UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Resilience in Regional Transmission Organizations and Independent System Operators	)))))	**Docket No. AD18-7-000**

COMMENTS AND RESPONSES OF PJM INTERCONNECTION, L.L.C.

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PJM Interconnection, L.L.C. ("PJM") hereby submits its comments and responses ("Comments") to the resilience issues and inquiries identified in the Federal Energy Regulatory Commission's ("Commission") Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures issued on January 8, 2018.[1] Through these Comments, PJM:

- outlines the considerable steps PJM and its stakeholders have undertaken, or have actively underway, to enhance the resilience of the portion of the Bulk Electric System[2] ("BES") operated by PJM, and

[1] *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, 162 FERC ¶ 61,012 (2018) ("Grid Resilience Order"). In the Grid Resilience Order the Commission (1) terminated the proceeding regarding the proposed rule on Grid Reliability and Resilience Pricing submitted to the Commission by the Secretary of the United States Department of Energy ("DOE") that was focused on providing cost-of-service compensation to generators with on-site fuel capability, and (2) initiated the above-captioned proceeding on Grid Resilience in Regional Transmission Organizations and Independent System Operators. The Grid Resilience Order directed each Regional Transmission Organization ("RTO") and Independent System Operator ("ISO"), including PJM, to submit initial comments and responses to the Commission on resilience in order to enable the Commission to holistically examine the resilience of the bulk power system. Hereinafter, RTOs and ISOs are referred to collectively as RTOs.

[2] In its questions, the Commission referenced the resilience of the bulk power system. In its responses, PJM is addressing resilience as it relates to the Bulk Electric System. The North American Electric Reliability Corporation ("NERC") defines Bulk Power System as: (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. NERC defines Bulk Electric System as: "Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy…" (the detailed list of systems modifying the definition are not provided herein). *See Glossary of Terms*

- details specific action steps the Commission (in some areas working with other federal and state agencies) could undertake to enhance overall resilience of the BES not just in the PJM Region but potentially across the nation.

Just as with so many issues before the Commission, enhancing grid resilience requires a careful balancing of many competing interests. Ultimately, the goal is to ensure that the BES can continue, into the future, to meet the needs of customers for the reliable and secure delivery of electricity at a price which remains just and reasonable. PJM has approached these Comments by striving to balance those different concerns and interests.

I. INTRODUCTION

There are a number of important initiatives that are underway and others that should be enhanced and made part of the Commission's focus with respect to system resilience. Defining resilience is an important first step as outlined below. Addressing the issues raised in the Commission's inquiries to the RTOs is an important second step.[3]

As a multi-state RTO, PJM has visibility into interstate and inter-system resilience vulnerabilities and restoration challenges. PJM's role in the resilience effort is not an exclusive role, but a partnership role that involves interaction and coordination with member Transmission Owners,[4] Load Serving Entities, end-use customers, the Commission, other federal and state agencies and regulatory commissions, and other stakeholders. But given the interconnected nature of the electric power grid, there is an important federal interest that must be recognized and advanced in addressing resilience. As a result, as proposed herein, the Commission should

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Used in NERC Reliability Standards, North American Electric Reliability Corporation (Jan. 31, 2018) ("NERC Glossary"), www.nerc.com/files/glossary_of_terms.pdf.

[3] Although PJM is supportive of this docket starting with an inquiry to the RTOs, grid resilience issues are not limited to RTOs. If anything, because of their scale and scope, RTOs are best able to evaluate overall grid resilience issues of the BES in their footprints. But the scope of the Commission's effort should in no way be limited to RTOs since many if not most BES grid resilience issues are truly national in scope.

[4] All capitalized terms that are not otherwise defined herein have the meaning as defined in the PJM Open Access Transmission Tariff ("Tariff"), Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement"), and Reliability Assurance Agreement Among Load Serving Entities in the PJM Region.

advance additional processes that could help with additional coordinated identification, authentication and mitigation of future grid resilience challenges, and authentication and mitigation of the vulnerabilities that currently exist.

To be clear, the PJM BES is safe and reliable today – it has been designed and is operated to meet all applicable reliability standards. However, improvements can and should be made to make the BES more resilient against known and potential vulnerabilities and threats. In many cases, resilience actions are anchored in, but go beyond what is strictly required for compliance with, the existing reliability standards. As a result, PJM has identified a number of recommended initiatives.

II. EXECUTIVE SUMMARY

In its broadest sense, resilience involves preparing for, operating through, and recovering from events that impose operational risk, including but not limited to high-impact, low-frequency events. However, resilience is not only about high-impact, low-frequency events. Rather, resilience also involves addressing vulnerabilities that evolved over time and threaten the safe and reliable operation of the BES (or timely restoration), but are not yet adequately addressed through existing RTO planning processes or market design. Many of the actions, policies, procedures, and market structures designed to improve system resilience are scalable and applicable to a wide range of potential risks and impacts. The challenge lies in the nature of high-impact, low-frequency events, because they are not amenable to quantitative, probability-based analyses commonly used for risk management[5] due to the difficulty of predicting the timing and impact of their occurrence. Probabilities of high-impact, low frequency events are generally unknown or extremely difficult to quantify, and the consequences or impacts of high-

[5] *See e.g.* Kaplan, S. and Garrick, B.J. (1981). On the Quantitative Definition of Risk. *Risk Analysis* 1(1).

impact, low-frequency events - although assumed to be intolerably high in terms of both human and economic costs - are difficult to quantify. Prudent resilience efforts to address verifiable vulnerabilities and threats are worthwhile despite the uncertainty, and can be effectively and efficiently managed through the use of a range of complementary analyses and strategies.

Accordingly, PJM requests that the Commission take the following actions to enhance resilience of the grid and interrelated systems that depend on the BES.

- Finalize through this proceeding a working definition and common understanding of grid resilience, clarifying that resilience resides within the Commission's existing authority with respect to the establishment of just and reasonable rates, terms and conditions of service under the Federal Power Act ("FPA").[6]
- Establish a Commission process, either informally through one or more of the Commission's existing offices, or formally through a filing process, that would allow an RTO to receive verification as to the reasonableness of its assessments of vulnerabilities and threats, including Commission utilization of information that may be available to it, but not available to the RTO because of national security issues. Those assessments, once verified, could then form the basis for RTO actions under its planning or operations authority consistent with its tariffs. Simply put, in coordination with other federal agencies such as the United States Department of Defense ("DOD"), DOE, United States Department of Homeland Security ("DHS"), as well as NERC, the Commission needs to provide intelligence and metrics to apply to resilience vulnerability and threat analyses that can then guide and anchor subsequent RTO planning, market design, and/or operations directives.[7]
- Articulate in this docket that the regional planning responsibilities of RTOs currently mandated under 18 CFR § 35.34(k)(7), and the NERC TPL standards (which among other things require RTOs to plan to provide reliable transmission service and assess Extreme Events to the BES), includes an obligation to assess resilience. The Commission should consider, after confirming that resilience is a component of such planning, initiating appropriate rulemakings or other proceedings to further articulate the RTO role in resilience planning including

[6] *See, e.g.,* Section 215, 16 U.S.C. §824o.

[7] Through this process, PJM would be seeking verification that its vulnerability identification or threat assessment is consistent with information (including classified information not necessarily available to PJM) held by the federal government and thus should be used to guide future actions. The verification would be solely of the identified vulnerability or assessed threat and would not preclude challenges in the context of a rate proceeding or otherwise as to the cost efficiency of addressing the vulnerability or threat.

affirmative obligations and standards to plan, prepare, mitigate, etc. As part of this effort, the Commission should reconcile its continued interest in transparency in planning processes under Order Nos. 890 and 1000 with the challenges of public disclosure of significant grid resilience vulnerabilities. Working with stakeholders, PJM has begun this process to include existing standards like NERC CIP-14 critical facilities and urges the Commission to provide assistance to ensure that the goals of transparency and information to end users do not become a means to disclose grid vulnerabilities that can be exploited by those with bad intent.

- Require that all RTOs (and jurisdictional transmission providers in non-RTO regions) submit a subsequent filing, including any necessary proposed tariff amendments, to implement resilience planning criteria, and develop processes for the identification of vulnerabilities, threat assessment and mitigation, restoration planning, and related process or procedures needed to advance resilience planning.
- Request that all RTOs (and jurisdictional transmission providers in non-RTO regions) submit a subsequent filing, including any necessary proposed tariff amendments, for any proposed market reforms and related compensation mechanisms to address resilience concerns within nine to twelve months from the issuance of a Final Order in this docket. PJM, together with its stakeholders, is already actively evaluating such potential reforms that advance operational characteristics that support reliability and resilience, including (i) improvements to its Operating Reserve market rules and to shortage pricing, (ii) improvements to its Black Start requirements, (iii) improvements to energy price formation that properly values resources based upon their reliability and resilience attributes, and (iv) integration of distributed energy resources ("DERs"), storage, and other emerging technologies. A deadline for submission of market rule reforms that the RTO feels would assist with its resilience efforts would help ensure focus on these issues in the stakeholder process.
- Request that PJM submit a subsequent filing, including any necessary proposed tariff amendments, to permit non-market operations during emergencies, extended periods of degraded operations, or unanticipated restoration scenarios. Such filings could including provisions for cost-based compensation when the markets are not operational or when a wholesale supplier is directed to take certain emergency actions by PJM for which there is not an existing compensation mechanism.[8]
- Establish improved coordination and communication requirements between RTOs and Commission-jurisdictional natural gas pipelines to address resilience as it relates to natural gas-fired generation located in RTO footprints. With respect to interstate pipelines, PJM respectfully requests that the Commission launch

[8] Any such RTO procedures would be limited, and would not interfere with DOE emergency actions under FPA, sections 202(c) or 215A. 16 U.S.C. §§ 824a(c), 824o-1.

additional initiatives addressing the interaction between RTOs and interstate natural gas pipelines as follows:

- PJM supports additional reforms to Order No. 787 to avoid the variable levels of information sharing provided by different pipelines in the PJM Region that resulted from the strictly voluntary nature of Order No. 787.
- PJM requests additional efforts by the Commission to encourage sharing of pipelines' prospective identification of vulnerabilities and threats on their systems and, sharing on a confidential basis in real-time, the pipeline's modeling of such contingencies and communication of recovery plans. This would ensure that the RTO has the best information in real-time to make a determination whether to increase Operating Reserves or take other emergency actions in response to a pipeline break or other contingencies occurring on the pipeline system. Although a degree of effective coordination and communication with the pipelines serving the PJM Region has been achieved, more of a focus on real time coordination of modeling of contingencies and real-time communication of same would ensure greater consistency in coordination and information and can bring gas/electric coordination, to the next level to face the next generation of resilience issues. Accordingly, PJM recommends a more holistic regulatory framework for identifying and coordination of modeling of (1) pipeline contingencies in RTO planning and (2) real-time impacts of adverse pipeline events on BES operations.
- PJM requests an increased focus on restoration planning coordination between RTOs and pipelines as each entity has valuable information that can affect the other's timely restoration.
- PJM urges the Commission to encourage the development of additional pipeline services tailored to the flexibility needs of natural gas-fired generation so as to encourage appropriate tailoring and pricing of services beyond today's traditional firm/interruptible paradigm.
- PJM believes that much can be done both in the Commission's exercise of jurisdiction over RTOs as well as interstate pipelines to improve generation interconnection coordination with pipelines in order to better align interconnection activities and timelines and minimize potential issues associated with generation facilities located in areas on pipeline systems where reliability or resilience benefits may be sub-optimal.
- Finally, PJM believes that more action is needed to support the harmonization of cyber and physical security standards between the electric sector and the natural gas pipeline system. PJM recognizes that this matter spans beyond the Commission but also involves the Transportation Security Administration ("TSA") and Pipeline and Hazardous Materials Safety Administration ("PHMSA"), but believes that through greater inter-agency coordination, a base level of resilience to

physical and cyber-attacks can be achieved even while still respecting the different regulatory authorities of each agency.

- In addition, greater communication and coordination is needed with the local distribution companies ("LDCs") that supply wholesale generation, and the Commission should support such efforts including evaluating whether communication and coordination obligations should be imposed on LDCs that supply jurisdictional wholesale generation.[9]
- As noted below, PJM is moving forward on requiring dual fuel capability at all Black Start Units but urges, as the next step, coordination across the nation of a consistent means to determine Critical Restoration Units and the development of criteria to assure fuel capability to such Critical Restoration Units.[10]
- RTOs, as part of their restoration role, should be asked to demonstrate steps they are taking to improve coordination with other critical interdependent infrastructure systems *(e.g.*, telecommunications, water utilities) that (i) could be impacted through events of type discussed herein, or (ii) are themselves vulnerabilities that could contribute to, or amplify the impact of such events. Coordination between the Commission, the Federal Communications Commission ("FCC") and DHS would provide additional federal support for such efforts.

PJM stands ready to work with the Commission and its stakeholders on each of these potential initiatives, and appreciates the Commission's leadership in this important area.

III. COMMENTS

As the Commission indicated, at the most basic level, ensuring resilience requires determining which risks to the BES to protect against, and identifying the steps that are needed to ensure those risks are addressed.[11] The Grid Resilience Order, *inter alia*, asks three broad questions. First, how should resilience be defined?[12] Second, how do RTOs assess threats to resilience?[13] Third, how do RTOs mitigate threats to resilience?[14] PJM's responses to the

[9] One possible manner of imposing obligations on LDCs might be as customers of interstate pipeline tariffs.

[10] PJM is focusing efforts on the second tier of generation used in restoration, commonly referred to as critical load units, and referred to herein as Critical Restoration Units.

[11] Grid Resilience Order at P 24.

[12] *Id.* at P 23.

[13] *Id.* at P 25.

[14] *Id.* at P 27.

Commission's questions are based on its independent evaluations and expertise, as well as input received in response to PJM's solicitation of comments from its stakeholders.[15]

1. Common Understanding of Resilience

The Commission proposed to define resilience as:

> The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event.[16]

The Commission requested that RTOs comment on the proposed definition, and whether any of the terms used to describe its understanding of resilience "require further elaboration to ensure a common understanding."[17]

The Commission's definition of resilience is consistent with general industry concepts concerning resilience, and is similar to the definition of infrastructure resilience utilized by NERC –

> The ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event.[18]

While the Commission's definition of resilience is acceptable, PJM respectfully suggests further refinement is needed to ensure the definition (i) accurately reflects what RTOs are capable of doing to protect the BES from vulnerabilities and threats, and (ii) does not impose upon RTOs additional liabilities and the imposition of a new duty and standard of care to which

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[15] *See* Comments posted with the meeting materials for the February 23, 2018 special meeting of the PJM Markets and Reliability Committee, at http://www.pjm.com/committees-and-groups/committees/mrc.aspx.

[16] Grid Resilience Order at P 23.

[17] *Id*.

[18] NERC, *Severe Impact Resilience: Considerations and Recommendations*, 12 (Board Accepted May 9, 2012, http://www.nerc.com/comm/OC/SIRTF%20Related%20Files%20DL/SIRTF_Final_May_9_2012-Board_Accepted.pdf.

they are obligated to comply. PJM proposes the following definition, which has commonality of intent with the Commission's definition, though the specific language differs for the reasons indicated herein:

> The ability to withstand ~~and~~ or reduce the magnitude and/or duration of disruptive events, which includes the capability to ~~anticipate,~~ identify vulnerabilities and threats, and plan for, prepare for, mitigate, absorb, adapt to, and/or ~~rapidly~~ timely recover from such an event.[19]

The refinements PJM proposes are intended to ensure the definition is realistic and requirements on RTOs are achievable.

In this regard, first, requiring the BES to "withstand" a disruptive event is concerning because RTOs should not be required to plan and design the BES to be invulnerable to a broad spectrum of hazards and corresponding impacts - regardless of the cost to do so or the incremental value that may be achieved in making such improvements for a contingency that will rarely, if ever, occur. For that reason, the word "and" should be changed to "or" in PJM's proposed definition to allow an RTO to make a rationale determination of the cost benefit of making certain system improvements.

Second, the word "anticipate" should not be included in the definition of resilience because RTOs cannot perfectly anticipate all potential risks, vulnerabilities or threats to the BES. Instead, it is more appropriate for RTOs "to identify vulnerabilities and threats."

Third, once such vulnerabilities and threats are identified, in addition to absorbing, adapting to and recovering from a disruptive event, RTOs also need to plan for and prepare for such an event, and mitigate against the identified vulnerabilities and threats, in order to develop mechanisms to prevent the BES from being disrupted.

[19] The redlines reflect changes PJM is proposing to the Commission definition of resilience. An underline reflects words PJM proposes to add to the definition, while a strike-through reflects words PJM proposes to delete from the definition.

Finally, the word "rapidly" should be replaced with the word "timely" in the definition of resilience because any recovery must be reasonably timely under the circumstances. The word "rapidly" could impose an unreasonable expectation depending on the circumstances or the event. Furthermore, including "rapidly" in a federal definition could engender unnecessary disputes and litigation after a successful timely restoration.

