integration Study found that integrating up to 30% variable wind and PV generation into the power system is technically feasible at a five-minute interval. 1 See http://www.ercot.com/news/releases/show/113533. See https://www.xcelenergy.com/energy_portfolio/renewable_energy/wind/co_wind_power. See http://www.sfgate.com/business/article/State-breaks-another-renewable-energy-record-11156443.php.

• Columbia Center on Global Energy Policy's Can Coal Make a Comeback Study found that a surge in US natural gas production due to the shale revolution has driven down prices and made coal increasingly uncompetitive in US electricity markets.

• International Energy Agency's The Power of Transformation: Wind, Sun, and the Economics of Flexible Power Systems Study found that up to 45% of variable renewable energy can be integrated without significantly increasing power system costs in the long run.

Other findings included:

• General Electric's Minnesota Renewable Energy Integration and Transmission Study found that using wind and solar energy to supply "40% of Minnesota's annual electric retail sales can be reliably accommodated by the electric power system." The study also determined that increasing solar to "achieve 50% renewable energy in Minnesota and 25% renewable energy in MISO North / Central (10% above current renewable energy standards in neighboring states)," the power system can be "successfully operated for all hours of the year," with no unserved load, no reserve violations, and minimal curtailment.

• The Brattle Group's Integrating Renewable Energy into the Electricity Grid noted the success to date of ERCOT and Xcel Energy Colorado shows that integrating variable renewable energy at penetration levels of 10-20% on average and at times above 50% – i.e., high relative to the current levels in most of the United States – is possible.

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13. NERC - 2016 Long-Term Reliability Assessment, available at http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016%20LongTerm%20Reliability%20Assessment.pdf

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Appendix C: Estimate of monetary costs and environmental impacts, including underlying assumptions

This Appendix describes our estimates of the potential total costs eligible resources may be compensated for under this Proposal, some of the readily foreseeable environmental impacts of the Proposal, and the assumptions underlying those estimates. Such estimates are challenging given the vague language and the uncertainty around key aspects of the Proposal.

Scope of the Proposal

We assume that the Proposal applies to all merchant coal and nuclear units in commission-approved RTOs with energy and capacity markets (*i.e.* PJM, NYISO, ISO-NE, and MISO).[285] Under these assumptions, we estimate that over 49 GW of coal capacity and over 43 GW of nuclear capacity would be eligible for compensation under this Proposal. As shown in the Table "Share of Generation Impacted by the Proposal", this represents a significant portion of the total operating capacity in each market under consideration. More than two thirds of the eligible resources are located in PJM.

Share of Generation Impacted by Proposal				
	Eligible Coal (MW)	Eligible Nuclear (MW)	Total Capacity (MW)	Eligible Resources as % of Total
PJM	37,538	29,039	199,296	33%
MISO	10,332	5,153	183,421	8%
New York	1,133	5,445	44,242	15%
New England	385	4,036	35,247	13%

Cost Estimate

Our analysis focuses on calculating the full costs eligible resources would be able to recover under the Proposal by examining the operating costs (fixed and variable O&M, as well

[285] For purposes of this analysis, we use the version of the Proposal published in the federal register, and assume that MISO qualifies as having a capacity market under its terms.

as fuel) of eligible resources in 2016. This estimate is of gross costs, not netting out any revenues from market participation, because the Proposal does not provide adequate detail to determine how it will interact with existing market structures[286]. Market revenues may or may not be used to offset some of the costs; however, the Proposal does not provide a clear basis to understand how this would be done. Furthermore, depending on whether eligible resources are allowed to bid into the wholesale markets or not, we would anticipate the bidding behavior and dispatch of these units to change, which would correspondingly affect eligible units' operating costs and capacity factors.

However, absent any clarity in the Proposal regarding how eligible resources may interact with existing markets, we use recent historical costs as a proxy for costs that eligible resources may recover under the Proposal. Based on data from SNL for the eligible units, the annual total of the fixed and variable costs of these resources in 2016 amounted to over $14 billion. Our examination of costs does not account for debt that may be on the books of eligible resources, and it does not include any separate provision of a "fair return on equity and investment." This estimate has the benefit of providing a clear and simple marker of the scale of costs at issue in the DOE proposal.

Eligible Resources: 2016 Data		
Total Capacity	93.1	*GW*
Total Generation	543,563	*GWh*
Total O&M (incl fuel)	14,494	*$ million*
Total Fuel	6,682	*$ million*
Total Fixed	5,971	*$ million*
Total Non-Fuel Variable	1,841	*$ million*
Average age	39	*years*

286 This analysis was structured to identify the total operating costs of eligible resources under the DOE Proposal, but does not represent the net incremental costs after netting out market revenues.

Effect of additional assumptions on cost

Several factors, depending on how the Proposal were implemented, would increase the costs that are eligible for compensation. The potential for compensation of eligible resources' full costs may incentivize coal resources that have converted to natural gas to switch back to coal, or resources with dual fuel capabilities to install storage facilities that enable them to meet the eligibility requirements. Such actions would increase the scope of units affected by the Proposal, and accordingly, the cost estimate. We also did not analyze the additional costs eligible resources would face to acquire 90 days of fuel storage (which is not the norm for coal units), which would increase expected operation and maintenance costs.

If eligible resources continue to participate in the wholesale markets, we expect they would bid offers into the energy market as must-take or self-schedule generation (i.e. as price takers), because resources would recover their costs through the Proposal's full cost-of-service mechanism. These resources would therefore clear the market and run whenever they are available (i.e. as much as possible, regardless of economics, except for times of scheduled maintenance, outages, etc.). Absent any constraints on this behavior, eligible resources would operate at significantly higher capacity factors than they have in the past, meaning the estimate above would underestimate the total costs eligible to be recovered by these resources. Similarly, in the eastern RTOs (PJM, NYISO, and ISO-NE) with mandated centralized capacity markets, eligible resources would bid in low and clear the capacity market. The table below presents illustrative increases in costs in a hypothetical scenario in which the utilization of the coal fleet increased as a result of this Proposal.

Potential Impacts of Increased Coal Utilization				
	2016 Data	*Increased Utilization (1)*	*Increased Utilization (2)*	
Total Eligible Capacity	49	49	49	*GW*

Average Capacity Factor	46%	60%	75%	
Generation	198,817	259,584	324,480	*GWh*
Total Operating Costs	6,204	7,752	9,352	*$*
CO_2 Emissions	220	287	359	*million short tons*
SO_2 Emissions	273	356	446	*thousand tons*
NO_x Emissions	180	235	294	*thousand tons*

It is difficult to determine precisely how the eligible resources behaving as price takers would impact the bidding behavior of the remaining resources, and the overall impact that this would have on market viability. As discussed in Section VI.E, at minimum, because the Proposal would displace some resources that are currently compensated for providing the same services in the wholesale energy, capacity, and ancillary services markets, the Proposal would have a chilling effect on investors and new entry into markets. In fact, investment banks declared that the Proposal may have the effect of ending competitive energy markets altogether.

Environmental impacts

Like the monetary costs of this Proposal, the environmental and public health impacts of this Proposal are also difficult to determine. Coal plants are a carbon-intensive source of electricity and the primary source of nitrogen oxides (NOx) and sulfur dioxide (SOx), which are key contributors to soot and smog, in the power sector. In keeping these resources online, rather than investing in new lower- or zero-emitting resources, one would expect to see additional carbon and other air pollution from the continued operation of these resources compared to a counterfactual case without this Proposal.

In 2016, reported carbon dioxide (CO_2) emissions from merchant coal plants in organized RTO/ISO markets amounted to 220 million short tons.[287] These power plants also emitted around 180,100 tons of NOx and another 273,000 tons of SOx.

Coal units slated to retire within the next year accounted for 13 million tons of CO2, 11,100 tons of NOx and 18,000 tons of SOx. With guaranteed recovery of their full costs, we would expect the Proposal to keep these at-risk coal units online.

