UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	))))))	Docket No. RM18-1

COMMENTS OF THE DELAWARE PUBLIC SERVICE COMMISSION, DELAWARE DIVISION OF THE PUBLIC ADVOCATE, AND DELAWARE DEPARTMENT OF NATURAL RESOURCES AND ENVIRONMENTAL CONTROL

Pursuant to the October 2, 2017 Notice Inviting Comments in the above-captioned docket, the Delaware Public Service Commission ("Delaware PSC"), Delaware Division of the Public Advocate ("DPA"), and Delaware Department of Natural Resources and Environmental Control ("DNREC") (collectively, "Delaware Agencies") hereby respectfully submit comments on the Notice of Proposed Rulemaking ("NOPR") issued by the Secretary of the Department of Energy ("DOE") on September 28, 2017 and published in the Federal Register on October 10, 2017.[1]

I. Introduction

On September 28, 2017, pursuant to section 403 of the DOE Organization Act,[2] the Secretary of Energy issued the DOE NOPR, directing the Federal Energy Regulatory Commission ("FERC" or "Commission") to consider initiatives related to cost-recovery for certain so-called "fuel-secure"[3] eligible grid reliability and resiliency resources[4] participating in Commission-jurisdictional

[1] *Grid Resiliency Pricing Rule*, 82 Fed. Reg. 46,940 (Oct. 10, 2017). ("DOE NOPR")
[2] 42 U.S.C. § 7173.
[3] *See* e.g. DOE NOPR at II.B. Eligible resources must be "fuel-secure," i.e. "Has a 90-day fuel supply on site…" DOE NOPR Proposed Rule at § (10)(i)(B).
[4] *See* DOE NOPR Proposed Rule at § (10)(i).

Regional Transmission Operators ("RTO") or Independent System Operators ("ISO") with day-ahead and real-time energy and capacity markets.[5] Between the time the rule was first published on September 29, and the Federal Register publication on October 10, the scope of the DOE NOPR was narrowed to only apply to RTO/ISOs with capacity markets.[6] This excluded RTO/ISOs with energy-only constructs from the effects of the proposed rule, therefore excluding California ISO, Southwest Power Pool, Electric Reliability Council of Texas, and perhaps, Midcontinent ISO. The rule certainly applies to only three RTO/ISOs: PJM Interconnection ("PJM"), ISO-New England ("ISO-NE"), and New York ISO ("NYISO"). The DOE NOPR proposes to compensate eligible resources for "fully allocated"[7] "operating and fuel expenses, costs of capital and debt, and a fair return on equity and investment."[8] On October 4, 2017, pursuant to 18 C.F.R. § 375.315(b)(2), the Commission's Director of Energy Policy and Innovation issued a guidance document for commenters posing questions that will assist Commission Staff in understanding the implications of the DOE NOPR.[9]

The proposed NOPR is so deficient in so many ways that we fear it will have significant unintended consequences that will adversely affect existing competitive energy markets. The NOPR is devoid of any information that would enable this Commission or anyone else to gain a full understanding of the potential costs or benefits to ratepayers. There is no factual basis to justify the NOPR's proposed solution to an imaginary problem, and the proposed rule ignores the actions that several RTOs have already taken to develop effective, competitive, and reliable energy markets. The adoption of the proposed new rules and regulations that would permit out of market energy

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[5] *Id.* at § (10)(ii).
[6] *Id.*
[7] *Id.* at § (10)(iii).
[8] *Id.* at § (10)(iv).
[9] https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14607221 Docket No. RM18-1 (Oct 4, 2014). ("Staff Guidance Document").

payments to so-called “fuel-secure” baseload units may well end the competitive markets’ ability to deliver low cost, reliable energy to Delaware consumers.

II. The DOE NOPR Does Not Make Clear Which Units Would Be Eligible.

The DOE NOPR, although repeatedly mentioning the purported resilience attributes of nuclear generation, appears to preclude nuclear units from becoming eligible resources under the rule. According to the proposed rule, eligible units must provide “essential” services, “including but not limited to voltage support, **frequency services**, **operating reserves,** and reactive power.”[10] However, the National Renewable Energy Laboratory (“NREL”) notes that “[n]uclear units have historically been built for base load and therefore usually do not provide operating reserves. Primary Reserve can be provided by any generator with a governor that can respond rapidly and that can maintain that response as frequency declines. Nuclear plant governors are typically blocked, preventing them from providing frequency responsive reserve.”[11] As such, it appears nuclear-fueled generation would not qualify as an eligible unit for the cost-recovery treatment of the NOPR.

Nor does the NOPR provide any reason why natural gas units would not be eligible if they acquired 90-days worth of onsite fuel. There appears to be little disincentive for this behavior, as all such units able to provide the correct attributes, once they accrue this fuel and become eligible, would be entitled to full return of their fuel investment *and* a fair return on equity.

III. The Lack of Detail in the DOE NOPR Does Not Allow Estimation of Potential Costs, and Therefore Does Not Provide Enough Information for the Commission to Find the Proposal Just and Reasonable.