And with regard to the Commission's inquiry whether any of the terms it used to describe its understanding of resilience requires further elaboration, for the purpose of clarification and to ensure a common understanding, PJM understands the terms "absorb" and "adapt" to mean the ability of asset-owners and operators on the BES to manage incidents as they are unfolding to minimize the initial impact in a prudent manner – not the ability to absorb a threat unscathed.

In issuing a definition of resilience, the Commission should clarify that resilience is included in its existing statutory authority. The FPA defines "reliable operation" as "operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, *or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements,*"[20] articulating resilience concepts. In addition, resilience efforts will require changes to transmission and infrastructure planning, operation rules, and market rules, as well as to recovery and restoration processes. All of these efforts implicate jurisdictional tariffs and rates and thus are within the Commission's existing authority with respect to the establishment of just and reasonable rates under the FPA.

Therefore, PJM asks the Commission to clarify in this proceeding that resilience is anchored in the Congressional definition of reliable operations as set forth in FPA, section 215,

[20] FPA, section 215, 16 U.S. Code § 824o(a)(4) (emphasis added).

but also is supported by the requirement for just and reasonable rates, terms and conditions of service and the requirement that the planning and expansion of the BES meet the needs of load serving entities.[21] By clarifying that resilience of the BES is within the Commission's authority, the Commission and PJM will be well positioned to advance resilience efforts within their respective processes and avoid jurisdictional challenges being raised in individual proceedings at the very time that timely action may need to be taken.

2. How RTOs/ISOs Assess Threats to Resilience

The second issue for which the Commission sought to gain a better understanding was "how each RTO/ISO currently evaluates the resilience of its system."[22] The Commission directed the RTOs to address a series of questions on that "issue and, as needed, to highlight any unique resilience challenges that exist in their respective regions."[23] PJM responds to each Commission question below.

(a) What are the primary risks to resilience in your region from both naturally occurring and man-made threats? How do you identify them? Are they short-, mid-, or long-term challenges?

In the resilience context, the term "risk" is comprised of several interrelated components: (i) potential loss or "vulnerability," (ii) cause or "threat," (iii) possibility or probability of occurrence, and (iv) impact. PJM interprets this question as seeking information regarding the primary resilience vulnerabilities. The primary vulnerabilities to the BES in PJM's footprint, resulting from both naturally occurring events and man-made threats, are:

(i) significant loss or disruption of infrastructure, including but not limited to critical transmission facilities or other significant BES assets;

(ii) significant loss or disruption of control systems, such as Industrial Control Systems or Supervisory Control and Data Acquisition (SCADA), and their supporting Information Technology ("IT") networks;

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[21] FPA, section 217, 16 U.S. Code § 824q(b)(3)(B)(4).

[22] Grid Resilience Order at P 25.

[23] *Id.*

(iii) significant loss or disruption of interdependent systems (i.e., natural gas pipelines or delivery systems, communication networks, and water utilities supplying generation);
(iv) degraded capability to execute restoration or Black Start; and
(v) significant loss of wholesale supply that exceeds current planning/ operating criteria.[24]

The degree of risk from each of these events differs by region. For example, the PJM Region, with its rich supply of Marcellus and Utica shale and the availability of multiple pipelines and natural gas storage facilities, does not face the same degree of vulnerability as would a region with more limited natural gas infrastructure such as New England. Nevertheless, a number of the threats listed above are common to all RTOs.

At its core, resilience involves identifying and addressing vulnerabilities that could jeopardize the safe and reliable operation of the BES, or BES restoration, and that are not currently addressed through existing RTO planning processes or market design. While some efforts will be tailored specifically to one particular threat, the focus should be on mitigation actions that are hazard agnostic and mitigate against multiple threats.

Categories of high-impact, low-frequency naturally occurring events and man-made threats are discussed in further detail in the response to question 2(c), and include:

(i) cyber-attack;
(ii) physical attack;
(iii) electromagnetic pulse ("EMP");
(iv) loss of interdependent systems;
(v) severe terrestrial weather;
(vi) earthquake; and,
(vii) geomagnetic disturbance ("GMD").

[24] Although obvious, it is worth noting that the overwhelming impact to customers from many of these events and, in particular, weather-related events arises from performance of the distribution system.

PJM identifies resilience vulnerabilities both independently and based on information available to it from its member companies, industry groups, and governmental entities. Specifically, PJM's independence and operational expertise, as the NERC-registered Balancing Authority, Planning Authority, Reliability Coordinator, Resource Planner, Transmission Operator, Transmission Planner and Transmission Service Provider[25] for a region that spans across all or part of thirteen states and the District of Columbia, position PJM with authority to perform regional-scale risk assessments and qualitative analyses to identify regional vulnerabilities based upon an examination of numerous potential scenarios. But there is more that RTOs such as PJM could do to identify and mitigate such regional vulnerabilities, even if addressing those vulnerabilities is not necessary for day-to-day safe and reliable operation.

As the Transmission Operator for its Transmission Operator Area,[26] PJM has engaged in both discourse-based and precaution-based strategies to advance resilience.[27] A discourse-based strategy denotes raising awareness, sharing information regarding vulnerabilities, and initiating collective institutional efforts. A precaution-based strategy involves an examination of vulnerabilities, often employing industry or technology best practices to take precautionary steps to mitigate the vulnerability.

For example, since March 2017 PJM's Security and Resilience Advisory Committee ("SRAC") serves as the primary forum to advance the dialogue on resilience and identify priority

[25] *See* NERC Glossary.

[26] The NERC Glossary defines Transmission Operator as: "The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission Facilities." Transmission Operator Area is defined as: "The collection of Transmission assets over which the Transmission Operator is responsible for operating."

[27] *See e.g.* Klinke, A. and Renn, O. (2002). A New Approach to Risk Evaluation and Management: Risk-Based, Precaution-Based, and Discourse-Based Strategies. *Risk Analysis* 22(6).

initiatives for the PJM stakeholder community.[28] Meeting topics include reports on recent cyber intrusions and trends in the electricity industry, engagement in multi-sector exercises dedicated to resilience-driven objectives and outcomes, and aligning ongoing industry research and policy development on resilience topics to ensure relevant outcomes. Issues raised in this forum produced an industry emergency communications research project to maintain critical functionality in a high-impact, low-frequency event, new frameworks for enhanced Black Start planning, partnerships for the integration of National Guard cyber assets for joint cyber response, and stakeholder participation in a newly formed, multi-sector exercise for a high-impact, low-frequency event.

Moreover, in 2017 PJM organized and sponsored two well-attended Grid 20/20 events, one on fuel diversity and resilience[29] and the other on grid security and resilience.[30] The April 2017 Grid 20/20 event facilitated a stakeholder discussion on fuel mix diversity and security issues and their intersection with resilience. The September 2017 Grid 20/20 event served as an effective venue in which PJM and its stakeholders, including representatives of state regulatory agencies, discussed grid resilience at the transmission and distribution levels.[31]

In an example of a precaution-based strategy, PJM focused particular attention on techniques to identify and mitigate natural gas infrastructure vulnerabilities. To advance

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[28] Detailed information about the SRAC, including meeting minutes and meeting materials, is available at http://www.pjm.com/committees-and-groups/committees/srac.aspx.

[29] *See* Grid 20/20: Focus on Resilience (Fuel Mix Diversity & Security), April 19, 2017 ("April 2017 Grid 20/20"), http://www.pjm.com/committees-and-groups/stakeholder-meetings/symposiums-forums/grid-2020-focus-on-resilience-part-1-fuel-mix-diversity-and-security.aspx.

[30] *See* Grid 20/20: Focus on Security & Resilience, September 19, 2017 ("September 2017 Grid 20/20"), http://www.pjm.com/committees-and-groups/stakeholder-meetings/symposiums-forums/grid-2020-focus-on-security-and-resilience.aspx.

[31] *See* Grid Resilience Order at n.31 ("We also note that the concept of resilience necessarily involves issues, topics, and questions that extend beyond the Commission's jurisdiction, such as distribution system reliability and modernization. The Commission encourages RTOs/ISOs and other interested entities to engage with state regulators and other stakeholders through Regional State Committees or other venues to address resilience at the distribution level.").

resilience, PJM developed operating procedures that will define specific processes to evaluate the risk on the BES of natural gas infrastructure vulnerabilities, with a clear understanding of natural gas infrastructure redundancy including generator dual-fuel capabilities. Those procedures also will operationalize gas pipeline contingencies under normal operations and external threat conditions, such as cyber and physical threats. In support of these efforts, PJM has entered into specific information-sharing protocols with nine interstate natural gas pipelines and five LDCs serving customers in the PJM Region. Further, PJM has created a gas operations function that supports the PJM control room. PJM employees in the control room monitor natural gas pipeline conditions, and stay in regular communication with pipelines regarding changes to those conditions. While much has been accomplished with gas-electric coordination, much more can and should be undertaken in this area to promote resilience, with Commission support.

On the supply side, PJM's risk assessments focus on the reliability and resilience attributes of wholesale generation and other supply. These metrics are rooted in existing criteria used for PJM's market such as ramp time, run time, and operational flexibility to determine what generation types are best suited to perform in adverse conditions with varying system constraints.[32] PJM's current generation fuel mix is diverse, as reflected in the illustration below which depicts the fuel mix of the energy produced in the PJM Region as of December 31, 2017.

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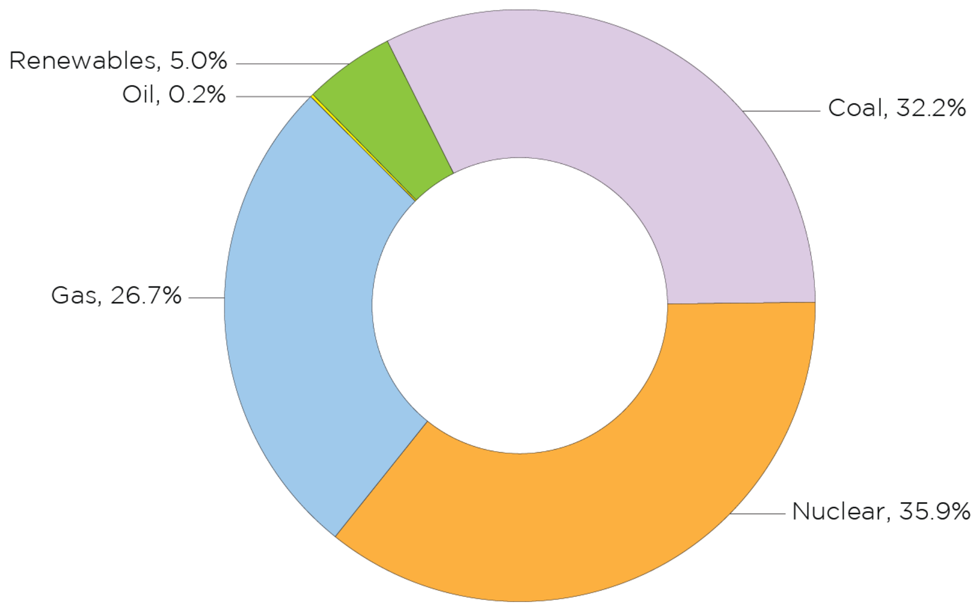
[32] PJM, *PJM's Evolving Resource Mix and System Reliability* (March 30, 2017), http://www.pjm.com/-/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.Ashx?la=en ("Fuel Report"); PJM, *Appendix to PJM's Evolving Resource Mix and System Reliability* (March 30, 2017), http://www.pjm.com/-/media/library/reports-notices/special-reports/20170330-appendix-to-pjms-evolving-resource-mix-and-system-reliability.ashx?la=en.



PJM is traditionally made aware of Transmission Owner determinations of critical transmission substations through the NERC Standard CIP-014-1 physical security process, and PJM performs the validation outlined in Requirement R2.[33] As a NERC-registered Transmission Operator, PJM also reviews all PJM Transmission Owner restoration plans for Black Start and Critical Restoration Units located in each of its twenty transmission zones within the PJM Region. PJM also participates in numerous electricity industry associations and consortia that work to identify vulnerabilities on the BES based on joint areas of interest including the Edison Electric Institute, Electric Subsector Coordinating Council ("ESSC"),[34] the North American Transmission Forum ("NATF") and the Electric Infrastructure Security Council. These entities all possess track records of great progress identifying and addressing resilience challenges within their respective scopes and memberships, adding to the resources brought to bear in this collective effort.

[33] *See* NERC Reliability Standard CIP-014-2 – Physical Security, Eff. Oct. 2, 2015, http://www.nerc.com/pa/Stand/Reliability %20Standards/CIP-014-2.pdf.

[34] PJM's Chief Executive Officer and President, Andrew Ott, represents the ISO RTO Council ("IRC") on the ESSC.

Finally, PJM obtains important information from governmental agencies at the local, state and federal level that have identified additional risks for consideration, including but not limited to the DHS Regional Resilience Assessment Program for Critical Infrastructure and Key Resource identification and interdependency analysis, the Federal Emergency Management Agency ("FEMA") Power Outage Incident Annex ("POIA") which provides an annex to the National Response Plan dedicated to response coordination for large black outs, and the state-level emergency operations plans and energy assurance plans.

With regard to the Commission's question whether the referenced risks to resilience in the PJM Region are short-, mid-, or long-term challenges, there is no question that we must build on the work already done on resilience to identify the activities that are best suited to mitigate resilience risk on all three time horizons. Significant effort should be expended to develop criteria and analytical tools for determining whether a risk requires mitigation, resilience plans, changing planning and operating procedures, as well as market mechanisms. Some of these challenges can be addressed quickly, while others will require a longer time frame to address.

PJM respectfully requests that the Commission establish a process that would allow an RTO to receive verification as to the reasonableness of its vulnerability and threat assessments to the BES based upon information submitted by the RTO and, importantly, also upon information that may be available to the Commission, but not available to the RTO because of national security issues. Those assessments, once verified, could then form the basis for RTO actions under its planning or operations authority consistent with its tariffs.

(b) How do you assess the impact and likelihood of resilience risks?

1. Impact of resilience risks

The loss of a BES facility is currently assessed using power system models to determine the potential for instability, uncontrolled separation or cascading outages. These models form the foundation for how resilience risks can be assessed, but the specific risks to be analyzed and the measuring criteria need to be further developed and specified. While these models do not assist in determining the likelihood of a particular risk occurring, they do demonstrate the potential impacts of their occurrence. PJM also performs other deterministic analyses and *ad hoc* analyses to assess certain resilience risks. In addition, as discussed further herein, PJM also utilizes NERC CIP-014 assessments performed by Transmission Owners and assesses "Extreme Events" to the BES in accordance with existing NERC TPL standards. There is additional work to be done with regard to the evaluation of contingencies from a resilience perspective in order to address these risks beyond what is needed for meeting existing reliability standards.

The impact of resilience risks related to the physical and cyber security of RTO operations is analyzed through the use of an ongoing corporate risk assessment informed by lessons learned and intelligence acquired from prior internal and external security events. The impact of data feed losses, data corruption, and dispatcher tool functionality, is assessed through a grid simulator and business continuity training and exercises to develop and refine recovery practices and identify potential vulnerabilities. A similar methodology is employed for risks posed to physical infrastructure to determine the appropriate level of site redundancy and business continuity needed to sustain critical grid operations.

PJM's authority to assess the impact and likelihood of resilience risks would be strengthened if the Commission affirmatively that the regional planning responsibilities of RTOs currently mandated under 18 CFR § 35.34(k)(7) include planning for resilience. The Commission should consider, after confirming that resilience is a component of such planning, initiating appropriate rulemakings or other proceedings to further articulate the RTO role in resilience planning including affirmative obligations and standards to assess the impact and likelihood of resilience risks, and to plan, prepare for, and mitigate such risks.

2. *Likelihood of Resilience Risks*

The assessment of the likelihood of certain naturally occurring events for resilience risks can be statistically quantified. For example, PJM uses a 1-in-100 year storm as a benchmark to address the risk posed by GMD for system planning and conservative operations. In addition, PJM can model various levels of natural gas availability/curtailments during projected cold weather events (i.e., events similar to the Polar Vortex in 2014 ("2014 Polar Vortex") and the bomb cyclone event in 2018) in order to assess projected outages of generation due to fuel availability, as well as related operating constraints of generation facilities in extreme temperatures.

Compared to naturally occurring events, the likelihood of a man-made threat is more difficult to quantify because they don't adhere to cyclical weather patterns and cannot be accurately forecasted or projected. Additionally, their effects are discriminate, likely targeting the most critical infrastructure as opposed to the indiscriminate and more random effects associated with naturally occurring hazards. PJM performs an internal annual security risk assessment based on the most current and actionable information available, obtained from classified and unclassified briefings provided by various governmental entities and industry information sharing resources such as the Electricity Information Sharing and Analysis Center ("E-ISAC"). Impact estimates are derived from cyber penetration testing, security exercises, business continuity recovery exercises (e.g., GridEx), and other exercise partnerships. These assessments are limited to PJM physical assets and supporting infrastructure. Additional NERC CIP-014 analysis performed by transmission owners and PJM considers additional issues such as the loss of a critical substation on real-time operations.

