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U.S. Department of Electricity
Office of Electricity
Attn: Guidance for Enhancing Grid Resilience

Re: Response to Request for Information Regarding Codes, Standards, Specifications, and Other Guidance for Enhancing the Resilience of Electric Infrastructure Systems Against Severe Weather Events

Pursuant to the U.S. Department of Energy (DOE) Office of Electricity's July 9, 2019 Notice of Request for Information (RFI) on Codes, Standards, Specifications, and Other Guidance for Enhancing the Resilience of Electric Infrastructure Systems Against Severe Weather Events,[1] Exelon Corporation (Exelon) respectfully submits the following comments.[2] Exelon appreciates DOE's attention to the issue of electric infrastructure resilience, which is quickly becoming a top priority for the nation's electric utilities. As the frequency, magnitude, and intensity of severe weather events continue to increase, electric utilities must be vigilant in preparing for these events, planning their infrastructure investments to ensure that their systems are capable of both withstanding severe weather events and rapidly recovering from any resulting service disruptions (in a word, resilient). In a world that increasingly depends on reliable electric service, investments that enhance electric infrastructure resilience have significant benefits for utilities' customers, reducing the number, duration, and magnitude of outages that they experience as a result of severe weather events.

However, planning and executing investments that improve the resilience of electric infrastructure against severe weather events is not without challenges. It requires accurate information about the nature of severe weather threats, their likely effects on electric infrastructure, and, as technology evolves, the availability of cost-effective

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[1] *Codes, Standards, Specifications, and Other Guidance for Enhancing the Resilience of Electric Infrastructure Systems Against Severe Weather Events*, Notice of Request for Information, 84 Fed. Reg. 32,730 (Jul. 9, 2019) (Grid Resilience RFI).

[2] This response to the Grid Resilience RFI focuses on severe weather events. However, cyber and physical threats also pose significant risks to the nation's electric infrastructure, especially threats that, if realized, could interrupt the flow of the natural gas on which power generation increasingly depends. As a result, Exelon discusses the potential for DOE to incorporate such threats in its efforts to support design, planning, and implementation of investments to enhance the resilience of electric infrastructure systems. In addition, Exelon is submitting these comments in its response to *Codes, Standards, Specifications, and Other Guidance for Enhancing the Resilience of Oil and Natural Gas Infrastructure Systems Against Severe Weather Events*, 84 Fed. Reg. 32,731 (Jul. 9, 2019) (Oil and Natural Gas Resilience RFI) to highlight the importance of considering the interdependencies of the nation's electric and natural gas infrastructure when assessing the consequences of vulnerabilities in the natural gas transportation system.

mitigation measures to reduce identified vulnerabilities. It takes significant time and resources for an electric utility to not only fully integrate resilience considerations into its design, planning, implementation activities, and business processes, but also continually reevaluate its resilience strategy as its gains experience with implementation and as new and better information about the threats that it faces becomes available. It can involve the deployment of new technologies and systems with which the utility (and, for first-of-a-kind technologies, sometimes the entire electric industry) has little experience. And reasonable plans for enhancing grid resilience are unlikely to be realized absent the opportunity for electric utilities to recover the costs of, plus a return on, the necessary investments.

But electric utilities need not face these challenges alone. DOE can play a significant role in supporting the design, planning, and implementation of investments that enhance electric infrastructure resilience, working with the electric industry to tackle the impediments to the development of a more resilient electric grid. First, DOE should provide a forum for electric utilities to develop a flexible framework that each utility can modify as needed to assess the resilience of its system against severe weather events. This forum should not be a one-time event; rather, it should involve regular meetings that allow utilities to share best practices and innovative resilience solutions on an ongoing basis, which can then be considered in updating the framework. Second, working independently or partnering with other federal agencies, DOE should leverage its technical expertise and financial resources to help utilities to implement their resilience frameworks (e.g., by researching improved weather models or providing funding for demonstration projects). Third, DOE should establish a design-basis threat (DBT)[3] for the electric industry, which would serve as an essential tool for utilities and regional transmission organizations/independent system operators (RTOs/ISOs) to identify both their vulnerabilities to severe weather events and cost-effective mitigation strategies to help address those vulnerabilities. Fourth, DOE should leverage the results of all of these initiatives (including the development of resilience frameworks) to facilitate the completion of its North American Energy Resilience Model (NAERM).[4] Finally, DOE should provide information to state and federal regulators and stakeholders about the need for and value of resilience investments. This last task is key to the success of any investment program to enhance electric infrastructure resilience – utilities rely on regulators to allow them to recover the costs of their investments, and without compelling evidence of the need for and value of investments in more resilient electric infrastructure, regulators may be unwilling to support those investments.

I. Introduction

[3] The U.S. Nuclear Regulatory Commission defines a design-basis threat as "a profile of the type, composition, and capabilities of an adversary." *See* Nuclear Regulatory Commission, *Glossary: Design Basis Threat* (Mar. 21, 2019), https://www.nrc.gov/reading-rm/basic-ref/glossary/design-basis-threat-dbt.html. *See also* 10 CFR § 73.1(a) (outlining particular threats against which licensees must design safeguards systems to protect). These comments explain how DOE and its partners could similarly support electric system resilience by establishing a DBT for severe weather events and other threats.

[4] *See* Department of Energy, *North American Energy Resilience Model* (July 2019) (DOE NAERM), https://www.energy.gov/sites/prod/files/2019/07/f65/NAERM_Report_public_version_072219_508.pdf.

On July 9, 2019, the DOE Office of Electricity issued the Grid Resilience RFI, in which it requests information from interested persons on current consensus-based codes, specifications, standards, and other forms of guidance used in both system design and operations for improving the resilience of electric infrastructure systems against severe weather events. Specifically, DOE seeks information on (1) specific technical design standards or requirements for physical system components, (2) relevant corporate business practices, and (3) analytic methods and tools for estimating the possible economic benefits from strategies, investments, or initiatives to enhance power system resilience. DOE explains that it will use the information that it gathers through this RFI to catalogue and synthesize existing expert knowledge about how to cost-effectively enhance the weather-related resilience of the electric grid.

Exelon appreciates the opportunity to respond to this RFI. Exelon is a holding company, headquartered at 10 South Dearborn Street, Chicago, Illinois, with operations and business activities in 48 states, the District of Columbia, and Canada. Exelon owns Atlantic City Electric Company (Atlantic City Electric), Baltimore Gas and Electric Company (BGE), Commonwealth Edison Company (ComEd), Delmarva Power & Light Company (Delmarva Power), PECO Energy Company (PECO), and Potomac Electric Power Company (Pepco). Together Atlantic City Electric, BGE, ComEd, Delmarva Power, PECO, and Pepco own electric transmission and distribution systems that deliver electricity to approximately 10 million customers in the District of Columbia (Pepco), northern Delaware and the Delmarva Peninsula (Delmarva Power), southern New Jersey (Atlantic City Electric), northern Illinois (ComEd), Maryland (BGE and Pepco), and southeastern Pennsylvania (PECO). Exelon Generation Company (ExGen) is one of the largest competitive power generators in the U.S., with approximately 33,000 megawatts of owned capacity comprising one of the nation's cleanest and lowest-cost power generation fleets, located in a number of organized markets. Constellation, an ExGen business unit consisting of subsidiaries and divisions of ExGen, is one of the nation's leading marketers of electricity and natural gas and related products in wholesale and retail markets. These businesses serve approximately 2.5 million residential and business customers in various markets throughout the United States.

Enhancing the resilience of our electric infrastructure against severe weather events is a priority for Exelon, and it is essential to the continued provision of reliable service to our customers. We are actively reviewing the material condition of our transmission and distribution systems, developing design and planning criteria to meet state and local standards, and assessing the threats that the increasing frequency, magnitude, and intensity of severe weather events pose to our assets and, more holistically, our systems. We are committed to investing in cost-effective mitigation measures to address our vulnerabilities, from hardening individual assets against severe weather events (e.g., elevating substations to prevent flooding) to developing system-wide capabilities that allow us to more rapidly identify and respond to system disturbances (e.g., communications infrastructure). From Exelon's perspective, resilience against severe weather events cannot be achieved through a single assessment that reflects a snapshot of our systems' vulnerabilities at a particular point in time. It requires an ongoing process, a framework that allows us to continually reassess our vulnerabilities and resilience strategy both as our understanding of the severe weather threats that our systems face improves and as we gain experience with the various options for mitigating our vulnerabilities. Such a flexible framework allows us to modify our approach as necessary to ensure that our resilience strategy is producing the expected results in a cost-effective manner. Resilience is more than just a buzzword for Exelon – it is an integral part of our approach to achieving our vision of a connected community for our customers.

Below, we explain why enhancing the resilience of the nation's electric infrastructure against severe weather events must be a priority for DOE, utility regulators, and infrastructure planners and owners. We then describe the role that DOE should play in supporting investments in resilient electric infrastructure. Finally, we discuss in greater detail Exelon's suggested approach to enhancing the resilience of transmission and distribution infrastructure (with some specific examples of practices that we are exploring), as well as the need for DOE's leadership in developing a framework for assessing the resilience of the electric system as a whole and, more specifically, the availability of resilient and fuel secure generation resources to serve load in light of severe weather threats.

II. Comments

A. The Importance of Electric Infrastructure Resilience

Our nation's energy infrastructure is essential to our national security and prosperity. As a society, we depend today on the secure and reliable supply and delivery of electricity in our daily lives more than ever; it is vital to our health and safety, underlies our communications and financial systems, and drives our economy. The sustained loss of electric service on a large scale would be catastrophic,[5] but even less significant service disruptions will become increasingly consequential as additional sectors of the economy, such as transportation, electrify. As a result, electric utilities cannot rely solely on compliance with mandatory reliability standards (which tend to focus on the prevention of widespread, cascading outages) to fulfil their customers' expectations for uninterrupted service. Instead, they must place continuing emphasis on proactively designing their systems and prioritizing their investments to cost-effectively reduce the number, duration, and magnitude of customer outages. And one of the major causes of such outages is severe weather events.

As DOE notes in the RFI, severe weather events are increasing in both frequency and magnitude. For example, the National Oceanic and Atmospheric Administration's National Centers for Environmental Information tracks the number of weather and climate disaster events with losses exceeding $1 billion per year. Since 1980, there have

[5] *See, e.g.*, *Exelon Corporation*, Exhibit A to Comments of Exelon Corporation, Prepared Direct Testimony of Dr. Paul Stockton on Behalf of Exelon Corporation at 9-10, FERC Docket No. RM18-1 (filed Oct. 23, 2017). For example, prolonged disruption of electric service would incapacitate a range of systems vital to Americans' daily lives, including electric and natural gas heating at residential, commercial, and industrial locations; water treatment plants; the food distribution system; the medical system; and communication networks. Exelon's comments in this FERC proceeding are attached as Attachment I.

been 250 such events, with total costs in excess of $1.7 trillion. The four years with the highest number of weather and climate disaster events with costs in excess of $1 billion all occurred in the past eight years (i.e., 2017, 2011, 2016, and 2018); three of the top four years in terms of the total cost of such events occurred during that same time period (i.e., 2017, 2012, and 2018).[6] Moreover, as noted in DOE's NAERM, "[w]eather-related and other natural disasters, which are the dominant cause of high consequence power outages, are projected to continue to increase in intensity and frequency."[7] This continuing trend of increasing frequency, magnitude, and intensity of severe weather events poses significant risk to the nation's electric infrastructure; it could increase the likelihood, duration, and magnitude of customer outages. Given the importance of reliable electric service in our society, such outages would be more than an inconvenience for our customers – they represent a significant service disruption that would affect nearly every aspect of our customers' daily lives. Enhancing the resilience of electric infrastructure against severe weather events is critical to preventing such outages and, when they do occur, ensuring that service can be quickly restored.

And even when severe weather events do not ultimately result in outages, they can expose systems vulnerabilities that, given a simultaneous contingency, could significantly disrupt service. For example, although PJM Interconnection, L.L.C. (PJM) did not face imminent blackouts during the 2014 Polar Vortex extreme cold weather event,[8] it experienced significant generation outages that spurred it to file its Capacity Performance capacity market reforms with the Federal Energy Regulatory Commission (FERC) to ensure that generators are available when required.[9] In assessing its system's performance during the subsequent December 2017-January 2018 Cold Snap (during which average temperatures were not as low as during the Polar Vortex), PJM found that the number of forced generator outages was reduced (potentially due to the implementation of Capacity Performance);[10] however, PJM also found that there was still room for improvement with respect to fuel security (in this case, the need to continue to improve gas-electric coordination capabilities and to analyze the tracking and transportation of fuel oil supplies), as well as the need to evaluate the system's vulnerabilities under extended periods of stressed operations.[11] Significantly, had the December 2017-January 2018 Cold Snap been longer, occurred outside of a holiday period and weekend, or been accompanied by a concurrent major contingency on the natural gas pipeline system, the level of system stress would have been much greater.

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[6] *See* National Centers for Environmental Information, *Billion-Dollar Weather and Climate Disasters: Overview*, https://www.ncdc.noaa.gov/billions/ (last visited Aug. 13, 2019).

[7] *See* DOE NAERM at 5. *See also* Adam B. Smith, "2018's Billion Dollar Disasters in Context," *National Oceanic and Atmospheric Administration*, February 7, 2019, https://www.climate.gov/news-features/blogs/beyond-data/2016-historic-year-billion-dollar-weather-andclimate-disasters-us 6 NOAA National Cent (last visited Aug. 19, 2019).

[8] *See* PJM Interconnection, L.L.C., *PJM Cold Snap Performance Dec. 28, 2017 to Jan. 7, 2018*, at 1 (Feb. 26, 2018) (PJM Cold Snap Report), https://www.pjm.com/-/media/library/reports-notices/weather-related/20180226-january-2018-cold-weather-event-report.ashx.

[9] *See* PJM Interconnection, L.L.C., *Strengthening Reliability: An Analysis of Capacity Performance*, at 2 (Jun. 20, 2018), https://www.pjm.com/-/media/library/reports-notices/weather-related/20180226-january-2018-cold-weather-event-report.ashx.

[10] *See id.* at 13-15.

[11] *See* PJM Cold Snap Report at 33.

Grid resilience is, then, a topic of national significance. DOE is uniquely positioned to support the development of assessment tools to assist utilities and RTOs/ISOs in strengthening grid resilience against such threats.[12] DOE has the national perspective needed to understand the full range of risks that electric utilities face due to the increasing frequency, magnitude, and intensity of severe weather events and experience with facilitating industry-wide discussions about energy-related challenges. In fact, any efforts stemming from this RFI would not be the first initiative that DOE has led on electric infrastructure resilience against severe weather events;[13] refocusing on these existing efforts and capitalizing on the information that they yielded in any new initiatives would help to facilitate quicker action on this high-priority issue. Moreover, DOE has existing relationships with key stakeholders, including the nation's Governors (through the National Governors Association), state legislatures (through the National Conference of State Legislatures), state energy offices (through the National Association of State Energy Officials), and state regulators (through the National Association of Regulatory Utility Commissioners). DOE can leverage these relationships to share information on the need for and value of investments in more resilient electric infrastructure, building consensus around electric utilities' strategies to harden their systems against severe weather events.

For these reasons, DOE should make supporting efforts to enhance grid resilience against severe weather events a priority.

B. DOE's Role in Supporting the Development of Resilient Electric Infrastructure

[12] DOE uses the definition of resilience established in Presidential Policy Directive 21, which defines resilience as "the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents." *Presidential Policy Directive on Critical Infrastructure Security and Resilience*, at 12 (Feb. 12, 2013), https://www.dhs.gov/sites/default/files/publications/PPD-21-Critical-Infrastructure-and-Resilience-508.pdf. Exelon supports the continued use of this definition.

[13] For example, DOE's Partnership for Energy Sector Climate Resilience is a voluntary initiative through which participating electric utilities and DOE collaborated to create new resources to facilitate risk-based decision making that support the development of cost-effective strategies to improve the resilience of energy infrastructure against extreme weather and climate change impacts. As part of the initiative, DOE committed to (1) share information and technical assistance on climate science, emerging climate resilience best practices, technologies, and policies, (2) develop and deploy tools for assessing vulnerabilities, (3) evaluate the costs and benefits of climate resilience investments, and (4) provide national recognition to its utility partners for implementing measures to enhance energy infrastructure resilience. *See* Organisation for Economic Co-operation and Development, *OECD Toolkit for Risk Governance: US Partnership for Energy Sector Climate Resilience*, https://www.oecd.org/governance/toolkit-on-risk-governance/goodpractices/page/uspartnershipforenergysectorclimateresilience.htm (last visited Aug. 14, 2019). In addition, DOE staff recommended that DOE "support utility, grid operator, and consumer efforts to enhance system resilience" in a 2017 report. DOE, *Staff Report to the Secretary on Electricity Markets and Reliability*, at 126 (August 2017) (August 2017 DOE Staff Report), https://www.energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf.

In the RFI, DOE requests information on "consensus-based codes, specifications, standards, and other forms of guidance for improving the resilience of electric infrastructure systems against severe weather events." While this effort to create a compendium of today's best practices is a step in the right direction, Exelon respectfully submits that even more than this must be done to address the formidable and ever-increasing risks that our nation's electric utilities will face from severe weather events in the future. Our understanding of the threats that severe weather events pose to our assets and systems is continually evolving. With more and better data about the frequency, magnitude, and intensity of such events, as well as improved weather models and modeling capabilities, we must be ready to regularly update our assumptions about the impacts that severe weather events will have on our infrastructure. And the mitigation measures available to combat our vulnerabilities to severe weather events are rapidly changing as well as technology continues to improve. In sum, the threats that we face, as well as the options available to cost-effectively mitigate our vulnerabilities, are dynamic in nature, and a static survey of best practices at a particular point in time will do little to promote resilience in the longer-term. DOE, utility regulators, and infrastructure planners and owners can – and must – do more.

While it may be tempting to use the best practices that are compiled to establish baseline "resilience standards" to support needed investments in enhancing electric infrastructure resilience against severe weather events, such an approach would only reflect our understanding of severe weather threats and effective mitigation measures at a particular point in time. This approach might also be too rigid to allow electric utilities to react to changing threat dynamics and might stifle innovation in developing more cost-effective solutions to address identified vulnerabilities. Nor would such an approach acknowledge that different utilities are differently situated with respect to their resilience posture. Different regions of the nation are more likely to experience different severe weather events. For example, the West is more prone to wildfires, the East Coast and Gulf Coast are more vulnerable to hurricanes, and the Midwest can experience severe flooding. Adopting a single set of best practices as generic standards would fail to account for these differences, potentially leading utilities to adopt mitigation measures against severe weather threats that they are unlikely to experience. In addition, generic standards could impose the adoption of specific mitigation measures industry-wide. Such a result would be inappropriate; the viability and prioritization of mitigation measures will vary by utility depending not only on its current state of preparedness in light of the particular threats that it faces, but also based on the specific needs and demands of its customers and the regulatory environment in which it operates. Accordingly, DOE should not use the RFI process to advocate for the establishment of mandatory resilience standards but should instead seek to identify and endorse best practices in design and planning criteria that can be tailored to the individual needs of particular utilities.

What the electric industry really needs is a flexible framework for assessing and mitigating their vulnerabilities to severe weather events and for regularly reevaluating their resilience strategies as they learn from their experience. Such a flexible framework should allow utilities to not only proactively plan and design their systems to withstand and recover from severe weather events, but also to nimbly react as better information about severe weather threats becomes available and as new technologies to more cost-effectively mitigate those threats evolve. Specifically, the framework should outline for utilities a general structure that they can use to (1) identify the severe weather events that their systems face, (2) assess current preparedness of their systems (i.e., identify their vulnerabilities), (3) identify potential mitigation measures, (4) prioritize their resilience investments (i.e., develop a resilience strategy), and (5) regularly revisit their resilience strategies. Such a framework would propagate best practices without being overly prescriptive – it would provide flexibility for each utility to best manage the particular severe weather threats that it faces given its current resilience posture and to reflect the priorities and preferences of its customers, regulators, and other stakeholders.