In addition, either currently mothballed coal units could come back into service or coal units that have recently converted to run on gas could revert to coal as their primary fuel. There are 1.3 GW of merchant mothballed coal units in eligible RTO/ISO markets. Using the highest emissions from the last five years (as 2016 data was not available), these additional resources could amount to 2,000 tons of NOx and 3,300 tons of SOx, which would present a direct harm to the public health of the surrounding communities. We did not attempt to determine the monetary costs that customers would bear if at-risk units are kept online and/or if mothmalled units are brought back online, but the environmental burden is clear.

While nuclear power plants do not release carbon emissions or conventional air pollution, the nuclear fuel cycle has a host of environmental and public health risks and impacts.[288]

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287 These figures represent emissions associated with eligible resources and not net incremental emissions under the DOE Proposal.

288 Broadly, the environmental harms from nuclear energy can be listed as: environmental impacts of uranium mining, processing, enrichment and nuclear fuel fabrication; routine radioactive emissions from nuclear power plants including airborne radionuclides and tritium leaks; adverse environmental impacts of nuclear reactor water consumption and waste heat; risk and consequences of unplanned outages, aging-related failure and downtime, and severe nuclear accidents that can be initiated by operator error, earthquake and storm, or terrorism; and spent nuclear fuel production, storage and transport prior to disposal in a deep geologic repository. *See*,

Policymakers that are interested in valuing the zero-carbon attributes of nuclear power should also take into consideration the significant environmental risks.

e.g., NRDC Policy Basics: Nuclear Energy (Feb. 2013), available at https://www.nrdc.org/sites/default/files/policy-basics-nuclear-energy-FS.pdf.

NOTE

Electric System Reliability: No Clear Link to Coal and Nuclear

John Larsen, Peter Marsters and Trevor Houser | October 23, 2017

US Energy Secretary Rick Perry has asked the Federal Energy Regulatory Commission (FERC) to intervene in wholesale markets to help keep coal and nuclear power plants online. The argument laid out in the Department of Energy's (DOE) Notice of Proposed Rulemaking (NOPR) is that these sources of power generation, which have been under pressure from weak load growth, cheap natural gas and expanding renewables, have unique value to grid reliability because they can store significant quantities of fuel onsite. Rhodium Group submits the following analysis as comments under FERC docket number RM18-1-000. In these comments we assess the degree to which fuel supply issues have been a driver of electric system outages and whether or not there is a link between "fuel secure" resources and more reliable power systems. We find that fuel supply issues were responsible for 0.00007% of lost customer electric service hours between 2012 and 2016 in the US and that there is no clear relationship between higher system levels of coal and nuclear generation and better system performance with regards to reliability.

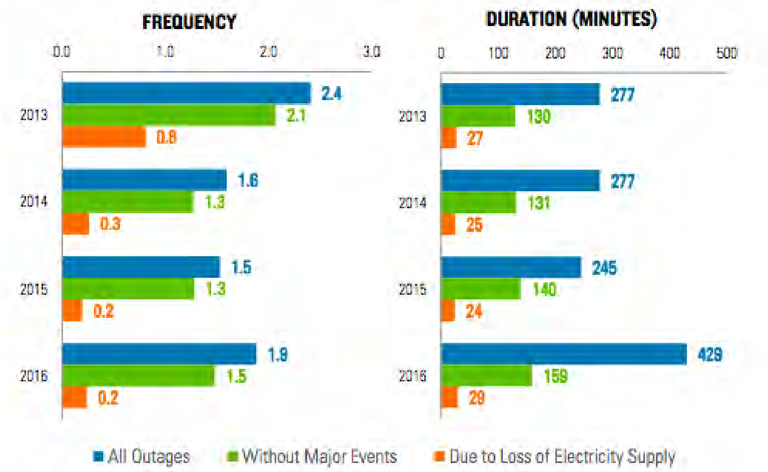
Sec. Perry has given FERC 60 days to address what he sees as the electricity reliability emergency created by the retirement of "fuel-secure generation" – namely coal and nuclear power plants that can store large quantities of fuel on-site. There have been a large number of coal and nuclear units retired in recent years as weak load growth, persistently low natural gas prices and rapid declines in renewable energy costs have led to reduced profit margins. Natural gas plants cannot store much fuel onsite and rely on a consistent stream of pipeline delivery. Absent large-scale battery or other storage, generation from wind and solar is limited to times of the day when the wind is blowing and the sun is shining. Has the growth in renewable and natural gas generation sources in recent years and simultaneous retirement of coal and nuclear plants created the reliability crisis Sec. Perry warns of? Absent intervention by FERC will additional retirements cause a spike in electric power outages? This analysis explores both questions by examining multiple sources of utility reliability and generation data from the DOE and Energy Information Administration (EIA).

MOST OUTAGES ARE NOT CAUSED BY A LOSS OF ELECTRIC SUPPLY

Using EIA's form 861 distribution utility data we examined the frequency and duration of electricity system outages from the average customer's point of view. Since 2013, EIA has asked all but the smallest utilities to report the frequency and duration of distribution system service interruptions lasting longer than 5 minutes using industry standard protocols.[1] Total outage numbers include all service interruptions encountered by distribution utility customers regardless of cause. From there, reports are broken down by whether "major event days" are included in totals and whether an incident is due to "loss of supply." Major events generally include severe weather or other unusual phenomena that occur less than 10% of the time. Importantly, loss of supply refers to the loss of electric supply to the distribution system and includes a range of possible issues, from a mechanical failure at a power plant to the failure of a transmission substation, as well as weather impacts on those same grid assets. It also includes fuel emergencies at power plants and generation inadequacy. Distribution system customer outages that don't occur during major events or loss of electric supply incidents are typically due to normal weather events or distribution system operations issues.

For utilities in the continental United States, the average customer experienced as few as 1.5 outages per year to as many as 2.4 from 2013 through 2016 with major events included (figure 1). Loss of electric supply played a role in as much as 30% of those outages (in 2013) and as few as 10% (in 2016). In 2015 the average customer experienced 1.5 outages a year due to all causes but only 0.2 due to lack of electricity supply. Across these outages, the average customer endured from 245 to 429 minutes of lost service inclusive of major events. However, only 24 to 29 minutes of the duration of these outages (as little as 7%) was due to a loss of electric supply. It is clear that factors related to and impacting the electric distribution system — not a loss of electric supply — were the cause of most customer outages and lost service minutes in this timeframe.

Figure I: US average customer electric outages, 2013-2016*



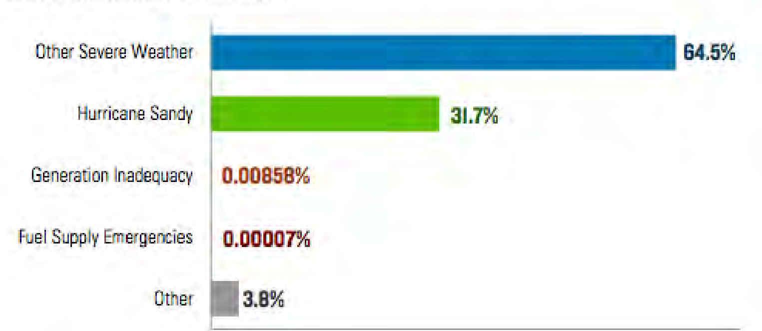
Source: Rhodium Group analysis, EIA. Note: Loss of supply during major events is included in loss of electricity supply.

POWER PLANT FUEL EMERGENCIES ARE RESPONSIBLE VERY FEW OUTAGES

While EIA's data allows us to establish the relatively small role that loss of electric supply plays in triggering electric distribution customer outages, DOE's form OE-417 allows us to quantify the frequency and total lost customer service hours due specifically to fuel supply deficiencies and emergencies occurring at power plants. This is a key issue of concern raised by DOE's NOPR and a major reason for the department's call for providing additional support for coal and nuclear plants. Whenever a utility experiences a major disturbance in electricity delivery to customers, it is required by law to fill out form OE-417, and submit it to DOE. On that form, the utility is required to list the cause of the disturbance, its duration, and the number of customers affected. These data are then published by DOE and included in EIA's Electric Power Monthly. We tabulated all the OE-417 reports since the beginning of 2012 to quantify the role that "fuel supply emergencies" (and not other factors causing loss of electric supply to customers) have played in causing outages. This is a period in which 32% of the country's coal-fired power generating units and 6% of its nuclear-generating units were retired.