(c) Please explain how you identify and plan for risks associated with high-impact, low-frequency events (e.g., physical and cyber attacks, accidents, extended fuel supply disruptions, or extreme weather events). Please discuss the challenges you face in trying to assess the impact and likelihood of high-impact, low-frequency risks. In addition, please describe what additional information, if any, would be helpful in assessing the impact and likelihood of such risks.

Given the inherent reliance of the BES on the functionality of interdependent infrastructure systems such as commercial communications and natural gas pipelines, resilience risks must be evaluated with a multi-sector lens. Thus, the resilience threats PJM identifies are limited to those capable of creating widely distributed damage to physical or cyber infrastructures that result in long-duration outages over large geographic footprints. As indicated above, PJM has identified the following seven categories of high-impact, low-frequency naturally occurring events and man-made threats to the BES – (i) cyber-attack; (ii) physical attack; (iii) EMP; (iv) loss of interdependent systems; (v) severe terrestrial weather; (vi) earthquakes; and, (vii) GMD.

PJM plans for risks in a variety of ways, sometimes based on the specific type of risk at issue. The challenges faced in assessing the likelihood and impact of the risks also differs based on the type of risk, as discussed below.

1. Cyber-attack

Cyber-attacks typically come from nation states, terrorists and un-attributable threats. To plan for and counteract cyber threats, PJM conducts penetration testing for cyber intrusion detection and remediation, and has commenced the planning for "Red Team/Blue Team" exercises to test and validate the ability of cyber security personnel to execute the cyber kill chain model to remediate cyber risk in accordance with the National Institute of Standards and Technology cyber framework. Best practices and policy development around a coordinated response to large-scale, regional impacts between government and the private sector and between industries are captured through the exercise programs at FEMA's National Exercise Division and the National Level Exercise, the DOE ClearPath exercise program, state-level exercises and the NERC-led Grid Ex series. PJM also organizes and executes an annual grid security drill during the off-years of Grid Ex to address lessons learned and evaluate the ability of the transmission and generation owners in the PJM Region to respond to high-impact, low-frequency events.

The challenge with trying to assess high-impact, low-frequency cyber-attacks is that many nation states have increased capability and interest to perform cyber-attacks. The motives behind attacks by nation states vary through a wide spectrum including intentional disruption of business operations, reconnaissance to potentially plan future attacks, theft of intellectual property, financial theft and political grandstanding. Given the number and breadth of potential cyber threats, it elevates the need for continued and enhanced intelligence sharing from the federal government as the primary source of human and signals intelligence on foreign and domestic actors. When considering the comparative risk of the different cyber threats, the large resources and more robust capabilities of nation state actors, they are considered to be the highest risk cyber threat to the electricity industry. Certain actors have expressed their intentions, in recruitment videos or otherwise, to attack the U.S. power grid to damage and disrupt the power grid to effect the general population and create fear. At this time, the cyber-attack capabilities of such groups are not fully known to the electricity industry, making the assessment by an RTO of the likelihood of a cyber-attack and its anticipated impacts more difficult. The challenge with un-attributable threats is that they are targeted attacks that cannot be attributed to a specific threat actor, often perpetrated by cyber criminals looking for financial gain. This category represents the most common form of attacks detected on the industry systems in the form of routine reconnaissance by likely cyber criminals searching for software vulnerabilities to exploit.

2. *Physical Attack*

With regard to physical attacks, PJM does not own the transmission or generation assets that comprise the BES. However, the member companies that do own and operate those BES assets have increased physical security at the BES sites significantly in the past few years. Specific measures which most member companies are now using for physical protection of the BES assets include specialized fencing, security cameras and restricted and electronic access. PJM Transmission Owners have updated their engineering standards to include enhanced measures for physical security of the BES assets. As for threats to PJM's dispatch and operations facilities, physical security drills are routinely conducted to ensure integration with local, state, and federal law enforcement entities and proper handling by PJM staff. PJM has also enhanced physical and electronic security around the dispatch and operations facilities.

Physical attacks can come from a variety of threats. To plan for and counteract physical threats, PJM conducts penetration testing for physical intrusion detection and response to test and validate the ability of security personnel and employees to detect and respond to suspicious events and intrusion attempts. PJM also conducts annual active shooter planning and exercises with federal, state and local law enforcement & public safety personnel with a strong focus on partnerships, prevention, preparedness, response, mitigation and recovery activities.

PJM also utilizes the DHS Office of Infrastructure Protection Assist Visits to:

- establish and enhance relationships;
- educate DHS and other federal, state and local law enforcement on how PJM fits into its specific critical infrastructure sector;
- identify the Office of Infrastructure Protection resources available to PJM to enhance security and resilience;
- reinforce the need for continued vigilance;
- focus on coordination, outreach, training, and education; and
- conduct security surveys which:
    - identify and document the overall security and resilience of the facility; and
    - identify PJM's physical security, security forces, security management, information sharing, protective measures, and dependencies related to preparedness, mitigation, response, resilience, and recovery.

As discussed further above, FEMA's National Exercise Division and the National Level Exercise, the DOE ClearPath exercise program, state-level exercises, and the NERC-led Grid Ex all also contribute to physical security best practices. Despite these efforts, however, PJM would benefit from additional coordination with federal agencies such as DOD, DOE, DHS, and other security/intelligence agencies with respect to the identification and warnings of specific threats.

3. Electromagnetic Pulse

PJM recognizes that EMP is a risk to the BES based on general industry knowledge and ongoing research. However, predicting and planning for EMP is problematic, because the potential effects of such an attack are not fully understood. Generally speaking, the best way to plan for this risk is to adequately protect the infrastructure most likely to be the target of an EMP attack, thereby mitigating the potential impacts and reducing the grid's value as a target. The challenges of hardening manifest in two ways—effectiveness and cost. At present, the effects of EMP on modern power system components are not adequately researched, making impact modeling inaccurate and ineffective in quantifying risk, particularly because the most detailed information regarding impacts and hardening techniques is in the possession of the federal government and is not available to RTOs. As a result, it is difficult to not only understand and predict what component failures should be expected in an EMP event, but what protective measures would be most effective for hardening grid components. Without access to this type of data, articulating the scope of damage and outages, identifying the most essential replacements parts for repairs, and determining the potential cost of hardening is challenging at best. If identifying and planning for EMP risk is of importance to the Commission, the Commission should clarify for the RTOs what steps it would like the RTOs to take in terms of mitigation for EMP, such as investigating shielding and any other measures.

4. Loss of Interdependent Systems

The assessment of risk with respect to interdependent infrastructure systems involves analyzing the impact of the loss of third-party infrastructure systems, and further takes into account shared vulnerabilities or interdependencies. To assess such risks, PJM depends on information provided by government and industry organizations that identify possible vulnerabilities and threats to infrastructure systems. The probability of such risks is largely informed by past events, since they are likely to reoccur if they have not been fully mitigated. Additionally, improvements in communication and coordination with such systems are intended to improve PJM's ability to anticipate future threats and their implications. Examples of such interdependent infrastructure systems include communication providers, interstate gas pipelines, LDCs, and water utilities. Other fuel delivery networks such as coal and oil could also be examples of interdependencies under certain circumstances. The challenge associated with the loss of interdependent infrastructure systems is that operation of the BES is heavily dependent on such systems and PJM doesn't have any control and only limited transparency into such systems.

Additional information is needed from the infrastructure systems with which the BES has the highest degrees of interdependency, specifically natural gas systems, commercial telecommunication networks and systems, and water delivery systems.

i. Natural Gas Pipelines

As the proportion of natural gas generation has increased in the PJM footprint, PJM's dependence on the natural gas pipeline infrastructure has grown significantly. In Order No. 787,[35] the Commission clarified that an exception exists to the Commission's rules on limitations of sharing of pipeline information by enabling voluntary sharing of information between pipelines and RTOs. Specifically, it revised its "regulations to provide explicit authority to interstate natural gas pipelines and public utilities that own, operate, or control facilities used for the transmission of electric energy in interstate commerce to share non-public, operational information with each other for the purpose of promoting reliable service or operational planning on either the public utility's or pipeline's system."[36] The purpose of the revisions was to "help maintain the reliability of pipeline and public utility transmission service by permitting transmission operators to share information with each other that they deem necessary to promote the reliability and integrity of their systems."[37] Although this was a helpful step, PJM's experience has shown that the implementation of Order No. 787 has varied markedly among the pipelines. The level of information sharing and communication differs notably among the pipelines with some simply providing information contemporaneous with that information being publicly posted while others provide the RTO, as the entity with real-time reliability responsibilities, with a more informative "look forward" as to the state of the pipeline system

[35] Communication of Operational Information Between Natural Gas Pipelines and Electric Transmission Operators, 145 FERC ¶ 61,134 (2013) ("Order No. 787").

[36] Order No. 787 at P 1.

[37] *Id*.

both day-ahead and in real-time so that PJM operators can best consider whether PJM itself needs to proactively move into conservative operations. By the same token, despite Order No. 787's blessing, some pipelines still contend that information that is specific to individual customers cannot be shared with system operators on a confidential basis, even for reliability reasons without requiring a circuitous process of obtaining end use customer consent. And other pipelines still believe that the Commission is somehow legally constraining them from providing information to PJM earlier than it provides it to the general public for fear of charges of discriminatory treatment. This is not to say that great progress has not been made. PJM appreciates the efforts that pipelines have made, in individual cases, to work with PJM. On the other hand, the inconsistency in the level and content of information shared is an obvious tangible limitation that stems from the voluntary nature of Order No. 787's requirements.

The Commission could help address these issues by opening a new docket to review progress under Order No. 787 and inquire whether further clarification and directives in this area are needed. In PJM's view, confidential information sharing should be both uniform and mandatory when the information is identified as needed to enhance the reliability of the BES as well as the pipeline system. The goal of this new level of coordination should be analogous to the equivalent level of coordination responsibility that the Commission through NERC has assigned Reliability Coordinators in the NERC standards for example IRO-014-3.[38] This standard outlines obligations for coordination and data sharing between entities responsible for infrastructure reliability and provides a good template for the level of coordination which should be similarly consistent and effective as between gas and electric operating entities.[39]

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[38] *See* NERC Reliability Standard IRO-014-3 - Coordination Among Reliability Coordinators, Eff. Apr. 1, 2017, available at http://www.nerc.com/pa/Stand/Reliability%20Standards/IRO-014-3.pdf.

[39] To be clear, there is additional work to be done with respect to analysis of supply and transportation disruptions for coal and oil as well, but the criticality of such disruptions tends to be less by comparison to those for natural gas.

In addition, greater communication and coordination is needed with the LDCs that supply wholesale generation, and the Commission should support such efforts including evaluating whether communication and coordination obligations should be imposed on LDCs that supply jurisdictional wholesale generation. The Commission should examine whether such cooperation and coordination requirements could be imposed on LDCs, if not directly than perhaps indirectly as shippers under Commission-jurisdictional tariffs. Additional concerns regarding the interaction between electric and gas sectors are discussed in response to Question 2(s).

ii. Commercial Telecommunication Networks and Systems

The challenge of achieving reasonable levels of cooperation and coordination is just as great, if not greater, in the communications sector, where legal and regulatory prohibitions on information exchange affects the ability to identify areas of mutual concern. The industry is in need of inter-agency review of this issue as between the FCC, state regulatory commissions, and the Commission with the goal of improving coordination with other critical interdependent infrastructure systems over which the Commission has no direct authority *(e.g.*, telecommunications, water utilities) that (i) could be impacted through events of type discussed herein, or (ii) are themselves vulnerabilities that could contribute to, or amplify the impact of such events. Therefore, PJM urges the Commission to work to further the development of federal mechanisms to allow and encourage targeted cross-sector information sharing, in coordination with the Commission, DHS, FEMA and the FCC, would greatly increase the ability to develop a more accurate and comprehensive risk assessment.

The proliferation of automation technology at all levels of grid operation has resulted in a growing dependence on uninterrupted data and voice connectivity between unmanned facilities and grid operators throughout the country to perform real-time load balancing and reliability functions. PJM has invested in redundant data centers and telecommunication providers as well as private lines and satellite communications, so as to avoid being solely dependent on the public switched network. While this provides PJM with resilient capability, there are still significant dependencies on commercial communications infrastructure that are beyond the purview of PJM and other PJM electricity industry participants. An improved understanding of comparable "common mode" failures in other industries is vital to ensuring more comprehensive risk assessments. The greatest challenge to assessing the impacts of these risks is accurate modeling of interdependent systems to better understand the breadth and depth of their impact on the BES.

5. Severe Terrestrial Weather

Severe terrestrial weather threats include common events such as hurricanes, wind storms, ice/snow storms and related occurrences such as storm surge flooding. From a resilience perspective, the frequency and magnitude of these events is decidedly on the rise and the resilience threat is the extreme storms that destroy infrastructure such that service cannot be restored. Recent hurricane events in Puerto Rico and the U.S. Virgin Islands highlight the potential impacts of such an extreme storm, and the duration of outages in both territories extended far beyond any events experienced in the continental United States.

PJM currently prepares for weather events by delaying outages, returning equipment being maintained to service, and entering into conservative operations to increase operational awareness and responsiveness. PJM has a staff meteorologist who analyzes weather conditions and terrestrial hazards, and works closely with system operators to inform system operations decisions.

6. *Earthquake*

The PJM footprint overlaps with three seismic zones, but it is largely outside of the nation's areas of the highest risk for the direct impact of an earthquake. However, the impacts associated with an earthquake could have significant effects on the functionality and survivability of the BES system. PJM does not currently plan for earthquakes because of the low regional risk. This is an area where Commission or NERC guidance on the appropriate risk assessment, risk tolerance level, and mitigation plan would be valuable. A significant challenge to assessing the risk of an earthquake is the unknown impact on interdependent systems. Guidance from the Commission or NERC standards to address this risk would be welcomed.

7. *Geomagnetic Disturbance*

The distinctive characteristic of GMDs, when compared to other Earth weather phenomena, is its *wide-area* of impact. A geomagnetic disturbance could engulf the entire PJM footprint. There are two NERC standards that mitigate the risk posed by GMDs – EOP-010 and TPL-007-1.[40]

PJM has implemented operating procedures to address the requirements of NERC Standard EOP-010.[41] These procedures are detailed in PJM's Emergency Operations Manual[42] and include monitoring early warnings provided by the National Oceanic and Atmospheric Administration and real-time field measurements, and taking conservative measures to mitigate the impacts of a GMD. PJM is currently working on the vulnerability assessment required by

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[40] *See* NERC Reliability Standard TPL-007-1 - Transmission System Planned Performance for Geomagnetic Disturbance Events, Eff. July 1, 2017, available at http://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-007-1.pdf.

[41] *See* NERC Reliability Standard EOP-010-1, Geomagnetic Disturbance Operations, Eff. Apr. 1, 2015, available at http://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-010-1.pdf.

[42] PJM, Manual 13: Emergency Operations, §§ 2, 3, 4 (rev. 65, Jan. 1, 2018), http://www.pjm.com/-/media/documents/manuals/m13.ashx.

NERC Standard TPL-007-1. The likelihood of this high-impact, low-frequency event is defined by the standard as a 1-in-100 year benchmark storm. This standard requires a corrective action plan to prevent instability, uncontrolled separation, or cascading.

8. Generally

In addition to the above, PJM plans for risks associated with high-impact, low-frequency events by conducting business continuity recovery exercises and grid operator training, participating in industry and government functional and table-top exercises, and conducting a recurring business impact analysis to identify new internal vulnerabilities and corresponding mitigation activities to reduce risk. These activities influence the development and improvement of operating procedures for PJM's Incident Response Team, Cybersecurity Incident Response Team and Operation Incident Response Team. PJM created these teams to respond during significant events, including high-impact, low-frequency events, and to coordinate internal and external activities related to response and recovery activities.

9. Challenges

Generally, the primary challenge to assessing the impact of a high-impact, low-frequency event is that it is impossible to anticipate or account for every situation. Moreover, evaluating high-impact, low-frequency events is uniquely difficult for events for which there is very little data available due to the infrequent occurrence of events of such magnitude. As a result, it is impossible to develop precise quantitative metrics for the measurement of resilience risks. To address this challenge, PJM uses information from external events to address the probability and impact of it occurring within PJM's footprint.

PJM has generally addressed the challenges to such risk assessments in its response above. Simply put, RTOs need to be expressly empowered to lead on resilience. In addition,

addition Commission leadership is needed on these issues, including setting forth work streams. As discussed in response to Question 2(a), there needs to a process for vulnerability threat verification. The Commission needs to provide intelligence and metrics to apply to resilience vulnerability and threat analyses, such that they can then guide and anchor subsequent RTO planning, market design, and/or operations directives. Overall there needs to be better information made available to the RTOs on the above-identified risks to enable the RTOs to assess the risks. This information could be supplied from a wide range of federal agencies and interdependent systems.