As discussed in section II.A above, DOE is uniquely situated to play a key role in the development of such a flexible resilience framework. It can provide an ongoing forum for electric utilities to discuss the framework and its inputs (e.g., available weather data and models, best practices for mitigation solutions, etc.), so that the electric industry can quickly and effectively respond as it gains new and better information about severe weather events and experience with mitigating them. It can provide a clearinghouse for the resilience-related information shared through this forum and could even support the development of case studies of proactive resilience investments that have saved customers money and/or enhanced service. It can also formally endorse any design standards, planning criteria, or best practices that result from the discussions, as well as the application of the framework itself to develop utility-specific resilience strategies. As discussed in greater detail below, such endorsement would support utilities' efforts to gain approval from regulators for their planned investments to enhance electric infrastructure, which will allow them to recover the costs of those investments.

In addition, acting independently or partnering with other federal agencies, DOE should muster its technical expertise and financial resources to support the electric industry's efforts to enhance the resilience of electric infrastructure against severe weather events. For example, DOE (potentially working in concert with the National Oceanic and Atmospheric Administration) could leverage the computing capabilities of the National Labs and federal funding for grid modernization to support the development of improved models for predicting the frequency, magnitude, and intensity of severe weather events.[14] DOE could also fund pilot programs or demonstration projects that involve the deployment of new technologies that enhance electric infrastructure resilience. The U.S. Department of Homeland Security (DHS) has just such a program. Through its Resilient Electric Grid program, DHS is partially funding a demonstration project that will significantly enhance the reliability and resilience of ComEd's system in downtown Chicago. Specifically, ComEd will deploy an advanced transmission technology (high temperature superconducting cables) to form a new looped transmission

[14] For example, on May 29, 2019, DOE issued its 2019 Grid Modernization Lab Call, giving interested parties the opportunity to apply for funding for projects to address the following six topic areas: (1) resilience modeling, (2) energy storage and system flexibility, (3) advanced sensors and data analytics, (4) institutional support and analysis, (5) cyber-physical security, and (6) generation. *See* Gil Bindewald, Kevin Lynn, Alicia Dalton-Tingler, Trevor Cook, and Carol Hawk, *Department of Energy's Grid Modernization Lab Call* (May 29, 2019), https://www.energy.gov/sites/prod/files/2019/05/f63/GMI-National-Lab-Call-2019-05-29.pdf.

path in a dense urban area where adding conventional high-voltage conductors would be impractical, if not impossible.[15] DHS, along with American Superconductor Corporation (the contractor who manufactures the high temperature superconducting material), will assume 53 percent of the demonstration project's costs. The project will provide valuable experience with deploying this advanced technology, particularly in dense urban areas where space may be limited or unavailable for resilience enhancing infrastructure upgrades that utilize conventional technologies. This experience will benefit not only Exelon, but also other utilities that could enhance the resilience of their systems through its adoption.

DOE should also work with FERC and other appropriate partners to develop a design-basis threat (DBT) that utilities and RTOs/ISOs can use to identify system vulnerabilities to severe weather events. A DOE-developed DBT would provide guidance to utilities and RTOs/ISOs on the severe weather threats that they should be planning to mitigate,[16] providing a baseline against which each utility and RTO/ISO can assess the resilience of its system and measure the adequacy of its mitigation efforts. Like the flexible resilience framework proposed above, the DBT should be dynamic – individual utilities and RTOs/ISOs should be able to modify it to reflect their unique circumstances and needs. Moreover, DOE should periodically update the DBT as improved information about the frequency, magnitude, and intensity of severe weather events becomes available. A DBT would also support RTO/ISO efforts to design their markets to better compensate supply resources, such as resilient and fuel secure generation, that mitigate the identified threats, a key condition for generation asset owners that operate in competitive markets to fund resilience investments.[17]

Finally, electric utilities cannot implement their resilience strategies without a mechanism for timely recovering the costs of the necessary investments. DOE can play a crucial role here as well. Specifically, DOE can help to inform state and federal regulators and government officials, as well as interested stakeholders, about the pressing need for utilities to enhance their infrastructure against severe weather events and the value that such investments will provide for the nation's electricity consumers. More resilient electric infrastructure will not come without costs, and regulators need assurance that investments to enhance grid resilience will provide concrete benefits for consumers. They need to understand that when a utility implements a resilience strategy to design its infrastructure to withstand and recover from severe weather events, it is acting prudently, working to reduce the frequency, duration, and magnitude of customer outages. This is

[15] *See Commonwealth Edison Company Superconductor Cable Project*, FERC Docket No. ER19-1478 (filed Mar. 29, 2019).
[16] As discussed in section II.D below, this DBT need not be limited to resilience threats from the increasing frequency, magnitude, and intensity of severe weather events; to more holistically and cost-effectively address electric system resilience, it could reflect the significant man-made threats (such as physical and cyber security threats) that our nation's electric and natural gas infrastructure faces as well. Incorporating threats to the nation's natural gas infrastructure is particularly important in light of the electric sector's increasing dependence on natural gas-fired generation.
[17] For a more detailed discussion of the need for an electric sector DBT, *see Exelon Corporation*, Comments of Exelon Corporation, FERC Docket No. RM18-1 (filed Oct. 23, 2017) (included as Attachment I).

true for both state regulators (who address cost recovery for distribution system investments) and federal regulators (who have jurisdiction over cost recovery for transmission assets). Again, DOE can leverage its existing partnerships, such as its work with the National Association of Regulatory Utility Commissioners, to share the importance and value of resilience investments. And it can support the development of case studies that demonstrate the benefits associated with investments in more resilient electric infrastructure to provide evidence on which regulators can rely in their decision-making processes. With better information, both state and federal regulators are more likely to recognize these investments as prudent and necessary to continue providing customers with the service they expect, facilitating the implementation of utilities' resilience strategies.

And while it is outside of DOE's control, timely and fair action on rate filings is critical to supporting investments in more resilient electric infrastructure. Prolonged regulatory proceedings and regulatory decisions that undermine the ability of utilities to recover their costs, either at the state or federal level, can hinder investments to enhance grid resilience.[18] Investment in resilient infrastructure can also be undermined where the potential for prolonged litigation is high, such as when the scope of issues subject to hearing or further regulatory process is wider than the modifications that a utility has proposed to its rate.[19] The regulatory uncertainty that results will discourage utilities from filing to adopt new rate structures and cost recovery mechanisms to support resilience-related investments, causing needed investment to languish. In addition, regulators need to demonstrate flexibility as they consider requests for cost recovery for unconventional technologies and investments that can enhance grid resilience;[20] otherwise, they may create barriers to new, more cost-effective solutions to mitigating utilities' vulnerabilities to severe weather events. DOE efforts to inform regulators about the urgency of resilient grid investments will help to focus them on the need for timely, fair, and flexible consideration of the rate filings that come before them.

In the next two sections, we provide examples of how a flexible resilience framework could be used to develop a resilience strategy for a utility's transmission and distribution infrastructure, as well as to evaluate the resilience of regional power systems against severe weather events. These examples are intended to provide a starting point for the discussions that we believe the electric industry should be having through the

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[18] *See, e.g., Commonwealth Edison Company,* 164 FERC ¶ 61,172 (2018) (rejecting the Exelon Companies' proposals to provide a mechanism to refund or recover, as appropriate, certain deferred income tax excesses and deficiencies that they previously recorded on their books and that they will record on an ongoing basis); *PJM Interconnection, L.L.C.,* 161 FERC ¶ 61,163 (2017), affirmed and clarified, *PJM Interconnection, L.L.C.,* 164 FERC ¶ 61,173 (2018). *See also, Commonwealth Edison Company,* Deficiency Letter, FERC Docket No. ER19-5 et al. (Nov. 21, 2018); *Commonwealth Edison Company,* Deficiency Letter, FERC Docket No. ER19-5 et al. (Jan. 28, 2019); *Commonwealth Edison Company,* 167 FERC ¶ 61,071 (2019) (setting the filings for hearing and settlement judge procedures).
[19] *See, e.g., PJM Interconnection, L.L.C.,* 167 FERC ¶ 61,192 (2019) (setting for hearing and settlement judge procedures issues seemingly beyond those that were included in the specifically proposed formula rate revisions, which would have better aligned incurrence and recovery of Pepco's transmission costs).
[20] For example, FERC recently demonstrated such flexibility when ruling on ComEd's request to functionalize its Superconductor Project (discussed above) as a transmission asset, allowing its costs to be recovered through transmission rates. *See Commonwealth Edison Company,* 167 FERC ¶ 61,173 (2019).

DOE-facilitated forum that we propose above. They reflect Exelon's preliminary thoughts on how to best incorporate resilience considerations into our planning and design processes, but they are just a beginning. Much work remains to fully address the challenges and threats that the increasing frequency, magnitude, and intensity of severe weather events pose for our systems.

C. Resilient Electric Infrastructure – Transmission and Distribution

Developing a resilience strategy for an electric utility's transmission and distribution systems is a multi-step process that incorporates a wide range of considerations. It begins with identifying system vulnerabilities (e.g., particular assets or aspects of the system that cannot be reasonably expected to withstand severe weather events or may impair the ability to rapidly restore service after such an event). To do so, a utility must first gain an understanding of the severe weather events that might affect its ability to provide service, the likelihood of such events occurring, and their expected severity. With the increasing frequency, magnitude, and intensity of severe weather events, relying on past experience in this analysis can be dangerous; however, forecasts of future trends can be fraught with uncertainty. Any role that DOE can play in supporting the development of more accurate weather models and providing access to the best available weather data would help to reduce this uncertainty, facilitating utilities' resilience planning.

Once a utility has identified the severe weather events that pose a threat to its system, it must determine the likely impacts that such events would have on its system. Doing so can require a utility to evaluate the condition of all of its infrastructure, as well as the current state of its business practices, such as planning criteria and design guidelines. When identifying likely system impacts, the utility may also identify the costs of such impacts. Combining the data about likely impacts and their costs with the likelihood of a given severe weather event occurring, the utility can then develop an understanding of the probability-weighted impacts and costs associated with different severe weather events (including the identification of high impact/low frequency events). With this information, a utility can prioritize its resilience investments in part by identifying the vulnerabilities associated with the most significant probability-weighted severe weather events in terms of system impacts and costs.

Next, the utility must consider potential solutions to mitigate its vulnerabilities, accounting for factors such as cost and feasibility of implementation. Again, DOE can facilitate this assessment by creating a clearinghouse for information about resilience-enhancing technologies and business practices (e.g., planning criteria and design standards). The utility can then define its resilience strategy, prioritizing their investments given the costs and benefits of different solutions and the preferences of its customers, regulators, and other stakeholders. In addition, the utility will evaluate opportunities to co-optimize its resilience strategy with its plans to address other transmission needs (i.e., the potential for investments to address other identified system needs to enhance resilience as well or for resilience investments to address other identified system needs). A resilience strategy will typically involve both physical enhancements to a utility's system (e.g., hardening utility poles against high winds, elevating or relocating substations in flood plains) and modifications to a utility's business practices (e.g., improving preparation protocols for severe weather events, deploying more secure and robust communication systems).

For example, Exelon is considering a wide range of options for inclusion in its resilience strategy. We provide a few examples below:

Distribution System Standards/Guidelines to Enhance Resilience

- Distribution Line Construction Standards: The National Electric Safety Code specifies three grades of construction for distribution lines, the highest of which is Grade B Construction. The grade of construction defines the strength and load factors to use when performing pole loading and guying calculations, and Grade B Construction facilities are stronger than the other grades because they are designed using higher load factors and lower strength factors. While the National Electric Safety Code currently requires Grade B Construction for only certain facilities (i.e., facilities that traverse railroad crossings, limited access highways, and navigable waterways), many of the Exelon Utilities have adopted Grade B Construction standards for all new pole installations. These standards lead to installations that are more resistant to damage from wind, ice loading, and adjacent pole failures.

- Customer Segmentation through Distribution Automation: The Exelon Utilities use Distribution Automatic Systems equipment to sectionalize their distribution circuit sections into groups of no more than 500 to 750 customers. This practice improves reliability by allowing us to more effectively limit customer outages during storms, as well as during preventive maintenance and other system work requiring de-energized circuits. During outage situations, the damaged portion of the feeder is isolated automatically or manually by opening the two adjacent reclosers. Power can then be quickly restored up to those points until field crews are able to make necessary repairs.

- Tree-Resistant Overhead Conductor Configurations: In heavily wooded areas that are prone to outages, the Exelon Utilities have begun to deploy specialized tree-resistant overhead conductor configurations (i.e., Hendrix Spacer Cable). Spacer Cable is a pre-engineered electrical distribution system designed for high reliability, low operating costs, and improved right-of-way flexibility. The conductors are covered with two or three layers of polymer designed to allow intermittent contact with ground points (e.g., tree branches) without causing an outage or nuisance tripping. The polymer is resistant to UV degradation, electrical tracking, and abrasion. The conductor is supported by a high-strength messenger that provides mechanical support and a system neutral and acts as a shield wire against lightning. The conductors are hung loosely beneath the messenger and supported by "spacers." The insulating properties of the covering allow the messenger and the conductors to be bundled into a compact area, thereby allowing greater flexibility in solving right-of-way problems.

- Fiberglass Crossarms: Fiberglass crossarms are approximately 30 percent stronger than wood crossarms. Unlike wood crossarms, they will not rot or succumb to woodpeckers or termites. They also exhibit an extremely high dielectric strength, which prevents the tracking of stray electricity on overhead structures. Because of these benefits, the Exelon Utilities are using only fiberglass crossarms for dead-end applications (i.e., terminating wire at the end of mainline or crossing) and are increasingly adopting fiberglass crossarms for use in tangent (i.e., straight line or slight angle) applications.

Transmission System Standards/Guidelines to Enhance Resilience

- Redundant Protection Systems: Modern relaying schemes provide for complete redundancy of protection systems at all voltage levels. These systems provide protection from system faults (such as damage from downed trees and limbs or vehicle pole strikes), allowing isolation of the impacted circuit(s). They also protect against cascading faults, which could extend outages beyond a localized area. Microprocessor relays provide real-time monitoring via SCADA back to the control rooms, improving situational awareness and allowing operators to more quickly respond to system disturbances.

- Flood Protection Measures: ComEd has established a flood mitigation plan to protect its substations that are at the greatest risk of flooding. These substations were risk-ranked using flood plain/flood-way information, along with information about the number of customers (including critical customers) that the substations serve. In most cases, ComEd will construct a flood wall around the entire substation to protect the infrastructure (i.e., equipment and buildings). The minimum height of the flood wall is the base flood elevation (100-year flood level) plus three feet. Each ComEd region is supplied with portable pumps and at least 500 sand bags for deployment in case of flooding, per ComEd's Flooding Inspection, Mitigation, and Response Plan for Substations and Vaults Procedure. These investments will significantly reduce the likelihood of substation damage due to flooding.

- Substation Firewalls: Fire separation and spacing between possible fire hazards at a substation can mitigate damage to assets located within a substation in case of a fire. While rare, fires can occur during high load system conditions (such as prolonged heat waves), extreme weather events, equipment failure, and system faults when protection schemes fail to operate as intended. Adequate separation and/or spacing can minimize damage to surrounding equipment and buildings that were not part of the initial fire source. Where spatial separation is not feasible, alternative fire protection features such as fire barriers can be deployed to achieve the same result. Fire barriers are at minimum three-hour rated for resistance to a fire exposure similar to what is expected. Permanent and precast concrete barriers have been installed around oil-filled equipment to protect the adjacent equipment, as well as control/relay buildings and switchgear buildings. Fire barriers can also deployed at the perimeter of the substation to protect neighboring structures.

- Emergency Restoration Structures: Several of the Exelon Utilities have stocked the equipment required to erect temporary structures to support the conductor when a transmission tower is damaged. Some of these temporary structures require guying that extends beyond the right-of-way, in which case temporary wood structures can be deployed.

- Steel Transmission Poles: To increase the resilience and overall reliability of their assets, Atlantic City Electric, Delmarva Power, and Pepco started a hardening effort in 2015 to update design standards and practices. This effort included the adoption of self-supporting steel monopoles for all new structures used at 138 kV, 230 kV, and 500 kV line voltages. Self-supporting steel monopoles enhance resilience over wood poles as they are less susceptible to wind damage and failure due to age. In addition, they have incorporated additional overload factors and higher than minimum wind loading requirements into their overhead transmission line design criteria and standards.

Importantly, a resilience strategy cannot be a static – a utility must adopt a process to periodically reevaluate its resilience strategy. First, each utility will gain valuable experience from implementing its resilience strategy, learning which approaches to enhancing resilience are the most cost-effective. A utility might uncover additional vulnerabilities through its implementation, requiring reprioritization of its investments. Better weather data and modeling may allow for more precise forecasts of the frequency, magnitude, and intensity of severe weather events. And new technologies may become available to more cost-effectively address identified vulnerabilities. A utility's reevaluation of its resilience strategy depends on new and improved information, and DOE can play a critical role in facilitating information exchange. As discussed above in section II.B, creating an ongoing forum for discussing a resilience framework, establishing a clearinghouse for resilience-related information and best practices, and developing case studies to demonstrate the benefits of resilience investments would help utilities to improve and enhance their resilience strategies. Likewise, leveraging DOE's technical expertise, credibility in providing endorsements, and financial resources, especially to support demonstration projects and research new technologies that could enhance resilience, would help to provide utilities with a wider range of cost-effective options to address their vulnerabilities.

Finally, the success of any utility's strategy to enhance the resilience of its transmission and distribution systems against severe weather events is dependent on the opportunity to recover the costs of resilience investments. While DOE itself cannot assure cost recovery for prudent investments to enhance the resilience of electric infrastructure, it can support those investments by informing and educating regulators of their value to the nation's electric customers. By endorsing the resilience framework developed through the forum as suggested above, as well as specific planning criteria, design standards, and best practices identified therein, DOE can provide regulators with a strong foundation for assessing utilities' resilience strategies. As the frequency, magnitude, and intensity of severe weather events increases, a prudent utility will develop a resilience strategy to protect its customers against prolonged service disruptions; DOE is uniquely positioned to bring national attention to the value that the implementation of such a strategy can provide. With this information, regulators will be more likely to understand the need for their timely, fair, and flexible consideration of utilities' proposals to recover the costs of resilience investments (the need for which is discussed in section II.B above). Such regulatory support is crucial for the electric industry to move forward with confidence in investing to continue to provide reliable service to customers in the face of increasingly frequent and intense severe weather events, and DOE has an important role in disseminating information on which regulators can rely.

D. Resilient Electric Infrastructure – Generation

Enhancing the resilience of the nation's transmission and distribution infrastructure is a necessary condition to mitigating the threat that the increasing frequency, magnitude, and intensity of severe weather events poses to the continued provision of reliable electric service, but it is not sufficient. Even the most resilient transmission and distribution infrastructure system will fail to provide reliable service to customers if the electric system as a whole (i.e., transmission, distribution, and generation infrastructure) is insufficiently resilient. For example, even if the transmission and distribution systems are capable of withstanding a particular severe weather event, electric service will nonetheless be disrupted if there are not enough resilient generation resources to produce the electricity necessary to serve load. And a generation resource is only as resilient as the infrastructure that supplies its fuel (e.g., natural gas-fired generators largely depend on natural gas pipeline infrastructure and face competition for supply from other natural gas users).[21] For example, a recent ISO New England Inc. (ISO New England) study concluded that the New England grid's overdependence on natural gas infrastructure that is highly vulnerable to disruption is a major threat to resilience.[22] The same may be true in the Mid-Atlantic/New York region – a study that

[21] *See, e.g.*, Peter C. Balash, PhD, John Brewer, Kenneth C. Kern, Chris Nichols, Justin Adder, Gavin Pickenpaugh, and Erik Shuster, *Reliability and the Oncoming Wave of Retirement of Baseload Units, Volume I: The Critical Role of Thermal Units During Extreme Weather Events* (Mar. 13, 2018), *available at* https://www.netl.doe.gov/energy-analysis/details?id=2594.