As commenters in this docket have already noted, the magnitude of the potential effect of the DOE NOPR is enormous. As certain independent power producing entities (“IPP”), which invest

[10] DOE NOPR at § (10)(i)(B). (emphasis added).
[11] Operating Reserves and Variable Generation, NREL, August 2011 at 11.

billions of dollars into the competitive markets, have already told the Commission, their investments to bring online new and efficient generating resources provide RTO/ISOs confidence in their continued ability to secure the necessary reserve margin for their footprints.[12] As we will discuss below,[13] the Commission's obligation to ensure just and reasonable rates for wholesale electricity rests on the economic theory of competitive markets which requires provision of accurate and competitive price signals for all generating units on a nondiscriminatory basis. The DOE NOPR's proposed subsidization of certain eligible generating units would undermine this economic theory and eliminate the ability for wholesale markets to provide a transparent and competitive market price. As a result, under the proposed rule the IPPs would "expect new investment in the development and construction of [non-subsidized] facilities to be severely impacted if it does not cease altogether."[14]

The impacts of the DOE NOPR are not limited to the IPP community; there is a potentially unlimited cost impact to end-use customers. Due to the lack of detail regarding the compensation structure for eligible units, the potential eligibility of (at least) all coal and natural gas units in the affected wholesale markets, and a myriad of other uncertainties, the Delaware Agencies cannot confidently determine an estimate of the proposed rule's potential costs. Indeed, the economic incentives set forth by the DOE NOPR are perverse. In contrast to the Commission's policy of just and reasonable rates through competition,[15] the DOE NOPR would encourage lavish and unnecessary spending on fuel supplies; as a result of this supply, these resources would become eligible under the proposed rule and be able to receive compensation not available to other

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[12] Letter from certain IPPs to FERC. Docket No. RM18-1 (October 11, 2017). Available at: https://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20171011-5142 Signatory IPPs include LS Power Development, Eastern Generation, Dynegy, Invenergy, Tenska, Advanced Power Services, Competitive Power Ventures, Moxie Energy, and Rockland Capital. ("IPP Letter").
[13] *Infra.* at Section V.
[14] IPP Letter at 3.
[15] *See* e.g. Order No. 888, 75 FERC ¶61,080 (1996) at 48-51. S*ee also Infra.* at Section V.

resources. Additionally, it is impossible to estimate the amount of resources that may be newly constructed specifically to receive compensation under the DOE NOPR. The NOPR does not limit the number of resources that could become eligible. As a result, a theoretically unlimited number of unnecessary new resources could be built and placed in service specifically for the purpose of recovering their full costs, without being subject to any sort of competitive pressure.

We anticipate challenges for other entities, including the Commission, in determining the potential cost of the proposal. The Staff Guidance Document poses 30 questions that delve deeply into this lack of detail. These questions are not narrow; they address the actual justification for the NOPR ("What is resilience…" "Is there a direct correlation between the quantity of on-site fuel and a given level of resilience…"), the eligibility for treatment under the proposal ("…should there be a demonstration of a specific need…" "…should new resources also be eligible for cost recovery…"), its implementation ("How would eligible resources receiving cost of service compensation under the proposed rule be committed and dispatched…"), and resulting rates ("Are there any other costs that would be appropriate to be included… "Should wholesale market revenues offset any cost of service payments stemming from the proposed rule?"). Without understanding the mechanics of the proposal, costs cannot be confidently estimated. Courts have held in other contexts that agencies must consider costs before effectuating regulations.[16] The uncertainty illustrated by the Staff Guidance Document shows the impossibility of even beginning to estimate the costs of the proposed rule. Because the Commission cannot assess the costs of the proposed rule, it therefore has no basis upon which to approve the proposed rule, let alone to find it just and reasonable.

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[16] *See* e.g. *Michigan v. EPA,* 135 S. Ct. 2699 (2015) ("The Agency must consider cost… before deciding whether regulation is appropriate and necessary"); *Illinois Commerce Comm'n v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009) (requiring allocations of cost to be "at least roughly commensurate" with benefits).

IV. Administrative Agencies Must Make Rational Connections Between Facts Found and Choices Made, and the NOPR Does Not Rationally Connect the Facts Found with the Choices Made.

A Commission decision must be supported by "substantial evidence in the record and reached by reasoned decision-making."[17] Such reasoned decision-making 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. Agency action that fails either requirement is arbitrary and capricious."[18]

The DOE NOPR fails to provide sufficient evidence to demonstrate that any decision based on the proposal survives scrutiny under the arbitrary and capricious standard. The sole justification provided in the NOPR is a purported "threat[] to grid reliability and resilience."[19] These supposed threats are not the threats that the NOPR claims. In the rare instances where the assertions in the NOPR are true, the NOPR misinterprets the effects of these facts. By doing so, the NOPR fails to form a rational connection between these facts and its proposed solution of allowing cost-recovery for all eligible units with 90-days of fuel supply on-site.

A. There is No National Security or Other Emergency Threatening the Reliability and Resiliency of the Nation's Bulk Electric System.

As the Commission knows, the Energy Policy Act of 2005 ("Act") provided the Commission jurisdiction over the reliability of the bulk-power system.[20] The Commission then certified the North American Electric Reliability Corporation ("NERC") as the Electric Reliability Organization ("ERO").[21] As part of its duties as the ERO, NERC annually releases a Long-Term Reliability Assessment ("LTRA"), explicitly detailing the "future adequacy and operational reliability of the

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[17] *Electricity Consumers Resource Council v. FERC*, 747 F.2d 1511 (D.C. Cir. 1984) (internal quotations omitted).
[18] *Southwest Power Pool, Inc. v. FERC,* 736 F. 3d 994, 997 (D.C. Cir. 2013) (internal quotations omitted).
[19] DOE NOPR at ¶ 46945.
[20] 16 U.S.C. § 8240(c)(1).
[21] 116 FERC ¶ 61,062 (2006).