(d) Should each RTO/ISO be required to identify resilience needs by assessing its portfolio of resources against contingencies that could result in the loss or unavailability of key infrastructure and systems? For example, should RTOs/ISOs identify as a resilience threat the potential for multiple outages that are correlated with each other, such as if a group of generators share a common mode of failure (e.g., a correlated generator outage event, such as a wide-scale disruption to fuel supply that could result in outages of a greater number of generating facilities)? The RTOs/ISOs should also discuss resilience threats other than through a correlated outage approach. Do RTOs/ISOs currently consider these types of possibilities, and if so, how is this information used?

RTOs should have leadership role in planning for resilience, including being required to identify resilience needs for contingencies that could result in the loss or unavailability of key BES infrastructure and systems. The RTOs should also identify and assess resilience threats using a correlated outage approach where there is potential for common mode failures as may be the case with fuel disruption scenarios. Historically, the BES has been assessed in accordance with NERC standards such as the TPL-001-4 standard.[43] The standard requires an assessment of the loss of facilities due to equipment failures as well as the loss of multiple facilities that may result from extreme weather conditions such as tornados. In addition to assessing the impact of

[43] *See* NERC Reliability Standard TPL-001-4 - Transmission System Planning Performance Requirements, Eff. Jan. 1, 2015, available at http://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf.

random equipment failures and extreme weather, it is important to assess the system for the impact of man-made threats such as the loss of an entire substation or other key transmission infrastructure, as well the loss of interdependent infrastructure.

The NERC CIP-014 standard requires Transmission Owner assessments to identify critical facilities that if rendered inoperable would result in instability, uncontrolled separation, or cascading outages. RTOs should be required to assess the impact of the loss of such critical facilities, including facilities that the RTO itself may identify as critical on a regional basis based upon existing NERC criterial or other criteria that is developed by the RTO. PJM is actively evaluating how to incorporate resilience into the planning process, including discussions regarding (a) making sure that system changes done as part of the Regional Transmission Expansion Plan ("RTEP") do not make the BES less resilient, (b) developing procedures to compare solution alternatives and ensure selection of the alternative that enhances resilience,[44] and (c) developing resilience criteria where the system has vulnerabilities that require mitigation. The Commission should require that all RTOs (and transmission providers in non-RTO regions) submit a subsequent filing, including any necessary proposed tariff amendments, to implement resilience planning criteria, including processes for the identification of vulnerabilities, threat assessment and mitigation, regional restoration planning, and related process or procedures needed to advance resilience planning. To be clear, RTO resilience planning not only includes traditional transmission planning, but also an enhanced role in guiding regional restoration planning efforts.

In order to give RTOs an affirmative role in planning for resilience, they must have clearly articulated authority to do so. This can easily be accomplished by the Commission

[44] Ideally, such analyses would also include an assessment of generation, energy storage, distributed resource alternatives, and technology alternatives.

articulating in an order concluding that the regional planning responsibilities of RTOs currently mandated under 18 CFR § 35.34(k)(7), which among other things, require RTOs to plan, direct and arrange needed transmission expansions, additions and upgrades to enable it to provide efficient, reliable and non-discriminatory transmission service, also include an obligation for RTOs to plan for and address resilience, pursuant to FPA, section 217 which requires the Commission to exercise its authority "under this chapter in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities."[45] Further, after confirming that resilience is a component of such planning as set forth in the regulations, the Commission should initiate a new rulemaking or other appropriate proceedings to further articulate the RTO role in resilience planning.

(e) Identify any studies that have been conducted, are currently in progress, or are planned to be performed in the future to identify the ability of the bulk power system to withstand a high-impact, low-frequency event (e.g., physical and cyber-attacks, accidents, extended fuel supply as part of a periodic review process or conducted on an as-needed basis.

PJM conducts independent studies and participates in industry studies to identify the ability of the BES to withstand high-impact, low-frequency events. Independent studies conducted by PJM include:

- Semi-annual Operations Analysis Task Force Seasonal Assessments, which include sensitivity analysis of Maximum Credible Disturbance and gas pipeline contingencies;
- Cascading Tree analyses[46] to assess the ability of the BES to withstand various extreme contingencies. These "extreme contingencies" include multiple facilities, such as the loss of an entire substations, loss of all transmission on a common right-of-way, loss of all generation at a single location and common-mode failures

[45] FPA, section 217, 16 U.S. Code § 824q(b)(3)(B)(4).

[46] A Cascading Tree analysis is an analysis PJM developed to model power flows through current or proposed transmission infrastructure to determine the likelihood of a cascading outage.

such as the loss of generators supplied by a common section of the gas pipeline system; and

- Extreme contingency assessments associated with the NERC Standard TPL-001-4.

The industry studies in which PJM has participated, which were intended to identify the ability of the BES to withstand a high-impact, low-frequency event, are:

- Cyber risk studies at the BES scale, which were limited to exercises such as Grid Ex, and are designed to test response policies and capabilities, but which do not generate a model or study related to the anticipated effects of a cyber event on interconnected systems. These exercises led to greatly improved coordinated, cross-sector and public/private cyber response capabilities as a means to speed recovery times, but additional study is needed to better understand the expected impacts of a large-scale cyber-attack; and

- GMD studies centered around the NERC Standard TPL-007-1 which outline the transmission system planned performance for GMD events. The standard provides information on the anticipated effects of ground induced current and direction for GMD vulnerability assessments. Also included are recommendations for system posturing and conservative operations intended to limit the anticipated effects of a GMD. Additional study is needed to better understand what physical infrastructure hardening is most operationally and cost effective to implement. PJM has participated in the EMP studies, including the Electric Power Research Institute ("EPRI") project with more than 50 industry participant organizations in a three-year study on the E1 and E3 pulse associated with a high-altitude nuclear detonation and their effects on the BES. This includes the testing of transmission and distribution critical components such as relays, breakers, insulators, and other low-voltage electronics to determine their survivability following an event. The study will help determine the probability of component failure and the potential for corresponding system impacts for the purpose of identifying and validating the most effective physical and operational mitigation measures. Once completed, additional research will be needed to aggregate the results to develop enhanced modeling of system survivability and cost-benefit analysis of mitigation strategies. At present, very little mitigation is in place for EMP due to the lack of information regarding the anticipated effects of EMP or the relative effectiveness of hardening techniques and operating procedures.

Despite these efforts, industry studies on cyber and physical attacks are currently limited to exercises designed to test response procedures following an event and are very limited in their assessment of the BES at large. The PJM studies that have been conducted to date have focused on identifying specific vulnerabilities such as the loss of a substation or common mode outages such as the loss of generation fed from common gas infrastructure, but have not taken into consideration the effects associated with the loss of multiple substations or critical system components as could be contemplated in a coordinated physical attack. More work is needed in this area.

(f) In these studies, what specific events and contingencies are selected, modeled, and assessed? How are these events and contingencies selected?

The events that PJM selects, models and assesses are based on threats previously experienced in the PJM Region, and are typically weather related such as the 2014 Polar Vortex and Hurricane Sandy in 2012. They are selected because PJM can use them to simulate what occurs when there is a loss of transmission and generation facilities. PJM selects these events using a vulnerabilities-based approach to create the circumstances needed to test grid operators on procedures ranging from targeted load shedding to Black Start. The extent of the impacts modeled is based on what is needed to test the survivability of the system and the ability of our grid operators to respond and remediate outages.

The contingencies selected, modeled and assessed to test operational limits by PJM are largely based on what PJM calls Maximum Credible Disturbance ("MCD") criteria. A MCD is defined as an event having a reasonable possibility of occurring (being credible), that is outside the normal N-1 contingency criteria regarding the anticipated impact on the system,[47] and involves forced outages of multiple facilities. These assessments are completed when or for elevated DHS security levels, elevated PJM security levels, solar magnetic disturbance forecasts, imminent severe weather, significant political events (Presidential Inaugural), any other phenomena that increases exposure of grid facilities (sabotage of BES facilities). While the

[47] PJM Manual 38, Revision 11, Dated Feb. 1, 2018, Attachment A, section A.5.

MCD contingency is not normally monitored because the likelihood of their occurrence under normal operating conditions is extremely low, under certain extreme conditions it may become prudent to consider these potential risks in PJM's daily system analysis, and modify operational philosophy to determine what effort may be required to enable the system to survive their potential occurrence. For example, it is not likely that a transmission tower carrying multiple lines will fail under normal weather conditions, however, if there is a tornado watch in the area, the likelihood increases and it is then prudent for PJM to consider that risk in its system analysis.

Additionally, PJM has established processes to model potential natural gas contingencies across the PJM footprint. Under certain system conditions or events affecting either the electric or gas infrastructure, PJM will operate to reflect the impact of gas infrastructure contingencies (pipeline ruptures, compressor station failures) on the PJM Region due to their potential impact on multiple natural gas generators. PJM staff has created procedures to ensure operators have a clearly defined process to address gas pipeline impacts the BES and required generation reserves.

(g) What criteria (e.g., load loss (MW)), duration of load loss, vulnerability of generator outages, duration of generator outages, etc.) are used in these studies to determine if the bulk power system will reasonably be able to withstand a high-impact, low-frequency event? Are the studies based on probabilistic analyses or deterministic analyses?

Because PJM does not have formal resilience criteria, PJM adapts existing analyses, such as the aforementioned NERCD CIP-14, MCDs, and Cascading Trees analyses, to derive conclusions about the ability of the PJM BES to withstand a high-impact, low-frequency event, and is working with stakeholders to determine how best to incorporate resilience into PJM's planning process and what criteria should be used.[48] If the Commission is concerned about the ability of PJM and its stakeholders to come to agreement on appropriate planning criteria to be

[48] PJM, *Resilience in System Planning*, Aug. 10, 2017), http://www.pjm.com/-/media/committees-groups/committees/pc/20170810/20170810-item-07-grid-resilience-in-system-planning.ashx.

utilized to address resilience, PJM requests that the Commission direct PJM to submit a filing proposing any necessary Tariff revisions required to implement resilience planning criteria, and develop processes for the identification of vulnerabilities, threat assessment and mitigation, restoration planning, and any related process or procedures needed to advance resilience planning, including any related procedures that PJM proposes to utilize in order to provide the proper level of transparency while also maintaining the security of the critical infrastructure together with any mitigation plan. As the stakeholder process responds best to deadlines, PJM would ask that the Commission provide for a filing by RTOs on these matters within nine to twelve months after the issuance of Commission direction to RTOs on this issue.

Generally, PJM uses deterministic studies and methods to determine if the BES will reasonably be able to withstand a high-impact, low-frequency event, focus on the loss of generation, loss of load, probability of cascading outages and voltage collapse. PJM typically uses probabilistic analysis based on the likelihood of weather conditions or corresponding load and generation unavailability given those system constraints are largely employed in the operations timeframe as input into the timing of declaring conservative operating procedures.[49] As noted above, however, there are other ways of conducting the relevant analyses other than probabilistic studies or deterministic studies.

(h) Do any studies that you have conducted indicate whether the bulk power system is able to reasonably withstand a high-impact, low frequency event? If so, please describe any actions you have taken or are planning as mitigation, and whether additional actions are needed.

While PJM has not conducted any studies that definitively address whether the BES as a whole is able to withstand a high-impact, low-frequency event, PJM has incorporated into its planning process and operating procedures improvements based upon its participation in multiple

[49] See PJM Manual 13.

industry studies which address the impacts of such events, and its own internal studies on specific segments or elements of the BES within its footprint.

That being said, mitigation efforts are needed to address the vulnerabilities to the BES that PJM has identified, and should be incorporated in the development of PJM's RTEP process. For that reason, as indicated above, PJM has commenced discussions with its stakeholders to incorporate resilience into its planning process. In July of 2017 PJM introduced the topic of incorporating resilience into the planning process with stakeholders.[50] These discussions are expected to continue through 2018. PJM is also working to develop analytical tools and procedures to assess the impact of proposed upgrades to ensure their implementation doesn't compromise the resilience of the BES.

Operating procedures can also mitigate the risk associated with high-impact, low-frequency events. However, neither the Tariff nor the Operating Agreement allow PJM to suspend market operations and pay generation providers based on their costs to operate at PJM's direction even if doing so is outside of the market. The ability of PJM to *adapt* in real-time in order to mitigate the risk is intrinsically associated with its *authority* to operate the system. Given that there are no current, explicit requirements to reinforce the BES to withstand or reduce the magnitude of high-impact, low-frequency events, whenever a contingency that is identified that would result in a violation to PJM planning or operating criteria for a high-impact, low-frequency event, PJM would have to establish conservative operating procedures to provide operators with instructions on how to respond to such threats. PJM would also need authority from the Commission, under such extreme circumstances, to suspend market operations, implement cost-based compensation, and direct operation of generation. Accordingly, if the

[50] PJM, *Resilience in System Planning*, posted for PJM's July 2017 Planning Committee meeting at http://www.pjm.com/-/media/committees-groups/committees/pc/20170713/20170713-item-08-grid-resilience-in-system-planning.ashx.

Commission believes PJM should have such authority in support of resilience, the Commission should require that PJM conduct a stakeholder process and submit a filing proposing amendments to the Tariff and/or Operating Agreement to permit PJM to direct resources to commence non-market operations during emergencies, extended periods of degraded operations, or unanticipated restoration scenarios, including provisions for cost-based compensation when the markets are not operational or when a wholesale supplier is directed to take certain emergency actions by PJM for which there is not an existing compensation mechanism.[51]

(i) How do you determine whether the threats from severe disturbances, such as those from low probability, high impact events require mitigation? Please describe any approaches or criteria you currently use or otherwise believe are useful in determining whether certain threats require mitigation.

PJM participates in industry groups that discuss threat identification and planning for reliability and resilience risk mitigation. In addition, PJM completes analyses as described in response to Question 2(e) to identify potential vulnerabilities to the BES. However, while PJM does take steps to address or mitigate certain vulnerabilities that could be implicated by a broad range of causes or threats, at present no explicit determinations are made regarding whether identified threats require mitigation because no formal criteria or approaches (hereinafter collectively referred to as "criteria") have been established to analyze whether threats from high-impact, low frequency events can or should be mitigated for system resilience.

In order for RTOs to make determinations regarding whether threats from high-impact, low-frequency events should be mitigated, criteria need to be developed and the Commission should direct the RTOs and transmission owners to develop such criteria and establish the verification process outlined below. These additional criteria can, and should, be anchored in the

[51] Any such RTO procedures would be limited, and would not interfere with DOE emergency actions under FPA, sections 202(c) or 215A. 16 U.S.C. §§ 824a(c), 824o-1.

conditions described in NERC Standard CIP-014-2. Specifically, threats may require mitigation if they affect vulnerabilities or create disturbances so severe they lead to (1) instability, (2) uncontrolled separation, and (3) cascading outages beyond current reliability criteria. Threats could be prioritized for mitigation based upon their comparative impact resulting from such a deterministic analysis. Once a risk for instability, uncontrolled separation, or cascading outages is identified, it could be mitigated through enhanced resilience criteria as part of an RTO's existing regional transmission plan.

An important consideration to keep in mind when establishing criteria is that it is not economically efficient to protect the BES from every conceivable risk. Therefore, any mitigation strategy must be prioritized in terms of having the most risk reduction across multiple threats and risk reduction benefits. As discussed above, the Commission should not require RTOs to strictly depend on quantitative analyses given the difficulties of assigning probabilities to various threats. An RTO's independence and regional expertise make it well-positioned to identify the vulnerabilities and mitigating solutions, and assess the efficiency, effectiveness, impact and feasibility of mitigation strategies. However, the verification process which PJM requests the Commission develop would significantly assist in ensuring that the RTO identification of threats and vulnerabilities is consistent with classified information available to the Commission and other federal agencies but not necessarily to RTO system planners.

(j) How do you evaluate whether further steps are needed to ensure that the system is capable of withstanding or reducing the magnitude of these high-impact, low frequency events?

PJM can evaluate whether additional actions are needed to enhance the system's ability to withstand or reduce the magnitude of high-impact, low frequency events by employing power system impact models for losses of infrastructure or systems that lead to instability, separation, or cascading outages. When an assessment results in system instability, separation, or cascading outages, it is indicative of a resilience vulnerability that needs to be further examined for mitigation. This does not imply the system is not reliable, but that more analysis and modeling is needed to determine the relative importance and severity of any potential resilience vulnerabilities that could be impacted by high-impact, low frequency events. With such modeling, assessments of the relative severity of potential vulnerabilities can be performed in a way that can focus system design and enhancement on the most reliable and economically efficient projects first. To do so in a more efficient and effective manner, enhanced modeling is needed which captures multiple modes of failure over wider geographic areas incorporating multiple infrastructure systems to account for interdependencies.