[22] *See* ISO New England, *Operational Fuel-Security Analysis* (Jan. 17, 2018) (ISO-NE Operational Fuel-Security Analysis), at 6-9, https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf. In this study, ISO New England modeled 23 possible scenarios that could occur in the 2024/2025 winter. In every scenario but

ICF prepared for the Nuclear Energy Institute found that a potential pipeline outage could result in up to 27 GW of electric generation, 18 GW of which are in PJM, being interrupted for an extended period of time.[23] Thus, mitigating the threats that severe weather events pose to generation resources entails considering more than just the vulnerabilities of the generation asset itself; it requires an analysis of the vulnerabilities of the interdependent infrastructure on which that asset relies to obtain fuel (i.e., a fuel security analysis), an analysis that DOE is uniquely positioned to facilitate.

DOE is also ideally-positioned to assess an additional factor affecting the availability of adequate resilient generation resources: the resilience of fuel resupply systems for dual-fuel generators. Dual-fuel capability can bolster system reliability and improve resilience against severe weather events;[24] however, such generators have not always been available when called upon during severe weather events.[25] Moreover, severe weather events can impede the resupply of secondary fuel, precisely when that fuel is most necessary to compensate for the interruption of natural gas supplies (e.g., if there are natural gas supply interruptions, dual-fuel generators may be competing for resupply against many thousands of other customers, including those operating backup generators for water systems, hospitals, cell towers, and other critical facilities). A recent ISO New England study notes that as more and more oil-fired power plants have retired, the delivery supply chain has declined as well.[26] DOE should account for these additional threats to the ability of dual-fuel generators to provide a hedge against severe weather effects on grid resilience.

While the framework for assessing the vulnerability of individual generation assets to severe weather events is similar to the framework used to assess the

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one, emergency actions were necessary to ensure that enough power was available to supply the grid. In 19 of the 23 scenarios, load shedding was necessary. *Id.*

[23] *See* ICF, *The Impact of Fuel Supply Security on Grid Resilience in PJM – Final Report* (Jun. 8, 2018), at 1, https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/icf-study-fuel-security-grid-resilience-201806.pdf. The study further found that, assuming additional retirements of existing nuclear units, up to 22 percent of the area's load would be at risk of being shed at peak demand should such an outage occur. Over a 60-day event, load shedding in PJM alone could occur in 280 hours over 34 days. *Id.*

[24] *See* ISO-NE Operational Fuel-Security Analysis at 52. *See also* North American Electric Reliability Corporation, *2013 Special Reliability Assessment: Accommodating an Increased Dependence on Natural Gas for Electric Power Phase II: A Vulnerability and Scenario Assessment for the North American Bulk Power System* (May 2013) at 4, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_PhaseII_FINAL.pdf.

[25] For example, in the 2011 Southwestern "Big Chill," a quarter of dual-fuel capable generating units that attempted to switch fuels failed to do so successfully due to inadequately maintained switching equipment or derating. *See* Federal Energy Regulatory Commission and North American Electric Reliability Corporation, *Report on Outages and Curtailments during the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations* (August 2011) at 151-152, https://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf. Similarly, during the 2014 Polar Vortex, owners of dual-fuel generators faced a number of other problems, including unit startup failures and run-times restricted by environmental regulations. *See* PJM Interconnection, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events* (May 8, 2014) at 39, https://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.

[26] *See* ISO-NE Operational Fuel-Security Analysis at 14, 16.

vulnerabilities of transmission and distribution assets (see the discussion in section II.C above), something more is needed to assess the vulnerability of the electric system (the transmission and distribution systems and generation working in tandem) to severe weather events, especially in regions with organized wholesale electricity markets. Specifically, the electric industry needs a DBT against which to plan their systems that reflects interdependencies between different categories of infrastructure (e.g., electric, gas, communications). Exelon has long advocated for the establishment of such a DBT, including through proceedings that are currently pending before FERC.[27] Now is the time for DOE to help lead the development of a DBT that accounts for the risk of increasingly severe weather (and, over time, cyber and physical threats to interdependent energy systems).

RTOs/ISOs should not be expected to devise their own severe weather DBTs in the first instance. Instead, drawing on its collaborative relationships across the Federal government (which RTOs/ISOs cannot replicate), DOE should partner with FERC, the National Oceanic and Atmospheric Administration, and other appropriate partners to provide data on the frequency, magnitude, and intensity of severe weather events that RTOs/ISOs should use in assessing their resilience. Developing such a DBT would help electric system owners/operators resolve assessment problems that are currently going unresolved. In particular, utilities and RTOs/ISOs lack a government-informed basis to identify widespread electric system vulnerabilities to severe weather events, threatening their ability to plan their infrastructure investments (and in the case of RTOs/ISOs, to design their markets) to ensure that they are resilient against the very real severe weather threats that they face. Therefore, DOE should support the development of a DBT for the electric industry, which would serve as an essential tool for the electric industry to identify cost-effective mitigation strategies to address the threats that it faces.[28] That said, as with transmission and distribution infrastructure, every region of the country faces threats from different severe weather events and the existing regional infrastructure has different vulnerabilities, especially in light of their different degrees of interdependence on other infrastructure (e.g., the reliance on natural gas-fired generation in certain RTOs/ISOs). DOE should thus structure the DBT to permit specific RTOs/ISOs to tailor threat planning to local circumstances and provide for the region-specific flexibility that resilience frameworks will require.

To develop the DBT for assessing the resilience of electric systems and interdependent energy infrastructure, DOE should work with FERC, the National

[27] *See, e.g.*, *Exelon Corporation*, Comments of Exelon Corporation, Docket No. AD18-7 (filed May 9, 2018) (Resilience Proceeding Comments); *Exelon Corporation*, Reply Comments of Exelon Corporation, Docket No. AD18-7 (filed Jun. 8, 2018) (Resilience Proceeding Reply Comments); *Exelon Corporation*, Post-Technical Conference Comments of Exelon Corporation, Docket No. AD19-12 (filed May 28, 2019) (Exelon Physical and Cyber Security Post-Technical Conference Comments).

[28] There are proven models for DBT development in the electricity subsector that could support such work. For example, the Electricity Information Sharing and Analysis Center partnered with power companies, DOE, and DHS to establish a DBT for physical security risks to critical grid assets. This DBT enables grid owners and operators to base their risk assessments and remediation efforts on a shared, carefully-vetted foundation and can serve as a template for similar efforts to improve energy sector resilience. North American Electricity Reliability Corporation, *State of Reliability 2016* (May 2016), at 7, https://www.nerc.com/pa/rapa/pa/performance%20analysis%20dl/2016_sor_report_final_v1.pdf.

Oceanic and Atmospheric Administration, DHS (including the Transportation Security Agency), the US Intelligence Community, and other appropriate stakeholders. Reflecting the Grid Resilience RFI's priorities, the DBT could initially focus on establishing baselines for the frequency, magnitude, and intensity of severe weather events that threaten electric infrastructure. However, as noted in the Oil and Natural Gas Resilience RFI, oil and natural gas companies and their government partners are "seeking ways to make these infrastructure systems more resilient against cyber and physical threats as well as severe weather events."[29] As rapidly as practicable, DOE should collaborate with its partners to incorporate cyber and physical threats into the electric industry DBT as well.[30] Given the increasing interdependencies between the electric and natural gas pipeline systems discussed above, the DBT should specify the scope and severity of the natural gas pipeline infrastructure losses that utilities and RTOs/ISOs should use when assessing the resilience of their systems. Once established, the DBT will provide a baseline against which each utility and RTO/ISO can assess the resilience of its system and measure its efforts to improve that resilience.

As with the framework that utilities use to assess the vulnerabilities of their transmission and distribution systems to severe weather events, the DBT should not be static – each utility or RTO/ISO could modify it to reflect the unique infrastructure challenges that the utility or RTO/ISO region faces, as well as to reflect the priorities and preferences of customers, regulators, and other stakeholders. In addition, DOE should periodically update the DBT as our understanding of the frequency, magnitude, and intensity of severe weather events evolves with improved data and modeling capabilities (as well as when new information on the physical and cyber threats that our energy infrastructure faces becomes available). Similar to the forum that Exelon proposes in section II.B above for ongoing discussions on a flexible resilience framework, DOE could establish an ongoing forum to discuss updates to its DBT.

As noted above, DOE has already begun work on the framework for establishing a DBT with its prioritization of the creation of a NAERM. DOE should leverage its work on energy infrastructure resilience to support its NAERM. DOE's July 2019 NAERM report emphasizes that a key purpose of the NAERM is to "advance existing capabilities to model, simulate, and assess the behavior of electric power systems, as well as associated dependencies on natural gas, and other critical energy infrastructures."[31] The recommendations in these comments provide significant opportunities to help DOE achieve its goals for the initiative. Specifically, by establishing a forum for electric utilities to develop a flexible framework for assessing system resilience against severe weather events, DOE can help gather utility input on assessment methodologies, criteria, and cost-effective mitigation options that will be valuable to the NAERM. DOE can also leverage its technical expertise and financial resources to help utilities implement their resilience frameworks in ways that achieve the NAERM's ultimate goal: to "improve

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[29] *See* Oil and Natural Gas Resilience RFI at 32731.

[30] *See, e.g.*, Resilience Proceeding Comments, Exhibit B, Fuel Resilience for the Bulk Power System: Threat-Based Modeling and Analysis, at 5-10 (highlighting the risks that foreign adversaries pose to U.S. energy infrastructure).

[31] *See id.* at 2.

energy sector resilience for the well-being of our citizens and national security."[32] Establishing a DBT to inform resilience assessments and help guide utility and RTO/ISO mitigation initiatives will be of foundational importance to achieving such progress. In addition, by providing information to state and federal regulators and other stakeholders about the need for and value of resilience investments, DOE can help facilitate the crucial, cost-effective investments in grid resilience envisioned in the NAERM.

Finally, as with transmission and distribution infrastructure, unless asset owners have the opportunity to recover the costs of resilience investments, they may not pursue all of the investments needed. In RTO/ISO regions, generators must rely on competitive markets for compensation for their investments to support resilience. It is thus imperative that the markets appropriately compensate generation resources for their resilience attributes. And it is not clear that markets are achieving this objective today[33] – the increase in the retirements of nuclear plants represents a permanent loss of resilient and fuel secure resources due to insufficient compensation for their resilience attributes. Without markets that compensate generation resources for their resilience attributes, these resources will not have the capital necessary to invest in resilience enhancements and, in some cases, may even retire despite the fuel security benefits that they provide, benefits that enhance the security and resilience of the electric system as a whole.

We face this exact challenge with our nuclear fleet. Our nuclear fleet has best-in-class performance with an average capacity factor of 94.6 percent, providing almost half of the emissions-free electricity in PJM from units that are fuel secure, resilient, and capable of operating even under the most extreme weather conditions. But for our generation to have an opportunity to recover the costs of resilience investments, whether related to severe weather events, cyber threats, physical hardening, or fuel security, market prices must reflect the benefits that these investments provide. As FERC has found in ISO New England[34] (and as PJM is finding through its fuel security analysis),[35] existing market rules do not produce prices that reflect the value of such investments. Indeed, in PJM's 2021/2022 Base Residual Auction (conducted in May 2018), only 22,000 MW out of the 32,700 MW of nuclear power that was offered cleared. The PJM

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[32] *See id*. at 3.

[33] For example, in response to PJM's proposed revisions to its market rules filed at FERC in Docket Nos. EL19-58 and ER19-1468 to effectuate enhanced price formation in its reserve markets, Exelon filed comments explaining that PJM's market is critically flawed – its longstanding practice of ensuring reliability by inflating load forecasts to commit reserve capability outside of the PJM reserve markets has for years suppressed prices and distorted price signals as to the actual operating condition of the system at a given time and, in turn, the value of reserves. Because the value of the resources committed through out-of-market actions are not reflected in market-clearing prices, all of the resources in PJM receive lower prices than they would if PJM's markets accounted for actual operating conditions. *See Exelon Corporation*, Comments of Exelon Corporation, FERC Docket Nos. EL19-58 and ER19-1486 (filed May 15, 2019).

[34] *See ISO New England, Inc.*, 164 FERC ¶ 61,003 (2018) (preliminarily finding that ISO New England's tariff may be unjust and unreasonable because it fails to address specific regional fuel security concerns).

[35] *See* PJM Interconnection, L.L.C., *Fuel Security Analysis: A PJM Resilience Initiative* (Dec. 17, 2018), at 1, https://www.pjm.com/-/media/library/reports-notices/fuel-security/2018-fuel-security-analysis.ashx?la=en (concluding that "[the] findings underscore the importance of PJM exploring proactive measures to value fuel security attributes, and PJM believes this is best done through competitive wholesale markets.").

market is therefore sending a clear (but incorrect) signal that these fuel-secure, zero-emission nuclear plants are not needed and should retire. As a result, there have been numerous nuclear plant retirement announcements, including Exelon's Three Mile Island which will shut down by September 30, 2019. Nuclear retirements are permanent and will likely continue unless their resilience, fuel security, and environmental attributes are recognized by the market.[36]

Thus, DOE's proposed focus in the Grid Resilience RFI on codes, specifications, and standards will not be sufficient to support the resilience of the electric system as a whole. The development of a DBT is needed for utilities and RTOs/ISOs to adequately assess their vulnerabilities to severe weather events and other threats. Once they have identified their vulnerabilities, they can adopt appropriate market mechanisms for valuing the resilience attributes of generation resources that can mitigate those vulnerabilities. DOE's development of a DBT would, then, support investments in more resilient electric infrastructure by helping utilities and RTOs/ISOs to identify the threats they face, as well as the severity and duration of the consequences of those threats being realized. It would help RTOs/ISOs and utilities to develop robust and cost-effective mitigation measures that address the identified threats and to prioritize their investments based on the associated risks and consequences. Moreover, it would facilitate RTO/ISO efforts to design their markets to better compensate supply resources, such as resilient and fuel secure generation, that mitigate the identified threats. While both FERC and individual RTOs/ISOs have made some progress on price formation,[37] there remains much work to do; DOE's establishment of a DBT for the electric industry would help that work to move forward.

III. Conclusion

In conclusion, the electric industry has made some progress in enhancing the resilience of the nation's electric infrastructure against severe weather events, as demonstrated by post-severe storm efforts in New Jersey, New York, and Florida. But there remains much work to do, and DOE can play a leadership role in supporting the

[36] And environmental attributes are a key consideration – compensating generation resources that exacerbate the trend of increasingly frequent and intense severe weather events for their resilience benefits will only worsen the threat in the long run.

[37] *See, e.g., Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, Notice, FERC Docket No. AD14-14-000 (issued Jun. 19, 2014) (initiating a proceeding to evaluate issues regarding price formation in the energy and ancillary services markets operated by RTOs/ISOs); *see also Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, 153 FERC ¶ 61,221 (2015) (setting forth price formation goals and directing each RTO/ISO to file a report on several price formation topics); *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, FERC Stats. & Regs. ¶ 31,384 (2016); *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 831, 157 FERC ¶ 61,115 (2016); *PJM Interconnection, L.L.C.*, 167 FERC ¶ 61,058 (2019) (directing PJM to revise its market rules to improve its fast-start pricing practices); *Enhanced Price Formation in Reserve Markets of PJM Interconnection, L.L.C.*, FERC Docket Nos. EL19-58 and ER19-1486 (filed Mar. 29, 2019) (proposing revisions to PJM's market rules to effectuate enhanced price formation in its reserve markets).

investments needed to enhance grid resilience. Specifically, DOE should facilitate efforts to develop a dynamic and flexible resilience framework on which utilities can rely, leverage its technical expertise and financial resources to assist in utilities' implementation of their resilience strategies, develop a DBT for assessing electric industry resilience, and inform and educate state and federal regulators and other stakeholders about the need for and value of resilience investments. These efforts will, in turn, help to provide a strong foundation for utilities to justify their investments in more resilient electric infrastructure when requesting cost recovery, and will provide the information necessary for RTOs/ISOs to design their markets to better compensate supply resources, such as resilient and fuel secure generation, that mitigate the identified threats. A more resilient electric infrastructure system will provide substantial benefits to the nation's electricity consumers, reducing the number, magnitude, and duration of outages that they will experience as a result of the increasing frequency, magnitude, and intensity of severe weather events. Thus, DOE should prioritize initiatives to enhance electric infrastructure resilience and look for opportunities to collaborate on resilience issues with partners like the National Association of Regulatory Utility Commissioners and the Edison Electric Institute.

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Dated: August 23, 2019

ATTACHMENT I

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

COMMENTS OF EXELON CORPORATION

Exelon welcomes the opportunity to comment on this important proposed rule. During the last seven years, we have cautioned that failure to evolve wholesale markets to ensure that they value the reliable, clean and affordable energy produced by the nation's nuclear fleet would lead to premature retirements of the most cost-effective fuel-secure and emissions-free generation on the system. Regrettably, that has occurred. Between 2002 and 2016, 4,666 MW of nuclear generating capacity announced retirement, approximately 4.7 percent of the U.S. total.[1] Another eight nuclear reactors with 7,167 MW of capacity have announced retirement plans since 2016.[2] According to Bloomberg, more than half of the nation's nuclear power plants are losing money.[3] The retirement of nuclear units—the most resilient and reliable generators on the system—and their replacement by resources that are neither fuel secure nor emissions-free will have a strongly negative impact on the grid's resilience, not to mention the environment.

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[1] United States Department of Energy, Staff Report to the Secretary on Electricity Markets and Reliability 29 (August 2017), *available at* https://energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf ("DOE Staff Report").

[2] *Id*. at 30.

[3] Jim Polson, *More Than Half of America's Nuclear Reactors Are Losing Money*, Bloomberg, June 15, 2017, *available at* https://www.bloomberg.com/news/articles/2017-06-14/half-of-america-s-nuclear-power-plants-seen-as-money-losers.

The Commission has not yet taken sufficient action to ensure the resiliency of the grid against threats that are increasingly salient. While the Commission has permitted two RTOs to impose material performance-based penalties on capacity resources, it has not been presented with a reform that would *require* wholesale markets to select resources based on a demonstrated ability to insulate customers from fuel security risks (or from the impacts of carbon and air emissions). Through his proposed rule, the Secretary of Energy has begun to do just that. He is asking whether wholesale markets in PJM, NYISO, and ISO-NE—which are designed to ensure we have *enough* megawatts to serve load—should also be designed to ensure we have the *right* megawatts to serve load: those that have a stable source of fuel that will enable the system to withstand interruptions that could dramatically interfere with the ability of the system to power our economy and society. We have begun to address the implications of risks from spare transformer shortages, EMP and GMD events, and physical and cyberattacks on the transmission system. But as stakeholders, we have been slow to appreciate and address the increasing risk profile of interruptions to and attacks on to the fuel delivery system *behind* the megawatts we are using to power our economy. The Commission should use this proceeding to change that.

Against the backdrop of this increasing risk profile, the supply of electricity is shifting quickly toward natural gas fired generators that lack on-site fuel. In the PJM region, 90 percent of the new installed generation over the last five years has been gas-fueled, and more than 90 percent of planned generation in the interconnection queue is as well.[4] New nuclear plants are no longer

[4] For the PJM RPM auctions from 2015/16 through 2020/21, 90% of new cleared installed capacity has been either natural gas-fired combustion turbines or combined-cycle generators (approximately 32.4 out of 36.2 total GW of new build, reactivated, or uprated capacity). *See* PJM Interconnection L.L.C., *2020/21 RPM Base Residual Auction Results,* Table 8, http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-report.ashx?la=en.

being built in market regions (where, other than renewable portfolio standards, there is little resource planning). So, with each retirement, the system irretrievably will lose the fuel security it enjoys today. This has exposed the American public to a new and grave danger—the potential for multistate blackouts lasting weeks or months resulting from natural gas supply disruptions.[5]

Natural gas generators rely on a pipeline network that can be disrupted by natural or human forces.[6] A study by PJM Interconnection, L.L.C. ("PJM") has revealed that a ***single*** gas pipeline in that region serves more than 11,000 MW of generation powering our Nation's most populated areas.[7] A disruption to that amount of generation could, in turn, further disrupt the gas pipeline network, leading to the potential of even more widespread generation outages. A prolonged outage (especially one where more than one pipeline is disrupted) would be catastrophic, leading to widespread loss of life and severe economic harm.[8] Water treatment plants, the food distribution system, the medical system, and communications networks all depend on a working electric grid, and these systems are not designed to withstand prolonged outages.[9] Moreover, as the transportation sector shifts its fuel source from gasoline to electricity, the cost of a widespread blackout become even more severe.