North American" bulk power system.[22] The most recent LTRA illustrated that each of the three ISO/RTOs affected by the proposed rule met and exceeded reliability requirements for the time horizon included in the assessment.[23]

There is especially no emergency in PJM. In March 2017 PJM issued a whitepaper specifically analyzing these topics from an operational perspective.[24] PJM claimed the purpose of the paper "represent[ed] PJM's effort to understand fuel diversity and its impact to reliability."[25] PJM performed a granular analysis of its operations and determined that there were 13 specific generator reliability attributes necessary to reliably operate a wholesale electricity grid.[26] PJM then analyzed a variety of different resource mixes to determine their reliability (i.e., how well those portfolios provided each of the 13 attributes required for reliable operation). Its findings are instructive: specifically, PJM notes that "the expected near-term resource portfolio **is among the highest-performing portfolios** and is well equipped to provide the generator reliability attributes."[27] Importantly, the referenced "near-term" resource portfolio is the portfolio forecasted under PJM's current market-based rules, anticipating the retirement of many units that the DOE NOPR would resuscitate.

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[22] 2016 Long-Term Reliability Assessment. NERC. December 2016. Available at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016%20Long-Term%20Reliability%20Assessment.pdf at vi.

[23] *Id.* at 104-105. ("ISO-NE's Anticipated Reserve Margin… remains above the Reference Margin Level through the assessment period." "In summary, New England has adequate capacity resources to meet the NERC Reference Margin Level throughout the 2016 LTRA study period.") *Id.* at 127. ("PJM RTO will have an adequate Anticipated Reserve Margin though the entire assessment period.") *Id.* at 108-109 (Compare 'Summary of Results' at 108, to the "approved… IRM requirement of 17.5 percent." Showing anticipated and prospective reserve margins greater than 17.5% reference requirement.)

[24] PJM's Evolving Resource Mix and System Reliability. PJM. March 30, 2017. Available at: http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx ("PJM Reliability Paper")

[25] *Id.* at 2.

[26] *Id.* at 16.

[27] *Id.* at 4 (emphasis added)

The DOE NOPR repeatedly[28] illustrates concerns with so-called "fuel-secure" resources being replaced by natural gas resources, but PJM's analysis shows these concerns are unfounded from a reliability perspective. To further illustrate the lack of reliability emergency in PJM, the PJM's Reliability Paper evaluated the reliability of projected future resource mixes with various compositions of fuel sources. Among the resource compositions addressed were portfolios with extremely high levels of contribution from natural gas resources. The paper notes that "portfolios composed of up to 86 percent natural gas-fired resources maintained operational reliability."[29] To study resiliency in addition to reliability, the PJM Reliability Paper subjected these future portfolios to a simulated Polar Vortex. Portfolios with up to 66% natural gas and as little as 9% coal proved resilient.[30] This analysis includes conservative estimates for the amount of natural gas-fired resources unavailable in such a scenario.[31]

B. PJM Has Continued to Develop Procedures and Market Rules to Ensure Reliability of All Capacity Resources, Including Natural Gas-Fired Resources.

While the PJM Reliability Paper demonstrates that portfolios can be operationally reliable and resilient with large amounts of natural gas-fired generation, there is a marked difference between modeling a reliable system and operating a reliable system. To that end, PJM has recently been involved in a number of initiatives seeking to further develop the reliability and deliverability of natural gas resources in grid operations.

The first of these initiatives is PJM's Capacity Performance paradigm, in which PJM proposed a new capacity product which would mandate generators be available for year-round

[28] DOE NOPR at ¶ 46943.
[29] PJM Reliability Paper at 5.
[30] PJM Reliability Paper Appendix at 41.
[31] *Id.* at 40. ("To determine these potential higher-than-average unavailability rates, generator performance data for high load days during winter 2014/2015 and winter 2015/2016 were analyzed by fuel type. The maximum unavailability rates during those days were applied to the portfolios…")

performance.[32] The CP structure specifically targets hours where generators are most needed to perform and couples economic incentives with penalties for those highest demand hours to ensure such performance.[33] The Commission specifically approved these reforms as part of a broader initiative to address the changing resource mix that is the subject of the NOPR,[34] and explained that economic incentives sufficiently compelled resource performance.[35] The Commission instituted these performance requirements on all units, noting that "PJM's [CP] revisions to the capacity market strengthen the relationship between a market seller's capacity revenues and its resource's real-time performance because the net revenue a market seller retains for providing capacity in a given delivery year is effectively linked to its resource's real-time performance in the delivery year."[36]

The CP construct has worked. Outages[37] in PJM have decreased substantially since the CP market design was implemented:[38]

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[32] *See* 151 FERC ¶ 61,208 (2015), *order on reh'g* 155 FERC ¶ 61,157 (2016). ("CP")
[33] 155 FERC ¶ 61,157 (2016) at P26.
[34] *Id.* at P25. ("…we continue to find that PJM demonstrated that ongoing changes in the resource mix in the PJM region justify an enhanced capacity product, citing evidence of current and expected generation retirements in PJM and PJM's increased reliance on natural gas as a fuel source. We note that PJM's proposal is part of a broader effort, by the RTOs, market participants, and the Commission, to adapt the nation's wholesale electric markets to the underlying changes in how electricity is generated and ensure that reliability is sustained during and after that transition. For example, in recent years, the Commission has convened technical conferences specifically addressing the operation of wholesale capacity markets and the increasing importance of coordination between the electric and natural gas industries for the reliability of the nation's electricity supply. Those efforts have resulted in both regional market changes, such as ISO New England, Inc.'s Pay for Performance capacity market reforms (upon which PJM's Capacity Performance program is modeled), and national changes to communication and coordination processes between the natural gas and electric industries. PJM's Capacity Performance proposal is a significant regional component of this larger effort to ensure that both existing and new resources needed to sustain reliability are available and perform when needed.") (internal citations omitted)
[35] *Id.* at P28. ("We continue to find that PJM's approach (as modified) to address the foregoing issues is based on sound economic principles and will improve resource performance and reliability by enhancing capacity resources' incentive to perform." (internal citations omitted)
[36] *Id.*
[37] Outages are measured in PJM through the equivalent demand forced outage rate. ("EFORd")
[38] 2016 State of the Market Report for PJM ("SOM"). Independent Market Monitor for PJM ("IMM"). March 9, 2017. Available at: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016.shtml at 253.