We find that between 2012 and 2016, utilities reported roughly 3.4 billion customer- hours impacted by major electricity disruptions. 96% of those lost service hours were due to severe weather (Figure 2). Fuel emergencies or deficiencies at power plants resulted in 2,382 customer hours of lost service or 0.00007% of the total. 2,333 of those customer hours were due to one event in Northern Minnesota in 2014 involving a coal-fired power plant.

Figure 2: Cause of major electricity disturbances in the US, 2012-2016
Share of total customer-hours disrupted



Source: DOE, EIA and Rhodium Group analysis

Several additional power plant fuel supply emergencies and deficiencies were recorded in the OE-417 data but most did not report a loss of customer service due to these incidents. Apparently, in these instances there were sufficient additional resources available to maintain electric supply to customers. Of the 498 total incidents reported since the beginning of 2012 through the end of 2016, 37 or 7% were categorized as fuel supply emergencies or deficiencies. Of these 37 events, seven did not result in any lost customer hours while 28 reported "unknown" or "N/A" with regard to the number of customers impacted. The remainder are the two events depicted in Figure 2. Of the fuel emergency or deficiency events that disclosed what fuel was at issue, 14 involved coal and 7 involved natural gas.

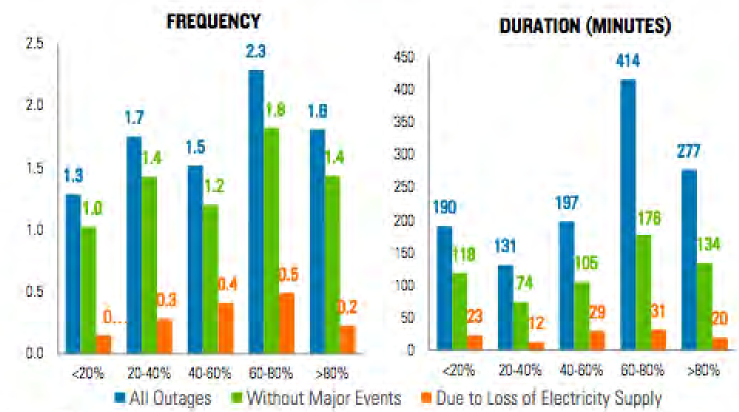
While the NOPR focuses primarily on the possible benefits of onsite fuel supply, it also expresses concern regarding the potential risk of inadequate generation resources during periods of peak demand due to the wave of recent coal and nuclear retirements. Here as well the OE-417 data is illustrative. While "generation inadequacy" resulted in slightly more lost customer hours than fuel supply problems, it still accounted for less than one-hundredth of one percent of the customer-hours impacted by electricity disturbances nationwide between 2012 and 2016. Utilities reported a handful of additional inadequacy events with zero or unknown customer hours lost representing less than 1% of total events.

THERE IS NO CLEAR LINK BETWEEN RELIABILITY AND FUEL SECURE GENERATION

Our analysis demonstrates that from a nationwide perspective, fuel supply issues are a very small driver of electric power outages and total lost electric service. In DOE's NOPR the department cautions that future retirements of coal and nuclear capacity will threaten reliability. We can assess whether there is reason for concern by analyzing the EIA form 861 reliability metrics for utilities operating in power systems with different amounts of coal and nuclear generation.

Using EIA form 923 generation data, we calculated the combined coal and nuclear share of generation in each balancing authority (BA) for years 2013 through 2016 and grouped them into five bins: <20% coal and nuclear, 20-40%, 40-60%, 60-80% and >80%. We then calculated customer weighted average reliability metrics for utilities operating in BAs within each bin. If increasing and/or maintaining the amount of coal and/or nuclear on the grid improved reliability going forward, we would expect to see fewer and shorter outages in BAs with more coal and nuclear generation historically. Instead, we find no clear relationship between coal and nuclear generation market share and the frequency and/or duration of power outages between 2013 and 2016 (figure 3). Indeed, if there is any observable relationship, it's a slight increase in both the frequency and duration of outages with higher levels of coal and nuclear generation, up to the >80% market share level especially for the frequency of outages due to loss of electric supply.

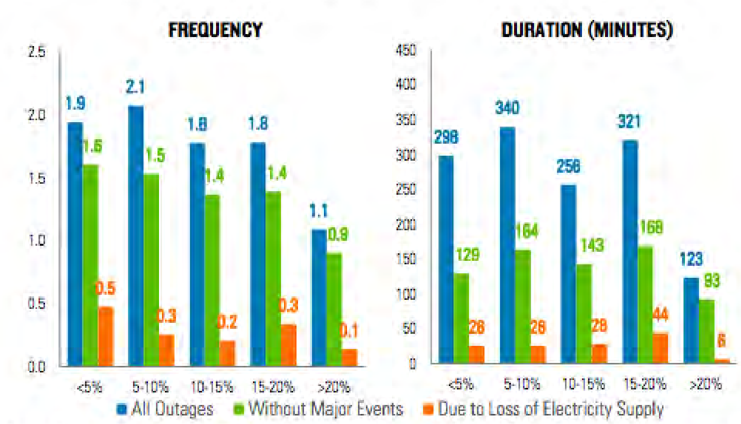
Figure 3. Average customer electric outages by combined coal and nuclear market share, 2013-2016*



Source: Rhodium Group analysis, EIA. Note: Loss of supply during major events is included in loss of electricity supply.

Using this same approach, we've assessed what the role of increasing penetration of variable renewable generation such as wind and solar has had on the same reliability metrics. If greater amounts of variable generation threaten reliability, we would expect to see an increase in the frequency and duration of outages for utilities in BAs with higher renewable energy penetration rates. Again, here we see no clear relationship. Reliability metrics are consistent as variable generation increases. The exception is for utilities in BAs with the highest levels of renewable deployment, which experienced the fewest and shortest outages between 2013 and 2016 (Figure 4).

Figure 4. Average customer electric outages by variable renewable market share, 2013-2016*



Source: Rhodium Group analysis, EIA. Note: Loss of supply during major events is included in loss of electricity supply.

CONCLUSION

Based on our analysis of EIA and DOE reliability and generation data we do not find evidence that fuel supply incidents at power plants are a major driver of electric system outages. We also find that increasing amounts of coal and nuclear generation on a utility's system has no clear relationship with higher performance regarding reliability metrics. Furthermore, increasing amounts of variable renewable generation on a utility's system has no clear relationship with lower performance regarding reliability metrics. We conclude that future coal and nuclear retirements alone are not likely to lead to greater or longer electric service outages. Conversely, maintaining or increasing the amount of coal and nuclear generation in a given balancing authority is not likely to lead to fewer or shorter electric service outages.

[1]Data used in this analysis was reported by utilities representing 73% and 55% percent of continental US retail sales for with/without major events and loss of supply respectively from 2012 through 2016. 2016 data used in this analysis is part of EIA's early release and is subject to revision.

** This portion of the analysis was commissioned by the Natural Resources Defense Council and Environmental Defense Fund, but was conducted independently by Rhodium Group, LLC. The findings and views expressed in this note are the authors' alone.*

5 Columbus Circle, New York, NY 10019 Telephone: +1.212.532.1157 Fax: +1.212.532.1162 Follow RHG

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

FERC Docket RM18-1-000

Prepared for Earthjustice

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AUTHORS

Ariel Horowitz, PhD
Avi Allison
Nina Peluso
Bob Fagan
Max Chang
Doug Hurley
Paul Peterson

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

CONTENTS

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

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[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

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[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]