These risks extend beyond the civilian sector. Because the nation's military facilities depend on the availability of power, long duration outages could pose serious risks for national

[5] Testimony of Paul Stockton, attached as Exhibit A, at 9 ("Stockton Testimony").

[6] *Id.* at 12-14.

[7] *Id.* at 18; PJM Reliability Analysis Update (Sept. 14, 2017), *available at* http://pjm.com/-/media/committees-groups/committees/teac/20170914/20170914-reliability-analysis-updates.ashx, pp. 8-11.

[8] Stockton Testimony at 10-11.

[9] *Id.* at 10-11.

security.[10] As a result, the nation's energy infrastructure is a target for hostile foreign powers and terrorist organizations.[11]

The Department of Energy ("DOE") should be commended for taking this risk seriously. Fuel security is an essential aspect of grid resiliency, and action must be taken to prevent an overreliance on a single type of generation resource vulnerable to fuel supply disruption. Some have argued that there is a greater need than ever before for flexible resources because of increased renewable penetration. The present demand for power, however, does not require that every resource on the system be flexible. Even in the most low-demand hours, PJM demand does not fall below about 60 GW (or about 40% of peak)[12], indicating that there is substantial room to accommodate resources that are optimized to produce low cost power at full output 24 hours per day, seven days per week without ramping. When operated in this fashion, these firm-fuel resources are low cost and provide the system with an important hedge against the possibility of natural gas supply disruption. Put another way, there are diminishing returns to flexibility as more flexible units are added to the system, and beyond this point of diminishing returns (about 60% of peak load in PJM), the key determinants of the value provided by resources are found in baseload operation and contribution to resiliency and system diversity. These firm-fuel resources provide the system with a necessary hedge against the possibility of natural gas supply disruption. Yet they increasingly face economic distress and are in danger of retirement.

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[10] *Id.* at 6.

[11] *Id.* at 5.

[12] For calendar years 2015 and 2016, PJM load did not fall below 57 (2015) or 58 (2016) gigawatts in any hour, or approximately 40% (2015) or 38% (2016) of peak demand in each respective year. *See* PJM hourly metered load data at http://www.pjm.com/markets-and-operations/ops-analysis/historical-load-data.aspx

This state of affairs is leading to rates that are not just and reasonable. The organized markets were not designed to address resilience to fuel supply interruptions, and as a result customers have been left exposed to catastrophic risks. As a result, the organized markets are no longer producing just and reasonable market outcomes, and they need modification in order to comply with the Federal Power Act. In particular, market rules undervalue the resilience benefits that nuclear units provide to consumers.

Below, we outline short-term, medium-term, and longer-term steps the Commission can take to address resilience in a way that appropriately balances its value to customers with the cost of achieving it.

First, the Commission should act immediately under Section 206 to correct energy price formation in PJM. Doing so will not by itself ensure that the generation mix in PJM remains resilient, but flawed energy pricing is exacerbating the economic stress faced by resilient firm-fuel units, and hastening their exit from the market. To summarize the problem: Resilient, firm-fuel resources in PJM are providing generation needed to serve customers, yet they are not paid for their cost of doing so. Resilient firm-fuel units operating at their economic minimum are not permitted to set the locational marginal price, even when they are the marginal resource and their output is needed to serve load. Consequently, in low-load conditions, energy prices often fall below the marginal cost of operating these units. Indeed, energy prices can be negative for extended periods of time, typically at night, even though resilient firm-fuel resources are serving load during those times and incur costs to do so. In such situations, energy prices do not reflect the true marginal cost of serving load. That is unjust and unreasonable, and is economically untenable for these resources.

The Commission can correct this problem now by acting under Section 206 of the Federal Power Act. PJM has identified this problem in the record developed as part of the Commission's May 2017 technical conference on state policies and wholesale markets. DOE has endorsed immediate action to move forward with energy price formation as a step toward improving the resilience of the grid. Addressing energy price formation is an immediate-term action the Commission can take to mitigate the economic distress faced by resilient units, while it evaluates what must be done to ensure resiliency and how best to achieve it.

Second, the Commission should not take action that would imperil irreplaceable firm-fuel resources, while it simultaneously considers how best to compensate the resilience they provide. Accordingly, the Commission should issue a policy statement declaring that units benefitting from state programs designed to preserve the operation of resilient nuclear resources by compensating them for their emissions-free attributes—such as the New York and Illinois Zero Emissions Credit programs—will not have their offers mitigated in FERC's markets. Having recognized the value of resilience and the significant contribution that nuclear plants make to achieving it, the mitigation of state programs intended to preserve those units would be myopic and counterproductive. Additionally, should a particular unit faced with imminent retirement be able to demonstrate its contribution to resiliency, the Commission should consider, on a unit-specific basis, taking steps that would allow that unit to continue operating, while the Commission considers more comprehensive solutions.

Third, the Commission should direct the organized markets covered by DOE's Notice of Proposed Rulemaking ("NOPR")[13] to report on other market-based reforms that could help to foster resiliency. For example, RTOs should examine the process for setting operating reserves

[13] Dep't of Energy, Grid Resiliency Pricing Rule, 82 Fed. Reg. 46,940 (2017) ("DOE NOPR").

procurement quantities in light of the possibility of a major natural gas pipeline outage. To take another example, NYISO is considering the inclusion of a carbon price in its energy market. Doing so not only would appropriately price the negative externality associated with carbon-emitting generation, but would also have the side benefit of providing support to resilient nuclear resources.

On the capacity side, interim improvements may also be possible. PJM and ISO-NE have adopted pay-for-performance capacity regimes and should be encouraged to closely scrutinize those market rules to ensure that the performance penalties are sufficiently rigorous. Additionally, the Commission has previously approved as just and reasonable short-term reliability measures in New England to ensure that units with on-site fuel receive incentives to maintain that capability in the winter. RTOs should report on whether those market rules could be adapted to provide interim support to resilient units while the Commission considers its options.

Finally, before adopting a final rule in this proceeding, the Commission should require the RTOs covered by the NOPR to submit detailed information that can be used to develop a richer understanding of where our grid's vulnerabilities lie; how those vulnerabilities match up against the intelligence community's threat assessments; and what steps must be taken to ensure a sufficient degree of resiliency to protect the nation from known and credible national security threats. With that design basis threat analysis in hand, the Commission can then identify which solutions will address the identified deficiencies in the most cost-effective manner.

Market-based solutions may certainly be developed to address this issue. The organized markets established by the Commission remain an extraordinary success. They have ensured that customers enjoy a plentiful supply of electricity at just and reasonable prices, but they have done so with prescriptive requirements (such as reserve margins and administratively-set demand curves) that mandate a physical expectation and use market forces to drive the most cost-effective solution. Once we determine a design basis threat around which the system should be planned, it may be possible to develop a fuel-neutral resiliency product that can place appropriate value on fuel-secure resources so as to ensure the requisite level of grid resiliency. Exelon believes that RTOs should be given the opportunity to propose such market reforms. But, given the urgency of the problem, we need to "get it right" the first time. So the Commission should also consider the efficacy of alternative remedies, including non-market approaches, particularly if those have the potential to achieve the goal at a lower overall system cost. The safety and security of the American people must remain the paramount concern, and the Nation should use whichever tools best address that concern.

The Capacity Performance ("CP") reforms in PJM are not a substitute for Commission action addressing resiliency. First, CP was intended to incentivize unit-specific investments to enhance reliable operations at the unit level. The resiliency challenges faced by the grid are systemic—and CP does not and cannot address the possibility that multiple generators with firm service on the same pipeline are simultaneously unable to perform. Second, the frequency and duration of expected penalty hours used to calibrate the non-performance penalty and associated penalty "caps" were focused on weather-related system stress, not intentional disruptions to fuel supply that could last longer than 30 hours. Simply put, CP was not intended to address the emerging national security threats discussed by Dr. Stockton in his testimony. Third, unlike weather events, it may not be possible to probabilistically determine the likelihood of malicious attacks or quantify the extent of the harm that would be caused. For example, what is the probability of a cyber or physical attack by a rogue nation or terrorist? How do we quantify the harm occasioned by the loss of military capability? Value of Lost Load (VLL) metrics may be less helpful in establishing the appropriate design standard here than in the case of CP. In any event, CP most certainly did not address these issues, and a more prescriptive approach may be needed.

The Commission should proceed expeditiously with this work. Nuclear retirements are irreversible; once customers lose the fuel security benefits these plants provide, those benefits are gone forever. Moreover, unless market conditions change in unforeseen ways, the threat to these units will persist. Low natural gas prices and slow load growth will continue to drive out resilient nuclear resources unless the Commission modifies the markets to appropriately value the benefits they provide.[14] If the Commission does not act expeditiously, the loss of these units will increase the risks to Americans' physical security and economic well-being.

I. The Commission Should Act under Section 206 to Correct Price Formation in PJM.

While the Commission considers the broader issues of resilience raised by the Notice of Proposed Rulemaking, it should take immediate action to correct a flaw in the PJM market. Currently, energy prices in PJM violate a fundamental principle of good market design – they do not reflect the true cost of producing energy, particularly at night or in other low-load conditions. Firm-fuel units are required to run at prices that do not cover their marginal costs. Because firm-fuel units have long start-up times and are needed to provide power during peak hours, they must also run during off-peak hours. Most of these firm-fuel units are also needed during off-peak hours, but not all of them. So, during these off-peak hours, many of the units are required to run at minimum load and PJM market rules do not permit these units to set energy market prices. Only the dispatchable portion of units can set LMP. As a result, firm-fuel units must operate at a loss

[14] DOE Staff Report at 57 ("[U]nless natural gas prices or electricity demand rise significantly faster than projected, the economic conditions of baseload generators are not projected to change significantly in the near term.").

because their costs exceed the LMP.[15] This flaw in energy price formation affects a significant fraction of the generation in PJM, including the vast majority of firm-fuel units. In 2016, over 60% of PJM generation was self-scheduled primarily due to long start up times and was exposed to the possibility that their revenues might not support their variable costs.[16]

The Commission can correct this problem today. PJM has clearly identified the problem and it merits a conclusion under Section 206 that existing tariff provisions are not just and reasonable. In the comments submitted as part of the May 2017 Technical Conference, a broad group of stakeholders agreed on the need for energy market reforms to ensure proper price formation.[17] Moreover, PJM has already identified a just and reasonable solution that is consistent with changes that the Commission already has largely accepted in MISO. Directing PJM to adopt that solution is consistent with the Federal Power Act and principles of good market design, and would provide immediate support to units that are needed for a resilient grid.

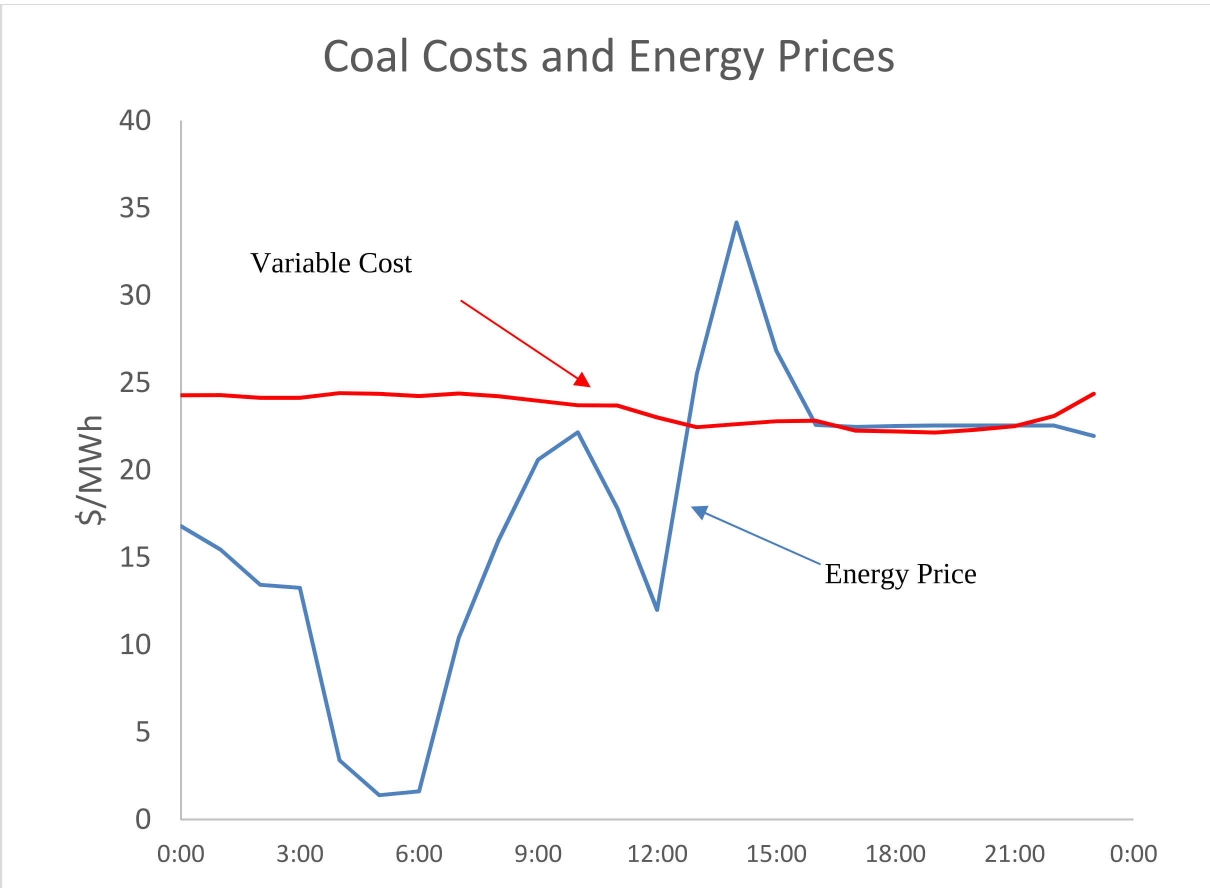
[15] This result is particularly harsh when prices become negative and these units have to pay money to operate. Negative prices are now occurring in certain areas of PJM in as many as 10% of the hours. "[N]uclear generation hubs located in Western Illinois have faced negative prices as much as 10-11% of the hours during the year in 2015/16." Maheen Bajwa and Joseph Cavicchi, *Growing Evidence of Increased Frequency of Negative Electricity Prices in U.S. Wholesale Electricity Markets*, IAEE Energy Forum, Fourth Quarter 2017, *available at* www.iaee.org/en/publications/newsletterdl.aspx?id=444.

[16] PJM Independent Market Monitor, *2016 State of the Market Report*, at 194 ("[I]n 2016, 61.8 percent in day ahead and 60.6 percent in real time of the total generation was self-scheduled.").

[17] *State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C.*, Docket No. AD17-11-000, Comments of Edison Electric Institute at 5-6; Comments of Electric Power Supply Association at 10-12; Comments of NRG Energy, Inc. at 15-17; Comments of Nuclear Energy Institute at 13-14; Comments of PJM Interconnection, L.L.C. at 4-5; Comments of PSEG Companies at 12-14.

A. PJM's Tariff is Not Just and Reasonable Because Prices Do Not Support Unit Commitment and Dispatch.

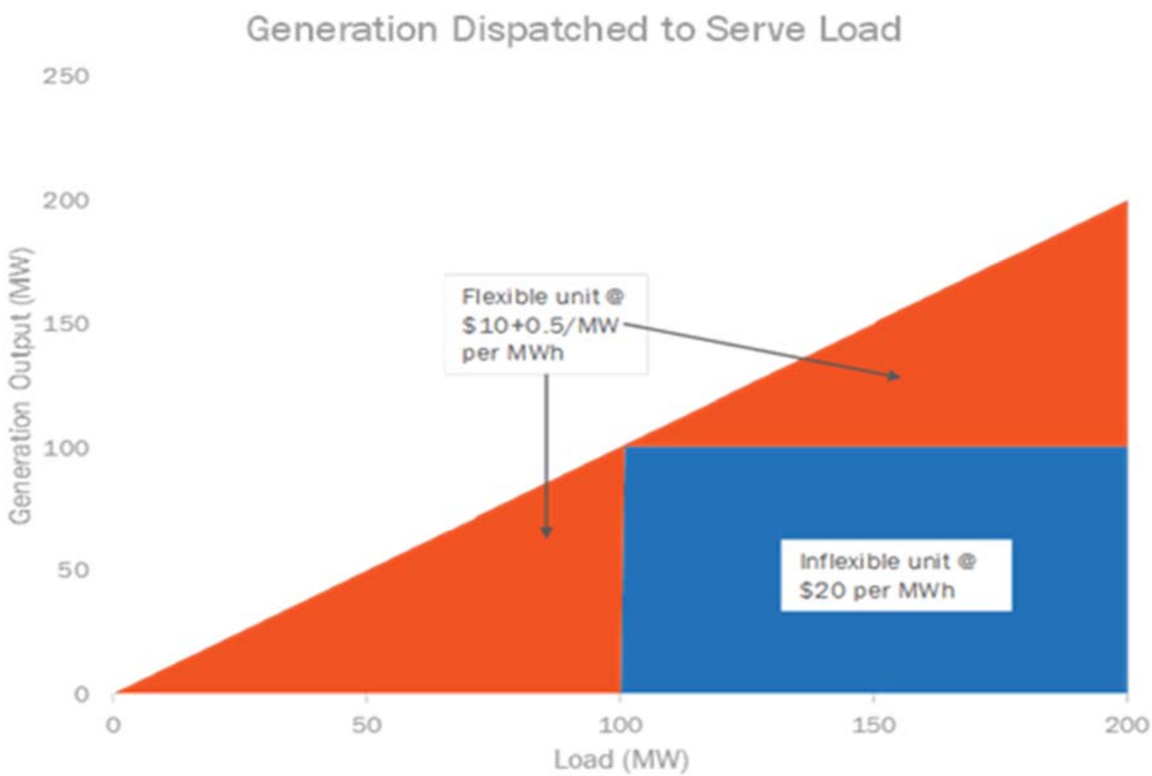
PJM's energy pricing regime violates the Federal Power Act because prices do not support unit commitment and dispatch when firm-fuel units operate at their economic minimum but are nevertheless the marginal resources for serving load. Consider the following example reflecting the operation, over the course of a day, of a typical coal unit in PJM with variable costs of approximately $25/MWh.



During the morning hours, energy prices fall below the unit's variable cost and it operates at a loss. However, it cannot reduce its output to zero. The unit will be needed later in the day when it will be called to serve load during peak hours. This unit also does not have the flexibility to quickly shut down and restart. If it shuts down, it will not be able to return to operation in time to ramp up later in the day. Instead, it reduces its output to its economic minimum, the point at which it will no longer be able to reduce output in response to dispatch instructions. RTO market rules do not currently allow units operating at their economic minimum to set price.[18] As a result, energy prices fall below $25 and the generator does not cover its variable costs.