Table 5-28 PJM EFORd data for different unit types: 2007 through 2016

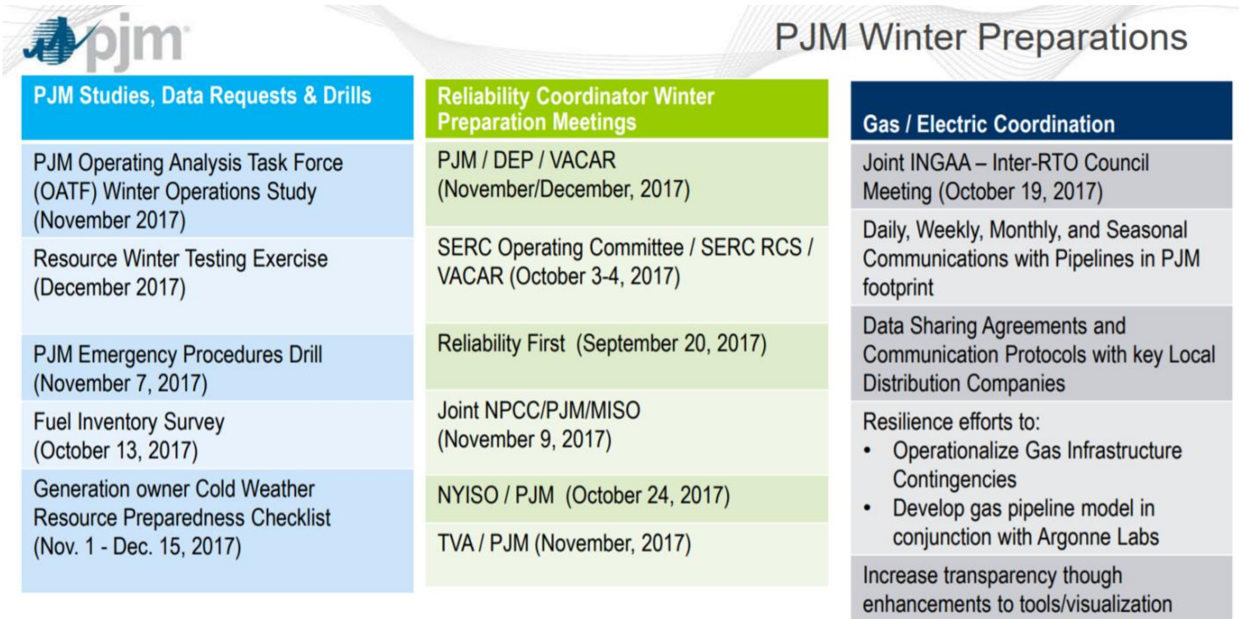
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Combined Cycle	3.7%	3.7%	4.1%	3.8%	3.4%	4.3%	3.1%	4.3%	2.8%	3.3%
Combustion Turbine	11.0%	11.1%	9.7%	9.0%	8.0%	8.2%	10.7%	15.8%	8.8%	5.8%
Diesel	11.7%	10.3%	9.3%	6.4%	9.3%	5.1%	6.6%	14.8%	9.1%	7.1%
Hydroelectric	2.0%	2.0%	3.2%	1.2%	2.9%	4.4%	3.7%	3.8%	5.2%	3.5%
Nuclear	1.4%	1.9%	4.1%	2.5%	2.8%	1.6%	1.2%	1.9%	1.4%	1.9%
Steam	9.1%	10.1%	9.3%	9.8%	11.2%	10.6%	11.6%	12.1%	10.2%	10.0%
Total	7.0%	7.7%	7.6%	7.3%	7.9%	7.5%	8.1%	9.4%	7.0%	6.3%

PJM's most recent analysis predicts a 6.07% EFORd in Delivery Year ("DY") 2018/19, 5.99% in DY 2019/20, 5.97% in DY 2020/21, and 5.89% 2021/22.[39] This is not an accident. PJM staff has worked with stakeholders to ensure that resources are available for year-round and winter performance, particularly after the implementation of CP. For instance, the electric market day has been aligned with the gas day to better facilitate the delivery of natural gas to generating units. These changes became effective in April of 2016.[40] In addition, PJM has an extensive list of winter preparations to ensure the deliverability of all resources:[41]

[39] 2017 IRM Preliminary Study Preliminary Results. PJM Presentation to the Markets & Reliability Committee. September 28, 2017. Available at http://pjm.com/-/media/committees-groups/committees/mrc/20170928/20170928-item-07-2017-irm-study-presentation.ashx at 3. ("2017 IRM Study")

[40] Frequently Asked Questions: Day-Ahead Market Timeline Change. PJM. Available at http://www.pjm.com/-/media/markets-ops/energy/day-ahead/faqs-on-day-ahead-market-timeline-change.ashx?la=en

[41] PJM Winter Operations and Market Performance. PJM. FERC Winter Operations Panel. October 19, 2017. Available at: https://www.ferc.gov/industries/electric/indus-act/rto/10-19-17-A-4-PJM.pdf