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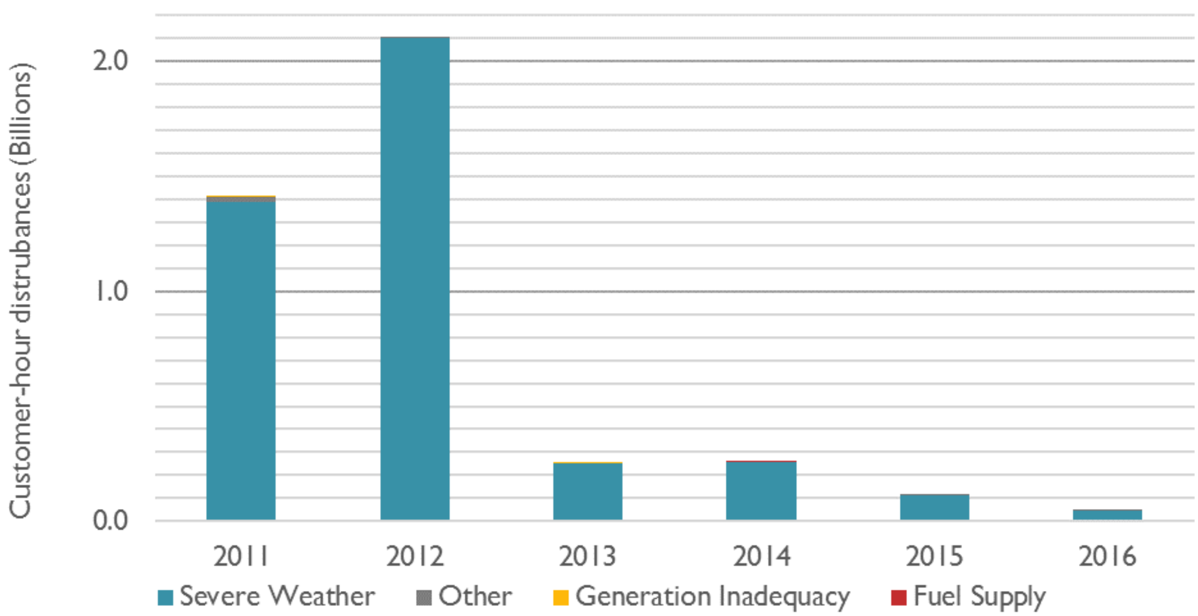
[41] This analysis owes its primary structure to a similar review published by the Rhodium Group on October 3, 2017. *See* http://rhg.com/notes/the-real-electricity-reliability-crisis

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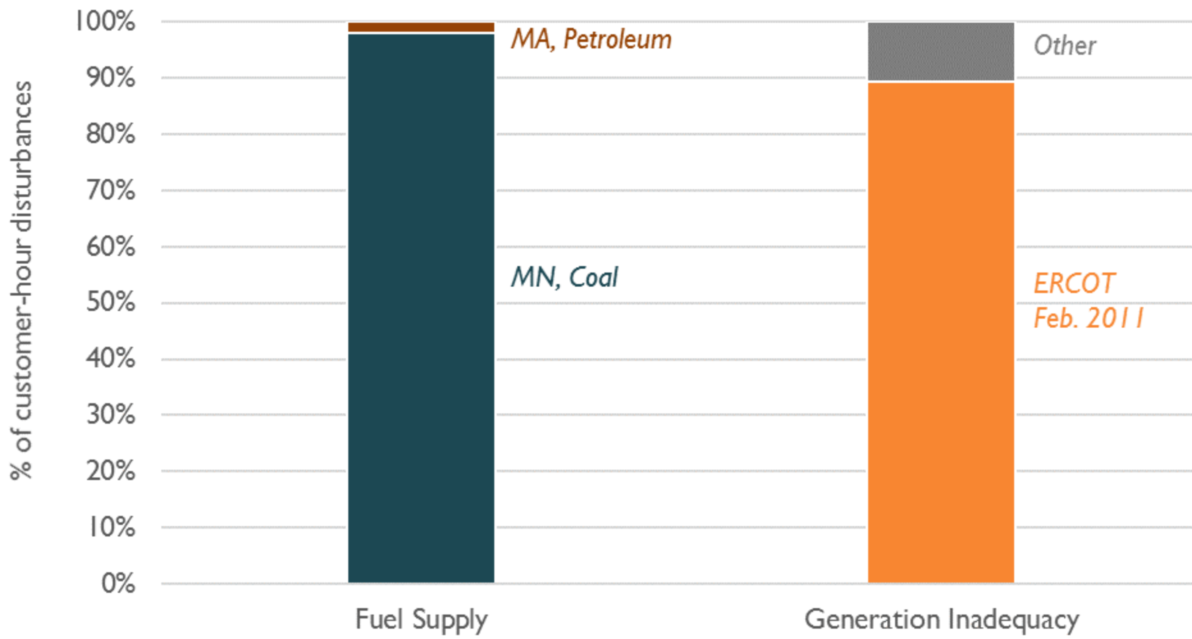
[44] Duluth News Tribune & Wisconsin Public Radio. "Minnesota Power to Idle Four Coal-Fired Electrical Generation Units". September 11 2014. Available online at http://www.duluthnewstribune.com/content/minnesota-power-idle-four-coal-fired-electrical-generation-units

[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

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.

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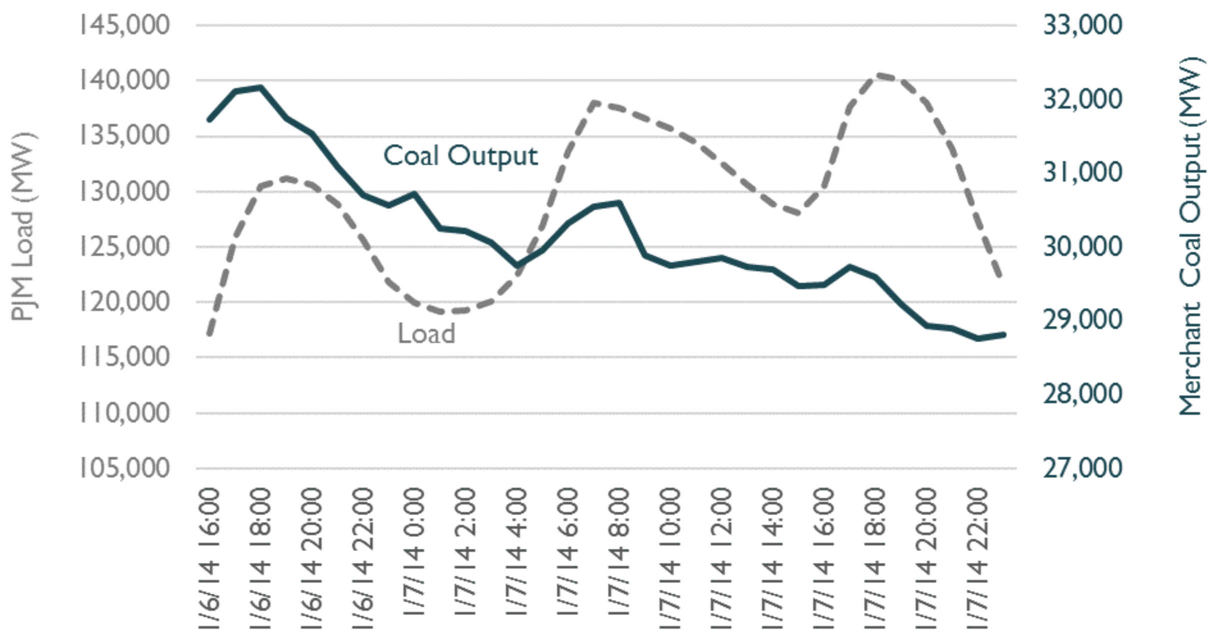
[52] DOE NOPR, pp2-3.