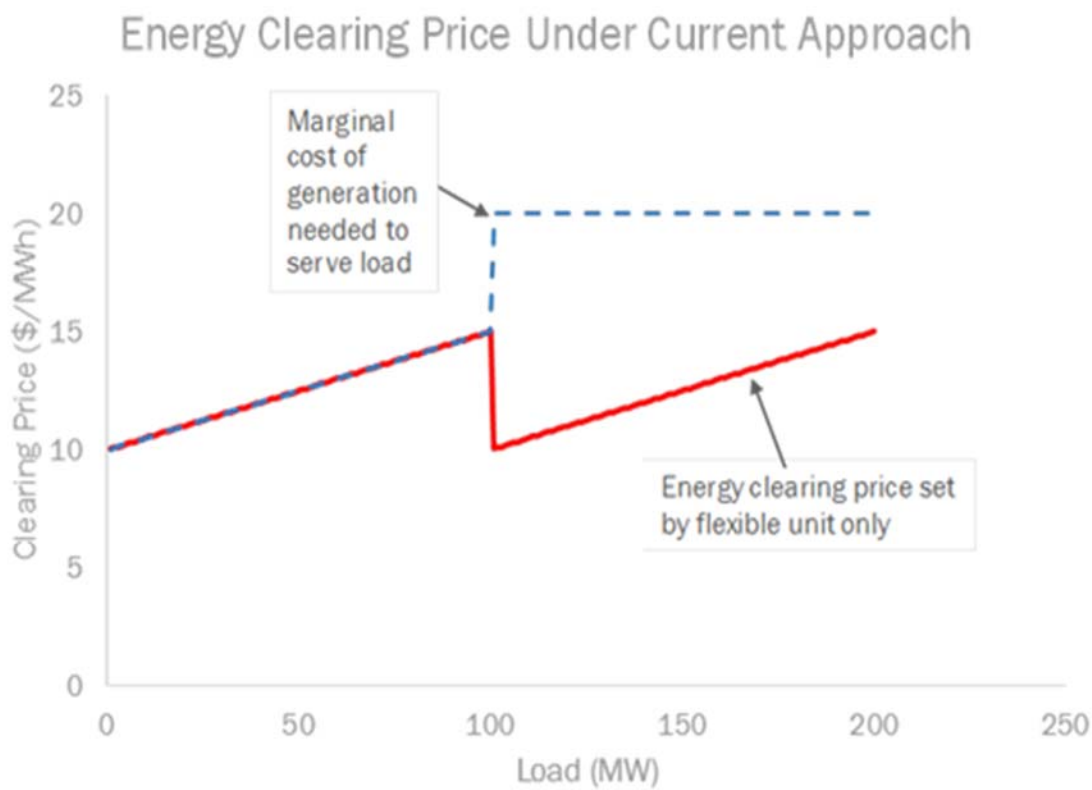
Worse still, units operating at their economic minimum cannot set price even at times they *are* called to serve load, if only a portion of their output is needed. For example, consider a market with two units: a baseload unit (shown in blue below) with a fixed output of 100 MW and variable costs of $20/MWh, and a flexible unit (shown in red) which can vary its output between 1 and 100 MW with an offer price starting at $10 at 1 MW of output and increasing by $.05 for each additional MW.

[18] *See Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, 153 FERC ¶ 61,221 at P 9-10 (2015) ("[Inflexible resources typically cannot set LMPs because the market pricing software does not treat these resources as dispatchable or as able to meet the next increment of load. . . [O]nly resources that can be dispatched up or down in response to changes in system conditions are eligible to set LMPs").



In this example, the baseload unit will be needed to serve load once demand exceeds 100 MW. Still, though, it will not be permitted to set the price—even when demand exceeds 100 MW—if only a portion of its power output is needed. The more flexible resource is dispatched down to make room, and under the current PJM rules, the energy price is set at the marginal cost of the unit displaced.

For example, as shown in the chart below, the energy clearing price increases from $10/MWh to $15/MWh as load increases, until demand exceeds 100 MW. At that point, the baseload unit becomes marginal. The energy price *should* equal the baseload unit's marginal costs ($20/MWh), since that is the cost needed to serve load. But instead, under current market rules, the energy clearing price is based on the marginal cost of the flexible resource that is turned down. Thus, if load increases from 100 MW to 101 MW, then the flexible resource is dispatched down to 1 MW to make room for the baseload resource. When this occurs, and the energy price falls from $15/MWh (the marginal cost of the flexible unit to generate 100 MW) to $10/MWh (the marginal cost of the flexible unit to generate 1 MW)—even though the true marginal cost of serving load has increased to $20/MWh (the marginal cost of the baseload unit).



That result is not just and reasonable. The energy clearing price falls as load increases, and the marginal unit receives a price that is less than its marginal cost. Neither should occur in a well-functioning market. In effect, current market rules allow consumers to benefit from the energy generated by firm-fuel units – not to mention the resiliency benefits these units provide – but do not fully compensate those units for the costs they incur in providing those benefits. The locational marginal price remains below the baseload unit's marginal cost, and the unit loses money. The clearing price in the market thus does not support the least-cost commitment and dispatch needed to serve load, because absent any other source of revenue the baseload unit would not seek to participate.

A market rule "patch" to pay only the baseload unit an uplift payment to ensure it recovers $20/MWH is not a solution. While in this example there are only two generators in the market, in the real world, every generator in the market (except for the uplift generator) would be undercompensated under the current price setting rules. This is clearly discriminatory and deprives fuel secure resources of energy market revenues to which they are entitled.[19]

In sum, these market rules result in the chronic under-compensation of firm-fuel generators. Plainly, it not sustainable for these generators to continue to operate at a loss. And once they exit the market, they will largely be replaced by gas generation[20] that may be more flexible, but which would compound the resiliency vulnerabilities now facing the fleet.

The current market rules were originally well-intentioned. The energy markets operate in a two-step process. The markets first must determine the appropriate security-constrained economic unit commitment and dispatch; next they must set prices based on that dispatch. The Commission must create market rules to ensure that the prices it sets are consistent with the unit commitment and dispatch. These prices must achieve two goals. Units must have the correct

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[19] The Commission has already recognized that the reliance on uplift payments creates market distortions that can support acting under Section 206. *See, e.g.*, *Fast-Start Pricing in Markets Offered by Regional Transmission Organizations and Independent System Operators*, 157 FERC ¶ 61,213, at P 3 (2016) (finding RTO practices preliminarily not to be just and reasonable because they "potentially creating unnecessary uplift payments").

[20] The overwhelming majority of generators in the PJM interconnection queue are new gas-fired units. *See* Operationalizing Gas Pipeline Contingencies Normal and Conservative Operations, PJM Operating Committee, October 10, 2017 at 4, *available at* http://www.pjm.com/-/media/committees-groups/committees/oc/20171010/20171010-item-16-gas-electric-contingencies-update.ashx

incentives to adjust their output in response to those price signals and LMP must provide sufficient compensation to cover the marginal cost of committed units.

When a baseload unit is marginal, however, the market design requires a trade-off. By limiting price-setting eligibility to flexible units, PJM achieves the goal of ensuring that prices send the correct dispatch signal to flexible units, but the energy price no longer reflects the marginal cost of serving load. This trade-off historically has been masked in PJM.[21] When renewable generation was uncommon and gas prices were high, off-peak energy prices seldom fell below the level necessary to cover the variable costs of firm-fuel units throughout the day. However, increased penetration of renewables, low load growth, and historically low gas prices have produced a combination of extremely low energy prices that are frequently below the variable costs of firm-fuel units that are needed to serve load. This change in circumstances has made the PJM energy market no longer just and reasonable: energy prices no longer reflect the marginal cost of serving load.

B. The Commission Already Has the Record Necessary to Find That the Current Tariff Is Not Just and Reasonable.

The Commission already has the record necessary to act under Section 206 to fix this market design flaw. As the DOE Notice of Proposed Rulemaking outlines, the Commission has been considering price formation for some time.[22] The particular problem discussed above has been highlighted in the record of those proceedings. On June 15, 2017, PJM issued its white paper

[21] *See* Comments of Andrew Ott, AD17-11-000, Transcript of May 1, 2017 Technical Conference at 291-292 (May 1, 2017).

[22] *See Grid Resiliency Pricing Rule*, Notice of Proposed Rulemaking, 82 Fed. Reg. 46,940, 46,944 (Oct. 10, 2017).

on this subject and entered it into the record of the May 2017 technical conference.[23] The white paper clearly describes this problem and highlights the need to reform pricing rules to allow firm-fuel units to set LMP. The DOE Staff Report endorses expediting price formation as a partial solution to the threat to resiliency from the loss of firm-fuel resources.[24] In fact, the DOE Staff Report specifically identified this proposal from PJM as a reform for the Commission to consider.[25]

The record before the Commission establishes that the current market structure does not produce just and reasonable rates for multiple reasons previously accepted by the Commission. For one, a foundational principle of locational marginal pricing is ensuring that the energy price "reflects the marginal cost of serving load at the specific location."[26] The Commission has repeatedly recognized that energy prices are not just and reasonable if they do not reflect the true marginal cost of production. The Commission has viewed the alignment of prices and marginal cost as a priority in the recent price formation proceedings. "LMPs and market-clearing prices used in energy and ancillary services markets ideally would reflect the true marginal cost of production, taking into account all physical system constraints, and these prices would fully compensate all resources for the variable cost of providing service."[27] The Commission has also

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[23] *Initial Post-Technical Conference Comments of PJM Interconnection*, L.L.C., AD-17-11-000, "Initiative 3" at PDF pages 32-37 (June 22, 2017) ("PJM White Paper").

[24] *See* DOE Staff Report at 126 ("FERC should expedite its efforts with states, RTO/ISOs, and other stakeholders to improve energy price formation in centrally-organized wholesale electricity markets.")

[25] *Id.* & n.467 ("After several years of fact finding and technical conferences, the record now supports energy price formation reform, such as the proposals laid out by PJM.") (citing PJM's June 15, 2017 white paper).

[26] Federal Energy Regulatory Commission, Energy Primer: A Handbook of Energy Market Basics 60 (Nov. 2015).

[27] *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 157 FERC ¶ 61,115, at P 7 (2016) (internal quotations omitted)

taken action under Section 206 on this basis. For example, the Commission relied on the failure of energy prices to fully reflect marginal cost as a reason to exercise its Section 206 authority and raise the offer caps in the organized markets.[28]

Additionally, the Commission has already recognized a version of this *specific* market flaw as a basis to declare that RTO tariffs are not just and reasonable. In December 2016, the Commission issued a Notice of Proposed Rulemaking on pricing of fast-start resources.[29] That Notice preliminarily concluded that pricing for fast-start resources is not just and reasonable because they cannot set price when operated at their economic minimum. The Commission stated:

> Fast-start resources are often required to be dispatched at their economic minimum operating limit or are block-loaded. Because the system may need fewer megawatts (MW) than the fast-start resource's economic minimum operating limit to meet load, other resources must be dispatched down. The resources that were dispatched down become the most economic option to serve the next increment of load. Therefore, *despite the fact that a fast-start resource is essentially marginal, this restriction prevents a fast-start resource dispatched at its economic minimum operating limit from setting the LMP*.[30]

The Commission preliminarily found that these market rules lead to pricing that is not just and reasonable because market prices "fail to accurately reflect the marginal cost of serving load."[31]

The same reasons support a comparable Section 206 conclusion here, but for units that are operationally-constrained. Just like fast-start resources, units operating at their economic minimum "are inappropriately prevented from setting prices."[32] Even when they are the marginal

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[28] *Id.* at P 15 (concluding that offer caps are not just and reasonable).

[29] *Fast-Start Pricing in Markets Offered by Regional Transmission Organizations and Independent System Operators*, 157 FERC ¶ 61,213 (2016).

[30] *Id.* at P 8 (emphasis added).

[31] *Id.* at P 36.

[32] *Id.* at P 37.

unit, market prices do not reflect their marginal costs. Just as the fast-start rules require revision, so too these market rules are no longer just and reasonable.

Like any flaw in price formation, the current flawed market design leads market participants to make inefficient short and long-term decisions. In the short term, the wrong units choose to participate in the market. Low-cost baseload units may decide not to participate in the market because they will be forced to operate at a loss in low-load conditions. In their place, other higher-cost units will be inefficiently dispatched. In the longer term, units that cannot even consistently recover their variable costs (let alone their fixed costs) will exit the market.

Many commissioners, current and past, have recently reiterated their support for markets. However, for markets to work, they must adhere to basic market principles such as marginal cost pricing and appropriate compensation for all attributes. Markets that do not follow such rules are markets in name only. The Commission has also recognized the need to adjust market rules when technological and market changes reveal that rules predicated on particular operational assumptions have grown outdated. For example, in Order 764, the Commission recognized the need to change market rules designed for traditional generation in response to the increased penetration of renewables. In response, it acted under Section 206 to adjust rules relating to transmission scheduling and other practices to ensure rates remained just and reasonable.[33] Similarly, in Order 719, the organized markets were required to adjust their rules to ensure that demand response resources could participate in the markets and have the market rules recognize

[33] *Integration of Variable Energy Resources*, Order No. 764, 77 FR 41,482 (July 13, 2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61,232 (2012), *order on reh'g*, Order No. 764-B, 144 FERC ¶ 61,222 (2013).

their unique operational characteristics.[34] More recently, the Commission issued a Notice of Proposed Rulemaking relating to the participation of storage resources.[35] This NOPR seeks to adjust market rules to reflect the physical and operational characteristics of electric storage to facilitate its participation in the market.[36]

All of these rulemakings rest on the same theory: Different technologies have different physical and operational characteristics. Technological change thus places pressure on market rules. Market rules that fail to adapt to technological changes or changes in other market inputs can become unjust and unreasonable. The same flaw exists here. These market rules are a relic of a different era. When energy prices were consistently high, the inability of these resources to set LMP was irrelevant. The marginal cost of firm-fuel units rarely exceeded the energy revenues that those units received throughout the day. Now, however, because tax-subsidized renewables and low gas prices have driven down the energy prices in low-load conditions, the market flaw has become apparent and the existing rules are no longer just and reasonable.

C. PJM Has Proposed a Just and Reasonable Solution for Setting LMP.

When taking action under Section 206, the Commission must replace the invalid rules with an alternative that is just and reasonable.[37] Here, PJM has proposed a straightforward solution to the pricing problem. It "would … allow the inflexible unit to set LMP, thereby transparently

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[34] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008), order on reh'g, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 (2009), order on reh'g, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[35] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 157 FERC ¶ 61,121 (2016).

[36] *Id.* at PP 9-10.

[37] *City of Anaheim v. FERC*, 558 F.3d 521, 523 (D.C. Cir. 2009) ("When the Commission finds a rate unreasonable, it shall determine the just and reasonable rate to be thereafter observed and in force.") (internal quotations omitted).

indicating the cost of the most expensive unit necessary to economically serve the load."[38] This change is the natural resolution to the market flaw identified above. This pricing strategy allows all units to set price regardless of the physical and operational characteristics, reduces or eliminates the need for uplift, and ensures that the energy price reflects the true marginal cost of serving load.

This pricing strategy is also consistent with the goals that FERC has emphasized throughout the price formation proceedings. The Commission has highlighted four objectives:

> The goals of the price formation proceeding are to: (1) maximize market surplus for consumers and suppliers; (2) provide correct incentives for market participants to follow commitment and dispatch instructions, make efficient investments in facilities and equipment, and maintain reliability; (3) provide transparency so that market participants understand how prices reflect the actual marginal cost of serving load and the operational constraints of reliably operating the system; and (4) ensure that all suppliers have an opportunity to recover their costs.[39]

The proposal to let baseload units set LMP furthers all four of these goals. Total market surplus is improved when market prices permit efficient unit dispatch and commitment and send accurate entry and exit signals. This scheme sets prices transparently and reflects the true cost of serving load, rather than disguising costs through uplift payments or ignoring the costs completely. Finally, by allowing all resources to set price, market revenues will compensate resources participating in the market for their marginal costs.

The Commission has already accepted a version of this proposal as just and reasonable. In December 2011, MISO recognized that a similar flaw existed in its pricing algorithm and proposed a very similar solution under Section 205. MISO faced the same issue that these units were unable to set energy prices and, when those units operated at their economic minimum, the locational

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[38] PJM White Paper at 3.

[39] *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Final Rule, 157 FERC ¶ 61,115, at P 4 (2016).

marginal price was below their marginal costs.[40] The Commission recognized that this pricing mechanism "may produce an inaccurate price signal."[41] It then accepted MISO's proposed solution to permit block-loaded fast-start resources to set the energy price.[42] The same approach should be adopted in PJM.

In selecting this market design, the Commission need not sacrifice the goal of ensuring that market prices send the right signals to resources. The Commission should also direct PJM to report on its efforts to ensure that this market change does not eliminate the incentives for flexible units to follow dispatch instructions. As discussed above, the strongest argument for the current pricing mechanism is that flexible units have the correct economic incentive to reduce output when a baseload unit comes on-line. If energy prices rise to the variable cost of the marginal baseload unit, inframarginal flexible units will see an energy price greater than their marginal cost and will have an incentive to continue to run. To address that incentive, PJM has discussed proposing an additional product that would compensate the flexible resource for turning down in response to the dispatch signal. The price of that product must be at least equal in value to the difference between the energy price and the flexible resource's marginal cost for the megawatts where the baseload unit is marginal and is setting the price. PJM should be encouraged to complete its discussions on the design attributes of this product and to report its progress to the Commission as soon as possible.[43]

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[40] S*ee Midwest Indep. Transmission Sys. Operator, Inc.*, 140 FERC ¶ 61,067, at P 4 (2012) (noting that MISO justified its filing on the grounds that block loaded resources cannot set LMP and the energy price reflects the cost of the unit backed down instead).

[41] *Id.* at P 38.

[42] *Id.*

[43] Initiating a Section 206 action in PJM would not necessarily require changes to any other tariff. While the record exists to take action in PJM, the evidence is less clear in the other RTOs. Each RTO has different energy and capacity market structures as well as a different mix of policies

II. The Commission Should Take Other Interim Steps to Protect Resiliency in the Markets.

While correcting the PJM energy market is important in the short term, the Commission should take other interim steps as well to protect resources needed for resiliency, while the Commission undergoes a longer-term process of developing more permanent compensation mechanisms. *First*, while it considers next steps, the Commission should ensure that state programs to support resilient nuclear units, including the New York and Illinois Zero Emission Credit programs, are not impeded. The Commission should issue a policy statement clarifying that these programs will not lead to mitigation. *Second*, the Commission should request RTOs to report on various other reforms that help protect the resiliency of the grid, such as changes to the operating reserves and capacity markets. While some efforts are underway, requiring the RTOs to report on these efforts would provide a more complete understanding of the risk to resiliency and current RTO efforts to protect the grid.

A. Existing Nuclear Units Provide Unique Resiliency Benefits to the System.

The DOE Notice of Proposed Rulemaking describes a current threat to the resiliency of the electric grid. While the Commission considers its longer-term options to respond to that threat, its first priority should be to do no additional harm to the viability of the resilient units that remain in the organized markets. In that regard, nuclear units in particular have proven their worth as resilient and dependable generators, particularly in times of extreme system stress. Their performance relative to other types of resources during the 2014 Polar Vortex – a reliability event DOE itself cited as an example of resiliency problems with the electricity grid – offers a good

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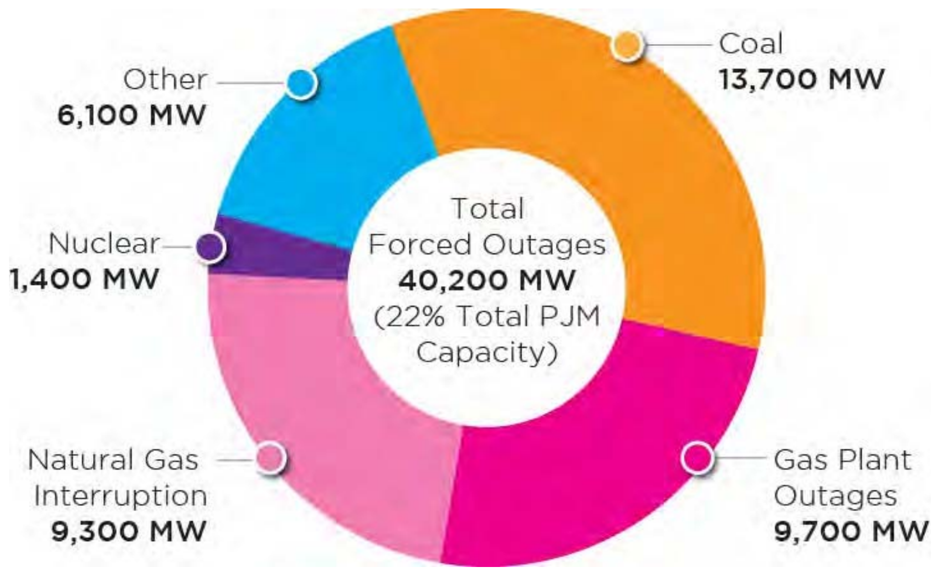
providing support for resilient resources. To the extent that the Commission believes that pricing in another RTO may raise similar concerns, the Commission could consider requiring that RTO to report on the problem.

example of the resiliency benefits nuclear units provide.[44] As the chart below demonstrates, during the critical evening of January 7, 2014, nuclear units had by far the least forced outages and were only responsible for 3% of the total outages in PJM.[45]

Figure 17: Outages by Primary Fuel – January 7, 7:00 p.m.[46]



[44] *See* DOE NOPR, 82 Fed. Reg. at 46,942.