The OATF Operations Study is particularly instructive. PJM analyzed 26[42] extreme contingencies regarding loss of gas pipelines, including loss of *all* LDC generation,[43] all gas pipeline or compressor failure contingencies that results in 1,000 MW or more of generation lost,[44] as well as temperature threshold gas contingencies.[45] PJM concluded that "**all** contingency scenarios [were] solved without issue,"[46] thus refuting the NOPR's implication that retiring units will be required to meet demand when "natural gas resources were diverted from electricity production to meet residential heating needs."[47]

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[42] PJM Reliability Paper at 37.
[43] Winter Outlook 2016/2017. PJM. Operating Committee. December 13, 2016. Available at: http://pjm.com/~/media/committees-groups/committees/oc/20161213/20161213-item-04-winter-outlook-2016-2017.ashx at 11 ("2016/2017 Winter Outlook") (LDC means Local Distribution Company.)
[44] 2016/2017 Winter Outlook at 11.
[45] *Id.* Such study contingencies interrupt all non-firm customers after a pre-determined temperature based on past conditions.
[46] *Id.* (emphasis added)
[47] DOE NOPR at ¶ 46942

C. The Polar Vortex Illustrated the Operational Flexibility of PJM During Periods of System Stress.[48]

The DOE NOPR explained that PJM "struggled to meet demand for electricity because a significant amount of generation was not available to run" during the Polar Vortex.[49] The rule also asserts that "fuel-secure plants that were scheduled for retirement" were dispatched instead, suggesting that fuel-secure resources were more available, and would be more secure into the future. But PJM's operational reports after the Polar Vortex directly refute this suggestion. Of the 40,200 MW of forced outages during the Polar Vortex, only 9,300 MW were due to natural gas delivery interruptions.[50] PJM's Vice-President of operations and planning testified that "natural gas interruptions, although significant, removed less than five percent of the total capacity required to meet demand on January 7, while equipment issues associated with both coal and natural gas units made up the far greater proportion of forced outages."[51] Addressing these equipment issues was the subject of the CP product, which the Commission found "will help incent investments in maintenance, duel or firm fuel, or weatherization to improve capacity resource performance, particularly during summer and winter peak periods."[52]

The NOPR's suggestion that retiring generation is more reliable than new entry generation also lacks factual support. The exceptionally low outage rates of new entry units under the CP paradigm demonstrate improved capacity resource performance. PJM predicts a large drop in average EFORd for DY 2021[53] "due to large amount[s] of deactivations with high EFORd (7,150 MW

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[48] This also answers Staff Guidance Document question "Need for Reform" #2.
[49] DOE NOPR at ¶ 46942.
[50] Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events. PJM. May 8, 2014. Available at: http://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 26.
[51] Statement of Michael J. Kormos Executive Vice President – Operations PJM Interconnection, L.L.C. Docket No. AD14-18. April 1, 2014. Available at: https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13502869 at 4.
[52] 151 FERC ¶ 61,208 (2015) at P466.
[53] DY 2021 will have 100% CP resources. *See* 2020/2021 RPM Base Residual Auction Results. PJM. Available at: http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-

with 14.56% Weighted Average EFORd) [and] large amount[s] of additions with low EFORd (16,980 MW with 4.42% Weighted Average EFORd)."[54]

D. Other Circumstances Illustrate the Arbitrary Nature of the 90-Day Fuel Requirement.

The NOPR assumes that so-called "fuel-secure" resources would be able to operate more successfully during severe weather events. Recent experience shows otherwise. During hurricane Irma, nuclear units shut down,[55] and baseload coal plants in Texas were *actually switched to natural gas* during hurricane Harvey.[56] During Harvey, the coal delivery system flooded to the point of failure, and no volume of coal maintained on-site would have had any effect on the availability of the unit.

The PJM manuals further illustrate the arbitrary nature of the 90-day on-site fuel requirement: "for PJM operations, fuel assurance is defined as the ability of a resource to maintain economic maximum energy output **for 72 hours**… Fuel assurance… is necessary in order to provide the energy and reserves needed to maintain system reliability…"[57] PJM stakeholders carefully consider the requirements in the PJM manuals by developing them closely to conform with the needs of the system for reliable operations. To the extent the NOPR relies on assertions that retiring units (that would presumably be saved from retirement by the rule) operate more reliably during extreme weather events than new entry units, and that 90-days of on-site fuel would further assist

report.ashx at 1. ("The 2020/2021 BRA [Base Residual Auction] is the first where PJM has procured 100%… CP Resources.") ("2020/2021 Auction Report")

[54] 2017 IRM Study at 7. Additions include only those queue projects that have executed an Interconnection Service Agreement.

[55] Florida nuclear plants to shut ahead of Hurricane Irma. Reuters. September 7, 2017. Available at: https://www.reuters.com/article/us-storm-irma-nuclearpower/florida-nuclear-plants-to-shut-ahead-of-hurricane-irma-idUSKCN1BI2IA

[56] Harvey's rain caused coal-to-gas switching: NRG Energy. S&P Global Platts. September 27, 2017. Available at: https://www.platts.com/latest-news/electric-power/houston/harveys-rain-caused-coal-to-gas-switching-nrg-21081527

[57] PJM Reliability Paper at 19 (citing PJM Manual 13 Attachment C). (emphasis added)

the reliability or resiliency of those generators, those assertions are not based in fact or rationally connected to the choices made in the DOE NOPR.