Additionally, resilience analyses can also be performed for restoration scenarios, which currently generally assume that a significant amount of the infrastructure and resources are available. However, power flow analysis tools are needed to conduct real-time assessments based on impacts from events as they are unfolding in order to accurately identify the activities likely to have the maximum positive effect on system restoration. RTOs and transmission owners are capable of modeling such scenarios based upon vulnerabilities or losses of infrastructure and assessing whether additional actions should be taken to mitigate risks. PJM has developed a Resilience Roadmap[52] and engaged its stakeholders through the Security and Resilience Subcommittee and other stakeholder committees to review existing processes, procedures and criteria to determine what enhancements can be made to move beyond reliability toward resilience. However, significant challenges still remain such as identifying the

[52] *See* PJM, *Draft Resilience Roadmap*, at http://www.pjm.com/-/media/committees-groups/committees/oc/20170606 /20170606-item-18-resilience-roadmap.ashx.

appropriate threat scenarios for which the BES should be reinforced, while at the same time balancing probability, risk and economic efficiency.

(k) What attributes of the bulk power system contribute to resilience? How do you evaluate whether specific components of the bulk power system contribute to system resilience? What component-level characteristic, such as useful life or emergency ratings, support resilience at the system level?

From a system planning perspective, the attributes of the BES that contribute to resilience are transmission design (robust and electrically dense versus sparse networks), proximity of generation to load centers, geographic dispersity of load and generation resources, margins on BES facility thermal and voltage limit loadings (i.e., the difference between normal flow and emergency capability), generator megawatt and megavar reserves, dynamic megavar reserves on transmission elements, level and availability of resource reliability attributes, the effectiveness of the system restoration plan including the proximity of Black Start Units to the next tier of Critical Restoration Units, the fuel security of both Black Start Units and Critical Restoration Units, and the redundancy of cranking paths used in restoration.[53]

PJM evaluates components of the BES to determine whether they contribute to system resilience by using regional expertise, operating experience and deterministic analyses. Specifically, PJM can perform power flow studies that simulate extreme contingencies. PJM can also evaluate and discuss lessons learned and perform after-the-fact simulations of actual events to ensure models, operating protocols, reserve calculations, incentives for performance and penalties for non-performance, for example, are accurate and appropriate.[54]

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[53] *See* Fuel Report at 6, 17, 35, 40.

[54] *See* PJM, *Technical Analysis of Operational Events and Market Impacts During the September 2013 Heat Wave* (Dec. 23, 2013), http://www.pjm.com/-/media/library/reports-notices/weather-related/20131223-technical-analysis-of-operational-events-and-market-impacts-during-the-september-2013-heat-wave.ashx?la=en ("2013 Hot Weather Report"); PJM, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events* (May 8, 2014), available at http://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx ("2014 Cold Weather

The component-level characteristics that support reliability and resilience at the system level include dynamic megavar and megawatt reserves, short-term equipment ratings, and the proper maintenance of generation and transmission assets. As noted in previous responses, PJM has conducted ad hoc assessments of the resilience of the system by simulating various high-impact, low-frequency events and other extreme events. In addition to capturing metrics such as the probability of cascading outages and amount of load loss or generation loss, PJM also captures facilities with a higher likelihood of contributing to a cascading outage. Studies have shown that some facilities are more likely to contribute to a cascade for multiple high-impact, low probability events. The design of these facilities can be reviewed to identify component-level limitations that are contributing to the likelihood of cascade. This concept can be extended to evaluation of system enhancements to determine the amount of "head-room" that they may create to promote the overall resilience of the BES.

In addition to these efforts, PJM performs a probability risk assessment on the 500/230kV transformer fleet based upon the historical failure rates of such transformers (not in response to specific threats) because the failure of one of these transformers may have a significant impact on the efficient operation of the BES for an extended period given the time to repair or replace the equipment. The probabilistic risk assessment, which includes production cost simulations and a condition assessment of the transformers, is used to make recommendations on the number and location of spare transformers. To establish the risk of a transformer failure, PJM reviews a condition assessment of the transformer provided by the asset owner and makes a determination regarding both the probability of failure and the consequences of the failure. The results of the probabilistic risk assessment are shared with the Transmission Owners to determine the

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Report"); PJM, *2015 Winter Report* (May 13, 2015), available at http://www.pjm.com/-/media/library/reports-notices/weather-related/20150513-2015-winter-report.ashx?la=en ("2015 Winter Report").

probability of a transformer failure event in which no spare transformer or mitigating action is available. If a spare transformer is needed to mitigate the risk of a transformer failure to the system, a transformer will be purchased by the Transmission Owner. PJM is considering extending this work to other critical components on the BES. Moreover, the PJM Transmission and Substation Subcommittee and the PJM Relay subcommittee have developed design standards which include various levels of redundancy such as relay protection and controls and station service batteries, and robust substation and equipment configurations that promote resilience.[55]

Spare equipment sharing models that provide utilities with access to spare transmission equipment for a fee do exist and should be further developed to enhance the ability to be resilient. A regional approach to a spare equipment sharing model to purchase and maintain spare transmission equipment with preplanned transportation and logistics support in the event of normal failures or a catastrophic event is a cost effective methodology that should also be further explored.

(l) If applicable, how do you determine the quantity and type of bulk power system physical asset attributes needed to support resilience? Please include, if applicable, what engineering and design requirements, and equipment standards you currently have in place to support resilience? Are those engineering and design requirements designed to address high-impact, low-frequency events? Do these requirements change by location or other factors?

As a Commission-approved definition of resilience has not been finalized, and PJM's request to the Commission to use resilience as a planning driver is still under stakeholder consideration, the question seeking the "quantity and type of bulk power system physical asset attributes needed to support resilience" is difficult to respond to in a broad fashion. Today, with

[55] PJM, *Protective Relaying Philosophy and Design Guidelines* (Aug. 15, 2013), http://www.pjm.com/~/media/committees-groups/subcommittees/rs/postings/protective-relaying-philosphy-and-design-guidelines.ashx.

the exception of its Black Start program, reserves and other generation/supply attributes procured by PJM, PJM does not explicitly identify the quantity and type of BES physical asset attributes needed to support resilience. However, as described above, PJM assesses the overall system performance primarily with respect to reliability, and is capable of doing so under certain extreme scenarios caused by certain threats. For example, mitigating critical facilities would materially advance resilience without necessarily determining a quantity and type of bulk power system physical asset attributes. In other cases, like Black Start, operating reserves, and load following, PJM is currently assessing whether it is procuring the right amounts of these services in the right manner through various analyses of system operations and efficiencies.

Further, PJM has developed design, engineering and construction guidelines for transmission facilities within the PJM Region to ensure the operability and reliability of the BES within the PJM Region. While the guidelines were not developed with the expressed intent to address resilience to high-impact, low frequency events, they do in fact support resilience because they make the system more robust and increase redundancy.[56]

PJM has also analyzed reliability attributes supplied through generation and other resources.[57] While these essential attributes support reliability, the maintenance or assurance of these attributes into the future are important to resilience mitigation. PJM will need to continue to conduct analysis of the anticipated future availability of these attributes so that it can proactively address the maintenance of these attributes through the markets. PJM will also consider the operational lessons learned from other RTOs in regard to resource mix and essential resource attributes to continue to analyze future trends in resource mix and their impacts on both reliability and resilience. This includes the high penetration of renewables in California

[56] The guidelines are posted on the PJM website at http://www.pjm.com/planning/design-engineering.aspx.

[57] Fuel Report at 3-6, 8, 11, 14-20.

Independent System Operator, Southwest Power Pool and Electric Reliability Council of Texas, Inc. ("ERCOT"), as well as the natural gas dependency in ISO-New England Inc.

(m) To what extent do you consider whether specific challenges to resilience, such as extreme weather, drought, and physical or cyber threats, affect various generation technologies differently? If applicable, please explain how the different generation technologies used in your system perform in the face of these challenges.

Generation within PJM is both geographically and fuel diverse, which provides an inherent level of resilience by avoiding circumstances in which a single weather event can affect a disproportionate number of assets or a dependence on a single fuel source can create a single point of failure. With regard to the extent to which PJM considers whether specific challenges to resilience affect various technologies differently, PJM does not focus on particular fuel types but instead identifies attributes that are needed from all resources and uses those attributes to create performance requirements. For example, the PJM Ancillary Service and capacity markets require resource adherence to such specific attributes. This model allows the generating unit owner to align the generating unit's operating capabilities, including fuel requirements and performance metrics, as necessary to meet the attributes established in the market. The Reliability Pricing Model ("RPM") three-year forward capacity market has technology-neutral performance requirements that identify operational attributes of generation assets without regard to fuel type.[58] In the same vein, PJM has minimum requirements for its Regulation market, some of which are pending before the Commission.[59] These market mechanisms and processes create the means to set operating capabilities to minimize unplanned outages of generation assets of types, regardless of fuel source.

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[58] Tariff, Attachment DD, section 8.

[59] Tariff, Attachment K-Appendix, section 3.2.2; Operating Agreement, Schedule 1, section 3.2.2; *see PJM Interconnection, L.L.C.*, Revisions to OATT and OA Re: Reg D Performance and Compensation, Docket No. ER18-87-000.

During periods of extreme weather and similar periods of enhanced operational awareness (such as the solar eclipse), PJM uses conservative operating procedures to address potential operational challenges in order to maintain system reliability.[60] In short, PJM takes steps to minimize operational risks to the system and affirmatively takes actions to dispatch generation out of merit (at its minimum load) in order have to it available. After the fact, PJM conducts event-specific analysis to determine future operator actions for similar circumstances.

(n) To what extent are the challenges to the resilience of the bulk power system associated with the transmission system or distribution systems, rather than electric generation, and what could be done to further protect the transmission system from these challenges?

1. Extent of Challenges to BES Associated with Transmission and Distribution Systems

The BES is an integrated system of electric generation, transmission and lower voltage distribution facilities and as such, resilience challenges can be initiated in any of these three areas. Nevertheless, the challenges to the resilience of the BES are primarily associated with the transmission and distribution systems.[61] The impact of resilience challenges to distribution facilities are typically local in nature whereas resilience challenges to transmission and generation may have a much broader and more significant impact in terms of load effected and duration of the event. This is a byproduct of several factors, including the availability of the personnel and material needed to conduct distribution repairs compared to generation or transmission. Replacement towers and wire for high-voltage transmission, EHV transformers

[60] PJM, Manual 13.

[61] Rhodium Group, *The Real Electricity Reliability Crisis* (October 2017), http://rhg.com/notes/the-real-electricity-reliability-crisis; U.S. Dep't Of Energy, *Transforming The Nation's Electricity Sector: The Second Installment Of The QER*, Ch. IV, Ensuring Electric System Reliability, Security, and Resilience 4-2, 4-31 to 4-36 (Jan. 2017), https://www.energy.gov/sites/prod/files/2017/01/f34/Chapter%20I%20Transforming%20the%20Nation%E2%80%99s%20Electricity%20System--The%20Second%20Installment%20of%20the%20QER.PDF ("Electricity outages disproportionately stem from disruptions on the distribution system (over 90 percent of electric power interruptions), both in terms of the duration and frequency of outages, which is largely due to weather-related events. Damage to the transmission system, while infrequent, can result in more widespread major power outages that affect large numbers of customers with significant economic consequences.").

and the corresponding personnel needed to complete these repairs on the transmission system are less readily available than their distribution system peers. Furthermore, the larger geographic footprints and greater dependence on automation means the BES is more impacted by interdependent infrastructure, such as natural gas pipeline and third party telecommunication systems.

2. *Protecting Transmission System from Resilience Challenges*

The transmission system can be further protected from resilience challenges by leveraging existing emergency procedures, initiating conservative operations for known threats to the resilience of the system (such as periods of high GMD and by maintaining robust reserve levels), utilizing shared reserve agreements and having a pool of spare equipment. In addition, enhanced dispatcher tools, such as oscillation detection informed by phasor measurement units and PJM's Dispatch Interactive Map Application, which is a geographic information system (GIS) based visualization tool, can be utilized to promote situational awareness of evolving system challenges. Training including participation in drills that simulate resilience threats will help ensure dispatchers take appropriate actions in response to actual events in real-time.

Robust long-term planning, including developing and incorporating resilience criteria into the RTEP, can also help to protect the transmission system from threats to resilience. The PJM planning process should not add new critical facilities nor make existing critical facilities even more critical. Proper criteria could ensure that the system is not made less resilient as a result of new facilities required for other drivers. For example, it may not be advisable from a resilience perspective to run another transmission line to an existing substation if so doing makes that substation more critical. System resilience should be a consideration in the evaluation of planning solution alternatives so that PJM can select solutions that enhance the resilience of the system and address other system needs. Furthermore, resilience vulnerabilities that are significant enough to warrant a transmission system enhancement designed specifically to mitigate the resilience vulnerability could be designed and integrated into the RTEP. Examples of this can include building redundancy into Black Start cranking paths, reducing the criticality of substations through transmission line siting, and power flow diversity for areas with load congestion or high concentrations of Critical Restoration Units. In addition to developing the specific resilience criteria, RTEP process changes would also be required.

Finally, emerging technologies such as microgrids, advanced storage and DER could also help to mitigate resilience challenges on the BES. Based on the NERC Distributed Energy Resource Task Force recommendations, there are several ways DER and microgrids can be better integrated with transmission systems to gain a resilience benefit, including:

- Requiring data sharing across the transmission-distribution interface;
- Requiring DER owners to provide real-time data for modeling;
- Coordination between distribution and transmission providers for DER capabilities such as inverter settings; and
- Improved ability to model DER in system planning studies.

However, the penetration of these technologies is not significant enough today to have any meaningful impact on system resilience. As these technologies continue to be deployed, PJM may be able to utilize them to enhance resilience, provided they are observable and able to be controlled on a regional scale similar to existing transmission and generation infrastructure, and coordinate with distribution system operators to leverage these technologies to enhance the overall resilience of the integrated system.

(o) Over what time horizon should the resilience assessments discussed above be conducted, and how frequently should RTOs/ISOs conduct such an analysis? How could these studies inform planning or operations?

With respect to the BES in the PJM Region, the resilience assessments discussed above should be conducted annually with a five year planning horizon, to align with the near term analyses performed as part of PJM RTEP processes to ensure strong local transmission owner involvement and a consistency of approach across the PJM footprint. Additional resilience studies can be performed as part of PJM's Black Start review process, or as other major events require based on the current geo-political environment, evolving threat vectors to the electricity sector or other risks including extreme weather. These studies could inform planning as an input to PJM's RTEP process or assist in refining existing conservative operating procedures.

RTOs should also review their resilience plans on a more frequent basis to the extent there are lessons learned from major events that may need to be addressed on a timeframe that is shorter than the proposed five year period. But to be clear, a significant amount of work needs to be done to further define the vulnerabilities, threats and related resilience criteria as well as the details of any such resilience assessments. There are vulnerabilities and issues that need to be addressed today, and Commission leadership is needed to ensure that these are dealt with in a timely manner.

(p) How do you coordinate with other RTOs/ISOs, Planning Coordinators, and other relevant stakeholders to identify potential resilience threats and mitigation needs?

PJM recognizes the benefit to coordination and sharing. Today, in PJM's role as a NERC-registered Planning Authority and Reliability Coordinator, PJM coordinates with other RTOs, Planning Authorities and Reliability Coordinators for reliability as required by NERC. PJM's operating responsibilities include coordination and communications during emergencies with its neighbors, the Midwest Independent System Operator, Inc., Tennessee Valley Authority, New York Independent System Operator, Inc., and the VACAR companies through joint operating agreements. PJM's planning responsibilities include providing study inputs and results to adjacent Reliability Coordinator Areas.[62]

For cyber security, PJM coordinates with other RTOs through several forums including the IRC Security Working Group which discusses current threats, mitigation approaches and lessons learned. In addition, PJM participates in the ESCC Cyber Mutual Assistance program which enables coordination of resource sharing through established agreements and defined activation processes for approximately 130 electricity utilities.

PJM also participates in various industry groups that discuss resilience-related matters from time to time such as the NATF Spare-tire Project to identify best practices for operating procedures following an Energy Management System (EMS) outage, and the EPRI Black Sky Communications Project to explore critical communications capabilities following a resilience-scale event.

(q) Are there obstacles to obtaining the information necessary to assess threats to resilience? Is there a role for the Commission in addressing those obstacles?

There are obstacles to obtaining information necessary to assess cyber security threats because RTOs can only base their threat assessments on open source information and certain classified intelligence, but the information from classified sources is limited and does not provide a full and complete understanding needed to detect and respond to cyber-attacks. In addition, RTOs lack access to all relevant information about supply chain threats which pose a significant

[62] NERC Glossary defines Reliability Coordinator Area as: "The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas."

risk to the electric industry. Without this information, the electric industry is unable to help to mitigate certain risks that may be associated with such threats.