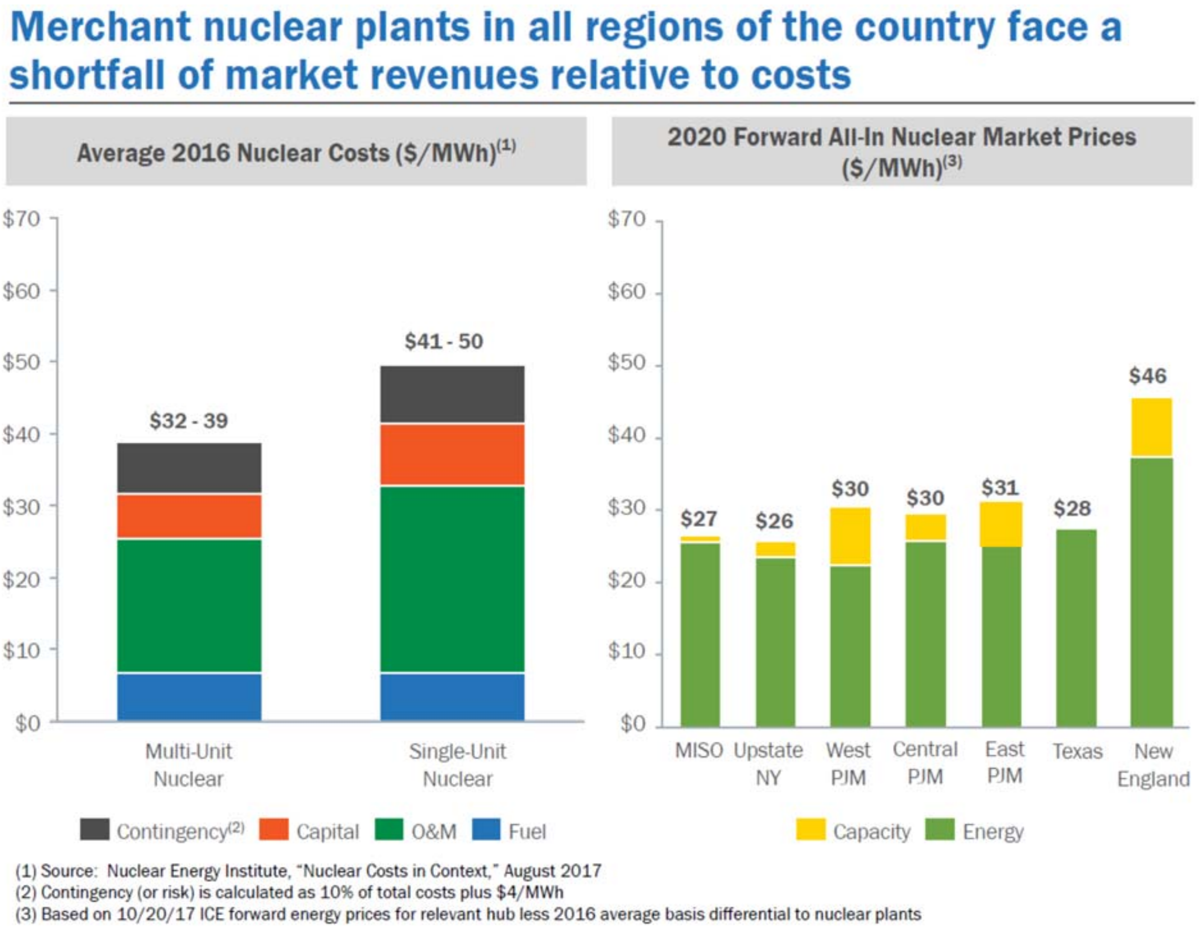
[45] The Polar Vortex is not the only time when the system relied on nuclear generation to keep the lights on during extreme weather conditions. For example, in 1994, extreme cold weather led to fuel supply disruptions in PJM, necessitating rolling blackouts. Subsequent analysis identified frozen coal and coal handling equipment, fuel oil delivery problems, and the interruption of natural gas supplies as prime causes. The stress placed on the system would have been all the more extreme if nuclear generation had been replaced by gas generation. *See* NERC, *Report on Electric Utilities' Response to the Cold Wave of January 1994* (Apr. 11, 1994), *available at* http://www.nerc.com/pa/rrm/ea/February%202011%20Southwest%20Cold%20Weather%20Event/NERC%201994%20Cold%20Wave%20Report.pdf; NERC, *Assessment of Previous Severe Winter Weather Reports 1983-2011* (July 2013), at 7, *available at* http://www.nerc.com/pa/rrm/ea/February%202011%20Southwest%20Cold%20Weather%20Event/Final_Draft_Assessment_of_Previous_Severe_Winter_Weather_Report.pdf.

[46] Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events, PJM Interconnection (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, at 26.

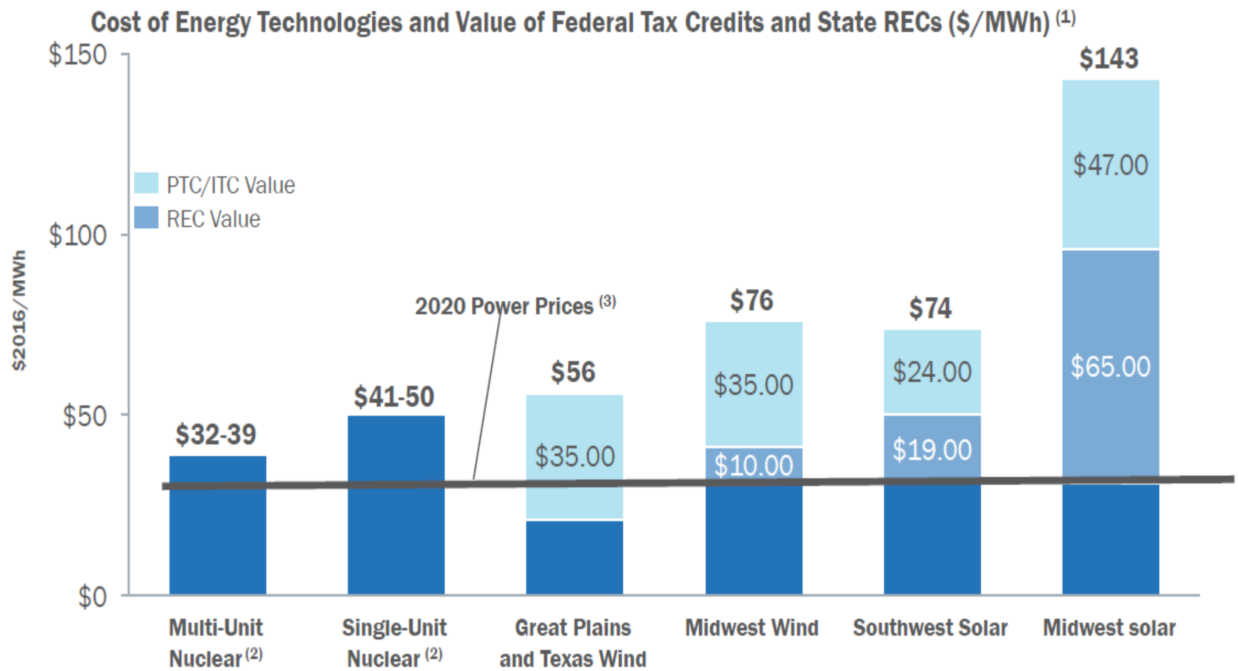
Moreover, of all generation, nuclear is alone in having a separate regulator – the Nuclear Regulatory Commission – that imposes safety and cybersecurity standards and engages in constant monitoring. Thus, from a resiliency perspective, the nuclear fleet is among the most "hardened" and prepared for adverse events and is constantly engaged in safety and reliability enhancements.

Yet nuclear plants have not been compensated for the resiliency value they provide to the system. As a result, many have retired prematurely—more than 10 GW of nuclear capacity has either retired or announced retirement plans—and many other nuclear units are in economic distress. Indeed, Bloomberg estimates that more than half of the nation's nuclear units are losing money.[47] As shown below, throughout the country, merchant nuclear plants face a shortfall of revenue relative to costs:

[47] Jim Polson, *More Than Half of America's Nuclear Reactors Are Losing Money*, Bloomberg, (June 15, 2017), *available at* https://www.bloomberg.com/news/articles/2017-06-14/half-of-america-s-nuclear-power-plants-seen-as-money-losers.



Without corrections to the market and full compensation for the attributes offered by this vital energy source, which produces over 60% of the nation's zero emission energy, the nation will suffer a massive wave of premature retirements. Yet ensuring the continued operation of nuclear plants is the most cost-effective way to achieve resiliency while also reducing emissions:



(1) Source: Nuclear Energy Institute, "Nuclear Costs in Context," August 2017; EIA AEO 2017 Levelized Cost of New Generation Resources
(2) Nuclear costs are comprised of fuel, O&M, capital expenditures and contingency. Contingency (or risk) is calculated as 10% of total costs plus $4/MWh
(3) Based on 10/20/17 ICE 2020 forward energy prices for relevant hub less 2016 average basis differential to nuclear plants

B. The Commission Should Issue a Policy Statement Declaring That Nuclear Facilities Receiving State Support Should Not Have Their Offers Mitigated on Account of That Support.

Given the vital role nuclear energy plays in providing resiliency and emissions-free energy for our customers, the failure of markets to adequately compensate nuclear generators for these attributes, and the irreplaceability of nuclear resources if they retire, the Commission should announce that it will not impede state efforts to support nuclear plants at risk of retirement. Both New York and Illinois have adopted state Zero-Emission Credit programs to provide additional revenue to nuclear units located within their boundaries. While the primary goal of these programs was environmental, the programs have the additional benefit of preserving units needed for system resiliency. These programs benefit nuclear units within the organized markets covered by the DOE NOPR and are targeted at units that otherwise would permanently retire. Ensuring these units' viability by protecting these state-supported revenue streams is thus consistent with the goals of the DOE proposal and the needs of a resilient electric grid.

Accordingly, the Commission should make clear that units receiving this type of support should not have their capacity or energy offers subject to mitigation. Natural gas generators have argued for mitigation of these state support programs to enhance their market position and to move the grid toward greater reliance on natural gas units. FERC should be mindful that natural gas and oil receive tens of billions of dollars annually in tax and other subsidies,[48] and additionally enjoy the benefit of using the atmosphere on a mostly unrestricted basis as a place to release carbon and other pollutants. Indeed, those who complain most vigorously about the need to preserve "free markets" are in fact the largest beneficiaries of tax and other subsidies. Some of the largest subsidies are shown in the table below:[49]

[48] Dirty Energy Dominance: Dependent on Denial, *Oil Change International* (Oct. 3, 2017), *available at* http://priceofoil.org/content/uploads/2017/10/OCI_US-Fossil-Fuel-Subs-2015-16_Final_Oct2017.pdf.

[49] The table below is excerpted from *id.* at 24-26, "Appendix 1: Complete List of U.S. Federal and State Fossil Fuel Production Subsidies." In total, federal oil and gas subsidies amount to $11 billion annually—not counting the implied of subsidy of being allowed to pollute without paying for the costs imposed on society.

Table 1: Federal Fossil Fuel Production Subsidies, 2015 to 2016

Subsidy Name & Description	Subsidy Type	Targeted Energy Source	Targeted Stage	2015 Estimate (in millions)	2016 Estimate (in millions)	Estimated Annual Average, 2015-2016 (in millions)
Federal Oil & Gas Production Subsidies						
Deduction for Intangible Drilling Costs* – 100% tax deduction for costs not directly part of the final operating of an oil or gas well	Tax expenditure	Oil & Gas	Exploration and field development	2, 317	2,267	2,292
Last-In, First-Out (LIFO) Accounting for Fossil Fuel Companies* – allows companies to undervalue their inventory, reducing taxable income; oil and gas companies account for over one-third of LIFO benefits	Tax expenditure	Oil & Gas	Cross-cutting	1,453	1,927	1,690[a]
Corporate Tax Exemption for Fossil Fuel Master Limited Partnerships* – allows companies to pay zero corporate income tax	Tax expenditure	Oil & Gas	Cross-cutting	755	2,473	1,614
Excess of Percentage Over Cost Depletion* – independent producers can deduct a percentage of gross income from production, rather than reflecting the value of the reserve depleted	Tax expenditure	Oil & Gas	Cross-cutting	1,502	1,118	1,310
Lost Royalties on Offshore Drilling for Leases Issued from 1996 through 2000 (Outer Continental Shelf Deep Water Royalty Relief Act)	Royalty relief	Oil & Gas	Extraction	1,072	1,072	1,072
Domestic Manufacturing Deduction for Oil & Gas* – allows oil & gas producers to claim a tax break intended for the manufacturing of goods	Tax expenditure	Oil & Gas	Cross-cutting	963	647	805
Dual Capacity Taxpayer Deduction* – allows oil and gas companies operating abroad to deduct royalty payments to foreign governments from U.S. income taxes	Tax expenditure	Oil & Gas	Remediation	527	533	530[b]

Accepting requests for mitigation from entities currently benefiting to this extent from fuel-specific subsidies would obviously be counterproductive as the Commission considers additional ways to improve the resilience of the grid. To the extent that the states are already taking steps to further the goals that DOE and FERC seek to accomplish, by preserving resilient and irreplaceable nuclear resource, their work should continue unimpeded.

C. FERC Should Direct the RTOs to Make A Filing Describing Other Measures that They Can Take to Support Resilient Units.

While the Commission considers how to design a market-based resiliency product, it should in the meantime direct the RTOs to consider other potential steps that would help to support a resilient grid.

For example, the RTOs should be encouraged to examine their method of procuring operating reserves. They may be able to take action, consistent with their tariffs, to increase operating reserves as needed to address the risk of disruption to the gas supply. Weather-related threats to the gas supply can pose a significant risk of economic harm and loss of life.[50] Similarly, a major pipeline outage from natural or human causes could have significant consequences in both the short and long-term.[51] Procuring adequate operating reserves to plan for these contingencies is a straightforward mechanism to reduce these risks as the Commission considers other possibilities.

PJM has already begun the process of considering changes along these lines. On October 10, 2017, PJM made a presentation to the Operating Committee outlining a proposed approach.[52] In brief, the RTO is considering changes to how it procures operating reserves to take in consideration the location of natural gas generators and the sources of their gas supply. In certain situations, the reserve market may choose not to dispatch certain units to avoid overreliance on particular natural gas pipelines. The Commission should require the RTOs to report on these efforts and to expedite their consideration.

The RTOs should also report on potential capacity market modifications. Certain markets covered by the Notice of Proposed Rulemaking have already recognized the need for enhanced capacity market designs to ensure that resources have an incentive to make investments to improve

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[50] *See Grid Resiliency Pricing Rule*, 82 Fed. Reg. 46,940 at 46,945 (discussing the Polar Vortex and Hurricanes Harvey, Irma, and Maria).

[51] Stockton Testimony at 10-11.

[52] *See Operationalizing Gas Pipeline Contingencies Normal and Conservative Operations*, Presentation dated October 10, 2017, *available at* http://www.pjm.com/-/media/committees-groups/committees/oc/20171010/20171010-item-16-gas-electric-contingencies-update.ashx.

their level of performance. In 2014, ISO-NE adopted its pay-for-performance scheme.[53] In 2015, the Commission approved the implementation of capacity performance in PJM.[54] Although these reforms were aimed at reliability, not resiliency—a distinction discussed further below—these reforms nevertheless help to support resilient units and therefore promote the goals set forth in the DOE NOPR. In these markets, the RTOs should consider whether the current penalty structure provides appropriate incentives to invest in performance. For example, in the Capacity Performance Order, FERC ordered PJM to revisit regularly the penalty rate and adjust it as needed to ensure performance.[55] The penalty rate was based on an assumption of 30 penalty hours per year, an estimate that was based on expected extreme weather (not manmade threats) and in any event appears to have been too high as recent years have had no penalty hours assessed. The Commission should urge PJM to consider changes to these and other capacity market features to protect the resilience of the electric grid.

RTOs can also explore tariff changes aimed at other problems—for example, carbon emissions—that would have the side benefit of supporting resilient resources. For example, a stakeholder process is underway in the NYISO market to discuss carbon pricing in that RTO's energy market.[56] That solution would provide additional revenue to resilient nuclear units while not disturbing the overall structure of that market.

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[53] *See ISO New England Inc.*, 149 FERC ¶ 61,009 (2014); *ISO New England Inc. and New England Power Pool*, 147 FERC ¶ 61,172 (2014).

[54] *See PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 (2015).

[55] *Id.* at 163.

[56] *See* Pricing Carbon into NYISO's Wholesale Energy Market to Support New York's Decarbonization Goals, August 10, 2017, *available at* http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Studies/Market_Studies/Pricing_Carbon_into_NYISOs_Wholesale_Energy_Market.pdf.

Organized markets have also adopted short-term structures in the past that have been used to ensure the availability of resilient resources in times of extreme conditions. The winter reliability programs in New England for oil and LNG storage have provided an adequate supply of power in that region for several years.[57] The Commission has approved those programs as just and reasonable as a transitional measure to a more robust permanent market design. Similarly, the Commission approved transitional auctions in PJM to move from a base capacity model to the capacity performance framework. To the extent organized markets need to take interim steps to retain resilient units while a broader process is underway, these programs can serve as a model of narrowly tailored solutions the Commission has previously approved. The Commission should direct the RTOs to report on whether programs such as these would be a just and reasonable interim mechanism of protecting the resilience of the grid. Additionally, if faced with the imminent retirement of a resource that can demonstrate its contribution to grid resiliency, the Commission should consider taking steps, on a unit-specific basis, to enable that unit's continued operation until the Commission can adopt a more comprehensive solution to address resiliency.

III. Before Determining the Solution, FERC Must Identify With Greater Specificity What Problem It Is Trying to Solve.

In order to identify the best and most cost-effective way to ensure a resilient grid, the Commission must first learn in greater detail what vulnerabilities the grid faces and, based on intelligence community assessments, which threats are the most important to mitigate. Once a Design Basis Threat analysis is complete,[58] then the Commission can identify the steps that must

[57] *ISO New England Inc. and New England Power Pool Participants Committee*, 152 FERC ¶ 61,190 (2015).

[58] *See* Nuclear Regulatory Commission Glossary, Design Basis Threat; https://www.nrc.gov/reading-rm/basic-ref/glossary/design-basis-threat-dbt.html (defining a design basis threat); 10 CFR § 73.1(a) (outlining particular threats).

be taken to address the threat, and the best and most cost-effective means for carrying out those steps. The rigorous analysis that must be the predicate for policy has not yet been done. As an initial step, the Commission should require the markets covered by the NOPR—PJM, NYISO, and ISO-NE—to expedite their planning efforts and report promptly on their readiness to respond to different types of significant systemic failure.

A. The Threat of A Black Sky Event Is Real and the Consequences Would Be Disastrous.

In its NOPR, DOE correctly notes the serious threat posed to the nation's electric grid by generation units that are insufficiently resilient, whether due to a fuel supply vulnerable to disruption, inability to operate in adverse weather conditions, or other factors that render units unable to provide energy at times of critical system need.[59] This threat is real, and it is immediate: Dr. Stockton's testimony outlines at length the critical danger to the bulk power system posed by "growing interdependencies" between natural gas and electric utilities.[60] These interdependencies increase the risk of mutually-reinforcing failures of *both* systems, in which disruption of the natural gas supply will interrupt the supply of electricity, which in turn will lead to further disruption in the ability of pipelines to deliver natural gas, and so on.[61] The result of such a combined failure—which could occur either because of malicious human action (either physical or cyber) or because

[59] *See* DOE NOPR, 82 Fed. Reg. at 46,941 ("The resiliency of the nation's electric grid is threatened by the premature retirements of power plants that can withstand major fuel supply disruptions caused by natural or man-made disasters and, in those critical times, continue to provide electric energy, capacity, and essential grid reliability services.").