V. <u>Any Final Order Resulting From the DOE NOPR Would Not Be Just and Reasonable.</u>

Several states, including Delaware, currently rely completely on PJM's wholesale markets for the supply of electricity to end-use customers.[58] After a recent review of the procedures for procuring Standard Offer Service ("SOS") supply for end-use customers,[59] the Delaware PSC recently affirmed prior decisions to continue procuring 100% from the wholesale electricity markets.[60] As a result, the Delaware Agencies have an acute interest in the competitiveness, and the resulting justness and reasonableness, of the PJM markets.

The framework underlying the DOE NOPR cannot produce just and reasonable rates in the wholesale markets targeted by the rule. For states that have ceded operational control of assets to RTO/ISOs,[61] the motivation is clear: to harness the benefits of competition to obtain the lowest possible price for end-use customers. This policy of just and reasonable rates through competition remains a key tenet of Commission policy:[62]

> Improving the competitiveness of organized wholesale markets is integral to the Commission fulfilling its statutory mandate 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 technologies, promoting demand response and energy efficiency, improving operating performance, exerting downward pressure on costs, and shifting risk away from consumers. National policy has been, and continues to be, to foster competition in wholesale electric power markets. This policy was embraced in the [Act][63] and is reflected in Commission policy and practice.

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[58] The Delaware PSC may procure electricity by other means pursuant to 26 *Del. C.* §1007 *et seq.*
[59] *See* Delaware PSC Docket No. 14-0283.
[60] *See* Delaware PSC Order No. 9064. (May 23, 2017).
[61] Generally, these are the states that comprise the three ISO/RTOs.
[62] Order No. 719, 125 FERC ¶ 61,071 (2008) at P1.
[63] Pub. L. No. 109-58, 119 Stat. 594 (2005).

The proposed rule will distort competition and therefore will result in unjust and unreasonable rates.

Competition fostered by the wholesale markets produces at least two major benefits: dispatch efficiencies and investment efficiencies.[64] Dispatch efficiencies grow with the size of the pool of resources available for economic dispatch. Market operators choose from this larger pool to dispatch the next-available-cheapest resource from a wider geographic area subject to security constraints. This larger geographic area allows more competition between resources, resulting in lower energy costs for consumers while also increasing efficiency. PJM estimates these dispatch efficiencies alone to be about $2.8-3.1B per year.[65] Investment efficiencies are the lodestar policy of wholesale markets. Investment efficiencies result from competition dependent on the market's repeated provision of adequate and competitive price signals. The purpose of these price signals is to incent capital markets and the IPP community to put their own capital at risk to install new, efficient, and competitive generation where it is most needed in the footprint.[66] As the Commission noted, "competition protects consumers by providing more supply options, encouraging new entry and innovation."[67]

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[64] *See* Resource Investment in Competitive Markets. PJM. May 5, 2016. Available at: http://www.pjm.com/~/media/library/reports-notices/special-reports/20160505-resource-investment-in-competitive-markets-paper.ashx at 4. ("PJM Resource Investment Paper")

[65] *Id.* at n.5.

[66] *See* e.g. *Order Denying Rehearing and Approving Settlement Subject to Conditions.* December 22, 2006. Docket Nos. ER05-1410 and EL15-148 at P44. (Explaining as unjust and unreasonable PJM's previous capacity construct that 1) "does not contain a locational element… [and] does not reflect the differing values of capacity in different locations," 2) "does not provide sufficient revenue to stimulate construction of new capacity or retention of current capacity," and 3) "does not provide a sufficient… forward price signal for capacity suppliers.")

[67] *Supra* n. 62.

While the DOE NOPR may affect dispatch efficiencies,[68] it has the potential to destroy any investment efficiencies, or any investment at all,[69] in the wholesale markets. The rationale behind investment efficiencies shows how the DOE NOPR would dismantle such benefits. Two different models exist to regulate generating units and determine the fashion in which they recover costs: the cost-of-service model and the competitive model. "Under the regulated cost-of-service paradigm, franchised monopoly utilities make investment decisions through planning processes, such as integrated resource planning programs."[70] In this model, captive end-use customers retain all of the myriad risks associated with the plant. These risks are often substantial. They include any risk associated with mismanagement, construction, fuel supply (retaining the unit through its useful life despite other fuel types being able to provide cheaper electricity), decommissioning, and any other conceivable risk associated with plant operations.

In contrast, the competitive model embraced by the Commission places these risks on those deploying capital to bring resources to market. Through competition, these potential resources bid against each other to provide energy and capacity at the lowest reasonable price. Analysis has shown that "returns on equity in [cost-of-service] generation are notably higher than the models would predict given the lower risks relative to merchant investors."[71] This is known as efficient entry, a crucial facet of the Commission's just and reasonable findings. Efficient exit signals through competitive price formation also provide substantial benefits. When resources fail to receive their going-forward costs, the market correctly provides an exit signal for that resource to retire. This is a crucial benefit of markets that the NOPR proposes to eliminate for certain eligible units. With no

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[68] The extent to which dispatch efficiencies would be affected would rest with the ability of the eligible units under the NOPR to alter their energy market bids to include any out-of-market payments; this is still to be determined as the Staff Guidance Document illustrates.
[69] *See* Comments of the Bipartisan Former FERC Commissioners. Docket RM18-1. October 19, 2017.
[70] PJM Resource Investment Paper at 6.
[71] *Id.* at ii.

ratepayer capital at risk, pressure on generators to retire is an important part of a healthy market life-cycle; old generation should retire and be replaced by new and efficient resources following locational price signals to areas where they are most needed. This competitive pressure and new entry especially benefits end-use customers, as these customers bear no risk of the generation resources competing in the market – so long as these retirements are occurring as the result of a transparent and competitive market price signal.