The ESCC and the E-ISAC continue to play a very positive influential role in removing obstacles in information sharing within the electric industry and across other sectors. Additional coordination and information sharing will be beneficial between the electric sector and local, state and federal government (FCC, FERC, DOE, DOD, DHS, and the Federal Bureau of Investigation), the telecommunications industry, natural gas pipeline industry and water utilities regarding critical infrastructure. Expanded participation in these information sharing partnerships is essential in improving the quality, relevance and timeliness of intelligence sharing.

(r) Have you performed after-the-fact analyses of any high-impact, low-frequency events experienced in the past on your system? If so, please describe any recommendations in your analyses and whether they have or have not been implemented.

PJM has performed post-event analyses including contributions to NERC analyses, PJM root cause analyses and PJM lessons learned on a number of extreme events on the BES in the PJM Region, including the events below, which vary in magnitude and impact to the PJM system, and are key events over the last 25 years:

- 1994 Deep Freeze (January 1994);
- 1999 Low Voltage Event due to insufficient reactive reserves (July 1999);
- 2003 Northeast Blackout (August 2003);
- 2012 Hurricane Sandy (October 2012)[63];
- 2013 Hot Weather Event (September 2013)[64];
- 2014 Polar Vortex (January 2014)[65];

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[63] RTO Insider, *Lessons from Hurricane Sandy: Dispersed Staffing, Generator Cuts* (June 11, 2013), available at https://www.rtoinsider.com/lessons-from-hurricane-sandy-dispersed-staffing-generator-cuts/.

[64] 2013 Hot Weather Report.

- 2015 Cold Weather Events (January - February 2015)[66];
- 2015 DC Low Voltage Disturbance Event (April 2015); and
- 2017/2018 Cold Weather Events (December 28, 2017-January 7, 2018) ("Cold Snap")[67].

Based on the results of these analyses, PJM has made numerous recommendations and changes to its rules regarding operations and planning, increased staffing, enhanced power flow models, implemented new tools and technologies, created generator preparedness checklists, updated its formula for resource adequacy and made market rules changes including Capacity Performance. PJM's recommendations are outlined in its published reports,[68] and PJM regularly discusses with stakeholders its recommendations at various stakeholder meetings.[69]

As a part of its standard business practice, PJM also reviews NERC lessons learned from high-impact, low frequency events that occurred outside of the PJM Region, as well as lessons learned and recommendations from other events, when the impacts result from unique circumstances that can be applied to PJM's system, and has modified PJM procedures, processes and tools as appropriate.[70]

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[65] 2014 Cold Weather Report.

[66] 2015 Winter Report.

[67] PJM, *PJM Cold Snap Performance Dec. 28, 2017 to Jan. 7, 2018* (Feb. 26, 2018), http://www.pjm.com/-/media/library/reports-notices/weather-related/20180226-january-2018-cold-weather-event-report.ashx ("2017-2018 Cold Snap Report").

[68] *See* 2013 Hot Weather Report, 2014 Cold Weather Report, 2015 Winter Report and 2017-2018 Cold Snap Report.

[69] *See* for example, PJM, *Hot and Cold Weather Recommendation Status* (January 2016), available at http://www.pjm.com/-/media/committees-groups/committees/oc/20160105/20160105-item-15-hw-and-cw-recommendation-status.ashx.

[70] PJM reviewed information about the lessons learned and recommendations from the ERCOT Cold Weather event of February 2011, WECC Southwest Blackout in September 2011, and the South Australian Blackout of September 2016, among others.

(s) Please provide any other information that you believe the Commission would find helpful in its evaluation of the resilience of the RTO/ISO systems.

As discussed above, loss of an interdependent system is both a significant vulnerability and threat to the BES. With the increase of natural gas generation on the PJM system, PJM has commenced significant efforts to better understand and prepare for this risk. But there are material areas of communication and coordination that need improvement and assistance from the Commission regarding the interdependencies between the gas and electric systems.

1. Gas/Electric Coordination

Considerable progress has been made on gas/electric coordination since the issue was debated and discussed at the series of roundtable meetings sponsored by then-Commissioner Phillip Moeller.[71] Since those meetings and the Commission's issuance of Order No. 787, PJM has entered into a Memorandum of Understanding ("MOU") with nine interstate natural gas pipelines from across the PJM footprint. The purpose of the MOU was to identify the specific types of information which would be shared and the communication and coordination procedures. The nine pipelines are Texas Eastern, Williams Transco, Columbia Gas Transmission, Dominion Gas Transmission, Dominion Cove Point, National Fuel Gas, Tennessee Pipeline, Natural Gas Pipeline of America, and Texas Gas. In addition, PJM has entered into similar data sharing agreements with the following LDCs: Dominion Energy Ohio, UGI Utilities, Virginia Natural Gas, Columbia Gas of Virginia and NICOR Gas.

The pipeline MOU and the LDC data sharing agreements provide for the sharing of reliability-based information wherein PJM can receive information on potential operational flow orders, expected pipeline system conditions, generator interruptions and estimates of restoration times in the case of line breaks or other system disturbances. By the same token, PJM shares

[71] *Coordination between Natural Gas and Electricity Markets*, Docket No. AD12-12-000.

with the above pipelines (on a confidential basis subject to agreed-upon non-disclosure agreements), its day-ahead commitment so that the pipelines can have better information going into the gas day as to what they can expect in terms of generator nominations and other demands on the pipeline system. PJM and the pipelines also engage in routine review of outage planning to ensure that best efforts are employed to schedule outages with the least impact on generation and transmission, particularly during potential high demand periods. During the winter months, PJM conducts individual weekly calls with interstate pipeline gas control representatives to review current and forecasted operating conditions for greater situational awareness. In addition, PJM has staffed a gas/electric coordination operations function, which supports the control room, that monitors gas pipeline conditions and is in communication with pipelines in response to those conditions.

Finally, PJM has encouraged pipelines to offer more flexible services for generators. Specifically, PJM has advocated for pipeline offerings that are reflective of and can better respond to the variable demand generators can place on the pipeline system. These efforts are designed to move beyond the binary 365 day a year firm product versus a fully interruptible product that has traditionally dominated the policy discussions to date. Rather, more flexible services would potentially enable more flexible but effective remedies to address constrained pipeline conditions than the more traditional remedies, such as the ordering of ratable takes and other remedial actions that are not well matched to a generator's variable demands on the pipeline system.[72] To date, the results of PJM's efforts on these issues have been far more mixed with the exception of some notable efforts such as the Texas Eastern Enhanced Electric

[72] The use of ratable take provisions, their impact on creating stranded gas and the compensation issues they create were major issues of contention before the Commission in Docket Nos. EL14-45-000 and ER14-2242-000.

Reliability Project Open Season Notice for Firm Service issued in July of 2017.[73] It should be noted that all of these efforts were enabled by the Commission's Order No. 787 and the attention that the Commission placed on effective gas/electric coordination dating back to its earliest efforts in this area.

Nevertheless, the time has come to move gas/electric coordination to the next level. Many of the next steps in gas/electric coordination are beyond the authority of any one RTO (or any one pipeline) to effectuate in any kind of uniform manner. As a result, through this submittal, PJM urges the Commission to drive further coordination through the exercise of its authority over both natural gas pipelines and the electric industry. Specifically, PJM urges the Commission to undertake the following initiatives, in addition to the Order No. 787 reforms discussed in PJM's answer to Question 2(c) above.[74]

2. Gas Pipelines Providing Services Tailored to Generation Needs

As noted above, the traditional world of long term contracts for pipeline transportation capacity and relatively predictable and steady demands placed by LDCs on the pipeline system throughout an entire season is rapidly changing as we see increased interconnection by gas-fired electric generation on the pipeline system. Through its Capacity Performance initiatives, PJM has sought to send a powerful message to the generation community should it simply "roll the dice" and assume that adequate transportation will be available on an interruptible basis during a day of particularly stressed conditions on the PJM system. Although PJM was hoping that the Capacity Performance changes would spur a corresponding array of new service offerings by

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[73] Enbridge, *Texas Eastern Enhanced Electric Reliability Project Open Season Notice for Firm Service*, https://infopost.spectraenergy.com/GotoLINK/GetLINKdocument.asp?Pipe=10076&Environment=Production&DocumentType=Notice&FileName=Open+Season++TETLP+EER.pdf&DocumentId=8aa164a25d85ef1d015d9a41501c014d.

[74] PJM also recognizes that improvements can be made with regard to communication and coordination between RTOs and suppliers/transporters of other fossil fuels, including oil and coal, regarding disruptions in the delivery of those fuels to generators.

pipelines (and generators seeking such options), at least on the public record such new pipeline services have not been offered as new open season requests (with the notable exception of the Texas Eastern open season). This is not to say that generators have not found ways to "firm up" their gas supplies. The significant reduction in outages associated with gas supply and transportation during the Cold Snap is a notable indication that more has been done. But such new flexible services, to the extent they have been offered, appear to have been confined to the secondary market in which available gas from LDCs or industrial customers is made available, for a price, on the non-transparent bilateral secondary market. Although this is an effective short term strategy to "move around" available capacity and take advantage of diversity in demand, it cannot, in the long run, serve as the sole means to meet the ever-growing demand for gas transportation by the generation sector.

The pipeline industry has noted some of the difficulties in achieving sufficient "precedent agreements" of a twenty-year length to support their pipeline certificate applications. The Commission has raised concern with the number of affiliate arrangements while others have raised concerns with potential market power issues associated with this capacity owned by a few predominant producers. Rather than continuing down a path of diminishing returns, now is the right time for the Commission to inquire of both the generator and pipeline industry what tariff reforms are needed so that pipeline tariffs reflect the needs of all of the pipeline's customers, including its generation customers, in a time when we are seeing record growth in new gas-fired generation. One such alternative could be the development of a gas generation specific tariff which would tailor specific rates and services to the generation fleet directly connected to the interstate pipelines. Such tariff reforms are not in lieu of the need for new infrastructure in specific locations. But the Commission should make sure that it is first ensuring that existing pipelines are being utilized most efficiently and in a manner which meets the needs not only of its seasonal load customers, such as LDCs, but also the needs of more short term and variable needs of the generation community. PJM would suggest an examination of these issues, on an individual pipeline basis, through targeted proceedings at the Commission so as to reflect the very different circumstances realized by different pipelines and different regions of the nation on this issue.

3. Planning and Operations Reforms

a. <u>Interconnection Coordination</u>

The processes for generation interconnection to the gas pipeline system and the BES are very different both substantively and from a timing viewpoint. Each process operates largely unaware of the other's processes and timelines. More can be done to coordinate each of the interconnection processes so that the pipelines are better aware of the interconnection requests coming from gas-fired generators and vice versa. Through the RTO generation interconnection processes, information is provided as to the relative merits or demerits of locating one's facilities at a given location on the transmission system. The pipeline interconnection process provides much of the same information to the generator as to optimal locations on the pipeline. But without more coordination between the transmission system and pipeline system interconnection processes, interconnecting generators cannot efficiently make the optimal location decision.

The Commission should direct each pipeline to work with the RTOs to better synchronize their interconnection processes and sharing of analyses and results and report their efforts to the Commission within a one-year period. Interconnection coordination would provide a small, but meaningful, step on the front end of coordination that could later avoid many of the problems associated with generation located in areas on either the pipeline or transmission system where reliability or resilience benefits may be sub-optimal.

b. Identification of Contingencies for RTO Planning

In accordance with the applicable NERC standard, PJM has modeled contingencies on the pipelines associated with the loss of one or more pipeline systems. Modeling the loss of an entire pipeline is ultraconservative as the nature of the pipeline system and the relatively slow speed of the movement of gas would argue that more limited disturbances should be modeled. PJM has begun those discussions with certain pipelines. However, this process lacks an overall national regulatory framework as well as the regulatory support to ensure that there is cooperation in identification of vulnerabilities and threats on the gas pipelines, modeling efforts and the sharing of system topology so as to make the modeling of contingencies accurate and meaningful. The Commission should direct cooperation on modeling in this area so that each RTO can appropriately carry out its responsibilities under the NERC Standard TPL-001-4.[75]

c. Modeling of Impact of Adverse Events and Their Impact on the Generation System in Real Time

RTOs have 24 x 7 capability to model the impacts of loss of generation or transmission lines in real-time so that operators can make informed decisions on appropriate actions to take in response. It is not clear that the same real-time modeling capability, let alone real-time sharing of this information, is available in the gas pipeline system and communicated, in real-time, to RTO system operators. Although pipeline operators do respond to system breaks, loss of compressor motors and other situations in real-time, and do, in many cases, communicate the specifics of those breaks to PJM, the modeling of the *impact* in terms of when downstream generators on that pipeline may experience an unacceptable pressure drop and for how long is

[75] *See* NERC Standard TPL-001-4.

not always available and communicated in real-time to the RTO system operators. By the same token, the RTO has little information as to the availability of automatic valves on the gas pipeline system that could isolate that break and allow for a back-feed of gas rapidly so that generation at a particular unit can be maintained.

Using its authority over the terms and conditions of gas pipeline tariffs and its reliability authority over the BES, the Commission should investigate the degree of real-time modeling capability available in each gas pipeline and the robustness of the systems in place to communicate information as to the effects of such a break on downstream generators to RTO system operators. This could be done, for starters, through a confidential Commission staff data request process working with RTOs and pipeline operators to ensure that state-of-the-art systems are both in place and properly staffed on a 24 x 7 basis.

Additional analyses are also needed with respect to disruptions to the supply or transportation of fuel oil and coal. Generating units in the PJM Region consumed significant amounts of oil during the recent Cold Snap, which stressed some on-site supplies. Nevertheless, while there is additional work to be done with respect to the impact of such supply and transportation disruptions on the BES, the need for this additional analysis is not as critical as that needed for natural gas pipeline disruptions.

d. Coordination of Restoration Plans

Although improvements have been made in coordination on planning and operations between PJM and the pipelines serving our footprint, the coordination of restoration plans to ensure alignment and interoperability following an event has been less successful due to several reasons. For one, the pipeline's obligation is to restore all firm service customers on a non-discriminatory basis consistent with the capabilities of the system. By contrast, RTOs focus on service to Critical Restoration Units, with a focus on particular facilities (such as restoration of service to nuclear power plants for safety reasons) as well as certain key generators needed to serve key Critical Restoration Units. The RTOs' focus on Critical Restoration Units is supported by individual LDC obligations to their retail customers through restoration plans approved by the state commissions. To further complicate the potential mismatch, LDCs have unique obligations to "human needs" customers which supersede any claims of discrimination between different otherwise similarly situated firm customers.

Further work is needed by the Commission to better identify and harmonize the specific restoration priorities of the transmission providers relative to pipeline operators. This could be addressed through a generic Commission proceeding which would first analyze the various policy directives on the books governing restoration priorities for each industry and then look at how those priorities, to the extent they may be inconsistent, can be better harmonized. Additionally, the Commission should consider working with state regulators to ensure there is a comprehensive way to coordinate on the issue of system restoration across the natural gas pipeline system, transmission system and LDC system.

e. Cyber and Physical Security Standards

The standards governing cyber and physical security are markedly different between the two industries. For the BES, detailed cyber and physical security standards (and penalties for non-compliance with these standards) are promulgated by NERC and approved by the Commission. Pipeline cyber standards and physical security standards (beyond specific pipeline standards promulgated by PHMSA) are overseen by TSA and largely voluntary in nature. Although legislation would be needed to change this disparate paradigm, there is little reason why the approach by TSA and FERC to these cross-industry topics needs to be so diverse.

PJM suggests, at the outset, that a matrix be issued illustrating areas of common approach and areas of divergence for each of the topical areas governed by the NERC standards, the PHMSA standards and the TSA guidelines. The industry could then comment on the justification for the divergent approaches for each topical area so that the discussion of this issue can get beyond mere surface comparisons and contrasts and instead analyze *in depth* whether the particular topic area is adequately covered and coordinated between these two regulatory regimes aimed at the common topics of physical and cyber security.

3. How RTOs/ISOs Mitigate Threats to Resilience

Finally, the Commission requested that after the RTOs identify the particular needs or threats to resilience, that they provide information regarding the ways to mitigate those risks.[76] Specifically, the Commission sought "comment on how RTOs/ISOs evaluate options to mitigate any risks to grid resilience," and directed the RTOs to answer the questions set forth below.[77]

> **(a) Describe any existing operational policies or procedures you have in place to address specific identified threats to bulk power system resilience within your region. Identify each resilience threat (e.g., the potential for correlated generator outage events) and any operational policies and procedures to address the threat. Describe how these policies or procedures were developed in order to ensure their effectiveness in mitigating the identified risks and also describe any historical circumstances where you implemented these policies or procedures.**

PJM's emergency operations procedures are described in PJM Manual 13.[78] The operating procedures addressing the following identified threats to BES resilience in the PJM Region - extreme weather and environmental emergencies such as extreme temperatures, thunderstorms, tornados and GMD, loss of natural gas infrastructure, sabotage and terrorism - are described in detail in Manual 13, sections 3 and 4.[79] During these identified events, the manual

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[76] Resilience Order at P 26.

[77] *Id*. at P 27.

[78] PJM, Manual 13, §§ 3, 4.