[60] Stockton Testimony at 12.

[61] *Id.* at 11-13.

of a natural disaster—could lead to a "black sky" power outage, in which multiple regions throughout the country could suffer a sustained loss of power lasting a month or more.[62]

The human and economic consequences of such an event would be devastating. As Dr. Stockton notes, it would constitute an unprecedented natural emergency. America is not prepared for such a sustained blackout:

> Many critical infrastructure systems and facilities have backup power generators and stored on-site fuel to keep them operating for a few days in a limited power outage. However, in a black sky event, the extensive length and geographic scope of power outages would soon produce failures in emergency power assets and the infrastructure system that rely on them. Blackouts of this severity would cause cascading failures across multiple critical infrastructure sectors..[63]

The damage would spread throughout other components of the economy that depend on electric power. A black sky event would cripple sectors crucial for the preservation of human life. The American public would lose access to food and clean water, health care, and basic sanitation. Even basic forms of communication would become virtually impossible:

> Hospitals would exhaust their ability to rely on backup power. Food manufacturing and distribution networks would cease to function. Other critical infrastructure sectors would also likely collapse. For example, water, wastewater, and cellular systems rely on a functioning power grid and are not currently prepared for such an event. A black sky event would likely disable those systems for sustained periods of time leaving them unavailable to the public.[64]

As the nation becomes increasingly dependent on electricity for transportation through vehicle electrification, we risk disrupting our ability to move people as well. Potentially even more serious, the event would cause a crisis of national security and might incapacitate the defensive capacity of the United States military:

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[62] *Id.* at 9.

[63] *Id.* at 10.

[64] *Id* at 11.

> [N]ational defense installations would begin to fail. Domestic military facilities can operate without power for short periods of time but are not designed to be independent of the electric grid for extended periods of time. Electric power is necessary to keep them in operation because they require access to transportation fuel, communication networks, water and wastewater systems that need electricity to operate.[65]

As Dr. Stockton concludes, "[a] black sky power outage would inflict immense disruption of national security."[66]

B. The Commission Should Require the Three RTOs to Report on Their Status.

The Commission has an essential role to play in preventing the disaster to the nation that a black sky event would entail. It must ensure a robust generation fleet that can overcome threats to resiliency, and doing so requires a thorough examination of where our vulnerabilities lie, which vulnerabilities are the most important to address, what needs to be done to address them, and the most cost-effective means of doing so.

To begin that process. the Commission should issue an order requiring that the three RTOs identified by the Secretary of Energy—PJM, NYISO, and ISO-NE—provide key data regarding the ability of their regions to survive the type of catastrophic high intensity low frequency events that Dr. Stockton describes in his testimony. Beginning with a focus on these three RTOs is appropriate, as all three have capacity structures that select the lowest cost resources without regard to resiliency, driving those markets toward a gas monoculture. Moreover, in those markets, states have largely not used their own regulatory authority to promote resiliency. Other RTOs lack capacity structures causing that particular resiliency issue, in part because they have more robust integrated resource planning overseen by state commissions.

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[65] *Id.*

[66] *Id.* at 10.

Specifically, these three organized markets should provide the Commission with the following information in the following time periods:[67]

Within **30 days**, an inventory of all fuel supply for all generation within in their footprint including, for each generator:

- For the primary fuel source:
  - Fuel source type.
  - On-site inventory reported as average days based on continuous full output.
  - The nature of the fuel supply arrangement (e.g., firm gas, long-term coal contract, purchases of oil on the spot market, etc.).
  - The primary method of fuel delivery (e.g., firm pipeline transportation, rail, barge, truck, etc.).
  - Environmental permitting limitations.
- For the secondary or back-up fuel (if any):
  - Fuel source type.
  - On-site inventory reported as average days based on continuous full output. For oil and diesel this should include both the actual inventory and the maximum potential that can be stored on-site.
  - The nature of the fuel supply arrangement, including the existence of firm resupply contracts, if any.
  - The primary method of fuel delivery.
  - Environmental permitting limitations.

Within **60 days**:

- A fuel reliance analysis detailing the impact on the organized market's ability to serve load if the supply of a particular fuel type is interrupted, or if the supply of a combination of fuel types is interrupted. The analysis should include:

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[67] *See* Order Directing Reports, *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, 153 FERC ¶ 61,221, at P 7 n.7 (2015); Federal Power Act §§ 301(b), 309.

- How much load would not be served if a particular fuel type were unavailable for any reason.
- How long primary inventories would last at generators.
- How long secondary inventories would last at generators.
- A generator's ability to resupply from existing secondary fuel inventories that are not on site.
- The market's ability to increase production of remaining fuels, including diesel fuel, to meet increased need for the fuel in light of other demands for that fuel.

- A load impact analysis detailing the consequences if load is unable to be served for a prolonged period of time. This analysis should detail multiple disruption and time combinations (e.g., 50% of load for one week, 75% of load for two weeks, etc). The analysis should include:
    - The financial impact to economy of the region.
    - The security of the region (e.g., loss of other critical infrastructure and life sustaining services).
- A contingency analysis detailing the ability of the system to withstand (for both short- and long-term) electric and gas failures. This analysis should model both existing and future generation mixes. The analysis should include:
    - Single gas pipeline failure.
    - Multiple gas pipeline failures (including shared right of ways and crossings).
    - Coordinated attacks on multiple gas pipelines supplying the majority of an organized market's gas.
    - Loss of all pipelines controlled by single company whether as a result of a physical or cyberattack.
    - Coordinated gas pipeline/electric failures.
- An assessment of the adequacy of existing capacity constructs in light of the resiliency findings, and suggestions of what changes need to be made.[68]

[68] *See* Stockton Testimony at 19-21,

PJM has already begun a component of this process and started to consider the consequences of the loss of a single pipeline standing alone. This study indicated that in PJM, more than 11 GW of generation is connected to a single pipeline.[69] A disruption of that pipeline would be catastrophic. While PJM is ahead of other RTOs in initiating a planning process,[70] its analysis needs to more robust. For example, PJM should consider the loss of multiple pipelines simultaneously because of the real risk that terrorists or foreign governments might target multiple infrastructure components simultaneously,[71] as well as the risk that an attack on the pipeline system could be accompanied by an attack on components of the electric system. It should also consider the increased risk that will occur if more coal and nuclear units retire and leave the grid even more dependent on natural gas. The reporting requirements outlined above will help improve that planning process.

The other two RTOs need to rapidly advance and expand the planning process as well. NYISO has begun to study whether its system has adequate fuel assurance, recently seeking comment on an evaluation it commissioned the Analysis Group to perform.[72] Unfortunately, while ISO-NE similarly has been evaluating the fuel security of its region, and has "identified fuel security as one of the potential risks to future system reliability," it has nevertheless decided to

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69 *See supra* note 7.

70 Stockton Testimony at 18-19.

71 *Id.* at 19.

72 *See* Analysis Group, *Capacity Resource Performance in NYISO Markets, An Assessment of Wholesale Market Options*, at 18, 26 (Sept. 2017), *available at* http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2017-09-28/Analysis%20Group%20Draft%20Capacity%20Resource%20Performance%209-26-17.pdf (noting that "[t]he potential for growing future reliance on gas-fired resources suggests that further attention to fuel-related performance may be important to preventatively addressing potential system reliability risks").

"delay finalizing the study until the FERC has provided direction to the industry on how to interpret the DOE NOPR," suggesting that it will release the study "once the NOPR is sufficiently resolved."[73] ISO-NE's decision to delay its release of data is difficult to understand and unfortunate because it deprives commenters and experts in this proceeding of relevant data that would be highly relevant to FERC's response to the NOPR.

The Commission should urge PJM and NYISO to expeditiously complete their studies, and should not countenance ISO-NE's decision to shield its evaluation from public view. Rather, the Commission should order the RTOs to report promptly on their progress in conducting these types of planning efforts.

C. A Final Rule Is Urgently Needed, But Further Action Should Be Informed by a Design Basis Threat Analysis.

Before adopting a final rule to address the need to ensure resilience, the Commission should collaborate with other federal agencies to conduct a design basis threat analysis to measure the resiliency of the grid.[74] Exelon believes DOE might be well-situated to spearhead this analysis given its access to information, its expertise, and its relationship with the intelligence community. Here, such an analysis would help identify what vulnerabilities exist and must be addressed to ensure resiliency. The assessment should account for likelihood that a natural or manmade interruption in the energy sector might disrupt multiple pipelines simultaneously as well as other serious risks.[75]

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[73] ISO New England, Study on Regional Fuel Security to be Delayed Pending Resolution of DOE Proposal on Grid Resiliency Pricing (Oct. 13, 2017), https://www.iso-ne.com/static-assets/documents/2017/10/20171013_fuel_security_analysis_delay_final.pdf.

[74] As Dr. Stockton explains, the Nuclear Regulatory Commission provides its licensees with such a threat assessment to help safeguard nuclear reactors. Stockton Testimony at 22.

[75] *Id.* at 19.

Once the Commission has a more detailed understanding of the bulk power system's vulnerabilities, and which of those vulnerabilities most urgently need to be addressed, it will be able to decide what steps must be taken to counter those threats and the best means of doing so. It can then order the organized markets to adopt tariffs that address this threat, and ensure that generators that provide vital and needed resiliency are able to do so in the years ahead. In considering whatever final action it decides to take, the Commission will need to solicit commentary and analysis from a wide array of stakeholders and market participants. But, regardless of whatever process the Commission deems necessary in coming to a final rule, it should act quickly and not allow the critical resiliency deficiencies that currently endanger the bulk power system to persist.

There are undoubtedly numerous ways markets could be reformed once the appropriate design basis is identified, and the Commission should expect the RTOs to develop solutions that best harmonize with their existing market designs. Key among these is providing sufficient financial support to units that currently make important contributions to system-wide resiliency, so that these units can continue operations and are not forced into retirement. As Dr. Stockton explains,

> Increased dependence on a single type of fuel heightens the risks of common mode failures: that is, the danger that a single attack vector (especially via cyber means) could enable the adversary to disrupt fuel supplies for power generation across major portions of the United States. A significant interruption of the natural gas supply available for electric generation can dramatically reduce the supply of electricity available to serve load. For example, a large-scale disruption of a natural gas pipeline would prevent that pipeline from delivering natural gas to the generators it serves. It would also incapacitate any downstream pipeline dependent on it as a source of gas. Because gas is delivered close in time to its use as a fuel for electric generation, the system would have little time to respond to the loss of a pipeline. Preserving a diverse generation mix that relies on multiple sources of fuel is essential to reducing this risk.[76]

[76] Stockton Testimony at 9.

The Commission should ensure, however, that market reforms achieve the Design Basis Threat with a high degree of certainty and minimize total system costs in doing so. It may be the case, for example, that compensating an existing resilient unit for its costs of operation is less expensive than building new plants or retrofitting an existing plant to be equally resilient. In other words, providing cost of service payments may be in customers' best interests.

In conclusion, Exelon applauds DOE's focus on the threat posed to consumers and the bulk power system by insufficiently resilient generation. The wholesale markets have a long history of successfully delivering reliable and reasonably priced power to consumers at just and reasonable rates. But they need reform to ensure that the grid retains its most resilient resources.

CONCLUSION

The risks of non-action are real and potentially grave. The declining fuel security of the power system and increased reliance on a vulnerable natural gas pipeline system has created a real possibility of widespread, long-duration blackouts that would have catastrophic consequences. The American public cannot afford to take that risk. Fortunately, solutions exist if we have the stimulus to pursue them. We look forward to working with the Commission to develop those solutions.

October 23, 2017

Respectfully submitted,

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Exhibit A

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

PREPARED DIRECT TESTIMONY OF

DR. PAUL STOCKTON

ON BEHALF OF

EXELON CORPORATION

OCTOBER 23, 2017

I. BACKGROUND AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Paul Stockton. My business address is 325 7th Street NW, Suite 250, Washington D.C. 20004.

Q. DR. STOCKTON, BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am the Managing Director of Sonecon LLC, a security and economic advisory firm in Washington, DC.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS, EMPLOYMENT EXPERIENCE, AND EDUCATIONAL BACKGROUND

A. I graduated with a Bachelor of Arts degree s*umma cum laude* from Dartmouth College and received a Ph.D. from Harvard University. From June 2009 until January 2013, I served as the Assistant Secretary of Defense for Homeland Defense and Americas' Security Affairs. In that position, I was responsible for Defense Critical Infrastructure Protection and led the creation of the Department's Mission Assurance Strategy. I also served as the Domestic Crisis Manager for the Department of Defense (DOD) and was responsible for Defense continuity of operations. I was the principal civilian advisor to the Secretary of Defense for providing Defense support to Federal Emergency Management Agency, the Department of Energy (DOE) and other Federal departments in Superstorm Sandy, Hurricane Irene, and other disasters. In addition, I was responsible for developing and overseeing the implementation of DOD security policy in the Western Hemisphere, including U.S.-Canada cooperation on Defense-related issues concerning energy sector resilience. From January 2012 until January 2017, I served as a Special Government Employee for the Department of Defense, and helped conduct studies to strengthen deterrence of cyberattacks, counter insider threats, and meet other infrastructure resilience challenges. I was twice awarded the DOD Medal for Distinguished Public Service, the Pentagon's highest civilian honor, and a Distinguished Public Service Medal from the Department of Homeland Security.

Q. WHO IS SPONSORING YOUR TESTIMONY?

A. My testimony is sponsored by Exelon. My testimony reflects my informed opinion and does not necessarily reflect the perspectives and policies of the Department of Defense or any other government department or agency.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. In June 2016, I testified at the Commission's Reliability Technical Conference in Docket AD16-15-000.

Q. PLEASE DESCRIBE THE BASIS FOR YOUR FAMILIARITY WITH GRID RESLIANCE PLANNING EFFORTS.

A. In addition to my professional experience, I am the author of multiple works that examine the severe threats to energy sector resilience, and analyze measures that policymakers and stakeholders can take to reduce those risks. In 2016, I authored *Superstorm Sandy: Implications for Designing a Post-Cyber Attack Power Restoration System*, published by Johns Hopkins University Applied Physics Laboratory; *Electric Grid Protection Handbook*

II, Volume 1: Resilient Fuel Resources for Power Generation in Black Sky Events, published by the Electric Infrastructure Security Council; and co-authored the Homeland Security Advisory Council's *Final Report by the Cybersecurity Subcommittee: Incident Response.* I am also widely published on other issues of homeland security, national defense and infrastructure resilience, including *Resilience for Black Sky Days: Supplementing Reliability Metrics for Extraordinary and Hazardous Events*, prepared for the National Association of Regulatory Utility Commissioners.

II. <u>PURPOSE OF TESTIMONY AND CONCLUSIONS</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I examine how the increased reliance on natural gas for power generation is creating new risks to electric grid resilience, and analyze the implications for U.S. national security. I evaluate the adequacy of current measures to assess and mitigate these risks. I also propose measures to strengthen the resilience of the grid, and meet the challenges highlighted by the Department of Energy.

Q. COULD YOU PLEASE SUMMARIZE YOUR CONCLUSIONS?

A. I believe that this proceeding provides an opportunity to address the risks created by the growing dependence of the electric grid on natural gas as a fuel source. My testimony addresses three overall findings. *First*, the growing dependence of power generation on natural gas poses potential risks to U.S. national security. *Second*, current initiatives to identify and mitigate risks arising from gas-electric system interdependencies are not adequate. *Third*, before the Commission can decide on appropriate actions to help strengthen fuel resilience, I believe that significant additional analysis will first be required to clarify the attributes of fuel resilience, develop metrics to assess them, and specify the threat against which fuel resilience should be measured. In particular, I recommend that a government agency (in consultation with appropriate Bulk Power System (BPS) entities) establish a Design Basis Threat (DBT) to help assess fuel resilience for power generation and that FERC gather additional data on the current status of resilience efforts. Finally, the Commission, in conjunction with other agencies, should implement measures that will ensure that resiliency is preserved.

Q. PLEASE SUMMARIZE YOUR FIRST FINDING. WHAT ARE THE POTENTIAL RISKS TO U.S. SECURITY POSED BY EMERGING THREATS TO ELECTRIC AND GAS SYSTEMS?

A. Russia, China, North Korea, and other potential adversaries may seek to disrupt U.S. defense capabilities by attacking the critical infrastructure on which our military bases rely. DOD's Mission Assurance Strategy emphasizes that "The Department of Defense's ability to ensure the performance of its Mission-Essential Functions (MEFs) is at growing risk. Potential adversaries are seeking asymmetric means to cripple our force projection, warfighting, and sustainment capabilities by targeting critical Defense and supporting civilian capabilities and assets – within the United States and abroad –on which our forces depend."[1]

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[1] Department of Defense, *Mission Assurance Strategy*, April 2012, p. 1, http://policy.defense.gov/Portals/11/Documents/MA_Strategy_Final_7May12.pdf.

The power grid and fuel supplies for power generation are potential targets for these adversaries. While military installations and other national security facilities are strengthening their emergency power capabilities to serve their critical loads, long duration, wide area power outages could jeopardize their ability to execute their MEFs. We must assume that adversaries know this – and, accordingly, that in future conflicts they will attack the power grid and the flow of gas on which power generation increasingly relies.

Q. PLEASE SUMMARIZE YOUR SECOND FINDING. ARE CURRENT EFFORTS TO IDENTIFY AND MITIGATE RISKS STEMMING FROM INCREASED RELIANCE ON NATURAL GAS ADEQUATE TO ENSURE RESILIENCE?

A. No. Existing BPS reliability standards focus on protecting and maintaining the reliability of BPS systems and functions. These standards do not apply to the gas systems that are increasingly vital for power generation. Indeed, no mandatory standards exist for gas system reliability that are remotely equivalent to those that help strengthen the BPS against attack. Current efforts to provide dual-fuel capability for natural gas plants are not sufficient. While some planning efforts have begun, they do not go far enough.

Q. PLEASE SUMMARIZE YOUR THIRD FINDING. HOW CAN THE COMMISSION BEST ADVANCE GRID RESILIENCE?

A. As measures go forward to strengthen fuel resilience, and thereby bolster U.S. security, Commissioners should take a holistic approach that will involve collaboration with a range of government and private sector entities. Work should begin immediately to develop a detailed assessment of the risks being created by increasing gas-electric system interdependencies. In my testimony that follows, I highlight a number of requirements for further analysis, including reporting requirements for RTOs to understand the current state of resiliency.

The Commission also should seek the creation of a DBT to help assess the resilience of fuel supplies for power generation and the potential value of measures taken to improve that resilience. Modelled on the approach of the Nuclear Regulatory Commission, a DBT should consider the type, composition, and nature of risks to resiliency including both catastrophic natural and manmade hazards.[2] That DBT should account for the risk –indeed, the likelihood – that if a major power decides to attack the U.S. energy sector, they will not merely strike a single pipeline, but seek to disrupt *all* major pipelines in a given region. Finally, implementation measures should be taken to ensure that the threat is appropriately mitigated and resiliency is preserved.

III. EMERGING RISKS TO RESILIENCY

Q. DID THE DEPARTMENT OF ENERGY FIND A RISK TO RESILIENCY FROM RELIANCE ON NATURAL GAS?

A. Yes. DOE's Notice of Proposed Rulemaking takes a crucial step forward to clarify these risks and highlight the value of measures to mitigate them. From 2002 until 2016, the share of electricity generated by gas-fired units increased from 18% to about 34% while the share

[2] *See* Nuclear Regulatory Commission Glossary, Design Basis Threat; https://www.nrc.gov/reading-rm/basic-ref/glossary/design-basis-threat-dbt.html (defining a design basis threat); 10 CFR § 73.1(a) (outlining particular threats).

generated by coal fell from about 50% to about 30%.[3] Risks of mutually-reinforcing failures between gas and electric systems have grown accordingly. DOE found that "the electric sector's growing reliance on natural gas raises concerns regarding the ability to maintain BPS reliability when facing constraints on the natural gas delivery systems."[4] Other key BPS stakeholders have reached similar conclusions. For example, Gerry Cauley, President and CEO of NERC, emphasizes that "[g]rowing reliance on natural gas continues to raise reliability concerns regarding the ability of both gas and electric infrastructures to maintain the BPS reliability at acceptable levels."[5]

Q. WHAT SPECIFIC RISKS DO YOU SEE?

A. In addition to the risks specified in the Notice, I would call the Commission's attention to three specific challenges: *First*, reliance on a single fuel creates the danger of "common-mode failures" where a lack of natural gas incapacitates multiple generators at the same time. *Second*, such failures could help create "black sky" power outages, which would entail outages lasting a month or more over multiple regions of the United States.[6] *Third*, rising gas-electric interdependencies create dangers of mutually-reinforcing failures.