Over the years, the Commission has continually approved just and reasonable changes to the PJM Tariff to foster the efficient entry and exit of units. Uneconomic generating units are unnecessary to ensure resource adequacy. Analysis indicates that "no evidence suggests the PJM markets inadequately compensate legacy units and thus are forcing a premature retirement of economically viable generators."[72] Indeed, PJM's analysis indicates that generating units are *less* likely to retire under PJM's market construct than under a cost-of-service model.[73] However, market constructs prove more likely than regulated environments to retire units that would require significant upgrade costs or that cost more to operate relative to other competitive generation.[74]

These retirement signals are not a flaw of markets, but a crucial benefit to end-use customers. The NOPR would eliminate these price signals and accordingly prevent exit of certain resources. Providing a payment equal to "fully allocated costs" divorces those eligible units from the competitive pressures of the market construct that are the foundation of just and reasonable rates.

Dismantling the benefits of efficient exit is not the NOPR's only unjust and unreasonable facet. By exempting certain resources from competitive pressure, the NOPR will (likely)[75] result in

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[72] *Id.*
[73] *Id.* at 31, Table 8.
[74] *Id.* at Figure 6.
[75] This again would depend on the final form of the rule, and any associated mitigation measures undertaken to potentially correct for subsidized units in the market.

collapsing energy and capacity market prices, preventing efficient economic entry. Prices will fall due to units receiving their full costs through an out-of-market payment. Such payments allow these eligible generators to bid lower than their actual costs into the market (because they are otherwise receiving the required revenues) resulting in selection of a cheaper, non-competitive marginal unit to set system price. Independent entities rely on a competitive market clearing price in order to retain confidence in their investments in the markets.[76] Several former Commissioners make this point succinctly in their comments: "[under the DOE NOPR] investor confidence would evaporate and markets would tend to collapse. This loss of faith in markets would thereby undermine reliability."[77] The DOE NOPR cannot be just and reasonable if it does not provide efficient signals for market entry and exit.

The PJM markets work under the status quo to provide efficient signals to its competitive market. Data from the IMM demonstrate that despite significant retirement in PJM since the start of the current capacity construct, the markets have worked to incentivize sufficient new replacement generation to ensure reliability.[78] While there have been more retirements in PJM since the start of PJM's capacity construct, PJM has continued to maintain an appropriate reserve margin. 21,371 MW of new offered capacity, with 15,318 MW placed in service, has entered the PJM markets since June 2007.[79] Despite 25,297 MW of deactivations, the reserve margin remains robust.[80] The most recent PJM capacity auction procured a reserve margin of 23.9%, well exceeding

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[76] PJM Stakeholders are currently examining this issue in the stakeholder process. The Delaware PSC and the DPA look forward to continued work with the PJM stakeholders to provide a competitive market price while accommodating state actions. The Delaware PSC and the DPA support the letter of the Organization of PJM States to the PJM Board in this regard (http://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20171010-opsi-letter-regarding-concerns-with-pjms-capacity-construct.ashx?la=en).
[77] *Supra* n. 69.
[78] *See* New Generation in the PJM Capacity Market. IMM. May 4, 2016. Available at: http://www.monitoringanalytics.com/reports/Reports/2016/New_Generation_in_the_PJM_Capacity_Market_20160504.pdf ("IMM Capacity Study")
[79] *Id.* at Table 5.
[80] *Id.* at Table 2.

the target reserve margin of 16.6%.[81] Such efficient entry and exit demonstrates the justness and reasonableness of the status quo. The DOE NOPR would severely hinder efficient price signals required for a well-functioning market, and will produce rates that are unjust and unreasonable.

An ancillary benefit of markets is their ability to deploy renewable resources based on economic conditions and public policy. The DOE NOPR would result in deleterious policy and health effects, in contravention of the State of Delaware's stated goals,[82] by limiting participation of renewable resources, thereby reducing supply diversity and increasing harmful air emissions. In contrast to the increased supply diversity provided by renewable resources, the DOE NOPR would permit eligible coal plants to operate and decrease supply diversity even when market conditions would not otherwise dispatch those units. Renewable resources, allowed the opportunity to compete through ISO/RTO market constructs, displace emissions of nitrogen oxides, sulfur dioxide, and carbon dioxide emitted by eligible coal resources. Disrupting markets to favor eligible resources would likely increase these emissions to the detriment of human health and the climate, and in contravention of the public policy goals of the State of Delaware.

VI. Response to Selected Questions from the Staff Guidance Document.

A. "Need for Reform" 1. What is resilience?

It would be impractical for any one entity to attempt to define resilience for the national or regional electric grid. We believe that regional stakeholders should collaborate to determine a definition of resiliency suitable for their collective interests. This definition should be

[81] 2020/2021 Auction Report at 1.

[82] 26 *Del. C.* § 351(b). ("The General Assembly finds and declares that the benefits of electricity from renewable energy resources accrue to the public at large… These benefits include improved regional and local air quality, improved public health, increased electric supply diversity, increased protection against price volatility and supply disruption, improved transmission and distribution performance, and new economic development opportunities.")

comprehensive and include definable metrics including allowing a determination of whether, in fact, a grid is 'resilient.'

The Delaware Agencies believe that any definition must include a preeminent role for ISO/RTOs in the area of cybersecurity. ISO/RTOs are in the position to best address the broad-scale challenges presented by cybersecurity threats. No other entity is sufficiently well-situated to coordinate the necessary efforts across an expansive footprint. The Delaware Agencies specifically applaud PJM for its continued efforts in this area, and would encourage this difficult but important work to continue.