[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,

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[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

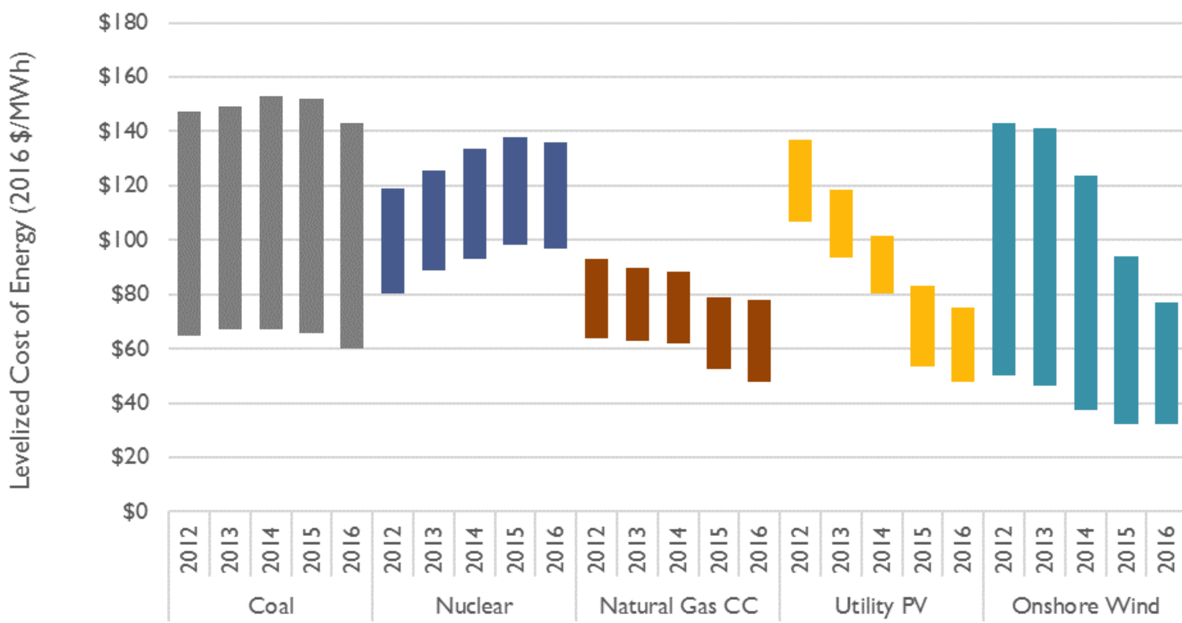
[73] In traditional cost-of-service regulation, incurred costs are subject to a "prudence review" by a regulatory commission or other entity to ensure that expenditures were reasonable and in accordance with the public interest. DOE's proposal makes no mention of such a review. Therefore, it is not clear 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.

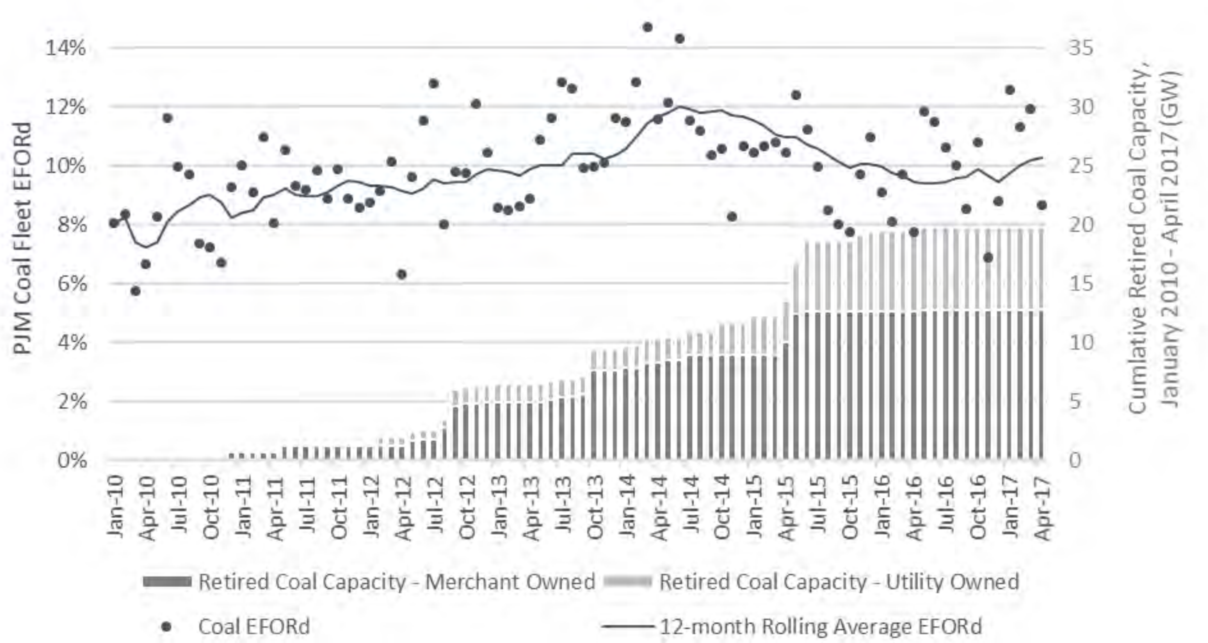
[92] Id.

[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]

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[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.

104 Liu, C. and Y. Xu. "Microgrid's Impact on Power Grid Resilience". Washington State University and Pacific Northwest National Labs. July 2016, p7. Available online at: http://resourcecenter.ieee-pes.org/product/-/download/partnumber/PESSLI1263.

105 Massachusetts Clean Energy Center. "Offshore Wind". Available online at: http://www.masscec.com/offshore-wind

106 NYSERDA. "Offshore Wind Energy". Available online at: https://www.nyserda.ny.gov/offshorewind

107 State of Maryland Public Service Commission. "Offshore Wind Energy RFP". Available online at: http://marylandoffshorewind.com/

108 Bureau of Ocean Energy Management. "Delaware Activities". Available online at: https://www.boem.gov/Delaware/

109 NYSERDA. "Governor Cuomo Announces $11 Million Awarded for Community Microgrid Development Across New York". March 23, 2017. Available online at: https://www.nyserda.ny.gov/About/Newsroom/2017-Announcements/2017-03-23-Governor-Cuomo-Announces-11-Million-Awarded-for-Community-Microgrid-Development

110 MassCEC. "Energy Resilience". Available online at: http://www.masscec.com/energy-resilience

Appendix F: Responses to Specific Questions posed by FERC Staff Regarding the Grid Reliability and Resilience Pricing, Docket No. RM18-1-000

Our organizations have chosen to submit comments in a manner organized to set forth the profound flaws with the DOE Proposal and the underlying premise that on-site fuel storage is essential to reliability. Nevertheless, to facilitate Staff's work in reviewing comments, we provide responses to most of Staff's specific questions below, with cross-references to our comments where these issues are discussed in greater detail (as applicable).

Need for Reform

1. What is resilience, how is it measured, and how is it different from reliability? What levels of resilience and reliability are appropriate? How are reliability and resilience valued, or not valued, inside RTOs/ISOs? Do RTO/ISO energy and/or capacity markets properly value reliability and resilience? What resources can address reliability and resilience, and in what ways?

   ***See Section IV.C, as well as Sections III.B, IV.B., V.C., VI.D, and Appendix E (Synapse).* This question aptly highlights one of the most significant flaws in the DOE Proposal. The suggestion that radical and precipitous action is needed absent even a definition of resilience or explanation of *how* the services that would make up undefined resilience are not already provided. This rushed process is not the correct forum to establish a definition of resilience.**

2. The proposed rule references the events of the 2014 Polar Vortex, citing the event as an example of the need for the proposed reform. Do commenters agree? Were the changes both operationally and to the RTO/ISO markets in response to these events effective in addressing issues identified during the 2014 Polar Vortex?

   ***See Section IV.D.* No. The 2014 Polar Vortex demonstrates that on-site fuel storage is no guarantee of generator reliability and analysis shows no correlation between on-site fuel storage and forced outage rates. For example, Rhodium Group analyzed outages from the past several years and determined that only .00007 percent of disturbances were due to fuel supply problems. They also found no correlation between so-called "fuel secure" resources and better system reliability. *See* Appendix D (Rhodium Group) to these comments. FERC and RTOs have already implemented reforms in response to the Polar Vortex. While we do not agree universally with the reforms implemented, the DOE Proposal makes no effort to acknowledge**

actions already undertaken to address the problems observed during the Polar Vortex.

3. The proposed rule also references the impacts of other extreme weather events, specifically hurricanes Irma, Harvey, Maria, and superstorm Sandy. Do commenters agree with the proposed rule's characterization of these events? For extreme events like hurricanes, earthquakes, terrorist attacks, or geomagnetic disturbances, what impact would the proposed rule have on the time required for system restoration, particularly if there is associated severe damage to the transmission or distribution system?