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[3] United States Department of Energy, Staff Report to the Secretary on Electricity Markets and Reliability 90 (August 2017).

[4] North American Electric Reliability Corporation, *Short-Term Special Assessment: Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation*, May 2016, p. 12.

[5] Gerry Cauley letter to Energy Secretary Rick Perry, May 9, 2017.

[6] Paul Stockton, *Resilience for Black Sky Days: Supplementing Reliability Metrics for Extraordinary and Hazardous Events*, at 3, National Association of Regulatory Utility Commissioners (2014).

Q. PLEASE DESCRIBE HOW RELIANCE ON A SINGLE FUEL CAN MAGNIFY RISKS OF COMMON-MODE FAILURES.

A. Increased dependence on a single type of fuel heightens the risks of common mode failures: that is, the danger that a single attack vector (especially via cyber means) could enable the adversary to disrupt fuel supplies for power generation across major portions of the United States. A significant interruption of the natural gas supply available for electric generation can dramatically reduce the supply of electricity available to serve load. For example, a large-scale disruption of a natural gas pipeline would prevent that pipeline from delivering natural gas to the generators it serves. It would also incapacitate any downstream pipeline dependent on it as a source of gas. Because gas is delivered close in time to its use as a fuel for electric generation, the system would have little time to respond to the loss of a pipeline. Preserving a diverse generation mix that relies on multiple sources of fuel is essential to reducing this risk.

Q. WHAT WOULD BE THE CONSEQUENCES OF A "BLACK SKY" OUTAGE?

A. A black sky power outage would inflict immense disruption on national security, the U. S. economy, and public health and safety.

Q. WHY WOULD THE HARM BE SO SEVERE?

A. Many critical infrastructure systems and facilities have backup power generators and stored on-site fuel to keep them operating for a few days in a limited power outage. However, in a black sky event, the extensive length and geographic scope of power outages would soon produce failures in emergency power assets and the infrastructure system that rely on them.

Blackouts of this severity would cause cascading failures across multiple critical infrastructure sectors. As highlighted in recent hurricane events, generators will quickly break down through overuse. Demand for replacing them in a wide-area outage will rapidly outstrip available supplies, given the vast number of facilities that will require such replacements. Moreover, on-site fuel supplies for emergency generators will quickly be depleted. Massive, multi-sector requirements for fuel resupply will emerge. Contractors responsible for sustain resupply operations will be unable to meet these requirements, especially since transportation systems, refinery operations, and other systems on which these contractors depend will also be disrupted in a black sky outage. Hospitals would exhaust their ability to rely on backup power. Food manufacturing and distribution networks would cease to function. Other critical infrastructure sectors would also likely collapse. For example, water, wastewater, and cellular systems rely on a functioning power grid and are not currently prepared for such an event. A black sky event would likely disable those systems for sustained periods of time leaving them unavailable to the public. Finally, national defense installations would begin to fail. Domestic military facilities can operate without power for short periods of time but most are not designed to be independent of the electric grid for extended periods of time. Electric power is necessary to keep them in operation because they require access to transportation fuel, communication networks, water and wastewater systems that need electricity to operate. The net result: black sky outages will have catastrophic effects on national security, the U.S. economy, and public safety. Adversaries seeking to achieve such effects will therefore be all the more tempted to build capabilities to create black sky events, and exploit the gas-electric interdependencies that could contribute to the severity of future blackouts..

Q. HOW COULD GAS-ELECTRIC INTERDEPENDENCIES CREATE MUTUALLY REINFORCING FAILURES?

As natural gas has become an increasingly important fuel for electric generation, natural gas pipelines have also come to rely on electricity to function. Key components of gas pipeline systems, including the compressors and industrial control systems that keep gas flowing to power generators and other users, are more reliant on electric power. Gas pipeline systems need compression pumps to sustain the flow of gas. Historically, these compressors were fueled with gas taken from the pipelines themselves. However, in many regions of the United States, these compressors are being replaced by variable speed electric-powered units to reduce onsite methane emissions and increase compressor efficiency. Black sky outages could interrupt the flow of electricity to these units, and (in a classic case of spiraling effects) magnify those outages by disrupting gas deliveries to power generators essential for power restoration.[7] Some compression stations do have emergency power generators and at least some on-site fuel to sustain operations in a blackout. However, as noted above, fuel resupply operations for these stations will be at risk of catastrophic disruption in long duration, wide area outages. These growing interdependencies create risks of cascading, mutually-reinforcing failures across both the electricity and oil and natural gas energy subsectors.[8] Because of the need for generators to receive natural gas

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[7] Electric Infrastructure Protection (EPRO) Handbook II (Vol 1 – Fuel), July 18, 2016, at 24, http://www.eiscouncil.com/App_Data/Upload/149e7a61-5d8e-4af3-bdbf-68dce1b832b0.pdf.s

[8] Electric Infrastructure Protection (EPRO) Handbook II (Vol 1 – Fuel), July 18, 2016, at 21, http://www.eiscouncil.com/App_Data/Upload/149e7a61-5d8e-4af3-bdbf-68dce1b832b0.pdf.s

fuel and the need for electricity by natural gas pipelines to deliver that fuel, a significant interruption of the supply of natural gas can start a chain of events that result in interruption of electricity, which can cause the loss of power to gas compressors, which can cause further interruptions of generator fuel supply, cascading toward a broader system outage. The result: *gas and electric systems will be vulnerable to mutually-reinforcing failures when such outages begin.*

Q. WHAT TYPES OF HAZARDS COULD CAUSE THESE FAILURES?

A. Both natural and manmade hazards pose risks. While I describe a few such potential vulnerabilities below, the Commission, in coordination with other knowledgeable agencies, should consider as many other such threats as possible and similarly develop and implement measures to ensure they are understood.

Q. WHAT ARE THE NATURAL HAZARDS THAT COULD CREATE SUCH MUTUALLY REINFORCING GAS-ELECTRIC SYSTEM FAILURES?

A. Catastrophic earthquakes could inflict massive damage on gas and electric infrastructure, and foster mutually-reinforcing failures between them that produce black sky outages. For example, a catastrophic earthquake in the New Madrid Seismic Zone would pose significant risks to PJM. Similar seismically active regions pose risks elsewhere. Other catastrophic natural hazards could also create such risks. Moreover, once a naturally-induced blackout was underway, adversaries could also exploit the resulting disruptions in gas-electric system interdependencies, and exacerbate the interruption of natural gas flows for power generation.

Q. WHAT ARE THE MANMADE RISKS?

A. In recent months, potential adversaries have staged sophisticated, multi-phase intrusion campaigns against the energy sector to insert Advanced Persistent Threats into our energy systems.[9] These efforts are part of a long-term trend towards increased severity in the cyber threats confronting electric and gas systems –a trend that is certain to continue. Coordinated physical attacks on critical gas and electric system infrastructure components pose an additional threat. Such attacks could come from the type of kinetic threats seen in the 2013 attack on the Metcalf substation in California[10], but also from unmanned aerial vehicles carrying advanced payloads and other non-traditional attack vectors. Combined cyber-physical attacks could magnify such risks of disruption.

Q. IN ADDITION TO THE CHANGE IN THE GENERATION MIX, WHAT ADDITIONAL FACTORS HAVE HEIGHTENED THE RISKS?

A. Electricity plays an increasingly important role in the operation of all other infrastructure sectors. DOE notes that "[t]he reliability of the electric system underpins virtually every sector of the modern U.S. economy, which depends on electricity – including sectors from food production to banking to health care. Electricity is at the center of key infrastructure systems that support these activities –transportation, oil and gas production, water, finance,

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[9] U.S. Computer Emergency Readiness Team, "Advanced Persistent Threat Activity Targeting Energy and Other Critical Infrastructure Sectors, October 21, 2017, at https://www.us-cert.gov/ncas/alerts/TA17-293A

[10] Rebecca Smith, *Assault on California Power Station Raises Alarm on Potential for Terrorism*, Wall St. J., Feb. 5, 2014.

and information and communications technology. Electricity-dependent critical infrastructures represent the core underlying lifeline framework that supports the American economy and society."[11] This "electrification of everything" heightens the potential payoff to adversaries of attacking the grid and its fuel supplies, and reinforces the imperative to mitigate the risks of increased reliance on natural gas for power generation.

IV. <u>CURRENT EFFORTS TO IDENTIFY AND MITIGATE RISKS TO RESILIENCY</u>

Q. WHICH STAKEHOLDERS HAVE A ROLE TO PLAY IN PRESERVING THE RESILIENCY OF THE GRID?

A. By issuing the proposed rule, the Department of Energy has taken a critical step forward to facilitate progress on resilience. Other key stakeholders include the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation (NERC), the Regional Transmission Organizations and Independent System Operators overseen by FERC, and other BPS entities. Commissioners and other entities may also wish to consult with the Department of Homeland Security, the Department of Transportation, and the Department of Defense, and other federal and state agencies.

Q. HAVE THE RELEVANT STAKEHOLDERS ADQUATELY CONSIDERED THE RISKS TO RESILIENCY?

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[11] Department of Energy, *Quadrennial Energy Review – Transforming the Nation's Electricity System: Second Installment of the QER*, January 2017, p. 7-3.

A. Stakeholders are making progress, but significant gaps remain in assessing risks to resilience and developing mitigation options. In particular, stakeholders need to account for the growing severity of the threat and the implications for adversary exploitation of gas-electric interdependencies. To the best of my knowledge, for example, no RTO has performed a comprehensive analysis of whether the system can survive the disruption of multiple natural gas pipelines system for an extended period of time.

Q. FERC HAS APPROVED MANDATORY RELIABILITY STANDARDS FOR THE BULK ELECTRIC SYSTEM. DO THE RELIABILITY STANDARDS AIM TO ENSURE RESILIENCY?

A. No. As noted above, NERC reliability standards apply to electric infrastructure, not gas transmission lines and other fuel systems on which the grid depends. Moreover, these standards focus on reliability, not resilience. Studies conducted for the National Association of Regulatory Commissioners and other studies have highlighted significant ways in which resilience differs from reliability. These studies have also examined why traditional metrics for assessing reliability are inadequate for resilience.[12]

Q. DO EFFORTS TO PROVIDE DUAL-FUEL CAPABILITIES TO NATURAL GAS UNITS PROVIDE ADEQUATE RESILIENCE AGAINST THIS THREAT?

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[12] *Resilience for Black Sky Days: Supplementing Reliability Metrics for Extraordinary and Hazardous Events*, National Association of Regulatory Utility Commissioners, February 2014), available at http://www.sonecon.com/docs/studies/Resilience_for_Black_Sky_Days_Stockton_Sonecon_FINAL_ONLINE_Feb5.pdf; Sayanti Mukhopadhyay, Public Utility Commissions to Foster Resilience Investment in Power Grid Infrastructure, available at http://www.sciencedirect.com/science/article/pii/S1877042816300052

A. Not yet. Generators that are able to utilize a secondary source of fuel if natural gas supplies are interrupted can provide a critical bulwark against cross-sector failure. Given that value, some markets have developed financial incentives to encourage the construction and retention of dual-fuel generators. However, there are indications that existing incentives may not be adequate. Moreover, these generators typically have enough secondary feel stored on site to operate for very limited periods. After that, fuel resupply will be essential to sustain their operations if natural gas flows remain interrupted. However, the same factors that will disrupt the resupply of fuel for emergency power generators will apply to resupply of the secondary fuels typically employed for dual-fuel generators. Demand for such fuel in a long duration, wide area outage will be vastly greater than the capacity of contractors to conduct resupply operations. This is especially true since such operations would need to go forward in severely disrupted environments, especially in terms of refining and transportation system functionality.

Q. HOW IMPORTANT IS ON-SITE FUEL STORAGE FOR ENSURING GENERATION RESILIENCE, AND WHAT ARE THE APPROPRIATE STANDARDS FOR RESILIENCE PRICING ELIGIBILITY?

A. Nuclear power plants can operate for many months between refueling operations. Accordingly, they can make special contributions to grid resilience. The proposed Rule also makes the case that because coal generators typically have many weeks of fuel supplies stored on-site, they are also highly resilient. However, much more comprehensive and systematic analysis of such issues should go forward before final decisions are made on eligibility and market design changes. Moreover, as these criteria design options are developed, it will be vital to avoid crafting them in ways that favor one source of generation over another for reasons irrelevant to grid resilience.

Q. WHAT CURRENT ANALYTIC INITIATIVES ARE UNDERWAY THAT COULD HELP ASSESS CURRENT FUEL RESILIENCE AND REQUIREMENTS FOR PROGRESS UNDER THE NOPR?

A. Valuable studies have already been conducted on the risks that interruptions in gas supplies pose to BPS reliability.[13] NERC is now conducting a much-needed special reliability assessment to determine impacts of a single point of disruption of natural gas facilities.[14] Along with other industry initiatives, PJM is conducting especially important studies of the potential risks created by increased reliance on natural gas, including in its *Natural Gas Contingency Scenario Analysis*.[15] I commend PJM for taking these critical steps forward. These and other industry studies analysis can provide a useful model for BPS entities

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[13] See: North American Electric Reliability Corporation, *Short-Term Special Assessment: Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation*, May 2016; Federal Energy Regulatory Commission, *Gas-Electric Coordination Quarterly Report to the Commission*, Docket No. AD12-12-000, December 18, 2014; Department of Energy, *Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector*, February 2015; American Electric Power, *Gas-Electric Harmonization: An AEP Perspective*, 2014; Midcontinent Independent System Operator, *Electric-Gas Coordination*, February 2015; and Eastern Interconnection Planning Collaborative, *Gas-Electric System Interface Study*, December 2014.

[14] *See* Agenda Item 3a, Special Assessment: Single Points of Disruption on Natural Gas Infrastructure, MRC Informational Session (April 13, 2017), *available at* http://www.nerc.com/gov/bot/MRC/Agenda%20Highlights%20nad%20Minutes%202013/MRC_Informational_Session_Conference_Call_and_Webinar_Agenda_April_13_2017.pdf.

[15] http://pjm.com/-/media/committees-groups/committees/teac/20170914/20170914-reliability-analysis-updates.ashx

nationwide to adapt to meet their own assessment requirements and fuel resilience challenges. However, as I discuss below, I believe other efforts are necessary.

V. ADVANCING GRID RESILIENCE

Q. WHAT ACTIONS SHOULD THE COMMISSION TAKE?

A. The Commission should obtain the analyses necessary to determine what actions to take next. For one, relevant information from the RTOs covered by the NOPR would help in this determination. Next, the Commission should collaborate with other agencies to conduct a DBT analysis.

Q. WHAT ADDITIONAL INFORMATION WOULD BE HELPFUL FROM THE RTOS?

A. PJM's analysis provides an extremely useful starting point, but it should be expanded. For example, analysis by RTOs should consider the loss of multiple pipelines simultaneously, as might occur in a coordinated physical or cyberattack. As noted above, any major power willing to take the risks of attacking a single U.S. pipeline may well decide to strike on a much more massive scale to disrupt U.S. defense capabilities, and seek to disrupt all flows of gas for power generation in a given RTO or ISO service area.

Useful additional information would include data from each generator on:

- For the primary fuel source:
    - Fuel source type.
    - On-site inventory reported as average days based on continuous full output.

- The nature of the fuel supply arrangement (e.g., firm gas, long-term coal contract, purchases of oil on the spot market, etc.).
- The primary method of fuel delivery (e.g., firm pipeline transportation, rail, barge, truck, etc.).
- Environmental permitting limitations.

- For the secondary or back-up fuel (if any):
  - Fuel source type.
  - On-site inventory reported as average days based on continuous full output. For oil and diesel this should include both the actual inventory and the maximum potential that can be stored on-site.
  - The nature of the fuel supply arrangement.
  - The primary method of fuel delivery.
  - Environmental permitting limitations.

The RTOs should also conduct a series of studies:

- A fuel reliance analysis detailing the impact on the organized market's ability to serve load if the supply of a particular fuel type is interrupted, or if the supply of a combination of fuel types is interrupted. The analysis should include:
  - How much load would not be served if a particular fuel type were unavailable for any reason.
  - How long primary inventories would last at generators' full output
  - How long secondary inventories would last at generators' full output
  - A generator's ability to resupply from existing secondary fuel inventories that are not on site.
  - The market's ability to increase production of remaining fuels, including diesel fuel, to meet increased need for the fuel in light of other demands for that fuel.
- A load impact analysis detailing the consequences if load is unable to be served for a prolonged period of time. This analysis should detail multiple disruption and time combinations (e.g., 50% of load for one week, 75% of load for two weeks, etc). The analysis should include:

    - The financial impact to economy of the region.
    - The impact to the security of the region (e.g., loss of other critical infrastructure and life sustaining services).
- A contingency analysis detailing the ability of the system to withstand (for both short- and long-term) electric and gas failures. This analysis should model both existing and future generation mixes. The analysis should include:
    - Single gas pipeline failure.
    - Multiple gas pipeline failures (including shared right of ways and crossings).
    - Coordinated attacks on the organized market's 3 of 4 biggest pipelines.
    - Loss of all pipelines controlled by single company whether as a result of a physical or cyber attack.
    - Coordinated gas pipeline/electric failures.
- The RTOs should also conduct an assessment of the adequacy of existing capacity constructs in light of the resiliency findings, and suggestions of what changes need to be made.

Q. DO THE RELIABILITY STANDARDS SUGGEST THAT THIS ANALYSIS IS APPROPRIATE?

A. NERC Reliability Standard TPL-001-4 directs transmission planners to assess the impact of extreme events, and if the analysis determines that such events cause cascading outages, the transmission planner should evaluate possible actions to reduce the likelihood or mitigate the consequences and adverse impacts to reliability.[16] I recommend that large-scale disruptions of gas supplies be included in such analysis. I also propose that planners

[16] *See* Requirements R 3.2 and R 3.5 of Standard TPL-001-4 – Transmission System Planning Requirements.

include contingency analysis of severe disruptions in secondary fuel resupply for dual fuel generators, and disruption of fuel resupply for backup power generators that serve critical natural gas compression stations and other key gathering and transmission infrastructure. Finally, planners should conduct sensitivity analysis on the degree to which retaining a mix of fuel-resilient generation assets, including nuclear assets, can help reinforce the resilience of the BPS as a whole.

Q. HOW COULD A DESIGN BASIS THREAT ASSIST THE COMMISSION?

A. At present, BPS entities lack a government-approved assessment of the threat against which they should measure the resilience of their fuel supplies. The Nuclear Regulatory Commission provides its licensees with a DBT to help design safeguard systems for the U.S. nuclear fleet. Fuel resilience issues pose a very different range of challenges. A DBT would help the Commission support analysis and mitigation of risks to fuel resilience. That effort should be led by a U.S. agency with access to appropriate threat information. The development of a DBT should also go forward in full consultation with the electric power industry, NERC, the E-ISAC, and other key sources of expertise. The design of the DBT should also leverage "best practices" developed by the NRC, and draw lessons learned from the NRC's past efforts that can help accelerate and improve the creation of a DBT for resilience.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	)))	RM18-1-000

DECLARATION OF DR. PAUL STOCKTON

I, Paul Stockton, declare under penalty of perjury that the foregoing Prepared Direct Testimony of Dr. Paul Stockton on Behalf of Exelon Corporation is true and correct.

Executed: October 23, 2017

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Paul Stockton