Especially at this early stage in developing its definition, resilience should not include provisions to become a **driver** in the transmission planning process ("RTEP"). Ostensibly to evaluate transmission needs relating to resilience, preliminary analysis has been presented in PJM to show the probability of a certain event leading to cascading transmission outages.[83] Crucially, to perform this analysis, PJM pushed the severity of the analyzed events past the boundaries of events defined in mandatory NERC Criteria,[84] to include "extreme events."[85] NERC mandates that the resulting effects from such "extreme events" be "identified" and "evaluated," but does not require additional construction to solve or otherwise remedy these potential issues. These mandatory criteria form the foundation for transmission investment throughout ISO/RTO planning processes nationwide. NERC illustrated its reasoning for limiting mandatory drivers in a 2007 Reliability Concepts whitepaper:[86]

> ...the brutal facts, as they say, are that utilities cannot afford to build or operate the Interconnection to avoid all risks... ***All the world's money***

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[83] *See* Resilience in System Planning. PJM presentation to Planning Committee. August 10, 2017. Available at: http://bit.ly/2uPeZVH

[84] *See* NERC Standard TPL 001-4 at 8-10. Available at: http://www.nerc.com/files/tpl-001-4.pdf

[85] *Id.* at § 4.4. ("Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated.")

[86]Reliability Concepts v. 1.0.2. NERC. December 19, 2007, available at: http://www.nerc.com/files/concepts_v1.0.2.pdf (emphasis added)

> ***cannot construct an electric system robust enough to remain unscathed from extremely unlikely and extremely severe events.*** While the consequences may be vast, some risks are simply unavoidable. Saying these consequences are also unacceptable is moot. Saying we don't want the events to happen is obvious.

Our major concern is the lack of meaningful discussion of resilience in the PJM stakeholder process. Stakeholders have reached no determination or consensus regarding the extent to which PJM should be resilient, or whether PJM currently plans its system to be resilient. Without such a consideration, the potential costs are limitless (e.g. PJM plans to N-1 contingency. Is true resilience N-1-1-1? N-1-20? N-1-100?). Additionally, due to the confidential nature of such critical facilities, it is unlikely that the nature of the violation, project submission, cost estimates, cost/benefit analysis, and other elements would be publicly available for stakeholder review. To the extent resilience-driven projects are included in the RTEP, which we oppose at this time, such projects should fall under the state agreement approach[87] for development of transmission solutions. Through this lens, each state would be consulted and would have to agree to pay the costs of any project before such costs can be allocated to the state. Use of the state agreement approach would provide states the authority to supervise their own spending for resiliency. To the extent that PJM seeks to make resilience a factor in RTEP planning (where PJM would consider resilience along with many other factors in the selection of a specific project to address a violation of an existing criteria), the we support the effort as long as PJM commits to making the manner in which it analyzes each project open and transparent.

B. "Need for Reform" 1. How are reliability and resilience valued, or not valued, inside RTOs/ISOs?

Generation reliability and resilience is currently valued in the wholesale market through the determination of the reserve margin and procurement of the generation resources it requires. NERC

[87] PJM Tariff Schedule 6 § 1.5.9.

developed[88] and FERC approved[89] a one-day-in-ten-year Loss of Load Expectation ("LOLE") for determining regional resource adequacy. This criterion results in a mandate that customers purchase more capacity than the previous year's peak load of the ISO/RTO footprint. In support of this requirement, NERC stated "experience has demonstrated… a target of 'one day in 10 years…' has provided adequate generating capacity in real time operation… *even under extreme conditions.*"[90] Partially on this NERC recommendation, FERC found the proposed LOLE criterion just and reasonable.[91] This FERC-mandated purchase of excess capacity under these parameters in order to provide confidence in operations even under extreme conditions is just and reasonable, as it is based in NERC's real-time operational experience. In contrast, the mandate of the DOE NOPR requiring load to pay for the subsidization of eligible units is not supported by substantial evidence (or *any* evidence), and should be rejected.

C. <u>"Need for Reform" 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 resiliency and reliability?</u>

Fuel diversity within a region or market is important. In an effective market that properly recognizes availability attributes, however, fuel diversity should not require supplemental payments. PJM's current market structure and resource mix succinctly demonstrate this theory: "[t]oday's resource profile in PJM is both reliable and diverse – with a combination of natural gas, coal, nuclear, renewables, demand response and other resource types."[92] For instance, PJM's 2016 resource mix was 33.8% coal, 26.7% natural gas, and 34.4% nuclear.[93] Even with a continued growth of natural gas capacity, fuel diversity is no worse than in 2005 when coal and nuclear resources

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[88] NERC Standard BAL-502-RFC-02. Available at: http://www.nerc.com/files/BAL-502-RFC-02.pdf
[89] Order 747, 134 FERC ¶ 61,212 (2011).
[90] *Id.* at P 32.
[91] *Id.* at P 31.
[92] PJM Reliability Paper at 3. (internal footnote omitted)
[93] 2016 SOM at Table 3-9. (Of 812,544 total GWh, 275,281 GWh from coal, 279,546 GWh from nuclear, and 217,214 GWh from natural gas)

generated 91% of the electricity in PJM.[94] It is quite clear that gas capacity in PJM's market, given current gas prices, has continued to be the most cost efficient resource for new entry generators and that will likely continue, depending on fuel price differentials. Efficient capacity market pricing should provide continued opportunity for competitive coal, nuclear, and renewable resources to continue operations. Considering historical resource mix issues, we see no measurable service impacts on system resiliency or reliability or from the changes in the fuel diversity mix.

VII. Communications

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[94] PJM Reliability Paper at 9.

VIII. **Conclusion**

For the foregoing reasons, the Commission should reject and take no further action on the DOE NOPR.

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Respectfully submitted,

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