   See Section IV.D. **The Proposal references the extreme weather events mentioned in this question but provides no assessment of what caused customers to lose power. Overwhelmingly, customers lost power in these events due to the vulnerability of transmission and distribution systems, not the absence of fuel-secure generation. According to recent analysis there is no correlation between on-site fuel and forced outage rate.** ***See*** **Appendix D (Rhodium Group). There is no evidence that the Proposal would have improved system restoration during such events.**

4. The proposed rule references the retirement of coal and nuclear resources and a concern from Congress about the potential further loss of valuable generation resources as a basis for action. What impact has the retirement of these resources had on reliability and resilience in RTOs/ISOs to date? What impact on reliability and resilience in RTOs/ISOs can be anticipated under current market constructs?

   See **Sections IV.B and VI.D, and Appendix E (Synapse). Retirement of coal and nuclear resources have not adversely affected reliability to date, and are not forecasted to do so in the future. Rather, system reliability is improving. Current market constructs are likely to better ensure system reliability than the proposal, which props up aging infrastructure whose performance is likely to decline over time. It does so at the expense of entry from newer resources likely to serve the system more reliably.**

5. Is fuel diversity within a region or market itself important for resilience? If so, has the changing resource mix had a measurable impact on fuel diversity, or on resilience and reliability?

Without a definition or common understanding of resilience, it is impossible to answer this question. DOE provides no evidence that fuel diversity is important to or necessary for system resilience or reliability.

Eligibility

General Eligibility Questions

1. In determining eligibility for compensation under the proposed rule, should there be a demonstration of a specific need for particular services? What should be the appropriate triggering and termination provisions for compensation under the proposed rule?

   As discussed in Sections IV and VII, there is no basis for FERC to determine that existing rates are unjust and unreasonable and to replace those rates with cost-based compensation for preferred resources. Nevertheless, as discussed in Sections V and VI, we note that unless compensation for additional reliability services is based on a demonstration of specific need, such compensation would lead to rates that are unjust and unreasonable.

2. As the proposed rule focuses on preventing premature retirements, should a final rule be limited to existing units or should new resources also be eligible for cost-recovery? Should it also include repowering of previously retired units? Alternatively, should there be a minimum number of MW or a maximum number of MW for resources receiving cost-of service payments for resilience services? If so, how should RTOs/ISOs determine this MW amount? Should this also include locational and seasonal requirements for eligible resources?

   There is no basis for FERC to determine that existing rates are unjust and unreasonable and to replace those rates with cost-based compensation for preferred resources. None of the options suggested above would facilitate just and reasonable rates. As discussed in Section IX, FERC should reject the DOE Proposal entirely.

3. Are there other technical characteristics that should be required for an eligible unit besides on-site fuel capability? If so, what are those technical characteristics and what benefits do they provide? What types of resources can meet the proposed eligibility criteria of the proposed rule? What proportion of total current generating capacity does this represent?

On-site fuel capability is not a technical characteristic directly relevant to reliability. Analysis has found that there is no correlation between on-site fuel and forced outage rate. See Appendix D. Measures related to the transmission and distribution system are a more appropriate focus in ensuring system reliability and resilience. See Sections IV and V.

4. If technically capable of sustaining output for a sufficient duration (and meeting other relevant requirements), should resources such as hydroelectric, geothermal, dual-fuel with adequate on-site storage, generating units with firm natural gas contracts, or energy storage (each of which might have a demonstrable store of energy to draw upon to sustain an electrical output, if not necessarily fuel) also be eligible? Why or why not? If technical capability is the appropriate criterion for eligibility, what specific technical capability should be required to be eligible?

   There is no basis for FERC to determine that existing rates are unjust and unreasonable and to replace those rates with cost-based compensation for preferred resources. No technical capability has been defined in the Proposal; however, if such a capability is subsequently defined, any resource possessing that capability should be allowed to compete to provide the service. Even if applied in a nondiscriminatory manner, providing resources with cost-based compensation except as a last resort is contrary to decades of FERC's efforts to promote wholesale competition. See Sections V and VII.

5. The proposed rule would require that eligible resources be able to provide essential energy and ancillary reliability services and includes a non-exhaustive list of services. What specific services should a resource be required to provide in order to be eligible?

   There is no basis for FERC to determine that existing rates are unjust and unreasonable and to replace those rates with cost-based compensation for preferred resources. The entire concept of eligibility for cost-based compensation based on the ability to provide services that could be obtained in a more targeted and efficient manner through competitive markets is fundamentally flawed and should be rejected.

6. The proposed rule would limit eligibility to resources that are not subject to cost of service rate regulation by any state of local regulatory authority. How should the Commission and/or RTOs/ISOs determine which resources satisfy this eligibility requirement?

There is no basis for FERC to determine that existing rates are unjust and unreasonable and to replace those rates with cost-based compensation for preferred resources. Regardless of how FERC interprets the question above, the DOE Proposal would not facilitate just and reasonable rates. As discussed in Section IX, FERC should reject the DOE Proposal entirely.

90-day Requirement

1. The proposed rule defines eligible resources as having a 90-day fuel supply. How should the quantity of a given resource's 90 days of fuel be determined? For example, should each resource be required to have sufficient fuel for 24 hours/day and sustained output at its upper operating limit for the entire 90-day period? Would there be any need for regional differences in this requirement?

   See Sections IV and V. FERC should reject the entire notion that on-site fuel supply is an attribute justifying compensation. Recent analysis finds no correlation between on-site fuel supply and forced outage rate. See Appendix D (Rhodium Study). Therefore, we offer no response regarding interpretation of the 90-day fuel supply criterion.

2. Is there a direct correlation between the quantity of on-site fuel and a given level of resilience or reliability? Please provide any pertinent analyses or studies. If there is such a correlation, is 90 days of on-site fuel necessary and sufficient to address outages and adverse events? Or is some other duration more appropriate?

   There is no correlation between on-site fuel supply and reliability. See Section IV.E, V.B.1, and Appendix D(Rhodium Study). However, there is a correlation between the penetration of renewable energy (fuel-free resources) and low forced outages rates. See Appendix D (Rhodium Study).

Fuel Supply Requirement

1. The proposed rule requires that resources must be in compliance with all applicable environmental regulations. How should environmental regulations be considered when determining eligibility? For example, if a unit that was capable of keeping 90-days of fuel on-site was subject to emission limits that would prevent it from running at its upper operating limit for 90 days, should that unit be eligible under this proposed rule?

   There is no basis for FERC to determine that existing rates are unjust and unreasonable and to replace those rates with cost-based compensation for preferred resources. FERC should take note that the

environmental and safety restrictions affecting coal-fired and nuclear plant operation weigh heavily against focusing on exclusively those resources to address any reliability challenges.

2. As the proposed rule references the need for resilience due to extreme weather events, including hurricanes, should there be any other eligibility criteria for the resource or fuel supply (e.g., storm hardening)? What considerations should be given to the vulnerability of 90-day fuel supplies to natural or man-made disasters such as extreme cold temperatures, icing, flooding conditions, etc. that may impact the on-site fuel supply?

    The vulnerability of 90-day fuel supplies to extreme weather conditions is another fundamental flaw rendering the DOE Proposal unjust and unreasonable. See Sections IV.D., IV.E., V, and VI.D. The proposal to offer cost-based compensation to any unit based on fuel-security is inherently flawed and cannot be redeemed by simply adding any other eligibility criteria.

3. Does the vulnerability or non-availability of on-site fuel supplies vary depending upon fuel type, location, region, or other factors?

    No response provided.

Implementation

1. How would eligible resources receiving cost of service compensation under the proposed rule be committed and dispatched in the energy market?

    The DOE Proposal is vague and inadequate in knowing with any certainty how resources owners may act. However, it is very likely that units receiving cost-based compensation would offer artificially low bids or act as price takers in the energy market in order to be dispatched as often as possible and in order to increase the costs on which they could earn a guaranteed rate of return.

2. How would eligible resources receiving cost based compensation under the proposed rule be considered in the clearing and pricing of centralized capacity markets?

    The DOE Proposal does not address these details. While there are several possible answers to this question, none would remedy the Proposal's fundamental defects under the FPA.

3. What is the expected impact of this proposed rule on entry of new generation, reserve margins, retirement of existing resources, and on resource mix over time?