[79] *Id*.

indicates that PJM will operate the BES more conservatively to reflect conservative transfer limit values, selected double-contingencies, and/or Maximum Credible Disturbances. During these periods, PJM will recall or cancel non-critical generation and transmission maintenance outages or take other actions, such as cost assignments to increase reserves and reduce power flows on selected facilities.

These operations procedures were developed, implemented and revised over the past twenty-one years based on real world operational experience, stakeholder feedback, PJM Region event review and lessons learned implementation, NERC lessons learned from areas outside the PJM Region, and emerging threat identification through industry and government communication channels. Operating procedures will continue to be developed to address any specific threat and will be documented for use by the PJM system operators.

In addition, as a result of the increased proportion of natural gas-fired generation in the PJM Region, PJM recently developed a process described in PJM Manual 3 to operationalize natural gas contingencies across the PJM Region.[80] This process specifies how PJM will prepare for and operate through degraded operations caused by gas supply issues, consistent with concerns raised by similar industry initiatives such as the 2018 ERO Reliability Risk Priorities reports.[81]

In June 2017, PJM commenced stakeholder discussions regarding the need to address natural gas pipeline contingencies and their impact on the BES.[82] PJM members have actively engaged in the stakeholder process, the outcome of which was the creation of new procedures to

[80] PJM, Manual 3: Transmission Operations, § 5 (rev. 52, Dec. 22, 2017), at http://www.pjm.com/-/media/documents/manuals/m03.ashx ("Manual 3").

[81] *See* NERC, *ERO Reliability Risk Priorities RISC Recommendations to the NERC Board of Trustees* (Feb. 2018), at http://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO-Reliability-_Risk_Priorities-Report_Board_Accepted_February_2018.pdf.

[82] *See* PJM, Draft Resilience Roadmap.

ensure operators have a clearly defined process to address gas pipeline impacts on generator availability, which have been incorporated into PJM Manuals 3 and 13 to provide additional details on preparing and operating through a gas pipeline or LDC failure and its' impact on the electric system.[83] Under this new process PJM will operate the BES to reflect the impact of gas infrastructure contingencies (pipeline ruptures, compressor station failures) on PJM natural gas-fired generators during certain system conditions, including severe temperatures/weather, pipeline outages (maintenance, force majeure events) and external cyber/physical security threats.[84] These new procedures were tested during the recent Cold Snap that occurred in late December 2017 through early January 2018 and proved to be successful in anticipating the potential impacts of gas pipeline contingencies. PJM further believes that these procedures will be effective as additional, natural gas-fired generation resources are added to the PJM system in the coming years.

Nevertheless, there is more to be done in planning, developing market mechanisms, coordination with interdependent systems, and restoration activities which is why, as noted above and below, PJM has outlined specific proposals for the Commission in this area. These proposals include:

- proposed market reforms and related compensation mechanisms to address resilience concerns and advance operational characteristics that support reliability and resilience, including (i) improved shortage pricing, and Operating Reserves market rules, (ii) improvements to its Black Start requirements, (iii) improved energy price formation that properly values resources based upon their reliability and resilience attributes, and (iv) integration of DER, storage, and other emerging technologies;
- proposed tariff amendments to permit non-market operations during emergencies, extended periods of degraded operations, or unanticipated restoration scenarios,

[83] Manual 3 at § 5; Manual 13 at §§ 3.8.

[84] A diagram that summarizes the initial process flow is provided as follows: http://www.pjm.com/-/media/committees-groups/committees/oc/20171107-special/20171107-item-03a-electric-natural-gas-infrastructure-constraints-flow-chart.ashx.

including provisions for cost-based compensation when the markets are not operational or when a wholesale supplier is directed to take certain emergency actions by PJM for which there is not an existing compensation mechanism;

- improved coordination and communication requirements between RTOs and Commission-jurisdictional natural gas pipelines to address resilience as it relates to natural gas-fired generation located in RTO footprints;
- greater communication and coordination with the LDCs that supply wholesale generation, including imposing communication and coordination obligations on LDCs that supply jurisdictional wholesale generation;
- requiring dual fuel capability at all Black Start Units and coordination across the nation of a consistent means to determine Critical Restoration Units and development of criteria to assure dual fuel capability to such units; and
- improve coordination with other critical interdependent infrastructure systems *(e.g.*, telecommunications, water utilities) that (i) could be impacted through events of type discussed herein, or (ii) are themselves vulnerabilities that could contribute to, or amplify the impact of such events; and similar coordination between the Commission and the FCC and DHS to provide additional regulatory support behind such efforts.

Commission directives to respond within a specified period of time is extremely helpful in focusing stakeholder efforts and leading the appropriate level of cross-industry cooperation resulting in meaningful RTO improvements. PJM suggests a time period of nine to twelve months after the issuance of any Commission order will be needed to file any rule changes proposed to improve cross-industry coordination, planning, restoration activities and market mechanisms. This timeframe affords a reasonable amount of time for RTOs (and jurisdictional transmission providers in non-RTO regions) to work with stakeholders to formalize the process, work through the scope, and present process solutions by mid to late 2019.

(b) How do existing market-based mechanisms (e.g., capacity markets, scarcity pricing, or ancillary services) currently address these risks and support resilience?

RTO wholesale electricity, Ancillary Service markets, capacity markets, and shortage pricing mechanisms were not originally designed specifically with resilience in mind. The primary driver in the development of these markets and mechanisms was to efficiently procure capacity and Ancillary Services to ensure that system reliability is maintained at the lowest reasonable cost to the consumer. However, the existing markets were designed with key features that work to ensure a more resilient BES. Two such examples are provided below.

PJM's RPM capacity market procures capacity for the PJM Region three years ahead of the Delivery Year for which the energy is needed.[85] The RPM market is solely focused on ensuring the availability of adequate supply and demand curtailment capacity to meet load and reserve needs in the future. A critical design component of RPM is a downward-sloping demand curve that values capacity as a function of the Installed Reserve Margin ("IRM").[86] As cleared capacity falls short of the IRM, capacity prices increase. As cleared capacity exceeds the IRM, capacity prices decrease. A critical function of this demand curve is that it values capacity in excess of the IRM (i.e. more capacity than is needed to meet the standard loss of load 1-in-10 criteria) when doing so reduces the loss-of-load-expectation commensurate with the cost of the additionally procured capacity. The valuing of this capacity helps to meet the power grid's needs by allowing PJM to withstand more severe operational conditions than it could if resources were procured only up to the IRM requirement. This indirectly addresses some resilience objectives by increasing PJM's operating capacity and reserve margins.

Similarly, PJM's Ancillary Service markets and shortage pricing mechanism (PJM's version of scarcity pricing) also address resilience risks to some degree, though they were not specifically designed with that objective in mind. The ten-minute Synchronized and Non-Synchronized Reserve markets clear every five-minutes and Regulation market clears on an hourly basis.[87] In the reserve markets, demand curves are used to articulate the requirements for

[85] Tariff, Attachment DD. section 5.4(a).

[86] Tariff, Attachment DD. section 5.10(a).

[87] Tariff, Attachment K-Appendix, sections 3.2.2(c), 3.2.3A(d), and 3.2.3A.001(c); Operating Agreement, Schedule 1, sections 3.2.2(c), 3.2.3A(d), and 3.2.3A.001(c).

the products. Currently, the demand curves allow for the procurement of reserves beyond the largest system contingency when it can be done inexpensively.

Shortage pricing is an additional market function implemented when the system cannot simultaneously meet energy and reserve needs. In these scenarios, prices for energy and reserves are escalated based on the aforementioned demand curves to incentivize non-capacity resources to provide energy during system shortages. This function is targeted more towards maintaining short-term reliability rather than addressing resilience objectives. Similarly, while PJM's shortage pricing mechanism was not specifically designed to address resilience, it does indirectly address resilience in that it gives resource owners an incentive to act in a manner that promotes reliability (by incentivizing them to generate and loads to curtail) during extreme events.

Assuming that resilience requirements can be clearly articulated, meeting them through market-based solutions that allow resources to compete to meet those requirements is the preferred way to ensure that these objectives are met at the lowest cost to consumers. The markets exist to ensure the most cost-effective resource mix to provide the long-term reliability and resilience of the power grid. As described more fully below in answer to Question 3(e), PJM believes that there are reforms that could be undertaken by all RTOs (and jurisdictional transmission providers in non-RTO regions) that would incentivize operational characteristics that support reliability and resilience, including (i) improved Operating Reserves market rules which would result in improved shortage pricing, (ii) changes to the criteria for Black Start Units and related performance requirements, including any additional rules for Critical Restoration Units, (iii) improved energy price formation that, in a resource-neutral manner, properly values resources based upon their reliability and resilience attributes, and (iv) integration of DER, storage, and other emerging technologies.

(c) Are there other generation or transmission services that support resilience? If yes, please describe the service, how it supports resilience, and how it is procured.

PJM plans the system to ensure an adequate level of reliable transmission services. To specifically address resilience and implement procedures that might require more to be done than that which is required under the applicable NERC standards, the Commission could provide assistance to RTOs by requiring them to plan for and address resilience, and confirm that resilience is a component of regional transmission system planning. PJM's responses to Question 2(k) discuss the component level characteristics ("transmission services") that support resilience at the system level.

On the other hand, there are generation services available in the PJM Region today that support resilience which include Black Start service, Reactive service, frequency response service, Day-ahead Scheduling Reserves ("DASR"), Synchronized Reserves, Non-Synchronized Reserves (collectively referred to hereinafter as "Generator Reserves"), and PJM's RPM forward capacity market. Based on existing rules, PJM has the ability to increase the day-ahead and/or real-time requirements for these services and it is not uncommon that PJM will increase reserves or Reactive requirements under stressed or conservative operations to support system reliability, and now resilience, as further discussed below.

Black Start service can be provided by designated generating units that are able to start without an outside electrical supply or the demonstrated ability of a unit with a high operating factor (subject to PJM approval) to remain operating, at reduced levels, when automatically disconnected from the grid. In PJM, this service is procured as part of a five-year Black Start request for proposal process and compensation is based on the Black Start Service cost formula detailed in Tariff, Schedule 6A.[88] Black Start Service supports reliability by designating specific

[88] Tariff, Schedule 6A.

generators whose location and capabilities are required to quickly re-energize the transmission system after a blackout. PJM is initiating efforts to further improve the provision of Black Start Service so that it supports resilience, and such efforts may include, for example, the implementation of requirements for fuel security, consideration of the next tier of Critical Restoration Units, and Black Start capability for all new fossil generation.

Reactive service provides the ability to maintain proper voltages, which prevent equipment damage such as overheating of generators and motors, support the transfer of megawatts over transmission system from generators to load, and reduce transmission losses. It is procured as part of the RTEP when studies indicate known deficiencies and through the interconnection of new generators, which have an obligation to satisfy minimum power factor requirements. Suppliers are compensated for reactive capability through cost of service rates established under Tariff, Schedule 2. Reactive service supports reliability and resilience by maintaining the ability of the system to withstand and prevent voltage collapse. Reactive service contributes to PJM's reactive reserves and supports the system currently under NERC reliability criteria. Voltage collapse is more likely to occur as a result of extreme contingencies where multiple events can contribute to voltage collapse conditions. Voltage collapse typically occurs very quickly and does not permit time to implement operator actions in order to mitigate voltage violations. Having additional reactive reserves on the system – over and above the current reserves – would contribute to resilience mitigation.

In its March 2017 Fuel Report,[89] PJM identified generator reliability attributes which are essential for reliability, as reflected in the table below which is reproduced from that report,.

[89] Fuel Report, Figure 6, at 16.

The preservation of these attributes, spread among the resource mix, for future years is a key component of resilience mitigation.

● = Exhibits Attribute
◓ = Partially Exhibits Attribute
○ = Does Not Exhibit Attribute

	Essential Reliability Services (Frequency, Voltage, Ramp Capability)					Fuel Assurance		Flexibility			Other		
	Frequency Response (Inertia & Primary)	Voltage Control	Ramp										
Resource Type			Regulation	Contingency Reserve	Load Following	Not Fuel Limited (> 72 hours at Eco. Max Output)	On-site Fuel Inventory	Cycle	Short Min. Run Time (< 2 hrs.)/ Multiple Starts Per Day	Startup/ Notification Time < 30 Minutes	Black Start Capable	No Environmental Restrictions (That Would Limit Run Hours)	Equivalent Availability Factor
Hydro	●	●	●	●	●	○	◓	●	●	●	●	●	●
Natural Gas - Combustion Turbine	●	●	◓	●	◓	●	○	●	●	●	●	◓	◓
Oil -Steam	●	●	●	●	●	●	●	●	○	○	○	○	◓
Coal - Steam	●	●	●	●	●	●	●	◓	○	○	○	◓	◓
Natural Gas - Steam	●	●	●	●	●	●	○	●	○	○	●	◓	◓
Oil/ Diesel - Combustion Turbine	●	●	○	●	○	○	●	●	●	●	●	○	◓
Nuclear	◓	●	○	○	○	●	●	○	○	○	○	◓	●
Battery/ Storage	◓	◓	●	●	○	○	○	●	●	●	○	●	●
Demand Response	○	○	◓	◓	◓	◓	◓	●	●	◓	○	●	●
Solar	◓	◓	○	○	◓	○	○	●	●	●	○	●	●
Wind	◓	◓	○	○	◓	○	○	●	●	●	○	◓	●

Frequency response service supports resilience by maintaining an interconnection frequency near 60 hertz, which is essential during a system restoration event.

Generator Reserves provides the additional capacity above the expected load and supports resilience by protecting the power system against the uncertain occurrence of future operating events, including the loss of capacity or load forecasting errors. DASR (thirty-minute reserves) is scheduled in advance. Additionally, Synchronized Reserves and Non-Synchronized Reserves (ten-minute reserves) are procured in real-time through the use of the Ancillary Service Optimizer. PJM system operators monitor and adjust reserves based on the forecasted operating conditions so reserve requirements as a percentage of anticipated load are maintained even during adverse circumstances. PJM system operators schedule additional reserves both day-ahead and in real-time under conservative operations scenarios to ensure the BES is resilient in response to high-impact, low-frequency events.

As indicated in PJM's response to Question 3(b), RPM supports resilience by valuing reserves beyond the IRM through acquisitions of capacity per a sloped demand curve in the RPM model. This allows PJM to withstand high-impact, low-frequency events because the reserve margin is higher and the loss-of-load-expectation is lower. RPM, through a "pay-for-performance" model, requires resources to deliver energy on demand during system emergencies or the market participant will be required to pay a significant penalty for non-performance.[90] Additionally, this model deploys a Variable Resource Requirement Curve, which is the demand formula used to set the price paid to market participants for capacity and the amount of capacity, permitting the commitment of additional resources above reserve requirements based on relative resource bid prices.[91]

(d) How do existing operating procedures, reliability standards (e.g., N-1 NERC TPL contingencies), and RTO/ISO planning processes (e.g., resource adequacy programs or regional transmission planning) currently consider and address resilience?

NERC has established standards to address specific threats to BES physical infrastructure such as NERC Standards CIP-014, CIP-009, EOP-010, TPL-001 and TPL-007. In that regard, NERC Standard CIP-014[92] requires entities to identify and protect transmission stations and substations and their primary control centers that, if rendered inoperable or damaged, could result in instability, uncontrolled separation, and cascading outages within an interconnection.

[90] Tariff, Attachment DD. sections 5.5A, 10A.

[91] Tariff, Attachment DD. section 5.10(a).

[92] *See* NERC Reliability Standard CIP-014-2.

NERC Standard CIP-009[93] requires certain recovery and reliability functions for some of the control systems used to manage the BES. Similarly, NERC Standards EOP-010[94] and TPL-007[95] require the assessment of GMD events and institution of plans to mitigate the effects of GMD events. Finally, NERC Standard TPL-001[96] specifies that transmission planners must establish system planning performance requirements that will result in reliable operations over a broad spectrum of system conditions and probable contingencies.

Notwithstanding the foregoing, updated and/or additional standards may eventually be needed to address the mitigation of critical facilities, in addition to vulnerability assessment and mitigation to address the gaps that currently exist in the regulatory regime. Consideration should also be given to whether NERC should implement new standards for minimum capabilities and requirements for new and updated equipment that address resilience risks, substation design, coordinated physical attacks on the BES and weather events.

With regard to how existing operating procedures currently consider and address resilience, please refer to PJM's response to Question 2(m) above. As PJM indicated in its responses to Questions 2(d), (g) and (h), PJM is in discussions with its stakeholders and other industry leaders to identify ways to incorporate resilience into its planning functions and what criteria should be used. Accordingly, PJM requests that the Commission direct PJM to submit in a timely manner such proposals for Commission consideration so that the need for more infrastructure-focused resilience reforms otherwise being considered in this docket are both

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[93] *See* NERC Reliability Standard CIP-009-6 – Cyber Security — Recovery Plans for BES Cyber Systems, Eff. July 1, 2016, available at http://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-009-6.pdf.