    See Section VI.D. and Appendix E (Synapse). **The DOE Proposal would provide a powerful incentive that could halt retirement of eligible units absent extraordinary circumstances. In the short run, the proposal would cause reserve margins to skyrocket, at significant and unjustified cost to consumers. In the long-run, reserve margins could decline as currently competitive, but noneligible resources retire in response to depressed prices caused by the Proposal. Whereas the current resource mix is trending toward low-cost, flexible resources, the Proposal could reverse that trend and result in a resource mix dominated by aging, inflexible coal and nuclear units. This threatens system reliability.**

4. Should there be performance requirements for resources receiving compensation under the proposed rule? If so, what should the performance requirement be, and how should it be measured, or tested? What should be the consequence of not meeting the performance requirement?

    The proposed cost-based compensation for resources with on-site fuel storage violates the FPA. The absence of a performance requirement is only one of many reasons this proposal would violate FERC's obligation to demonstrate that newly-proposed rates would be just and reasonable. Even if a performance requirement were added, the Proposal would still violate the FPA for many reasons. For example, the on-site fuel requirement (which is not based on substantial evidence) would still unjustly limit which resources could offer to meet that performance requirement. Moreover, cost-based compensation of certain resources for meeting a performance requirement remains unjust and unreasonable given the likely over-procurement of that performance commitment, and overpayment for those commitments.

5. Should there be any restrictions on alternating between market-based and cost-based compensation?

    It is unclear whether the questions refers to restrictions on FERC's decision to alternate between market-based and cost-based compensation, or generating resources' decision to alternate. For the former, should FERC reverse its decades-long trend toward preferring market-based rates, the Administrative Procedure Act requires that FERC offer a well-reasoned explanation, supported by substantial evidence, for doing so. If the latter, the Proposal would violate the FPA under either option. We do note,

however, that allowing alternating between mechanisms would result in the highest possible rates for consumers.

Rates

1. The proposed rule lists compensable costs that should be included in the rate as operating and fuel expenses, costs of capital and debt, and a fair return on equity and investment. Are there other costs that would be appropriate to be included in the rate? Would any of the listed costs be inappropriate for inclusion?

    None of the costs are appropriately included. The structure of the Proposal in compensating costs without robust evidence that a specific resource is necessary for system reliability is fundamentally flawed.

2. Should wholesale market revenues offset any cost of service payments stemming from the proposed rule?

    The Proposal violates the FPA regardless of how this question is answered. We note, however, that unless revenues are offset, owners of eligible generators will experience windfall profits to an even greater degree, imposing higher costs on customers.

3. How should RTOs/ISOs allocate the cost of the proposed rule to market participants?

    Costs that are unnecessary to provide reliability services that are unspecific cannot be allocated on a principled basis. *See Section V.D.*

4. How would the requirement that eligible resources receive full cost recovery be reconciled with the requirement, as stated in the regulatory text, that resources be dispatched during grid operations?

    This question illustrates one of many ways in which the DOE Proposal is incoherent. These two provisions appear to work in unison to encourage dispatch of eligible generators at all cost, which would result in uneconomical outcomes that impose massive costs on consumers.

Other

1. The proposed requirement for submitting a compliance filing is 15 days after the effective date of any Final Rule in this proceeding, with the tariff changes to take effect 15 days after the compliance filings are due. Please comment on the

proposed timing, both to develop a mechanism for implementing the required changes and to implement those changes, including whether or not such changes could be developed and implemented within that timeframe.

There is no basis for FERC to determine that existing rates are unjust and unreasonable and to replace those rates with cost-based compensation for preferred resources. That said, as discussed in Section IX, the proposed timeline for submitting a compliance filing is manifestly unreasonable. Our organizations have participated in the stakeholder processes leading up to compliance filings and have observed that many months are generally required for evidence and stakeholder input to be considered properly. The effective date is equally absurd, as it would allow FERC essentially no time to review compliance filings for a massive change in RTOs' tariffs.

2. Please comment on the proposed rule's estimated burden of $291,042 per respondent RTO/ISO, to develop and implement new market rules as proposed, including the potential software upgrades required to do so.

The RTOs are best positioned to respond to this specific question, but this figure appears to be extremely low considering the radical nature of the changes proposed.

3. Please describe any alternative approaches that could be taken to accomplish the stated goals of the proposed rule.

The stated goal of the Proposal is to prevent the retirement of uncompetitive coal and nuclear units. This goal is plainly illegal and no alternative approach to accomplish it would pass muster under the FPA. If the goal of the Proposal were understood to be increasing the resiliency of the electric system during extreme weather or other disruptive events, then FERC should proceed in a methodical manner that first defines the concept, and examines the manner in which it overlaps with existing regulations. See Section IV.C. *See also* Comments of Natural Resources Defense Council and the Sustainable FERC Project, filed today in RM18-1 (discussing an appropriate process for FERC to define resiliency and determine whether any additional compensation is needed to ensure reliable service).

Such an investigation might ultimately focus on ways to reduce barriers to the development of distributed energy resources, microgrids, and generally to strengthen the transmission and distribution systems using tools within the Commission's jurisdiction. A system reliant on centralized, fuel-dependent generation is highly vulnerable to disruptive events.

4. What impact would the proposed rule have on consumers?

    The costs to consumers would be outrageously high. Although it is impossible to accurately determine the costs of the Proposal given its many ambiguities, it is clear that those costs would be in the billions. *See Section VI, Appendix C.* There is no evidence that consumers would see any benefit from the Proposal in terms of improved reliability. Rather, they could well see decreased reliability since the rule would increase the operation of aging, less reliable units. *See Sections IV, IV and VI.D and E, and Appendix E (Synapse)*.

5. The Commission may take notice of relevant public information, including information in other Commission proceedings. If a commenter views information in another Commission proceeding as relevant to the proposed rule, please identify that information and explain how it is relevant to the proposed rule. Such information may include a filing previously submitted by the commenter.

    No response provided aside from sources cited within these comments and appendices.

Appendix G: Protest of Public Interest Organizations, Docket No. ER15-623, Appendix B: Efforts Underway to Reduce Forced Outages in Time for the Next Delivery Year and Into the Future

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C. Docket Nos. ER15-623-000

EL15-29-000

PROTEST OF PUBLIC INTEREST ORGANIZATIONS

. . . .

Appendix B: Efforts Underway to Reduce Forced Outages in Time for the Next Delivery Year and Into the Future

As a result of the January 2014 winter events, *numerous efforts are already underway to reduce forced outage rates* in the summer and winter at generating plants, including the following:

- One of PJM's important efforts to avoid the high level of forced outages last January involves testing of certain generators and the use of a mandatory winter preparedness checklist. PJM's Operating Committee approved the changes to "improve the performance of resources during extreme cold weather events" by performance verification or testing of resources during and before cold weather, requiring a cold-weather preparedness checklist to be completed, and testing dual-fuel capability.[289]

[289] *See* January 1, 2015 Cold Weather Recommendation Status at 3, http://www.pjm.com/~/media/committees-groups/committees/oc/20150106/20150106-item-13-14-cold-weather-and-hot-weather-recommendation-update.ashx ("January 1, 2015 Cold Weather Recommendation Status"). The Operating Committee's two part proposal on "Cold Weather Resource Performance Improvement" requires, starting *this* winter:
generators to use a "Generation Resource Cold Weather Checklist…. prior to the winter season to prepare generation resources for extreme cold weather operations."; and
requires certain generators to perform a "Generation Resource Operational Exercise... The exercise will be conducted prior to the onset of cold weather with the purpose of identifying and correcting start-up, operational and fuel switching problems."
See Operating Committee – Special Cold Weather Resource Improvement Final Proposal Report September 4, 2014 at 2, http://www.pjm.com/~/media/committees-groups/committees/oc/20140917/20140917-cold-weather-resource-improvement-proposal-report.ashx. PJM's Operating Committee "approved the solution package and endorsed the

PJM's Cold Weather Resource Performance Improvement changes "focuses on enhancing unit performance during cold weather conditions and adequately scheduling units to meet systems conditions **reliability and economically**."[290] PJM began testing generators November 1, 2014, and 98% of PJM's installed capacity have started using the winter preparedness checklists; this should enhance unit performance during cold weather conditions *starting this winter*. [291]