[94] *See* NERC Reliability Standard EOP-010-1.

[95] *See* NERC Reliability Standard TPL-007-1.

[96] *See* NERC Reliability Standard TPL-001-4.

analyzed concurrently and are informed by the impact these particular market reforms have on retaining and attracting resources with attributes needed to ensure grid resilience.

(e) Are there any market-based constructs, operating procedures, NERC reliability standards, or planning processes that should be modified to better address resilience? If so, please describe the potential modifications.

Focusing on physical infrastructure is clearly important for the reasons addressed earlier in PJM's responses, but without a compensation mechanism that properly values the attributes that any particular resource brings to the grid; we will inevitably frustrate many of the initiatives seeking to integrate emerging technologies such as microgrids, advanced storage and DER to mitigate resilience challenges on the BES. Further, without a proper compensation mechanism, we will fail to properly attract the funding this capital-intensive industry needs to make some of these critical investments, particularly those needed to ensure a resilient generation fleet. That being the case, resilience efforts warrant a review and refinement market-based constructs, operating procedures, industry collaboration and planning processes. PJM has addressed revisions to its operating procedures in its response to Questions 2(m), 3(a) and 3(d), industry collaboration in its response to Question 2(p), and planning processes in response to Questions 2(c), 2(d), 2(g) and 2(h).

As stated in response to Question 3(b), there are several market-based constructs that indirectly address resilience such as the RPM and Ancillary Service markets. The primary goal of these markets when they were implemented was to efficiently procure capacity and Ancillary Services to ensure that reliability is maintained at the lowest reasonable cost. Today we operate under a set of rules, written in a vastly different time, that limit the ability of certain generating units operating at the direction of the system operator to contribute to efficient and transparent prices. These units are still compensated for their costs to operate, but because they are not able to set clearing prices, those clearing prices are artificially lower than they should be. This has a price-suppressive effect on all generating units, including nuclear, coal, natural gas-fired and renewable generation. PJM believes that modifications to these market constructs could and should be made to align with current reliability needs and resilience objectives. Price formation reforms, along with reforms to pricing during certain times when we are approaching temporary shortage conditions, would, in our view, go a long way to properly compensating *all* generation needed to serve the demand for electricity. Specifically, the modifications would address PJM's reserve markets, shortage pricing market rules, and price formation. Accordingly, PJM requests that the Commission direct PJM to submit in a timely manner proposals for Commission consideration that improve retaining and attracting resources with attributes needed to ensure grid resilience, as discussed further herein.

1. Reserve Markets

PJM's current market design for reserves is based on the short-term reliability needs of the BES. PJM currently utilizes a thirty-minute DASR market that is cleared simultaneously with energy in the Day-ahead Energy Market, and real-time Synchronized Reserve, Non-Synchronized Reserve and Regulation markets. While these markets have served PJM well since their implementation, they can be enhanced to better value resources relied upon to meet reliability and resilience objectives.[97]

The current requirement for the DASR product is based on the average load forecast error and average forced outage rate and is only applied day-ahead. While these requirements are generally sufficient for most days, they do not address high-impact, low-frequency occurrences

[97] Tariff, Attachment K-Appendix, sections 1.11.4A and 3.2.3A (Synchronized Reserve), sections 1.11.4B and 3.2.3A.001 (Non-Synchronized Reserve), section 3.2.3A.01 (Day-ahead Scheduling Reserves), and sections 1.7.18 and 1.11.4 (Regulation); Operating Agreement, Schedule 1, sections 1.11.4A and 3.2.3A (Synchronized Reserve), sections 1.11.4B and 3.2.3A.001 (Non-Synchronized Reserve), section 3.2.3A.01 (Day-ahead Scheduling Reserves), and sections 1.7.18 and 1.11.4 (Regulation).

where the load forecast error or forced outage rate may be far above the mean, or, other known system threats potentially require the scheduling of additional reserves. Additionally, the DASR market only procures thirty-minute Operating Reserves in the Day-ahead Energy Market but there is no corollary in real-time to ensure that reserve amount is maintained.

PJM believes that a real-time, thirty-minute Operating Reserve market should be implemented that is based on a probabilistic representation of load forecast and generator performance uncertainty rather than based upon the means (or averages) of these variables. For example, during severe weather events, load is typically very uncertain. This uncertainty may occur due to the lack of similar historical days to use for load forecasting or due to potential load fluctuations resulting from storm damage to the transmission and distribution systems. It is in these cases that more reserves are needed on the system to manage the uncertainty.

Like load, generator performance tends to be less certain during severe weather, typically cold weather and storms, than on a normal day. As shown in PJM's 2014 Cold Weather Report and subsequent cold weather event reports, the forced outage rate of generation in severe cold can be triple the average.[98] This adds to reserve needs on these days. By determining the needed level of reserves based upon a probabilistic representation reflecting the uncertainty rather than averages, an efficient market should procure the optimal level of needed reserves to manage severe operating events and clearly reflect the value of those reserves in a market price. All of this should decrease the need for PJM operators to take out-of-market action. An Operating Reserve market would provide substantial operational benefit to PJM as it would clearly reflect the value of resources that can start quickly to perform functions such as backfilling Synchronized Reserve once it is deployed, respond to greater than average load forecast error,

[98] 2014 Cold Weather Report at 4, 9.

and be used to replace natural gas generation connected to a pipeline that has experienced a failure.

In addition to the thirty-minute reserve market changes, PJM also believes that designing the real-time Synchronized Reserve and Primary Reserve demand curves based upon on the actual uncertainty rather than the traditional "largest system contingency" will likewise improve the ability of the PJM system to respond to severe or stressed operating conditions and enable the markets to better articulate that value of such products. The implementation of these new curves would still respect the requirements used today, but would better reflect the value of additional reserves in reducing the probability of shedding load.

Another market enhancement that would help meet reliability and resilience objectives would be to explicitly model the Synchronized Reserve and Primary Reserve products in PJM's Day-ahead Energy Market. Today, the only reserve product that PJM schedules in the Day-ahead Energy Market is the thirty-minute DASR product. Modeling all reserve requirements needed in real-time in the Day-ahead Energy Market will ensure that all of these products are accounted for in the scheduling of the system.

Finally, PJM needs to further improve the locational aspects of reserve products. These market reforms are critically necessary to the continued reliability and resilience of the PJM system as it is experiencing a significant number of retirements and changing power flows. Resilience of the wholesale supply portfolio is dependent on having the right resources, with the right attributes, in the right location to respond to the threat – and that should be driven by markets sending the correct price signals where possible.

2. *Shortage Pricing*

The changes to the demand curves for the reserve products that PJM discusses above would also help improve shortage pricing by incentivizing non-capacity supply resources to respond to system emergencies earlier than they would otherwise. Under today's market design, PJM implements shortage pricing upon the shortage of ten-minute reserves.[99] This is a very severe operating condition and could be too late to incentivize the response needed to avoid more severe procedures such as load-shedding. Implementing a thirty-minute Operating Reserve market and enhancing the demand curves for all reserve products would result in clearer market signals prior to emergency conditions to avoid more severe emergencies and service disruptions, all of which would improve the ability of the PJM system to absorb a disruption such as a high-impact, low-frequency event.

3. *Price Formation*

A significant initiative that is currently underway in PJM is reviewing and enhancing price formation. PJM's current Locational Marginal Price ("LMP") formulation does permit all needed resources to compete to set the LMP which results in price suppression and consequently distorted market signals. PJM has proposed reforms to its pricing method in a paper published in November 2017 that describes its proposed changes.[100] Generally, PJM seeks to allow all PJM-scheduled resources to compete to set the LMP and include start-up and no-load costs in the LMP where applicable. PJM believes these changes will result in prices that better reflect actions taken by system operators and more appropriately value all resources providing energy.

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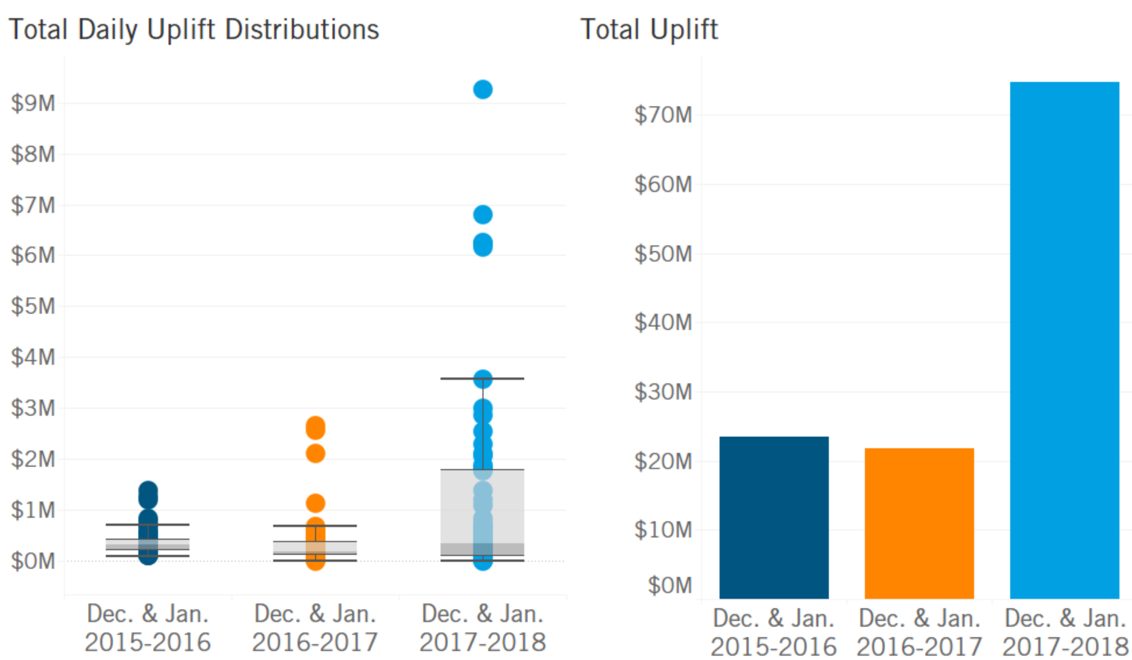
[99] Tariff, Attachment K-Appendix, sections 2.2 and 2.5; Operating Agreement, Schedule 1, sections 2.2 and 2.5.

[100] PJM, *Proposed Enhancements to Energy Price Formation* (Nov. 15, 2017), at http://www.pjm.com/-/media/library/reports-notices/special-reports/20171115-proposed-enhancements-to-energy-price-formation.ashx.

The first principle of ensuring reliability and resilience with respect to supply portfolio is ensuring that the wholesale markets are sending the correct price signals. The second principle is compensating suppliers based upon the operational attributes necessary to support reliability and resilience. We must examine whether the PJM markets are meeting these core principles. During the Cold Snap, the peak load reached 137,522 megawatts, which is the sixth highest overall winter peak demand in the PJM Region. The grid and the generation fleet generally performed well. However, as noted in PJM's 2017-2018 Cold Snap Report, and as reflected in the table below which is reproduced from that report, there was a significant increase in uplift, even as compared to prior winters.[101]



This spike in uplift charges during the Cold Snap illustrates the need to reform pricing for energy and reserves in order to ensure that there is a reliable and resilient grid. Uplift is paid to generators when the LMPs do not cover the costs of a generating unit, and thus the generating unit does not respond to the price signal. PJM operators then have to take an out-of-market

[101] 2017-2018 Cold Snap Report, Figure 29, at 28.

action to bring the generating unit online. The generating unit is paid its costs outside of the market even though it is needed to provide locational Operating Reserves or to serve load, and thus should be contributing to price formation. PJM must enhance market pricing so that prices accurately reflect the cost of serving load.

PJM believes that two particular market reforms would further the goals of this docket to thoroughly address and enhance BES resilience, specifically (a) reforms to the Operating Reserve market, and (b) reforms to appropriately value all resources that are needed to meet load and respond to PJM operator directions. Although market reforms for Operating Reserves and energy pricing are being considered independently of this docket, they do have important cause and effect relationship on maintaining a diverse supply portfolio and ensuring that the right resources with the right operational attributes are in the right locations. These market reforms are an important and inter-related component of ensuring grid resilience, together with reforms in other areas such as transmission planning and system restoration.

Accordingly, PJM requests that the Commission direct PJM to submit in a timely manner such proposals for Commission consideration so that the need for more infrastructure-focused resilience reforms otherwise being considered in this docket are both analyzed concurrently and are informed by the impact these particular market reforms may have on retaining and attracting resources with attributes needed to ensure grid resilience. Although PJM is proceeding on price formation market reforms in its stakeholder process in any event with the plan for a filing later in 2018 with the Commission, this early-on expression of desire by the Commission to align the timing of these efforts will be helpful to ensuring that the Commission considers both sets of reforms informed by the impact one may have on the other. A deadline for the submission of any relevant market reform filings by PJM would assist significantly in that goal.

4. Resilience Planning Process

PJM recommends the Commission establish a process, either informally through one or more of the Commission's existing offices, or formally through a filing process, that would allow an RTO to receive verification as to the reasonableness of vulnerability and threat assessments based on information that may be available to the Commission but not available to the RTOs because of national security issues. Those assessments, once verified, could then form the basis for RTO actions under its own planning or operations authority consistent with its tariffs. In coordination with other federal agencies the Commission needs to provide intelligence and metrics to apply to resilience threat analyses that can then guide and anchor subsequent RTO planning, market or operations directives.

Further, the Commission should articulate in this docket that the regional planning responsibilities of RTOs include an obligation to assess resilience. After confirming that resilience is a component of such planning, the Commission should also consider initiating appropriate rulemakings or other proceedings to further articulate the role of RTOs in resilience planning to include, among other things, thresholds to mitigate and build.

As part of this effort, the Commission should reconcile its continued interest in transparency in planning processes under Order Nos. 890 and 1000 with the challenges of public disclosure of significant grid resilience vulnerabilities. Today, the procedures and decision making used by RTOs to develop their transmission planning are required to be open and transparent. However, a balance needs to be struck between having an open and transparent planning process, for example, addressing the need for particular grid improvements and understanding the sensitivity and confidentiality of critical infrastructure information so that we do not inadvertently publicly release highly sensitive information about vulnerabilities on the grid. To date, the regulators and RTOs have addressed this issue through labeling information as Critical Electric Infrastructure Information ("CEII"). But the CEII rules utilized by the Commission and at the state level are designed around a "right to know approach with some verification of the bona fides of the requestor. Yet, the federal government doesn't approach classified information this way. Rather that system is based on the provision of access based on a demonstrated "need to know." There needs to be an appropriate balance between customer rights and safeguarding system information. PJM believes that an appropriate balance can be maintained which respects customers rights and provides an opportunity for customers to examine (and potentially challenge) the costs of any such upgrades but also safeguards the vulnerability and mitigation effort. But for this balance to be workable, additional direction from the Commission – as much of its regulatory regime to date has, understandably, been driven by moving toward greater transparency in the planning process without the corresponding focus on tightening rules around CEII.

Working with stakeholders, PJM has begun this process to include existing standards like NERC CIP-14 critical facilities and urges the Commission to provide assistance to ensure that the goals of transparency and information to end users not become a means to make public significant grid vulnerabilities that can be exploited by those with bad intent. The Commission should require that all RTOs (and reliability coordinators and transmission providers in non-RTO regions) submit a subsequent filing, including any necessary proposed tariff amendments, to implement resilience planning criteria, including processes for the identification of vulnerabilities, threat assessment and mitigation, restoration planning, and related process or procedures needed to advance resilience planning.[102]

[102] The Commission is authorized to provide the relief requested. In a Statement of Policy issued on September 14, 2001, a few days after "9/11," the Commission indicated that it "views the reliability of our Nation's energy

IV. CONCLUSION

Ensuring the resilience of the BES requires a careful balancing of many competing interests. PJM appreciates the Commission giving RTOs the opportunity to address this very important issue, and is committed to working with the Commission, and other stakeholders, to develop criteria and processes needed to address resilience concerns and ensure that the BES can continue, into the future, to meet the needs of customers for the reliable and secure delivery of electricity at a price which remains just and reasonable.

Respectfully submitted,

/s/ Jacqulynn Hugee

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transportation systems and energy supply infrastructure as critical to meeting the energy requirements essential to the American people." *See Extraordinary Expenditures Necessary to Safeguard National Energy Supplies*, 96 FERC ¶ 61,299 (2011), at 1. It also made clear that it has the authority to "approve applications to recover prudently incurred costs necessary to further safeguard the reliability and security of our energy supply infrastructure in response to the heightened state of alert." *Id*. Therefore, PJM respectfully requests that the Commission establish a process for an RTO to report to the Commission the risks that it identifies (on a confidential basis) and that it intends to mitigate, and to receive Commission staff verification of those risks, similar to NERC CIP-014 with Commission staff verifying.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Audubon, PA, this 9th day of March, 2018.

/s/ Jacqulynn Hugee

Jacqulynn Hugee

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