- After last winter's polar vortex, PJM's Planning Committee was asked to perform a "Winter Peak Study Update", and the results of that study were presented to PJM members on December 4, 2014.[292] Significantly, the test looked at 2019, stressed the "winter risk" load deliverability areas, targeted specific load deliverability areas based on feedback from PJM operations, and tested an extreme polar vortex scenario. *Id*. The extreme polar vortex scenario used a 90/10 load forecast, which is what PJM says they experienced during last winter's polar vortex, shut off all chronically curtailed gas units (7,100 MWs), and all gas curtailed at least once in the last 7 years (another 9,400 MWs), and, in addition, turned off all of the planned gas in the queue with a signed Interconnection Services Agreement (which is likely to be built) – for a total of 25,700 MW of gas outages (or 19% of PJM's installed capacity). *Id*. at 68. Despite the extreme cold weather modeled, 19% of forced outages, and the loss of many more gas units than were out during the polar vortex (25,700 MWs in the modeling vs. 19,000 MWs during the polar vortex), PJM experienced no transmission violations and PJM also did not have any capacity shortfalls.[293]

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manual language with no objections and no abstentions". *See* http://www.pjm.com/~/media/committees-groups/committees/mc/20141027-webinar/20141027-item-12c-oc-report.ashx (emphasis in original).

[290] *See* Operating Committee – Special Cold Weather Resource Improvement Final Proposal Report September 4, 2014 at 2, http://www.pjm.com/~/media/committees-groups/committees/oc/20140917/20140917-cold-weather-resource-improvement-proposal-report.ashx (emphasis added).

[291] As of January 2, 2015, 156 units with a total installed capacity of 9350 MWs have been tested, with another 980 MWs scheduled for January 5. *See* "Cold Weather Generation Resource Preparation Update dated January 6, 2015 at 2. http://www.pjm.com/~/media/committees-groups/committees/oc/20150106/20150106-item-04-cold-weather-generation-resource-preparedness-update.ashx. The vast majority of units tested to date passed the test, and the ones that did not were able to identify issues so the generation owners could fix them before the units were needed. *Id.* This should help reduce forced outages as the purpose of the test is to identify and correct start-up, operational and fuel switching problems. In addition, 98% of PJM's installed capacity indicated that they completed their own checklist or the one provided in PJM's Manual 14D. *Id*. at 3.

[292] *http://www.pjm.com/~/media/committees-groups/committees/teac/20141204/20141204-reliability-analysis-update.ashx* at 63-74.

[293] *Id*. at 64, 69, 73 and 74. *See also* PJM's CP filing at 17 ("On a megawatt basis, [during the polar vortex] natural gas interruptions accounted for 9,300 MW of outages… other natural gas outages related to issues such as start failures due to cold weather or issues with using back-up fuel accounted for another 9,700 MW and are related more to weatherization and maintenance issues than the inability to secure gas supplies and transportation."

- The Operating Committee has recommended significant changes to improve gas unit commitment, communication and coordination starting the winter of 2014/15 - to improve the clarity, transparency and standardization of handling long-lead gas unit commitment due to fuel restrictions and consider tools, processes, market construct, as well as communication and notification protocols.[294] PJM has already implemented a number of these items, which should help gas unit commitment and coordination immediately.[295]
- Pursuant to a FERC Notice of Proposed Rulemaking, PJM and others are working on gas/electric industry coordination.[296]
- The Operating Committee worked with generation owners to identify fuel sources and limitations, emission limitations, as well as use and validation of outage types.[297] PJM has already obtained this information and completed an internal report that allows PJM to view the data, and fuel data will be mapped once fields are available on eMKT.[298]
- On December 15, 2014, PJM filed in FERC Docket No. EL15-31-000 for relief during the winter of 2014/2015 from the $1,000/MWh energy offer cap should a rise in gas prices or other system conditions force generation resources to incur fuel costs that cause their marginal costs to exceed the offer cap.[299]
- PJM is improving data sharing with the gas industry; starting in November 2014 PJM initiated daily gas notification emails, and has had weekly calls with pipeline companies since December 2014.[300]
- As of October, 2014, PJM developed a tool to confirm external capacity resources availability, day-ahead and real-time market commitments, and actual performance.[301]
- PJM has reviewed and enhanced the tools and processes for accepting Emergency Energy Bids.[302]
- On September 25, 2014, PJM filed at FERC a request to alter the Variable Resource Requirement (VRR) curve, which will shift the VRR curve to the right and thus procure

[294] *See* January 1, 2015 Cold Weather Recommendation Status at 1 *supra*.
[295] *Id*. at 1 (Manual process in place as of January 1, 2015; automatic functionality available as of February 9, 2015). Other implemented items include extended cold notification/startup time parameters, notification/startup alerts and time parameter obligations for long lead time generators, peak and off peak periods and PJM operator actions. *See* Gas Unit Commitment Coordination – 2012 Notification and Start Up Proposal Review at 2 http://www.pjm.com/~/media/committees-groups/committees/oc/20150106/20150106-item-05a-2012-notification-and-start-up-proposal-review.ashx. and Gas Unit Commitment Coordination – Intraday Cost Update ad New eMKT Field Manual Process Update http://www.pjm.com/~/media/committees-groups/committees/oc/20150106/20150106-item-05b-gas-unit-commitment-manual-process-update.ashx .
[296] *See* January 1, 2015 Cold Weather Recommendation Status at 2 *supra*.
[297] *See* January 1, 2015 Cold Weather Recommendation Status at 1 *supra*.
[298] *Id*. eMKT allows PJM members to submit information and obtain data needed to conduct business electronically in the Day-Ahead, Regulation and Synchronized Reserve Markets
[299] http://www.pjm.com/~/media/documents/ferc/2014-filings/20141215-el15-31-000.ashx.
[300] *See* January 1, 2015 Cold Weather Recommendation Status at 1 *supra*.
[301] *See* January 1, 2015 Cold Weather Recommendation Status at 2 *supra*.
[302] *See* January 1, 2015 Cold Weather Recommendation Status at 3, *supra*.

more capacity.[303] The Commission accepted that filing, with one non-relevant modification, by Order dated November 28, 2014, in Docket No. ER14-2940-000.[304]

- Other Cold Weather changes that PJM has implemented to decrease outages, or is in the process of implementing, are changes to energy and reserve pricing, increasing the synchronized reserve requirement, implementing an exchange volatility proposal, studying gas infrastructure adequacy, and improving communications, procedures, and interregional coordination.[305]
- With respect to Hot Weather performance improvements, PJM has made numerous changes in 2014 to improve performance including: creating a tool (the Dispatch Interactive Map Application or DIMA) to visualize the location and amount of DR available to provide relief from operational issues; revised Tier 1 calculations to reflect available synchronized reserves; improved communication and notification protocols; collected information on unit characteristics and limitations; updated PJM's system modeling; improved its emergency procedures tool; and is currently evaluating facility limits with MISO and NYISO.[306]

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[303] *See* PJM's September 25, 2014 filing at Docket No. ER14-2940-000 to modify the PJM Open Access Transmission Tariff, http://www.pjm.com/~/media/documents/ferc/2014-filings/20140925-er14-2940-000.ashx .

[304] On November 28, 2014, in Docket No. ER14-2940-000, the Commission issued an Order conditionally accepting PJM's proposed Tariff revisions of September 25, 2014 to the PJM Tariff, subject to a compliance filing. PJM proposed changes to its capacity market demand curve and the Variable Resource Requirement (VRR) Curve were accepted. The Commission granted PJM's requested effective date of December 1, 2014. http://www.pjm.com/~/media/documents/ferc/2014-orders/20141128-er14-2940-000.ashx.

[305] *See* January 1, 2015 Cold Weather Recommendation Status at 1-3, *supra*.

[306] *See* January 1, 2015 Hot Weather Recommendation Status at 1-2, http://www.pjm.com/~/media/committees-groups/committees/oc/20150106/20150106-item-13-14-cold-weather-and-hot-weather-recommendation-update.ashx ("January 1, 2015 Hot Weather Recommendation Status")